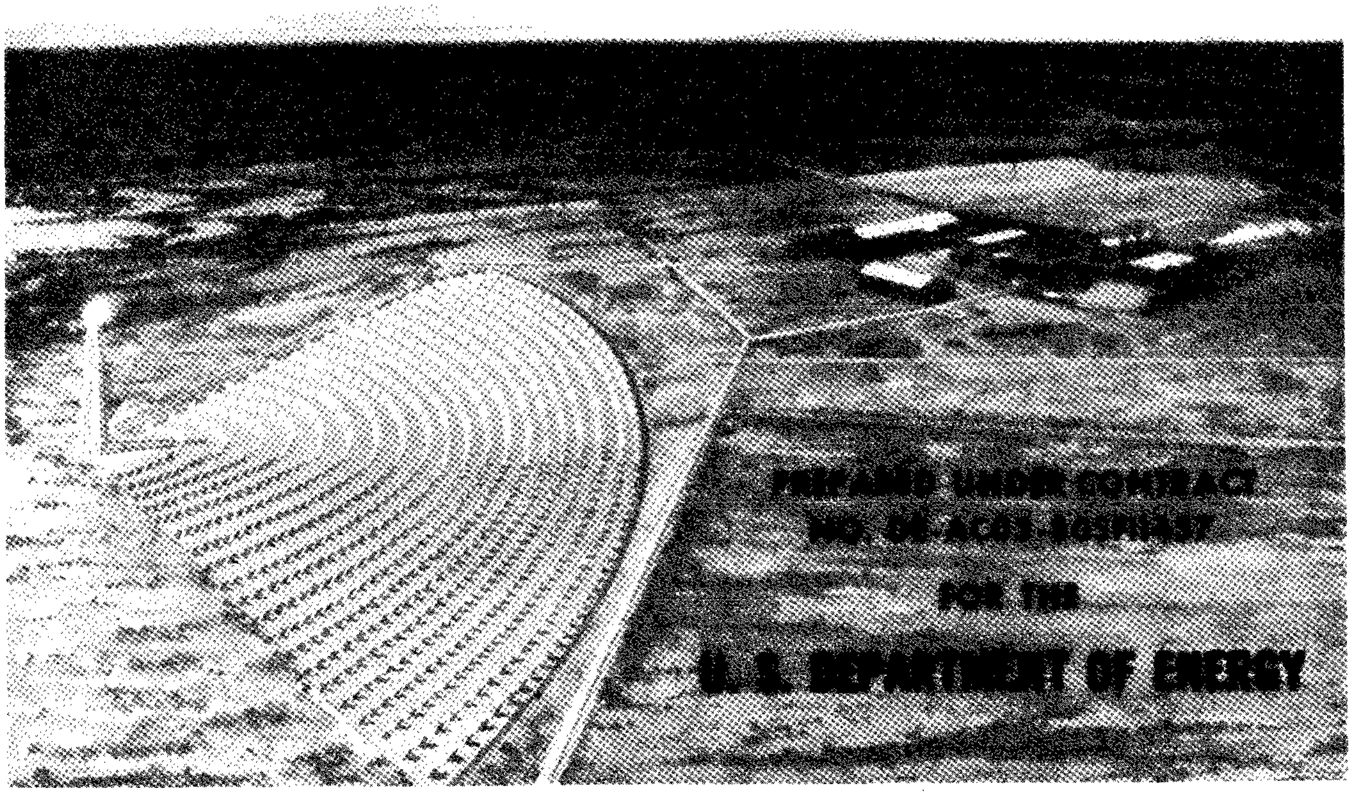
VOLUME I

DOE/SF/11437-1

FINAL REPORT

JUNE 1981

TEXASGULF SOLAR COGENERATION PROGRAM



GENERAL ELECTRIC COMPANY
ADVANCED ENERGY PROGRAMS DEPARTMENT
PHILADELPHIA, PENNSYLVANIA

GENERAL ELECTRIC

NOTICE

VOLUME I

DOE/SF/11437-1

TEXASGULF
SOLAR COGENERATION PROGRAM

FINAL REPORT
JUNE 1981

PREPARED UNDER CONTRACT
NO. DE-AC03-80SF11437

FOR THE

U. S. DEPARTMENT OF ENERGY

GENERAL ELECTRIC COMPANY
ADVANCED ENERGY PROGRAMS DEPARTMENT
PHILADELPHIA, PENNSYLVANIA

GENERAL ELECTRIC

FOREWORD

This is the Final Report for the Texasgulf Solar Cogeneration Program. The report was prepared for the Department of Energy (DOE) by the Advanced Energy Programs Department of the General Electric Company (GE). The documented work was performed from September 1, 1980, to June 1, 1981, under Contract No. DE-AC03-80SF11437 of the DOE San Francisco Operations Office (DOE-SAN).

The GE Program Manager was Dr. Howard E. Jones and the GE Technical Manager was Mr. Stuart I. Schwartz. The DOE/SAN Program Manager was Mr. Keith Rose and the Technical Manager was Mr. John S. Anderson of SANDIA-Livermore.

Other General Electric components which participated in the study were the Industrial Sales Division, Energy Systems Programs Department, Mechanical Drive Turbine Department, and Corporate Research and Development. The Texasgulf Chemicals Company (Tg) was a subcontractor with Mr. Kenneth Bishop as Project Manager and Mr. Wayne Herrington as Technical Manager. Brown & Root Development, Inc. (BARDI) was a subcontractor to Texasgulf with Mr. Pete Karnoski as Project Manager.

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ABSTRACT

A site-specific conceptual design was generated for a near-term Solar Cogeneration Facility based upon solar central receiver technology. Various system trade studies were conducted to select an optimum system configuration for the selected industrial site, as well as a configuration with the potential for wide industrial applicability. System performance and cost estimates were prepared and utilized to assess the economics of the near-term facility, as well as a similar commercial-size facility. A development plan was then generated with the objective of efficiently achieving facility operation by 1985.

The selected industrial site is Texasgulf's Comanche Creek Sulfur Mine near Fort Stockton, Texas. The Solar Cogeneration Facility will provide 100% of the mine's electrical needs and 20% of the process heat needs. The facility will operate 24 hours per day, 365 days per year in the hybrid (solar and fossil) or fossil only modes of operation. High reliability, a definite requirement for Frasch process sulfur mining as well as other industrial process heat operations, is incorporated into the design. Annual fuel savings resulting from operation of the Solar Cogeneration Facility at Comanche Creek are projected to be about 228 million cubic feet of natural gas. The facility will require minimum development and can be operational as early as 1985. Successful operation in a realistic industrial environment will provide the necessary data to initiate commercialization activities for solar cogeneration.

As technology advancements and mass production reduce the cost of solar hardware, and as competing energy costs continue to increase, commercial solar cogeneration plants are projected to be cost-competitive.

TEXASGULF SOLAR COGENERATION PROGRAM
FINAL REPORT DISTRIBUTION

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Section 1

EXECUTIVE SUMMARY

1.1 PROJECT SUMMARY

The United States needs to achieve energy independence through the development and widespread usage of alternate energy sources and energy conservation. Solar cogeneration offers the opportunity to proceed along both of these paths. Solar energy is a renewable, environmentally attractive energy resource that will be available as long as life on this planet exists. Cogeneration results in much more efficient utilization of energy and correspondingly conserves energy.

The objective of this study was to evaluate a site-specific, near-term Solar Cogeneration Facility with future potential for wide industrial applicability. The team of General Electric, Texasgulf and Brown & Root Development, Inc. has worked well together to generate a sound conceptual design which readily meets this objective. The Texasgulf Solar Cogeneration Facility is soundly based on existing solar central receiver technology developed by DOE. The Solar Cogeneration Facility (SCF) employs conventional water/steam working fluid, will save significant quantities of natural gas fuel, is sized large enough to readily measure the solar contribution and be meaningful to Texasgulf while small enough to minimize capital and O&M costs, and is readily adaptable to many other industrial applications. The SCF requires minimal development and can be operational as early as 1985. Successful operation will provide the necessary data to initiate commercialization activities for solar cogeneration.

The Comanche Creek Mine located near Fort Stockton, Texas, is an ideal site for evaluating solar cogeneration. The site has excellent levels of direct normal solar insolation and more than adequate land is available for installation of the SCF. The SCF, as an add-on to the existing process heat plant, will provide 100% of the mine's electrical needs and 20% of process heat needs. The SCF will operate 24 hours per day for 365 days per year in the hybrid (solar and fossil) or fossil modes of operation. High reliability, a definite requirement for Frasch sulfur mining as well as other industrial process heat operations, has been incorporated into the design. Annual fuel savings resulting from operation of the SCF at Comanche Creek are projected to be about 228 million cubic feet of natural gas or 40,000 equivalent barrels of oil. These fuel savings will actually result from reduced natural gas consumption by West Texas Utilities due to the reduction of electrical power delivered to the Comanche Creek Mine. Texasgulf's savings, in turn, will be a reduction in purchased power costs.

Texasgulf has reviewed the technical and economic results of this study to determine the extent of their participation in follow-on activities. The SCF configuration developed in this study was judged to be a technically feasible, practical application of solar energy in an industrial process. However, the economics of the near-term SCF indicate that significant DOE cost sharing would be required in order for Texasgulf to realize a reasonable return-on-investment. This would result in the taxpayer paying the bulk of the capital cost, rather than industry. Texasgulf feels that industry, the major potential beneficiary, should fund such activities rather than the taxpayer. Accordingly, Texasgulf has decided to terminate their participation in the Solar Cogeneration Program at this time.

Texasgulf feels that this study was a meaningful undertaking and the results of this study will provide data for their consideration of solar cogeneration for future installations. If solar cogeneration then appears to be cost competitive, as a result of decreased costs for solar hardware and/or increased costs of alternate energy sources, Texasgulf will seriously consider the use of solar cogeneration.

CONCLUSIONS

The comprehensive conceptual design and evaluation of the Solar Cogeneration Facility for Texasgulf's Comanche Creek Sulfur Mine has led to several important conclusions (summarized in Table 1-1) with respect to the specific application as well as to solar cogeneration in general.

Table 1-1

TEXASGULF SOLAR COGENERATION FACILITY

- Technically Feasible
- Optimally Sized
- Minimal Development
- Attractive Economic Potential
  - 1st Pilot Plant
  - Commercial Plants
- Wide Industrial Applicability
- Benefit to Industry
- Future Potential for Expanded Solar Contribution

1. **THE SOLAR COGENERATION FACILITY IS TECHNICALLY FEASIBLE**
   The enormous quantity and quality of engineering input from General Electric, Texasgulf, Brown & Root Development, Inc., Sandia Corporation, Aerospace Corporation, and DOE leaves no doubt that the system as defined is a technically feasible, practical application of solar energy in an industrial process. There is also no doubt that the system will operate successfully and fit well into Texasgulf's present Comanche Creek Mine operations.

2. **THE SOLAR COGENERATION FACILITY IS APPROPRIATELY SIZED**
   The SCF is sized large enough to be meaningful to Texasgulf while at the same time being small enough to minimize capital and O&M costs. The size is also large enough to clearly measure the solar contribution and obtain meaningful data on operation and maintenance.

3. **THE SOLAR COGENERATION FACILITY REQUIRES MINIMAL DEVELOPMENT**
   The design is soundly based on solar central receiver technology developed by DOE. Confident design of the natural circulation water/steam receiver will not require development testing at DOE's Central Receiver Test Facility. Non-solar components employ existing state-of-the-art technology, with the majority of components categorized as off-the-shelf.

The Solar Cogeneration Facility can be operational at Comanche Creek by 1985 with an aggressive DOE Program.

4. **THE SOLAR COGENERATION FACILITY HAS ATTRACTIVE ECONOMIC POTENTIAL**
Economic analyses indicate that even though this first-of-a-kind Solar Cogeneration Facility will not be cost-effective, Texasgulf can realize a reasonable return-on-investment with significant levels of DOE cost sharing. Future cost-effectiveness of Commerical Solar Cogeneration Plants appears realizable as the cost of solar hardware (mainly heliostats) decreases through technology advances and mass production and as competing energy costs continue to increase.

5. **THE BASIC SOLAR COGENERATION CONCEPT HAS WIDE INDUSTRIAL APPLICABILITY**
The basic system concept has the capability of providing low to intermediate temperature hot water or steam for numerous industrial process heat applications. In addition, the concept will provide electricity at power to heat ratios up to 25% for use by industry and/or sale to electrical utilities. These system characteristics were selected since they are representative of a large industrial market, including: chemical production, oil refining, enhanced oil recovery, food processing, and textiles. As previously mentioned in conclusion number 4, the potential exists for future cost-effectiveness of similar commerical solar cogeneration plants. The achievement of cost-effectiveness will provide industry with a viable alternative energy source and should lead to widespread industrial utilization of solar cogeneration.

6. **SUCCESSFUL PROGRAM COMPLETION WILL BENEFIT INDUSTRY**
Energy intensive industries, such as Texasgulf's sulfur mining operations, have realized a tremendous increase in the cost of energy and corresponding increase in production costs over the past few years. Methods of reducing these costs, such as alternative energy sources and energy conservation have begun to receive major emphasis in corporate planning. The successful completion of this program will provide industry with a meaningful industrial evaluation of solar cogeneration, including realistic construction, performance, operation and maintenance data bases, along with associated costs. This will provide industry with the necessary data to seriously consider the use of similar solar cogeneration plants as alternatives to other energy sources. Increased interest and utilization by industry will enable increased production of solar hardware with corresponding cost reductions. Therefore, this Solar Cogeneration Program will be an important initial step toward the cost effective commercialization of solar cogeneration systems.

7. **THE SOLAR COGENERATION FACILITY HAS FUTURE POTENTIAL FOR EXPANDED SOLAR CONTRIBUTION**
The configuration of the SCF developed during this study will provide a meaningful near-term pilot plant but is not necessarily the optimum configuration for future commercial plants. The SCF configuration has not necessarily been optimized in terms of configuration and performance due to the limited effort involved, the constantly evolving nature of the design throughout the effort, and the fact that near-term costs of heliostats, natural gas and electricity were utilized. Additional system trade studies and/or analyses which should be accomplished in future efforts include:

1) Impact of using projected commercial plant costs of heliostats, natural gas and electricity to select the pilot plant configuration. For example, the selected SCF configuration utilizes a saturated steam solar receiver which feeds into a natural gas fired superheater. In addition, only a small amount of buffer thermal storage is incorporated. The SCF was configured this way since the near-term cost of solar hardware (e.g. heliostats) and

corresponding cost of solar energy is greater than for equivalent fossil energy. However, a different configuration incorporating a superheat solar receiver and long term storage might have been selected if projected commercial costs had been utilized. This would, in turn, result in a pilot plant configuration with a larger solar contribution which would possibly be more representative of a future commercial plant. Such a configuration, however, would also result in less attractive economics for the near-term pilot plant due to the higher near-term costs of heliostats and lower near-term costs of natural gas and electricity.

2) The amount of superheat and the heat exchanger configuration should be reassessed in future efforts in order to ensure optimized system performance. A superheat configuration was selected late in the study and accordingly, the amount of superheat and the heat exchanger configuration were not necessarily optimized. It is doubtful that this fine tuning will have much effect on the economics of the near-term pilot plant. However, the impact on the economics of a potential commercial plant could prove to be significant.

1.2 INTRODUCTION

The United States has become increasingly dependent on the use of historically cheap oil and natural gas for its primary energy sources over the past 40 years. However, recent events such as rapid price escalations of these fuels, worldwide recognition that these resources are finite and therefore limited in supply, and increased importation of oil resulting in supply uncertainties and balance of payment deficits have spurred the U.S. to initiate a widespread search for alternative energy sources and methods of energy conservation. Accordingly, U.S. Government Legislation in recent years has attempted to decrease the usage of critical oil and natural gas fuels, provide incentives for the usage of alternate fuels and renewable energy resources such as solar energy, and encourage energy conservation through expanded usage of more efficient cogeneration systems.

Solar energy is recognized as an inexhaustible source of energy with the potential for significantly reducing our nation's consumption of critical oil and natural gas fuels. The Solar Central Receiver configuration appears to offer great promise for future cost effective utilization of solar energy for electric power generation, industrial process heat and cogeneration (coincident generation of both process heat and electricity or mechanical power with high efficiency) applications. Accordingly, DOE has elected to assist the development of this solar option with a goal of early commercialization for the technology now being evaluated. Through the DOE Solar Cogeneration Program, industry will be able to obtain first hand operating experience with solar thermal cogeneration systems. This will provide an important first step toward industrial acceptance of solar thermal cogeneration systems by providing realistic cost, performance and reliability data.

In September 1980, DOE awarded a contract to the General Electric Company and Texasgulf Chemicals Company for the conceptual design and evaluation of a Solar Cogeneration Facility for Texasgulf's Comanche Creek Sulfur Mine near Fort Stockton, Texas. The program organization is shown in Figure 1-1. The Advanced Energy Programs Department (AEPD) of the General Electric Company (GE) managed the project, performed the system engineering and integration, and conducted economic analyses of the facility. Other GE components which provided technical support to AEPD included: Energy Systems Programs Department (master control subsystem engineering), Corporate Research and Development (thermal storage trade studies), Industrial Sales Division (cost estimates for trade studies), and Mechanical Drive Turbine Department (steam turbine-generator engineering). The Texasgulf Chemical Company provided system requirements and specifications, economic assumptions, and review/approval of system integration efforts. Brown & Root Development, Inc., a subcontractor to Texasgulf, provided site layout, Architect-Engineer services, tower engineering and balance-of-plant engineering.

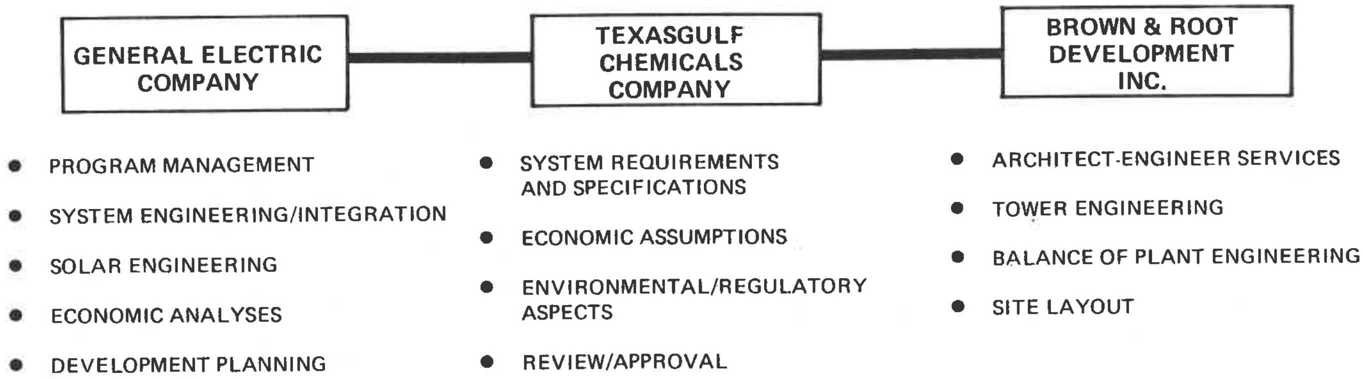


Figure 1-1. Program Organization – Conceptual Design

The major objective of the study was to develop and evaluate a site-specific conceptual design of a near-term Solar Cogeneration Facility with future potential for wide industrial applicability. The facility was to displace oil and/or natural gas fuels and utilize a solar central receiver configuration. The baseline facility configuration and Texasgulf site were selected during the proposal activities based upon best satisfying the DOE objectives. A system specification was developed for the baseline facility and updated as the study progressed. Various system trade studies were performed in order to select a facility configuration for the conceptual design. A conceptual design of the facility was then prepared along with system performance and cost estimates. An artist's concept of the Solar Cogeneration Facility at Comanche Creek is shown in Figure 1-2. Economic analyses, utilizing various financial scenarios, were then conducted. Finally, a development plan leading to system operation by 1985 was prepared.

1.3 SITE DESCRIPTION

Texasgulf, Inc. is a natural resources company which finds, develops and produces chemicals, metals and energy products. The basic organization of Texasgulf, Inc. is divided into three companies: Texasgulf Chemicals Company, Texasgulf Metals Company, and Texasgulf Oil & Gas Company. The Texasgulf Chemicals Company produces sulfur at three Frasch mines in Texas, recovers sulfur from sour gas in Canada, and has equity interest in Frasch sulfur mines in Mexico. Recoverable Frasch sulfur reserves owned by the Company in Texas are estimated at about 16.3 million long tons.

Texasgulf has always been interested in energy conservation. This attitude is not so much from patriotism as from pure economic realities. Sulfur production, as well as many other Texasgulf operations, is highly energy intensive. That is, most of the cost of the product is in the cost of energy. This points to energy savings as the primary area of cost savings and corresponding profit increases. Past experience has shown that savings in labor costs and capital costs have a very small impact on sulfur production costs. In the past few years as energy has become not only more expensive but actually in short supply, Texasgulf's concern with energy conservation has sharply increased. Not only energy conservation, but alternate energy sources as well, have begun to receive serious consideration. Therefore, Texasgulf elected to participate with General Electric to evaluate a Solar Cogeneration Facility at their Comanche Creek Sulfur Mine near Fort Stockton, Texas.

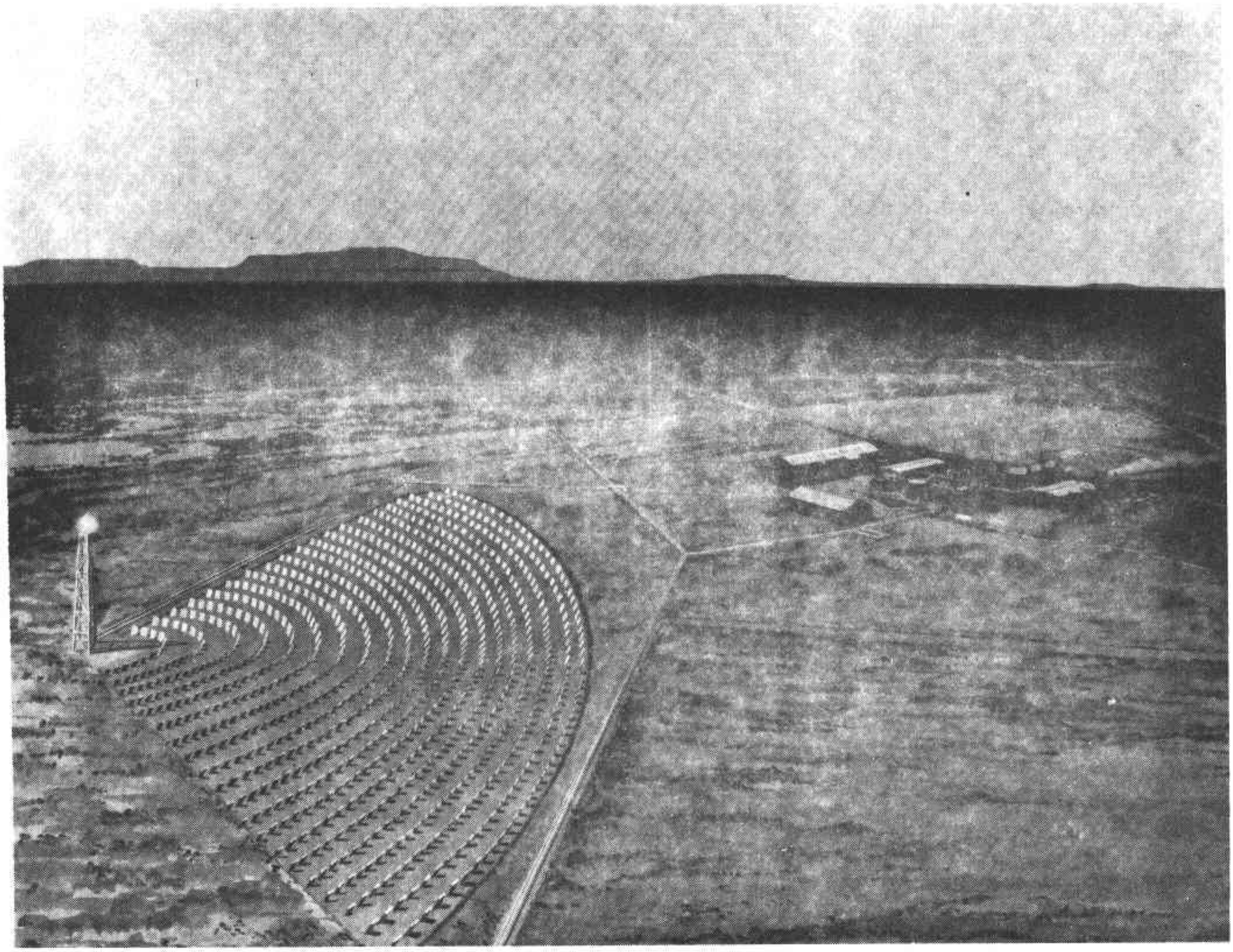


Figure 1-2. Artist's Concept of Texasgulf Solar Cogeneration Facility

The existing Comanche Creek Plant was designed and built in 1975. The plant provides superheated water at 177° C (350° F), 1.7 MPa (250 PSIA) for the Frasch process mining of sulfur, as typically illustrated in Figure 1-3. Well water is preheated, treated and then superheated by natural gas fired heaters. The superheated water is injected into underground sulfur deposits to melt the sulfur, which is then brought to the surface by compressed air. Major pieces of equipment include pumps, hot process softener vessels, and eight (8) natural gas fired heaters. Electrical energy to drive the various pumps, water heater blowers, and air compressors is currently purchased from West Texas Utilities. The average electrical power requirement is 2.8 MW_e, while the peak requirement is about 3 MW_e.

The Comanche Creek Plant is designed to produce 15×10^3 m^3 (4.0 million gallons) per day of superheated water. During 1980, the plant produced about 610×10^3 kg (600 long tons) of sulfur per day by providing about 12×10^3 m^3 (3.2 million gallons) of superheated water and consuming 272×10^3 m^3 (9.6 million cubic feet) of natural gas and 2.8 kW of electrical power daily. The plant operates around-the-clock for 365 days per year. There are no scheduled outages and maintenance activities are performed with minimum reductions in mine water loads or, when applicable, with built in spares.

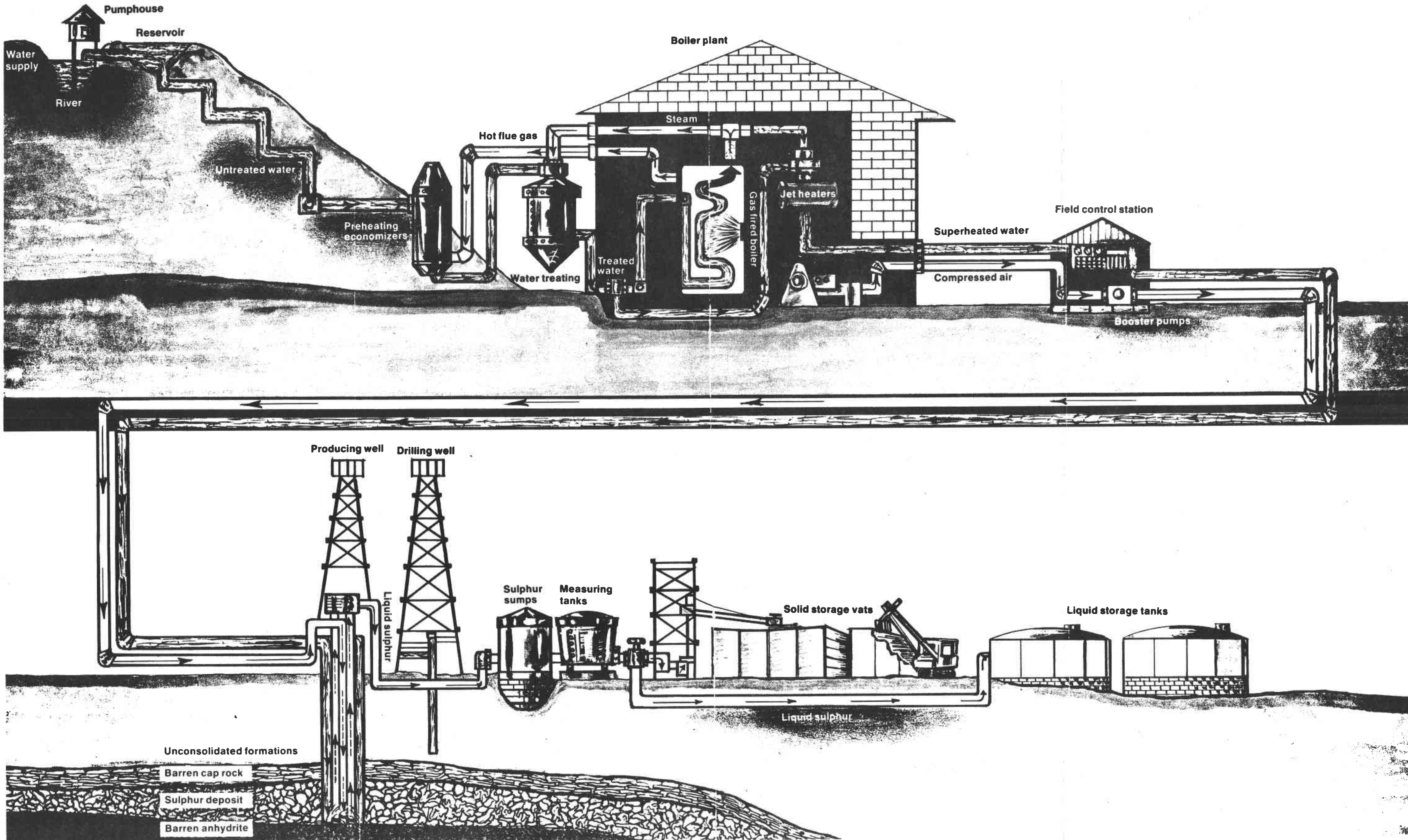


Figure 1-3. Typical Frasch Sulfur Mining Operation

The Comanche Creek Mine is ideally suited for the efficient utilization of solar energy with excellent solar insolation, moderate climate and good land availability.

Texasgulf is currently conducting exploration for additional sulfur deposits in West Texas. If this exploration is successful, new sulfur mines will likely be constructed. Successful industrial operating experience with solar cogeneration systems, accompanied by projected cost decreases in solar hardware and increases in fossil energy costs, will result in serious consideration of utilizing a full-scale Solar Cogeneration Facility at these new mines. In addition, the process heat and electrical requirements of the Solar Cogeneration Facility for the Comanche Creek Mine are similar to those of numerous other industrial applications. Therefore, wide industrial applicability should be also readily achievable.

1.4 CONCEPTUAL DESIGN DESCRIPTION

The major emphasis during the conceptual design was to define a feasible and highly reliable Solar Cogeneration Facility (SCF) configuration for the Comanche Creek Mine, based on existing and/or near-term technology in order to minimize engineering development. A schematic of the basic solar cogeneration concept is shown in Figure 1-4. The quantity and quality of engineering input from General Electric, Texasgulf, Brown & Root Development, Inc., and Sandia leaves no doubt that the facility as designed is a technically feasible, practical application of solar energy in an industrial process. There is also no doubt that the facility will operate successfully and interface well with existing Comanche Creek Plant operations.

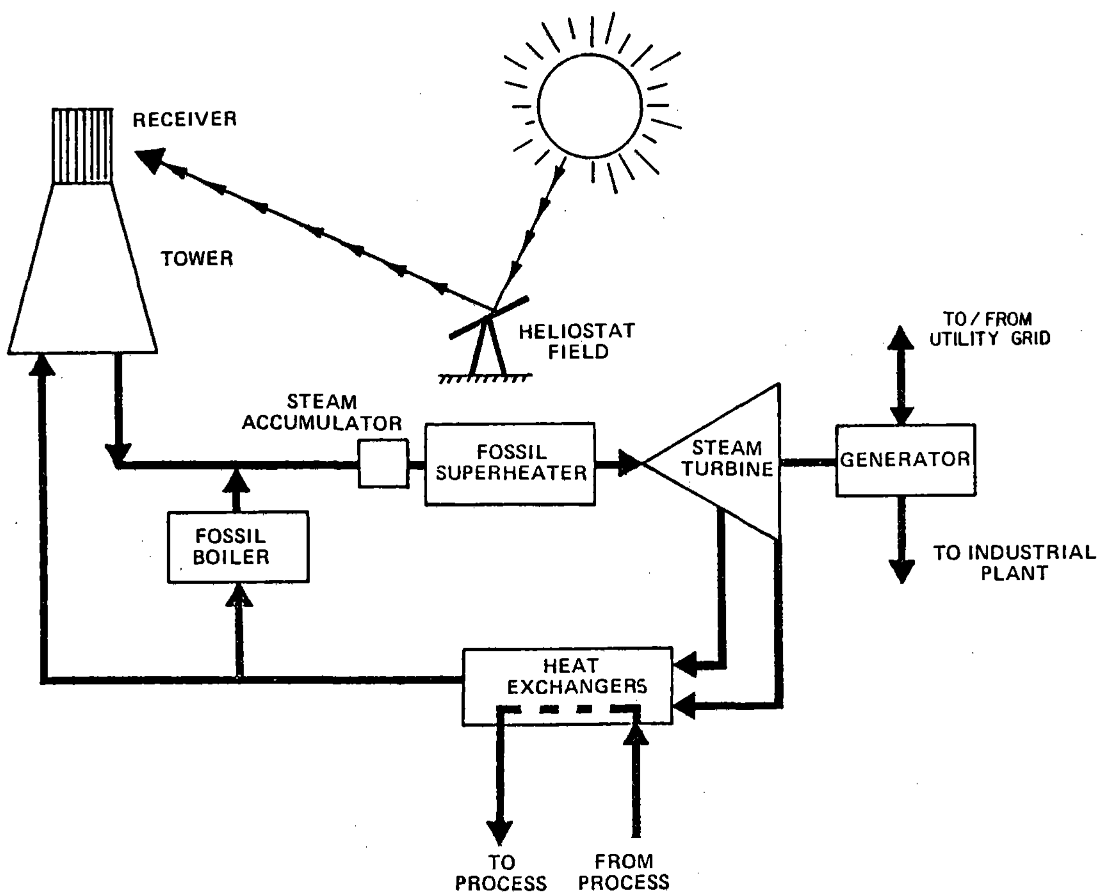


Figure 1-4. Solar Cogeneration Concept Schematic

The Comanche Creek Mine currently utilizes an existing natural gas fired plant to produce process heat (superheated water) for mining and purchases all required electrical power from West Texas Utilities. The SCF will be an add-on to the existing process heat plant. The SCF is designed to provide/displace about 20% of the process heat currently provided by the existing process heat plant and to provide 100% of the electrical power required for the mining operation.

The SCF will be located to the south of the existing plant, in a 166,000 m^2 (41-acre) area where future mining is not planned, as shown in Figure 1-5. The solar portion of the SCF will utilize a central receiver configuration. About 588, DOE Second Generation Heliostats (52.8 m^2 each) will be utilized in a north-field arrangement. The heliostats will reflect solar radiation onto an exposed, flat, natural circulation, saturated water/steam receiver located atop a 70-meter tower. The saturated steam which is generated will be fed into a steam accumulator located adjacent to the existing plant. A natural gas fired boiler is utilized in parallel with the solar receiver to maintain a constant output of saturated steam from the steam accumulator whenever the solar generated steam is inadequate and/or unavailable. The steam accumulator is sized for about five minutes of buffer storage in order to smooth transitions during operation in the Hybrid (Solar and Fossil) Mode. Saturated steam from the steam accumulator is fed into a natural gas fired superheater, and this superheated steam is then admitted to the steam turbine. Steam to generate process heat for the mining operation is obtained from an extraction port, as well as from the exhaust of the steam turbine. This steam is fed into closed loop heat exchangers to heat water for the mining operation. The condensed steam is then returned to the solar receiver and fossil boiler. The steam turbine also drives a generator to produce electricity for the mining operation, with any excess electricity distributed to West Texas Utilities.

The SCF will be operated in the Hybrid and Fossil Modes, with mode selection depending on the availability of solar insolation, for 24 hours per day, year-round, with the exception of scheduled turbine maintenance. Highly reliable system operation is imperative for the Frasch process mining of sulfur. Therefore, redundant components are utilized in certain areas, such as feedwater pumps and the exhaust heat exchanger, to enable uninterrupted facility operation while performing minor maintenance.

The interface between the SCF and the existing plant is relatively simple. Interfaces and process flow characteristics are shown in Figure 1-6. Interfaces consist only of four piping connections, control interfacing, and electrical power connections.

The SCF is sized so that the solar contribution can be readily measured, as well as being meaningful to Texasgulf. The size of the SCF was purposely kept as small as possible to reduce capital cost requirements while at the same time satisfying the above objectives. The SCF will provide 100% (3 MW_e) of the Comanche Creek Mine's electrical requirements. Excess electrical power will be distributed to West Texas Utilities and power can be drawn from the utility when required. The existing plant has experienced electrical power outages at times in the past. Therefore, construction of the SCF will improve the critical reliability of electrical supply for the mining operation. The SCF will also supply 20% (21.6 MW_t) of the existing plant's process heat. The turbine exhaust heat exchanger will provide about 3.4 MW_t to preheat cold well water to 46° C (115° F) in preparation for hot treatment. The extraction heat exchanger will receive treated water at 109° C (228° F) and provide about 18.2 MW_t to further heat the water to 177° C (350° F) for use in the sulfur mining operation. Existing plant water heaters will be turned down to compensate for the process heat supplied by the SCF. A conceptual design summary table for the SCF is presented in Table 1-2.

There should be no safety problems with the SCF. Heliostat beam control will be patterned after the safe practices developed at the DOE Central Receiver Test Facility. In addition, Texasgulf is experienced with similar fossil fired cogeneration systems at their Newgulf Mine in Newgulf, Texas.

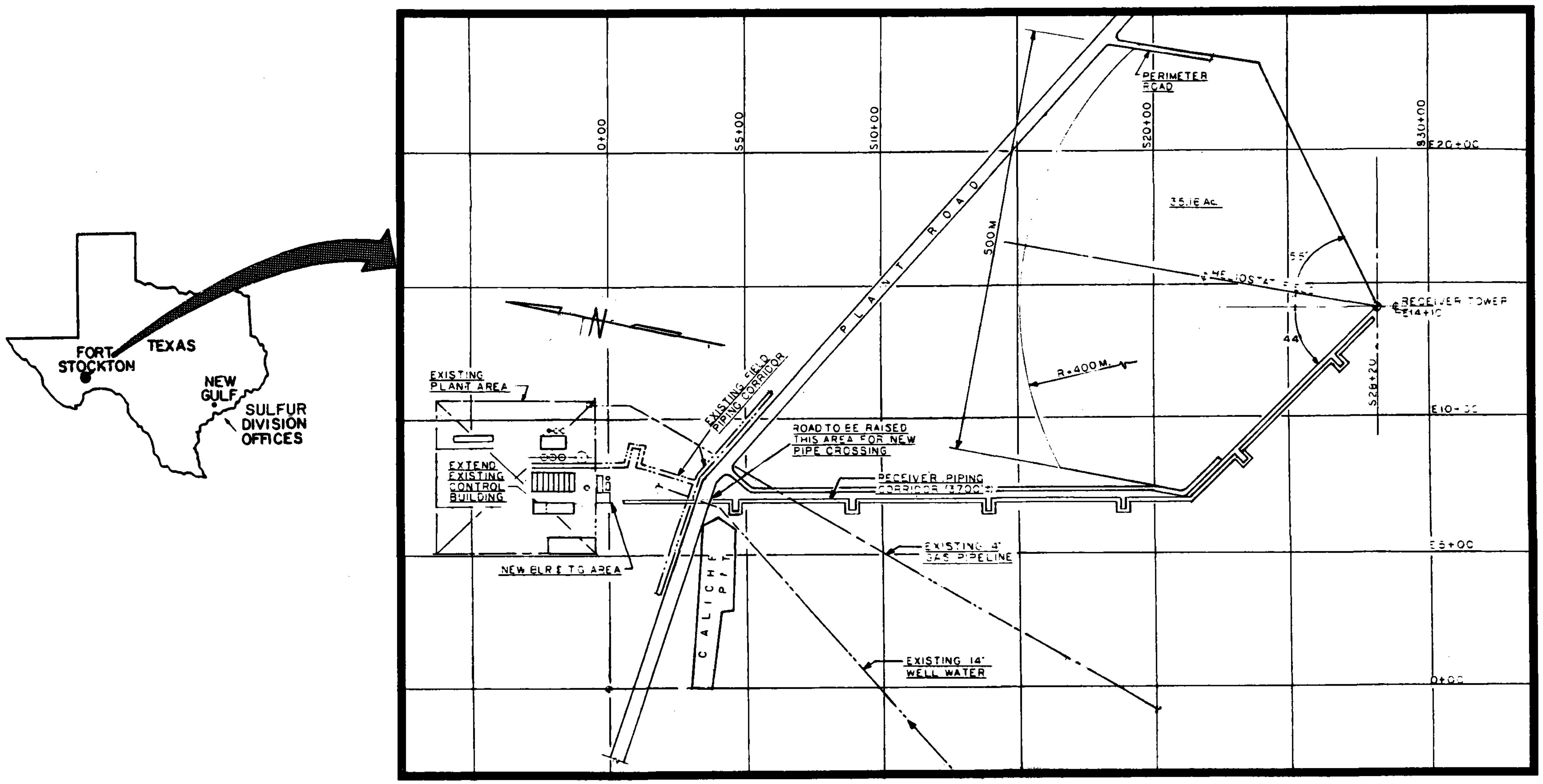


Figure 1-5. Selected Cogeneration Facility Location

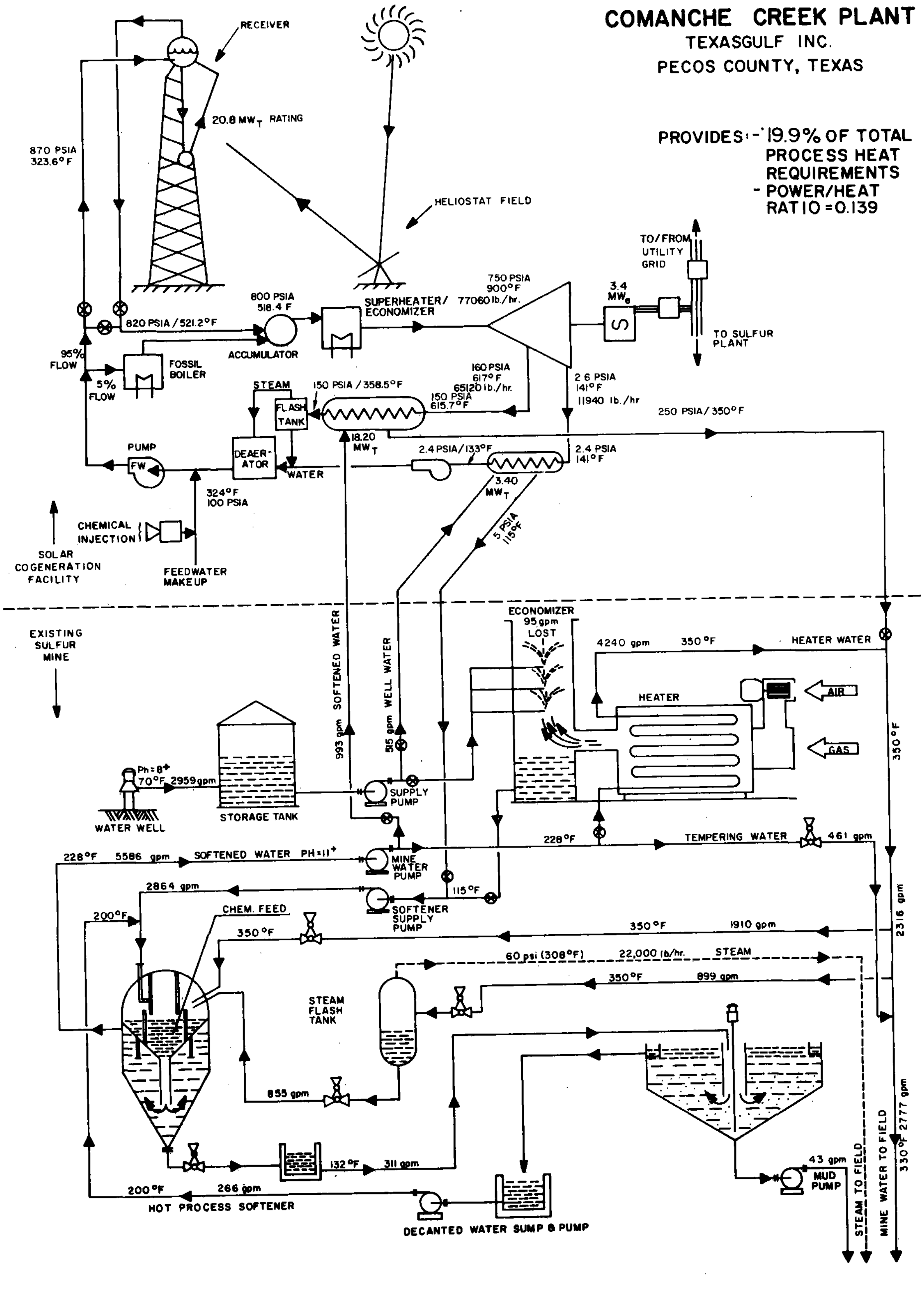


Figure 1-6. Solar Cogeneration Facility Process Flow and Interface Schematic

Table 1-2

SCF CONCEPTUAL DESIGN SUMMARY TABLE

1. Prime Contractor:	General Electric Company, Advanced Energy Programs Department, Dr. Howard E. Jones — Program Manager, Mr. Stuart I. Schwartz — Technical Manager
2. Major Subcontractors:	Texasgulf Inc., Texasgulf Chemicals Company, U.S. Sulfur Operations Mr. Kenneth Bishop — Project Manager, Mr. Wayne Herrington — Technical Manager; Brown & Root Development, Inc. (Subcontractor to Texasgulf), Mr. Pete Karnoski — Project Manager.
3. Site Location:	Comanche Creek Sulfur Mine; Fort Stockton, Texas
4. Facility Characteristics:	
• Turbine Type	3.5 MW_e General Electric Uncontrolled Extraction Superheat Steam Turbine-New
• Turbine Inlet Conditions	5.2 MPa/483°C (750 psia/900° F)
• Turbine Outlet Conditions	Extraction — 1.1 MPa/325° C (160 psia/617° F) Exhaust — 17.9 kPa/61° C (2.6 psia/141° F) Electric — 3.4 MW_e Gross, 3.0 MW_e Net
• Process Fluid and Purpose	Superheated Hot Water for Injection into Sulfur Mines to Liquify Underground Sulfur
• Process Fluid Conditions	• High Pressure Heat Exchanger — 1.7 MPa/177° C (250 psia/350° F) Hot water for Sulfur Mining • Low Pressure Heat Exchanger — 138 kPa/46° C (20 psia/115° F) for preheating water prior to treatment
• Fossil Energy Subsystem	
— Saturated Boiler	
-- Type	Package Type, Saturated Steam Industrial Boiler
-- Inlet Conditions	5.99 MPa/162° C (870 psia/324° F)
-- Outlet Conditions	5.51 MPa/270° C (800 psia/518° F)
-- Type Fuel	Natural Gas
-- Output Power	1.0 to 20.8 MW_t
— Superheater	
-- Type	Package Type, Refractory Furnace with Radiant & Convection Heaters
-- Inlet Conditions	5.51 MPa/270° C (800 psia/518° F)
-- Outlet Conditions	5.17 MPa/482° C (750 psia/900° F)
-- Type Fuel	Natural Gas
-- Output Power	5.8 MW_t
5. Design Point:	Noon, Equinox

Table 1-2 (Continued)
SCF CONCEPTUAL DESIGN SUMMARY TABLE

6. Receiver:	
• Receiver Fluid	Water/Steam
• Configuration	External Flat Panel
• Type	Natural Circulation, Recirculating
• Elements	Saturated Boiler/Steam Drum
• Outlet Temperature	272° C (521° F)
• Outlet Pressure	5.65 MPa (820 psia)
• Support Tower	70 m optical height, free standing, structural steel
7. Collector Field:	
• Number of Heliostats	588
• Mirror Area Per Heliostat	52.8 m^2 (568 ft^2)
• Cost	\$260/m^2 Installed (1980\$)
• Type	DOE Second Generation Heliostat (Typical)
• Field Configuration	North Field
• Total Mirror Area	31,030 m^2 (333,870 ft^2)
• Total Collector Field Area	142 × 10^3 m^2 (35 acres) excluding service roads 166 × 10^3 m^2 (41 acres) including service roads
8. Buffer Storage (Accumulator)	
• Duration	5 minutes — 0.89 MWh_t
• Media	Steam
9. Project Cost:	
• Total Project Cost (Heliostat Cost of \$260/m^2)	\$20.67 Million (1980\$) (Does Not Include O&M Costs)
10. Construction Time:	2-1/4 Years
11. Solar Cogeneration Facility Contribution at Design Point	
• Solar Receiver Output	19.8 MW_t max. operating, 20.8 MW_t design rating
• Fossil Superheater Output	5.8 MW_t
• Electrical Power	3.0 MW_e net, 100% of Total Plant Electrical Power
• Mechanical Power	None
• Process Power	21.6 MW_t, 19.85% of Total Plant Process Power

Table 1-2 (Continued)
SCF CONCEPTUAL DESIGN SUMMARY TABLE

12. Solar Cogeneration Facility Contribution — Annual	
• Solar Receiver Output	48,390 MWh_t
• Fossil Boiler Output	133,820 MWh_t
• Fossil Superheater Output	50,810 MWh_t
• Electrical Energy	26,280 MWh_e, 100% of Total Plant Electrical Energy
• Mechanical Energy	None
• Process Energy	189,220 MW_t, 19.85% of Total Plant Process Energy
13. Solar Fraction of SCF	
• Design Point	78%
• Annual	20.8%
14. Annual Fossil Energy Saved	40,136 Barrels of Crude Oil Equivalent (5.8×10^6 Btu/Barrel Oil)
15. Type of Fuel Displaced	Natural Gas
16. Ratio of $\frac{\text{Annual Energy Produced By Solar}}{\text{Total Mirror Area}}$	1.56 $\frac{MWh_t}{m^2}$
17. Ratio of $\frac{\text{Capital Cost}}{\text{Annual Fuel Displaced}}$	303.06 $\frac{\$}{MWh_t}$
18. Site Insolation (Direct Normal)	
• Design Point	950 W/m^2
• Annual Average	2.6 MWh/m^2
• Source	Solmet Data for El Paso, Texas, modified for Fort Stockton altitude and latitude
• Site Measurements	No site measurement accomplished to date. Site measurements planned for next phase of program.
19. Cogeneration Utilization Efficiency	79%

1.5 SYSTEM PERFORMANCE

The design point selected for the solar portion of the Solar Cogeneration Facility (SCF) is noon, equinox. This design point was selected since it provides the maximum thermal input to the receiver for a north-field heliostat arrangement. Solar system performance at the design point, as shown in Figure 1-7, was estimated using two computer programs. Collector field performance was evaluated with the MIRVAL code developed by Sandia. Receiver losses were evaluated using an in-house GE developed computer program. For a reference direct normal insolation value of 950 W/m^2, the solar system efficiency at the design point is 70.5%. At the design point, solar generated power to the gas fired superheater is 19.8 MW_t and gas fired boiler power is 1 MW_t. An additional 5.8 MW_t is provided by the gas fired superheater, resulting in a turbine inlet power of 26.6 MW_t. This power is then converted to 21.6 MW_t of process heat and 3 MW_e net of electrical power.

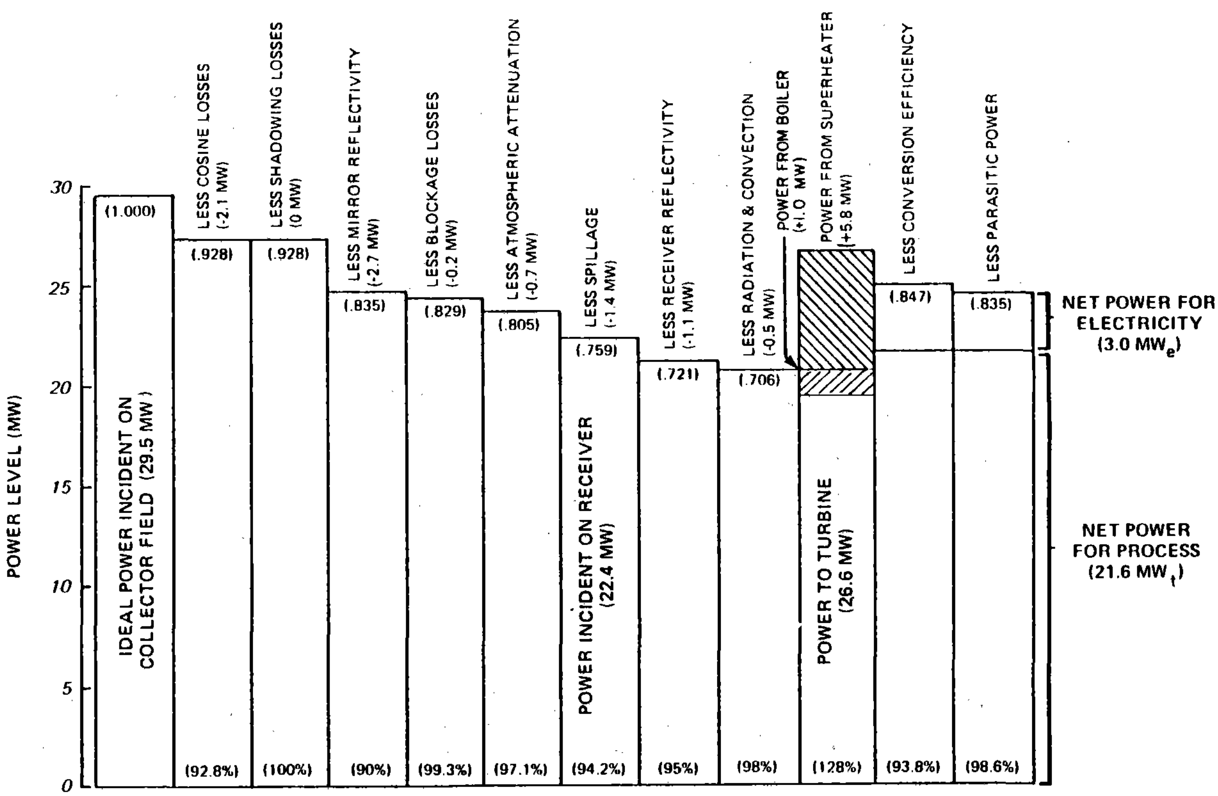


Figure 1-7. Equinox Noon Design Point Power Cascade

Annual performance for the SCF, as shown in Figure 1-8, was estimated using the previously mentioned Sandia-developed MIRVAL code, the Sandia-developed STEAEC code, and hour-by-hour SOLMET data for El Paso, Texas, adjusted for the Fort Stockton site characteristics. The solar portion of the facility will supply 48.4 GWh of energy annually at the inlet of the gas fired superheater.

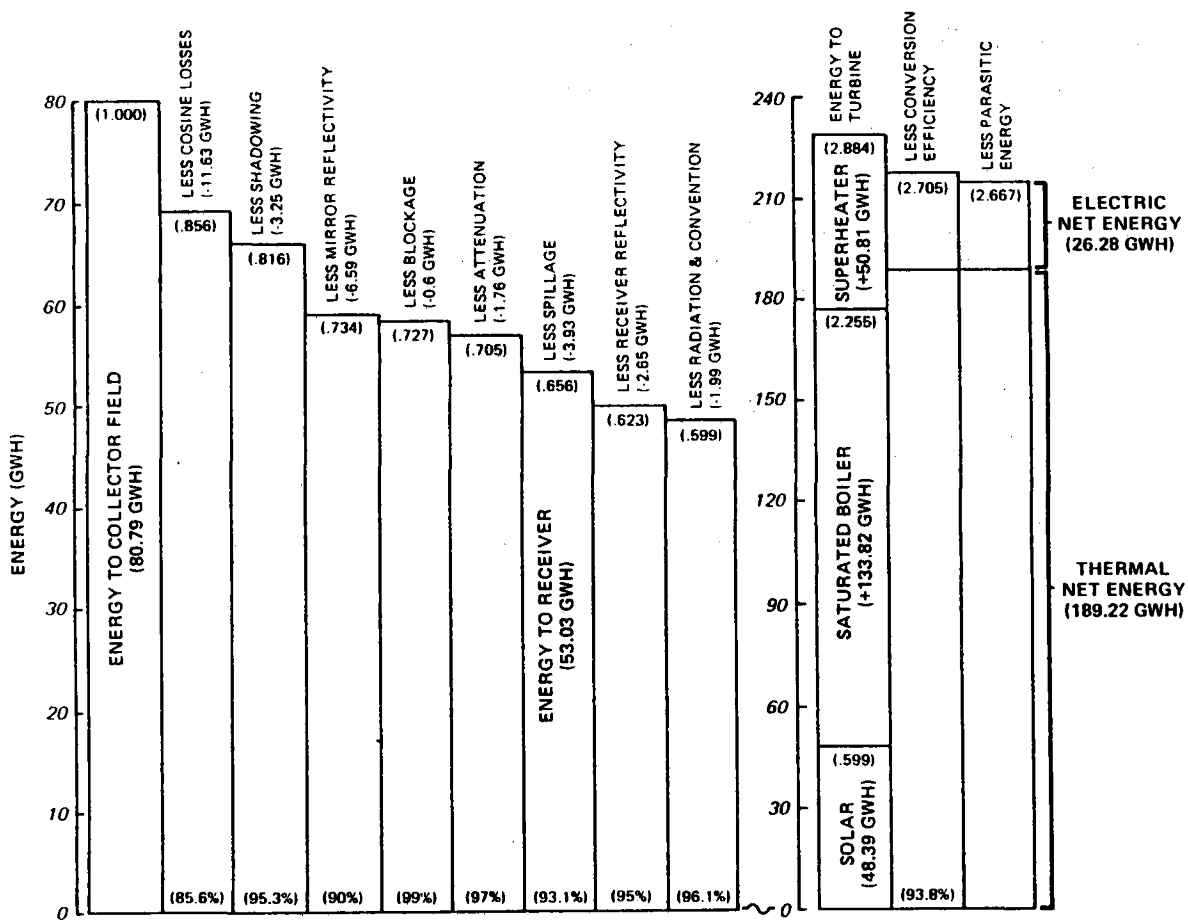


Figure 1-8. Energy Cascade—Annual Summary

This corresponds to an annual solar system efficiency of about 60%. The annual energy provided by the gas fired boiler at the inlet of the gas fired superheater is 133.8 GWh. The gas fired boiler is utilized to maintain a constant input to the superheater whenever solar energy is less than design point and during night operation. The gas fired superheater provides an additional annual energy input of 50.8 GWh. Therefore, annual energy input to the turbine is about 233 GWh. This energy is then converted to about 189 GWh of process heat and 26.3 GWh of net electrical power. The annual cogeneration utilization efficiency, considering efficiency losses of the gas fired boiler and superheater, is 79%.

Annual fuel savings resulting from operation of the SCF at Comanche Creek are projected to be about 228 million cubic feet of natural gas or 40,000 equivalent barrels of oil. These projected fuel savings result from the natural gas which will be saved by West Texas Utilities.

1.6 ECONOMIC FINDINGS

Projected capital costs for the design, construction and startup of the Solar Cogeneration Facility (SCF) at the Comanche Creek Mine are about $20.7 million (1980 $), as shown in Table 1-3. A large share, about 41%, of the capital cost is for the heliostats. Annual operating and maintenance expenses of the SCF are estimated at about $252,000. The Comanche Creek Mine will realize an annual energy savings of about 25.1 GWh of electricity since the SCF will provide 100% of the mine's electrical needs. Related cost savings to Texasgulf over the lifetime of the SCF will be dependent on the cost of electricity which would normally have been purchased from West Texas Utilities, which is heavily dependent on the use of natural gas to generate electricity. The quantity of natural gas consumed annually by the Comanche Creek Mine will remain approximately the same as currently used for the existing plant.

Table 1-3

SOLAR COGENERATION FACILITY – 1ST PILOT PLANT CAPITAL COST SUMMARY

	Cost Element	Capital Cost* (10^6\$)
5100	Site Improvements	0.695
5200	Site Facilities	1.198
5300	Collector Subsystem	8.446
5400	Receiver Subsystem	3.068
5500	Master Control Subsystem	0.751
5600	Fossil Energy Subsystem	1.754
5800	Electric Power Generating Subsystem	1.514
5900	Other Subsystems	3.096
	Total Construction Cost	20.522
	Owner's Cost	0.149
	Total Project Cost	20.671

*All costs expressed in 1980$

Economic analyses were conducted utilizing Texasgulf supplied financial assumptions to determine an after tax discounted cash rate of return (DCRR), which considers the time value of money. Industry has traditionally calculated return on investment based on the use of inflated cash flows over the projected lifetime of the facility. However, during periods of high inflation, such as this country is currently experiencing, this approach leads to a deceptively high calculated return on investment. Another approach which is beginning to receive widespread usage is to calculate the return on investment with a zero general inflation rate, while still considering the cost escalation of specific items over general inflation. Use of this approach leads to the determination of a more meaningful real return on investment. Therefore all DCRR calculations made for this study are based on the more realistic zero general inflation approach.

1.6.1 Near-Term Solar Cogeneration Facility

Major baseline financial assumptions for the near-term SCF at the Comanche Creek Mine include: First full year of operation is 1986 with a 20-year facility life, 25% investment tax credit, 10 year accelerated depreciation, 46% income tax rate, 3% natural gas cost escalation above general inflation, and 1% electricity cost escalation above general inflation. Several variations to these assumptions were also evaluated in order to determine the DCRR sensitivity to key financial parameters.

Economic analyses of the SCF indicate that Texasgulf can obtain a positive after tax real return on investment with appropriate levels of DOE cost sharing for this pilot facility, as shown in Figures 1-9 and 1-10. For example, Texasgulf may realize an after tax real discounted return on investment of 10% if DOE cost shares 80% of the capital investment and the average costs of natural gas and electricity over the 20 year life of the facility are $3 per million Btu and 3.5 cents per kWh, respectively. The average cost of natural gas over the lifetime of the facility and related electricity costs could well be much higher than this considering the probability of near-term decontrol of natural gas, along with the continuation of price escalation above general inflation. In fact, some projections indicate that the impact of the deregulation of natural gas will be a rapid increase in price such that natural gas will approach the cost of No. 2 fuel oil. Such a rapid cost increase for natural gas would result in a significantly higher return on investment for Texasgulf and/or allow a larger proportion of cost sharing by Texasgulf.

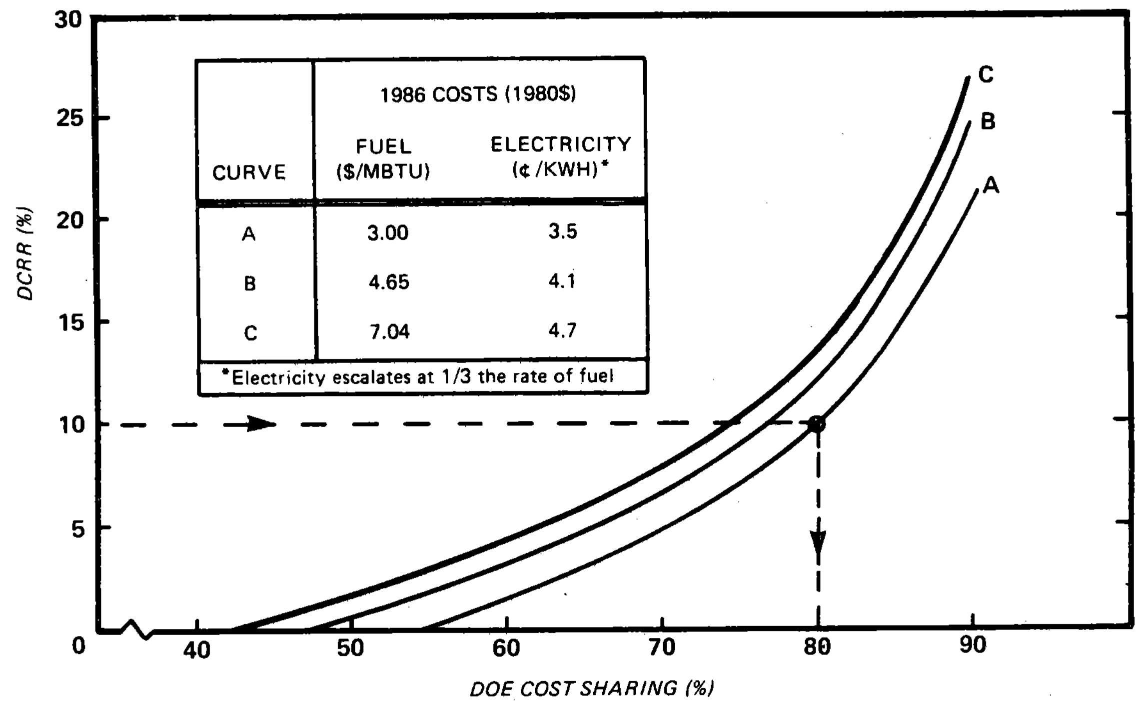


Figure 1-9. Solar Cogeneration Facility – Pilot Plant Economics

1.6.2 Commercial Solar Cogeneration Plant

In order to assess the future potential of this solar cogeneration concept for wide industrial applicability, economic assessment of a Commerical Solar Cogeneration Plant was also conducted. The commercial plant was sized (130 MW_t)to completely supply the process heat and electrical needs of the Comanche Creek Mine, with excess electricity being sold to the local electrical utility. Commercial plant cost (Table 1-4) and performance were scaled from the near-term Solar Cogeneration Facility, with consideration of non-recurring costs and reduced costs for mass produced heliostats.

Economic analyses of the Commercial Solar Cogeneration Plant indicate that a reasonable return on investment may be obtained as heliostat costs decrease and costs of natural gas and electricity increase, as shown in Figure 1-11. For example, an after tax real discounted return on investment

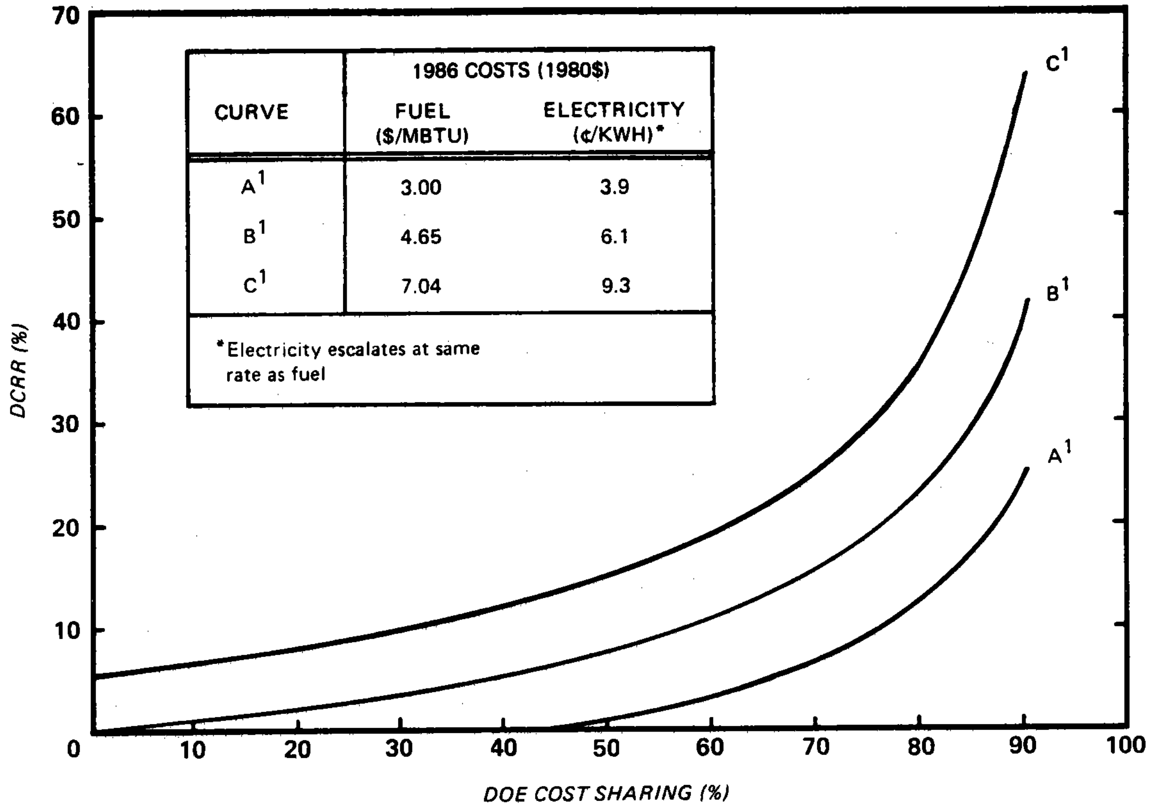


Figure 1-10 Solar Cogeneration Facility – Pilot Plant Economics

Table 1-4

COMMERCIAL SOLAR COGENERATION PLANT CAPITAL COST ESTIMATE*

Account Code	Item	Cost (1000 $)
5100	Land	2,027
5200	Buildings	3,495
5300	Collectors	46,640
5400	Receiver	7,431
5500	Controls	2,625
5600	Fossil Energy	6,131
5800	EPGS	5,589
5900	Other	12,153
	Total Construction	86,091
	Owner's Cost	625
	Total	86,716

*All costs expressed in 1980 $

of 17.5% relative to the existing Comanche Creek Plant configuration is projected at a heliostat cost of $136/M^2 (projected mass production cost at 25,000 units/yr in 1980 $) and an electricity sale price to the utility of 8 cents per kilowatt-hour (which corresponds to a purchased cost of electricity of 11 cents per kilowatt-hour). Similar analyses, as also shown in Figure 1-11, indicate that the Commercial Solar Cogeneration Plant will also have a significantly higher return on investment than a completely gas fired cogeneration plant. A coal-fired cogeneration comparison was not attempted during this study, but should be evaluated in future efforts.

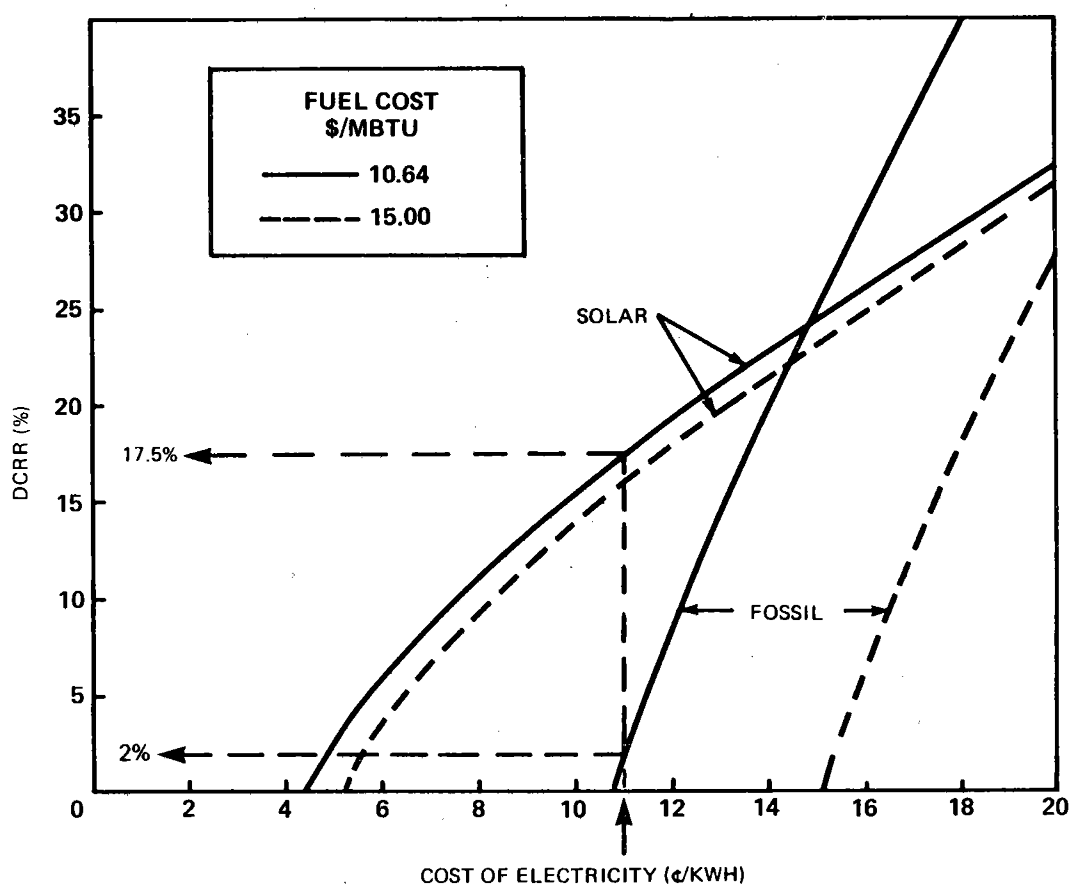
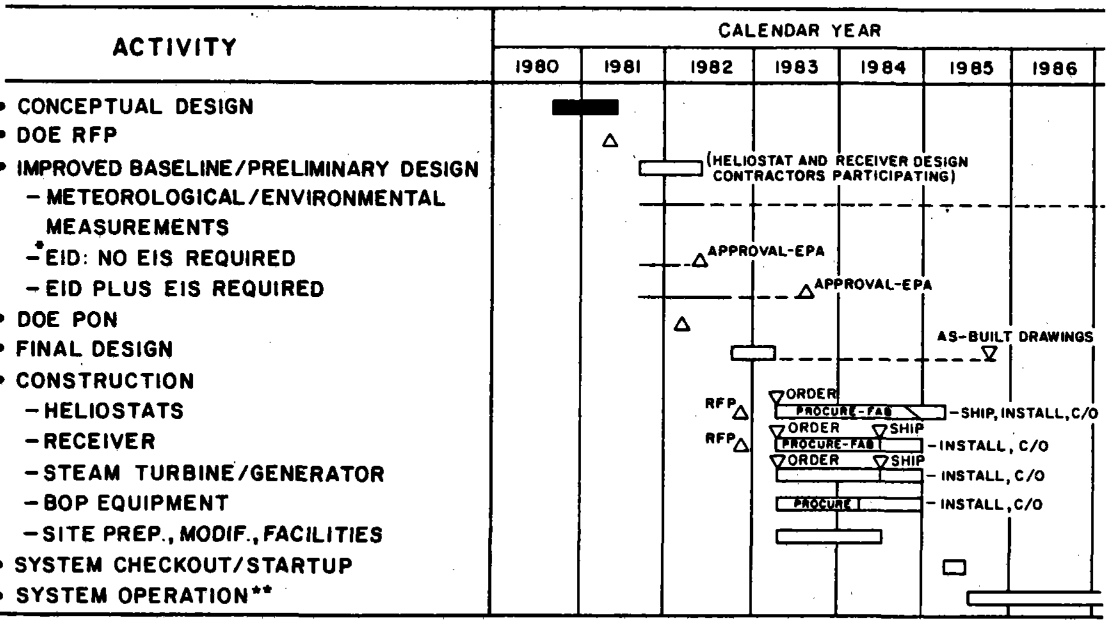


Figure 1-11. Commercial Solar Cogeneration Plant Economics

It should be noted that the economic results presented in this report are site and application dependent. Therefore, extrapolation of these results to different sites and/or applications — where such factors as insolation levels, system configurations, and financial assumptions may vary significantly — should be accomplished with extreme caution.

1.7 DEVELOPMENT PLAN

A development plan for the Solar Cogeneration Facility (SCF) has been prepared with the major objective of efficiently achieving system operation by mid-1985 (Figure 1-12). Early operation will increase the attractiveness of the SCF to Texasgulf since the resulting energy cost savings will extend the economical operation lifetime of the sulfur mine.



* PROBABLE SITUATION – IF EIS REQUIRED, SCHEDULE FOR CONSTRUCTION, CHECKOUT/STARTUP AND OPERATION DELAYED ABOUT 6 MONTHS.

** SYSTEM OPERATION WILL CONSIST OF A 1-12 MONTH SYSTEM PERFORMANCE VALIDATION PHASE FOLLOWED BY A TWO-YEAR JOINT USER/DOE OPERATION PHASE. TEXASGULF WILL THEN CONTINUE TO OPERATE THE SYSTEM FOR AS LONG AS OPERATION IS ECONOMICAL.

Figure 1-12. Development Schedule and Milestone Chart

The development plan and schedule was prepared jointly by General Electric, Texasgulf, and Brown & Root Development, Inc. and reflects input from several equipment vendors. The schedule is based upon efficiently achieving system operation by mid-1985 and correspondingly, an aggressive DOE program was assumed.

Based upon preliminary assessments, minimal adverse environmental impact is projected for the SCF. Therefore, obtaining the necessary environmental permits should pose no problem.

Only minor engineering development will be required for the SCF. The current system configuration consists of available state-of-the-art technology, with a large portion of the system components categorized as off-the-shelf. Preliminary discussions with receiver contractors have indicated that the natural circulation saturated water/steam receiver is well within the state-of-the-art and that even panel tests should not be required for confident design. Heliostat development is proceeding under parallel DOE 2nd Generation Heliostat Development Programs, which should result in suitable heliostats being available in a timely manner for incorporation into this program.

Early procurement of hardware, prior to completion of the Final Design Phase, does not appear to be required. The longest lead hardware item identified to date is the heliostat. A time of two years from order through installation/checkout was assumed for the development schedule. However, delivery times appear to vary greatly, depending upon whether or not fabrication/assembly lines are operating prior to order placement, as well as the scheduling of competing orders. Therefore, heliostat delivery schedules will be defined in much more detail during the design phase and will play an important role, in addition to cost and performance, in the selection of a heliostat hardware contractor.

The following approach for conducting future phases of the program was developed prior to Texasgulf's decision to forego further program participation. Although this approach will now not be utilized, it is presented here in order to provide DOE with what is felt to be an attractive approach for conducting other related future activities.

Starting with the Preliminary Design Phase, the industrial user, Texasgulf, would assume the prime contractor role. General Electric and Brown & Root Development, Inc. would support Texasgulf as subcontractors, as shown in Figure 1-13. The overall objective of the planned program is to successfully evaluate the capability of a SCF for industrial use. Texasgulf would design, construct, operate and maintain the SCF in a manner similar to that normally utilized by Texasgulf for any new plant. Important data regarding costs, operation, performance, reliability and maintenance would be developed during the program which would help to determine whether or not solar technology can satisfy the criteria of industry. Acceptable results would help to encourage the commercialization of solar cogeneration as an industrial energy alternative.

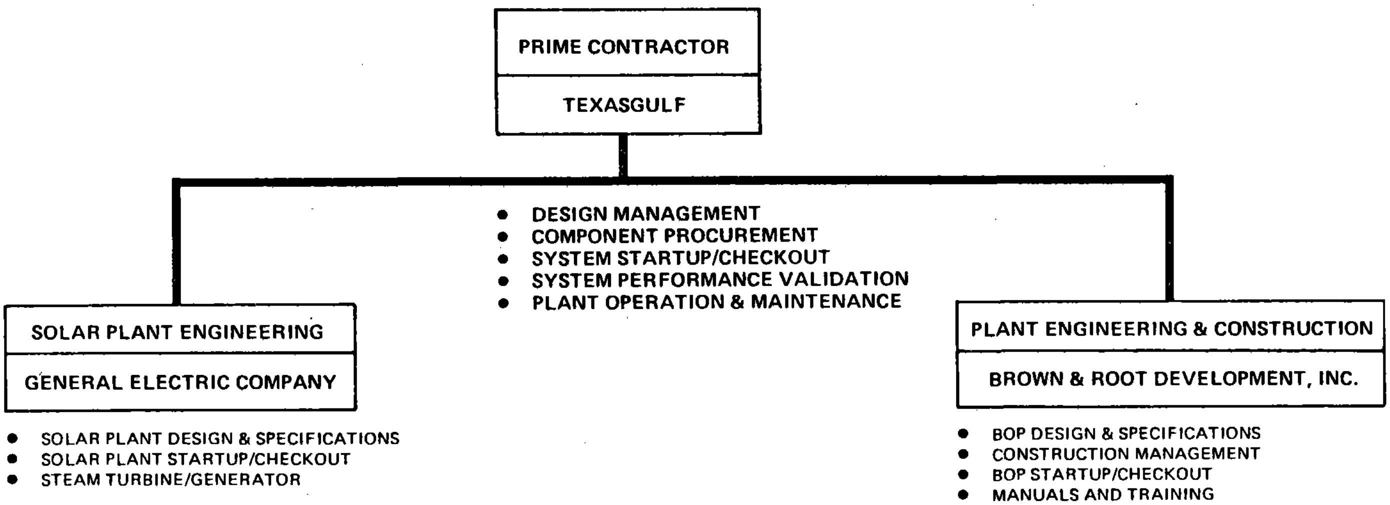


Figure 1-13. Program Organization – Future Activities

The collective efforts of the industrial user, the Federal Government, and participating industries should result in a team effort which permits each entity to operate within their normal realm of expertise. The industrial user would be responsible for the successful completion and operation of the SCF and would work to maintain the support of state and local officials for the project. The Federal Government and its agents would be expected to provide the necessary support of its agencies and supply information to justify partial DOE funding for the project. Industry would be asked to support the project with well-designed equipment manufactured in an efficient manner at a reasonable cost. Industry's support for the project could result in new free enterprise opportunities for the commercialization of solar technology.

1.8 SITE OWNER'S ASSESSMENT

Texasgulf's energy intensive operations such as sulphur mining and electrolytic metal winning, combined with the extraordinary increases in costs of hydrocarbon based energy, have created a corporate program in energy research and conservation. The plants at Texasgulf's operating sulfur mines were designed for maximum energy efficiency within the limits of a reasonable return on capital. As the price of natural gas in the past few years went from 7¢ per 1000 cubic feet to $2.50, alternate fuels were investigated. Coal and even a garbage derived fuel were considered as boiler fuel, but present plants could not be altered for solid fuel use.

One of Texasgulf's potash mines in Utah presently uses solar energy for evaporation and crystallization of potash salts. The sulfur division was ordered to study the possibility of solar heated water for Frasch process sulfur mining. The resulting internal Texasgulf study considered only a low temperature solar collector, one site, no cogeneration, and no storage. This was a very limited study and under imposed restraints, the return on investment appeared to be very low. These results did not eliminate Texasgulf's interest in solar energy and therefore, Texasgulf was eager to participate with General Electric and DOE in a search for an economical means of conserving energy. The Texasgulf Solar Cogeneration Program over the past year with Texasgulf working intimately with General Electric, BARDI, and DOE has investigated alternate locations, optimized size, cogeneration, storage, superheat, and produced a complete analysis of the project economics. The actual basic design of the plant is essentially complete and it is felt that energy savings have been maximized and facility costs minimized considering the limited amount of effort involved.

The economics of the Solar Cogeneration Facility (SCF), which are based upon near-term costs of solar hardware (heliostats) and fossil/electrical energy, indicate that significant DOE cost sharing will be required in order for Texasgulf to receive a reasonable return-on-investment. Texasgulf requires a higher return-on-investment than many other industries due to the higher risk involved with a natural resource type of business. Texasgulf, like any business, has a limited amount of capital funding for investment purposes. Therefore, investment decisions must be made by considering all potential investment opportunities and selecting those investments which will maximize the return of owner's equity. While Texasgulf could possibly receive a reasonable return-on-investment based upon funding a small portion of the capital cost of the SCF, the bulk of the capital cost would have to be provided by the taxpayer. The construction and operation of this SCF should provide a meaningful data base for future industrial usage of solar cogeneration which would most directly benefit industry, while indirectly benefiting the taxpayer. Texasgulf, therefore, feels that industry, the major potential beneficiary, should fund such activities rather than the taxpayer. Accordingly, Texasgulf has decided to terminate participation in the Solar Cogeneration Program at this time.

Texasgulf's participation in this current study has been a meaningful exercise which has established a good data base for the evaluation of solar cogeneration as a potential candidate for future installations. Participation in the study has eliminated Texasgulf's earlier concerns about the high risk of solar technology. After visiting the DOE Central Receiver Test Facility at Albuquerque, New Mexico, misgivings concerning safety and operational reliability have been eliminated. Almost by definition, a solar steam and electric plant will be a plus in environmental impact considerations. The solar cogeneration configuration developed during this study appears to be a practical application of solar energy in an industrial process requiring both low pressure steam or superheated hot water and electricity. This situation exists for most petrochemical and natural resource process industries, including Texasgulf's phosphate mine in North Carolina and the soda ash plant in Wyoming. Therefore Texasgulf will be able to utilize this study in the future to evaluate the economic competitiveness of solar cogeneration for new plants. As heliostat costs are decreased through mass production and other energy costs increase, it appears that solar cogeneration has good potential to become economically competitive with other more conventional energy systems.

Section 2
INTRODUCTION

Section 2

INTRODUCTION

The Texasgulf Solar Cogeneration Program, DOE Contract No. DE-AC03-80SF11437, was conducted over an eleven (11) month period from September 1, 1980 to August 1, 1981. Total contract funding was $438,000. The Advanced Energy Programs Department of the General Electric Company was the Prime Contractor. Dr. Howard E. Jones was the GE Program Manager and Mr. Stuart I. Schwartz was the GE Technical Manager. The place of performance was Building 23, Room 289, 1 River Road, Schenectady, New York 12345.

This phase of the program consisted of the preparation of a conceptual design for a near-term, site-specific Solar Cogeneration Facility (SCF), along with evaluations of facility performance and economics. Subsequent sections of this report document the technical work performed. This introduction provides an overview of the project and describes the selected Texasgulf Chemical Company site.

2.1 STUDY OBJECTIVE

The major objective of the Program was to develop a site-specific conceptual design of a near-term SCF with future potential for wide industrial applicability. This major objective was broken down by GE into several subobjectives as shown below:

1. Prepare a conceptual design of a site-specific SCF.
   - Maximize energy savings.
   - Minimize facility costs.
   - Maximize use of off-the-shelf equipment.
   - Optimize facility size to be meaningful to Texasgulf and compatible with DOE program objectives.
   - Minimize facility intrusion into existing plant operation.
2. Assess Economics.
   - Site-specific SCF.
   - Additional Solar Cogeneration Plants at Texasgulf.
3. Assess wide applicability.
   - Evaluate competitive economics.
   - Investigate concept adaptability for other industries.
4. Prepare a development plan for the site-specific SCF.
   - Identify component development needs.

- Identify long-lead hardware items.
- Structure plan for startup by 1986.

In addition, the SCF was to utilize a Solar Central Receiver configuration and displace oil and/or natural gas fuels.

Solar energy is recognized as an inexhaustible source of energy with the potential for significantly reducing our Nation's consumption of critical oil and natural gas fuels. The Solar Central Receiver configuration appears to offer great promise for future cost effective utilization of solar energy for electric power generation, industrial process heat and cogeneration (coincident generation of both process heat and electricity with high efficiency) applications. Accordingly, the U.S. Department of Energy (DOE) has elected to assist in the development of this solar option with a goal of early commercialization for the technology now being evaluated. Through the DOE Solar Cogeneration Program, industry will be able to obtain firsthand operating experience with solar thermal power systems. This will provide an important first step toward industrial acceptance of solar thermal power systems by providing realistic cost, performance and reliability data.

2.2 TECHNICAL APPROACH AND SITE SELECTION

2.2.1 Technical Approach

The basic technical approach utilized by General Electric (GE) was derived from the DOE objective that the basic Solar Cogeneration Facility concept has wide industrial applicability. Achievement of this objective is very important to help ensure the successful commercialization of cost competitive solar cogeneration designs. Therefore, initial activities consisted of establishing ranges of process heat temperatures and power-to-heat ratios that would encompass a significant portion of the potential industrial cogeneration market. These activities resulted in the selection of general system requirements as shown below:

- System capable of supplying low to intermediate temperature process heat, <246° C (475° F)
- System electrical to thermal power ratio of 10-15%

The selection of these two items is described in greater detail in Section 3.1.

A generic system concept was then developed which met the above system requirements (refer to Section 3 for details). An industrial site, which also met these system requirements as well as other site selection criteria, was then selected, as described later in this section.

The activities during this phase of the Texasgulf Solar Cogeneration Program were divided into seven major tasks, as shown in the program schedule of Figure 2-1. Activities conducted during each of these tasks are summarized below.

Task 1 — Preparation of System Specification

This task consisted of the preparation of a Preliminary System Specification consisting of a system description, environmental criteria and conceptual design data base. The Preliminary System Specification was continually updated as the conceptual design evolved and the final version of the System Specification is incorporated as Appendix A of this report.

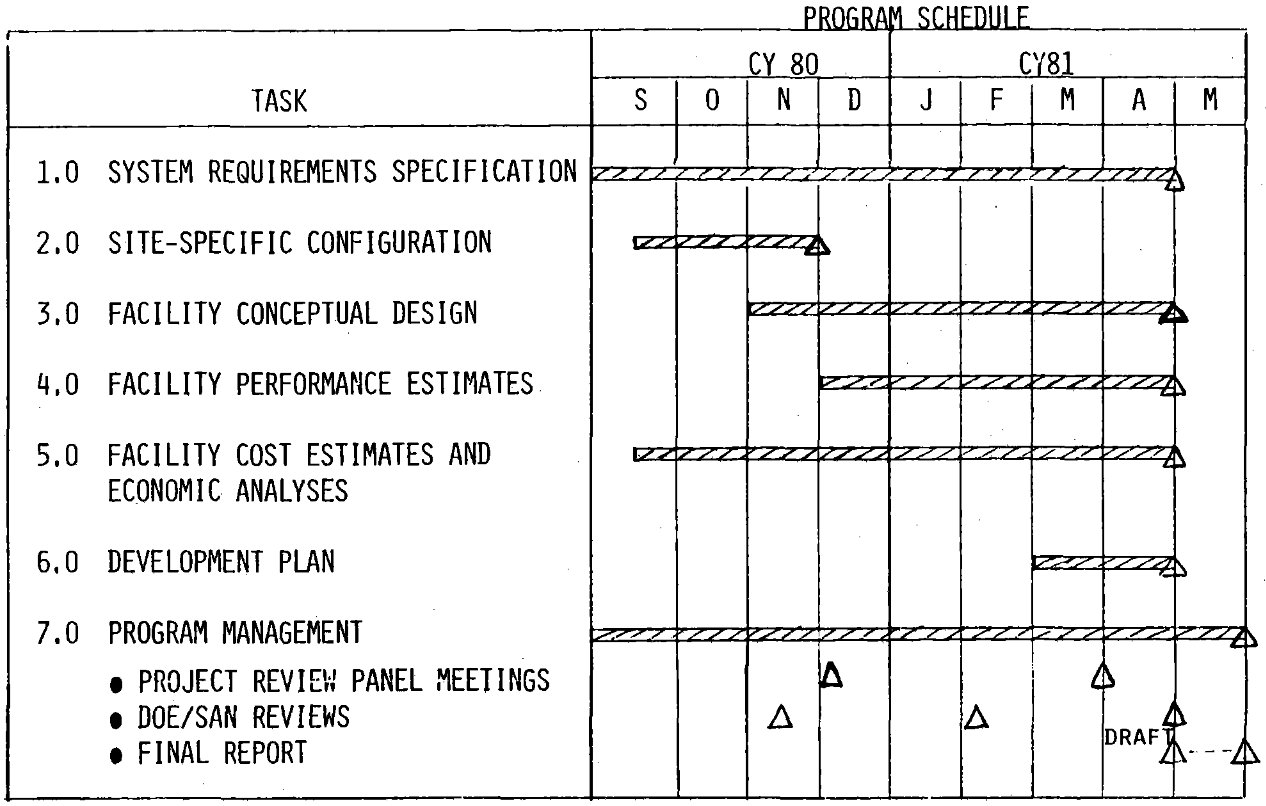


Figure 2-1. Schedule — Texasgulf Solar Cogeneration Program

Task 2 — Selection of Site-Specific Configuration

This task consisted of developing system evaluation criteria, conducting various system tradeoff studies and selecting the optimum facility configuration for conceptual design efforts. The results of this task are documented in Section 3 of this report.

Task 3 — Facility Conceptual Design

This task consisted of conceptual design activities for the facility configuration selected in Task 2. Efforts consisted of system integration, subsystem conceptual design, definition of system operating modes, environmental assessment, definition of required regulatory permits, and an assessment of health and safety aspects of the facility. The results of this task are documented in Sections 4 and 5 of this report.

Task 4 — Facility Performance Estimates

This task consisted of estimating the performance of the system. Estimates were prepared for the design point and annual performance. The results of this task are documented in Section 4.5 of this report.

Task 5 — Facility Cost Estimates and Economic Analysis

This task consisted of two major activities. First, facility cost estimates were prepared, starting with preliminary design and continuing through system operation. These cost estimates were then utilized, along with system performance estimates and various economic assumptions, to conduct economic analyses of the facility. The results of this task are documented in Sections 4.7, 4.8 and 6 of this report.

Task 6 — Development Plan

This task consisted of preparing a development plan for the SCF. The development plan includes activities starting with Advanced Conceptual/Preliminary Design through Facility Operation by Texasgulf. The results of this task are documented in Section 7 of this report.

Task 7 — Program Management

This task consisted of program administration and direction, cost/schedule control, subcontracting, reporting and program status reviews.

A program summary work flow is shown in Figure 2-2. The work was initiated with preparation of a preliminary system specification, which was continually updated throughout the contract. Trade-off studies were performed to select an optimum facility configuration for the conceptual design efforts. Based upon the resulting conceptual design, facility performance and cost estimates were prepared. These estimates, along with various economic assumptions, were utilized to assess facility economics. A development plan, encompassing future program efforts through facility operation, was then generated. This final report has been prepared to document the work performed.

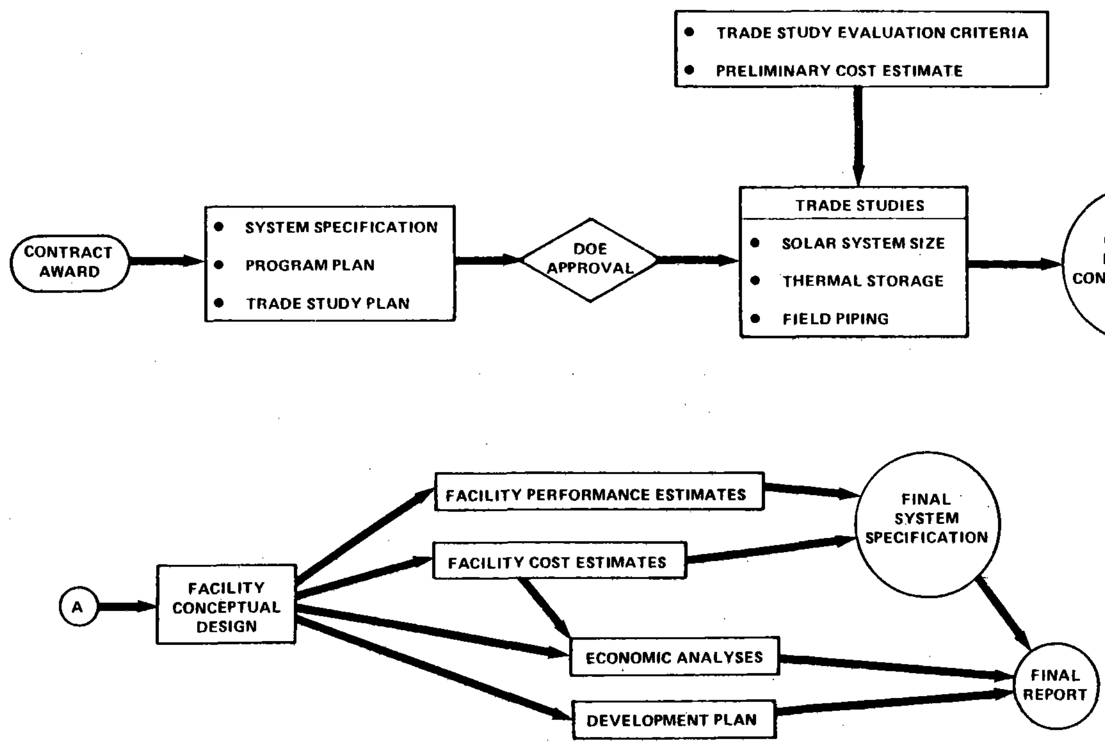


Figure 2-2. Program Summary Work Flow

2.2.2 Site Selection

Site selection criteria were established during the proposal phase in order to propose a specific site. These criteria were derived from the DOE program objectives. A summary of the site selection criteria, along with anticipated characteristics of the selected Texasgulf Chemical Company site, is presented in Table 2-1. Numerous industrial sites were assessed against these criteria during the proposal efforts. The selected Texasgulf site was found to best meet the established criteria.

Table 2-1

SITE SELECTION SUMMARY

Criteria	Results for Texasgulf Site
Large displacement of oil and/or natural gas	Displace ~243 × 10^6 cu. ft. of natural gas per year
Available land to meet solar requirements	Solar facility requires 50 acres out of more than 7000 acres available
High availability of solar insolation	~2900 kWh/m^2 per year
Process heat requirements in low to intermediate range (<475° F)	350° F hot water
Power/heat ratio 10-15%	12% for baseline concept
Year round plant operation preferred	Year round operation at 24 hours per day, 365 days per year

2.3 SITE LOCATION

The selected site, Texasgulf's Comanche Creek sulfur mine, is located 26 km (14 mi) northeast of Fort Stockton, Texas and approximately 454 km (245 mi) east of El Paso. The mine is located in Block 26 of University Lands in Pecos County (Figure 2-3). In all, Texasgulf leases 31 km^2 (7680 acres) from the University of Texas to be used for any purpose relative to the mining of sulfur. Rail service to the mine is provided by the Atchison Topeka and Santa Fe Railroad which borders the northern edge of the site.

2.4 SITE GEOGRAPHY

The Comanche Creek site and property adjacent to it are of desert composition with sparse vegetation. The land slopes up very gently to the north, approximately 3.5 m (12 ft) in 610 m (2000 ft). The basically flat land has essentially no topographical features to prevent the proposed development and offers the opportunity to preserve natural drainage. The solar collectors will occupy 0.128 km (31.5 acres) of land and will be located southeast of the existing plant.

The soil is relatively uniform, consisting of sandy silts and silty sands. It varies in relative density from loose to depths of 0.6 m (2 ft), medium dense to depths of 3.0 m (10 ft) and very dense below that depth. The soil has a relatively high bearing capacity and will support major structures at a depth of 0.6 m (2 ft). The depth to ground water is below 10.6 m (35 ft).

The site is at an elevation of 913 m (2995 ft) above sea level. Its geographic coordinates are:

- Latitude 30° 52′ N
- Longitude 102° 55′ W

2.5 CLIMATE

Fort Stockton has an arid subtropical climate with hot summers. The environment is good for solar applications. Details of the climate are discussed in the following sections.

2.5.1 Precipitation

Typical climatological data is best represented by the thirty-year period from 1938 to 1967 for which the mean annual total precipitation was 31.1 cm (12.23 inches). More than 70% of the total precipitation normally falls in the six-month period from May through October. 1941 was the wettest year with a total rainfall of 74.4 cm (29.3 inches). June, 1941 recorded both the maximum monthly rainfall of 15.3 cm (6.0 inches) and the maximum daily rainfall of 9.9 cm (3.9 inches). Precipitation in the form of snow is very rare with the greatest depth recorded as 5.0 cm (2.0 inches) in February, 1961.

2.5.2 Temperature

For this same thirty-year period the mean annual temperature was 18.4° C (65.2° F). The warmest month was July with an average temperature of 27.7° C (81.9° F) and the coolest month was January with an average temperature of 7.8° C (46.1° F). The highest temperature recorded during the period was 44.4° C (112° F) in June 1939; and the lowest temperature was −15.6° C (4° F) in December 1953.

2.5.3 Wind

The closest wind recording stations are at Midland, Texas about 145 km (90 mi) northeast of Fort Stockton and at El Paso. Table 2-2 shows that the El Paso winds tend to be slightly higher than those at Midland. The winds at the site should be between those at El Paso and those at Midland.

Table 2-2

WIND DATA

PARAMETER	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
Midland, TX													
Mean Wind Speed (mph)	9	10	11	11	11	11	9	9	9	9	9	9	10
Prevailing Direction	S	WSW	WSW	S	SE	SSE	SE	SE	SSE	S	SW	WSW	SSE
Fastest Mile Wind (mph)	41	67	48	38	52	58	29	30	40	32	32	37	67
Direction	NNW	WSW	WSW	SW	SSW	NNE	N	NE	N	NNE	N	SSE	WSW
El Paso, TX													
Mean Wind Speed (mph)	10	11	13	13	12	11	10	9	9	9	10	10	11
Prevailing Direction	N	N	WSW	WSW	W	S	S	S	S	N	N	N	N
Fastest Mile Wind (mph)	61	69	70	66	70	68	65	63	58	58	57	66	70
Direction	SW	W	SW	NW	NW	N	N	N	SW	W	W	W	NW

GENERAL ELECTRIC

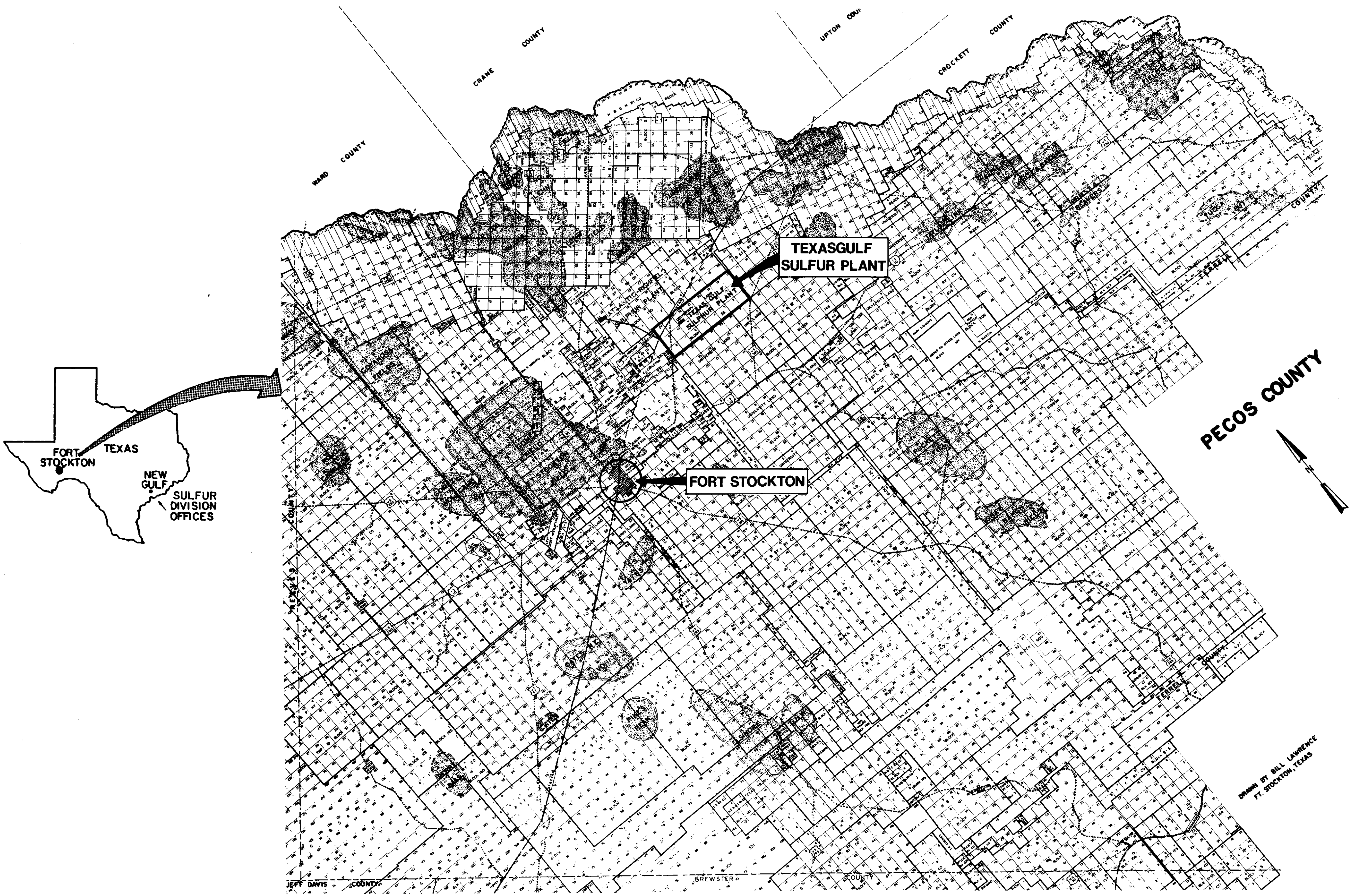


Figure 2-3. Map of Pecos County, TX Showing Location of Texasgulf Site

2.5.4 Cloud Cover

National Weather Service data for El Paso (Table 2-3) shows that the area receives 80% of the annual available sunshine, which should be approximately representative of the Comanche Creek Site.

Table 2-3

CLOUD COVER DATA

PARAMETER	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
El Paso, TX													
Percent Possible Sunshine	74	77	81	85	87	87	78	78	80	82	80	73	80
Number Hours of Sunshine	234	236	299	329	373	369	336	327	300	287	257	236	3583
Mean Sky Cover, % (Sunrise to Sunset)	37	36	34	29	26	24	40	38	31	27	28	35	32

2.5.5 Solar Radiation

No direct insolation data exists for the Fort Stockton area. To estimate the direct insolation for Comanche Creek, El Paso insolation data (~ same latitude) was used with adjustments made for differences in altitude.

The insolation data from the El Paso SOLMET tape was modified by 98% as described in Section 5.5 of Appendix A. This adjustment was applied across the board to all the El Paso insolation data. The resulting predicted daily average insolation for Comanche Creek is 7.13 kWh/m^2-day.

2.6 EXISTING PLANT DESCRIPTION

The Comanche Creek Mine utilizes the Frasch Process for mining of sulfur, as typically shown in Figure 2-4. Well water is preheated, treated and superheated to 177° C (350° F) at 1.72 MPa (250 psia) in the plant. This superheated water is tempered with hot treated water for close temperature control and distributed through insulated piping to a producing well. Precise temperature control is mandatory for maximum sulfur production.

The superheated water flows into the well at depths of 213-274 m (700-900 feet) in the outer of three concentric pipes. Elemental sulfur is melted underground and collected in a pool into which the middle concentric pipe end is submerged. Compressed air is fed through the inner pipe to mix with the molten sulfur, aerating it in order to airlift it to the surface. The air is then removed from the liquid sulfur and the sulfur is piped to liquid or solid storage vats.

This sulfur mine was designed and built in 1975. Major pieces of equipment in the Comanche Creek Plant include pumps, tanks, hot process softener vessels, and natural gas-fired water heaters. The plant has a once through flow of water (100% makeup) which is obtained from approximately 20 water wells located five miles from the site. In 1980, four additional water treatment tanks were added to allow the use of Rustler water, a sulfide laden water with high hardness, which is more abundant than the original source of water.

The existing plant supplies the process heat for mining as follows: Incoming raw water is first heated to 46° C (115° F) in direct contact economizers with the hot flue gases off the fired water heaters. It is then mixed with Rustler water, the secondary water that is sulfide laden and contains high total hardness. Next, this blended water is sprayed into hot process softeners and heated to approximately 109° C (228° F) with 34.5 kPa (5 psia) steam in order that deaerating and softening may be adequately accomplished. After that the hot softened water is pumped through the fired water heaters where it is heated to 177° C (350° F). This 177° C (350° F) water is tempered with 109° C (228° F) water to get the desired mining temperature of about 166° C (330° F).

Solar process heat will supply energy to the existing process at two points. A schematic showing the existing plant processes and interfaces with the Solar Cogeneration Facility is shown in Figure 2-5. A side stream of well water will be heated from 21° C (70° F) to 46° C (115° F) in a heat exchanger located at the condensing (exhaust) end of the turbine/generator. The second input of heat energy will occur with a side stream of 109° C (228° F) treated water being heated to 177° C (350° F) in a condensing heat exchanger located at the extraction port of the turbine/generator unit.

From an energy viewpoint, the Comanche Creek Plant and the Solar Cogeneration Facility complement each other, the sulfur plant being a useful heat sink for the solar condenser.

Electrical energy for the Comanche Creek Plant currently is purchased from West Texas Utilities. This 2.87 MW avg (3.0 MW peak) of electrical power drives the water well pumps, process water pumps, water heater blowers, and air compressors. The Electrical Subsystem will interface with the existing electrical distribution facilities and will supply electrical power, relieving the utility company's load.

2.7 EXISTING PLANT PERFORMANCE

The Comanche Creek Plant is designed to produce 1.51×10^4 m^3 (4.0 million gallons) per day of superheated water. During 1980 it produced approximately 3.2 million gallons of superheated water and consumed 2.72×10^5 m^3 (9.6×10^6 ft^3) of natural gas and 2.8 MW of electrical power daily. Variances off design were due mainly to limitations in the supply of raw water and to reduced needs for superheated water as dictated by the sulfur production area.

In the arid climate of West Texas, water is a precious commodity because it is not abundant and because the water that is available is often of extremely poor quality. The original plant water supply comes from water wells producing in the Trinity Sands Aquifier. It is of moderately good quality (600-700 ppm hardness), but experience has shown that the Trinity Sands do not yield sufficient quantities of water. Consequently, in 1980 a second water source was obtained. This water, termed Rustler water, is abundant but contains sulfides (300 ppm) and high hardness (2300 ppm). It presents special problems because hydrogen sulfide fumes are released as the water is heated and the high hardness is difficult and costly to treat. Facilities were installed to scrub the hydrogen sulfide gas fumes from the vented gases. Currently, the Comanche Creek Plant uses approximately 2.8 million gallons of Trinity Sands water and 1.0 million gallons of Rustler water daily.

The Comanche Creek Plant operates around-the-clock, 365 days per year with no scheduled outages; maintenance activities are performed with minimum reductions in mine water loads or, when applicable, with built in spares.

In 1980 two unscheduled outages occurred, both on April 14 and due to electrical power interruptions by the utility. Problems are caused when an outage such as this occurs, both in the Sulfur Production area as well as in the Plant area. Frasch sulfur mining requires a constant flow of superheated water. Unscheduled shutdowns cause abrupt changes underground as well as freezing of molten sulfur in the liquid sulfur collection system, disrupting the mining process. The extent of disruption of the normal sulfur production levels depends on the duration and impact of the outage.

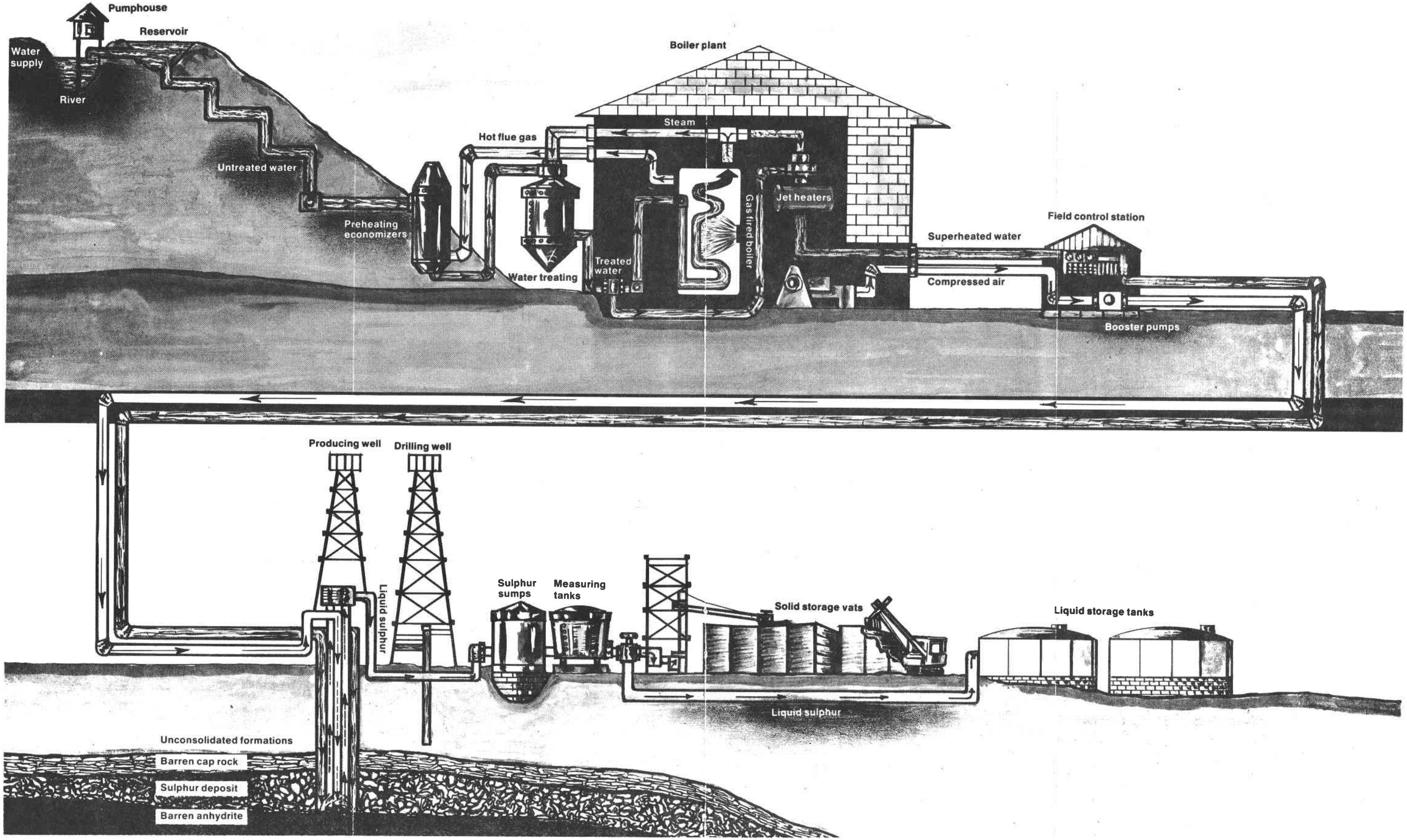


Figure 2-4. Frasch Sulfur Mining Operation

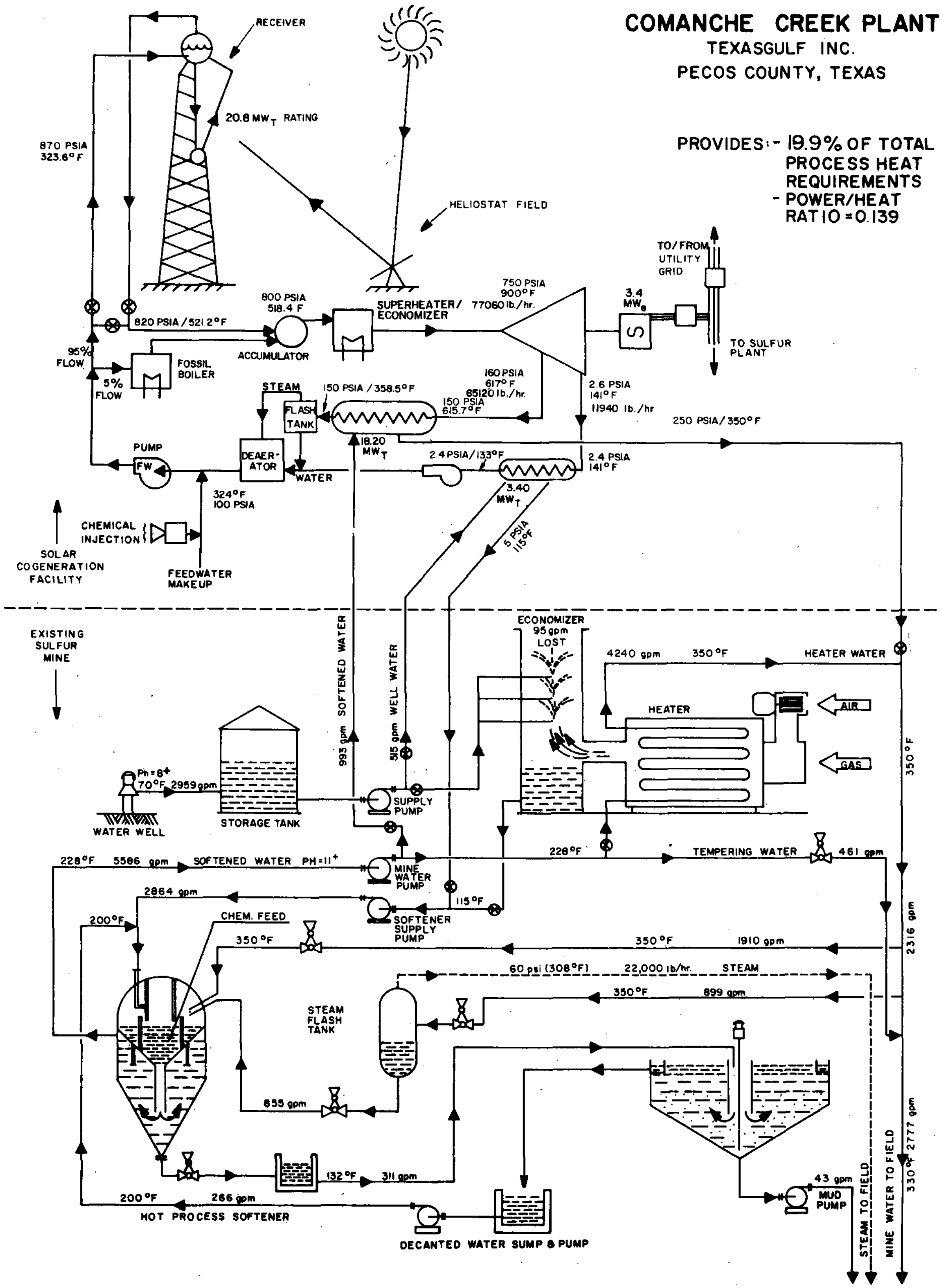


Figure 2-5. Process Flow Schematic

In-house power generation with the Solar Cogeneration Facility will minimize outages due to utility power failures.

2.8 PROJECT ORGANIZATION

The Texasgulf Solar Cogeneration Program was conducted by a team composed of the types of organizations required to take the Solar Cogeneration Facility from conceptual design through construction and operation. The project team consists of the General Electric Company (designer-manufacturer), Texasgulf Chemicals Company (owner-user), and Brown & Root Development Inc. (architect-engineer).

2.8.1 Organizational Structure

The program was led by the Advanced Energy Programs Department of the General Electric Company (GE) with the support of GE's Energy Systems Programs Department, Corporate Research and Development Center, Mechanical Drive Turbine Department, and Industrial Sales Division. The Texasgulf Chemical Company of Texasgulf Inc. was the subcontractor. Brown & Root Development Inc. was, in turn, a subcontractor to the Texasgulf Chemical Company. Texasgulf is well qualified to follow through on this program and assume the lead role during any resulting design, construction and operation activities. Texasgulf regularly subcontracts with Brown & Root for design and construction of plants. In fact, Brown & Root was responsible for the design and construction of the existing Comanche Creek Plant.

The respective roles of each of the project team members during the current program are summarized in Table 2-4.

2.8.2 Project Review Panel

In recognition of the near-term nature of the Solar Cogeneration Project, General Electric established a Project Review Panel to provide guidance and perspective to the project team. The members of the Project Review Panel are shown in Table 2-5. Mr. Donald C. Berkey, Vice President and General Manager of General Electric's Energy Systems and Technology Division (parent division of the Advanced Energy Programs Department) acted as chairman. The purpose, composition and activities of the panel are summarized in Table 2-6.

The Project Review Panel proved to be very beneficial to the program in a number of ways:

- Exposed the program and solar cogeneration concept to other potential industrial users
- Involved state and local officials to obtain support for current and future activities
- Acquainted the local electric utility with the program in order to lay the groundwork for electricity buy/sell rate discussions
- Obtained panel guidance and recommendations for use by the project team during the study

2.9 FINAL REPORT ORGANIZATION

This final report consists of seven (7) major sections plus appendices. An Executive Summary, which includes a program assessment by Texasgulf, is presented in Section 1. This Introduction is Section 2. The remaining five sections, 3 through 7, and Appendices cover the detailed technical work accomplished during the Program, as shown in Table 2-7.

Table 2-4
PROJECT ORGANIZATION

- General Electric Company
  - Advanced Energy Programs Department (AEPD)
    - Program Management
    - Systems Engineering
    - System Integration
    - Solar Engineering
    - Economic Analyses
    - Development Planning
  - Energy Systems Programs Department (ESPD)
    - Master Control Subsystem Engineering
  - Corporate Research & Development (CR&D)
    - Thermal Storage Trade Studies
  - Mechanical Drive Turbine Department (MDTD)
    - Steam Turbine-Generator Engineering
  - Industrial Sales Division (ISD)
    - Cost Estimates for Trade Studies

- Texasgulf Chemicals Company (Texasgulf)
  - Site Requirements & Specifications
  - Environmental Impact
  - Facility/Plant Interfaces
  - Economic Assumptions
  - Regulatory Requirements

- Brown & Root Development Inc. (BARDI)
  - Architect-Engineer Services
  - Tower Engineering
  - Balance of Plant Engineering
  - Site Layout

Table 2-5
PROJECT REVIEW PANEL MEMBERSHIP

Member Name	Position	Organization
D.C. Berkey, Panel Chairman	Vice President and General Manager	General Electric Company – Energy Systems & Technology Division
B.J. Tharpe	General Manager	General Electric Company – Advanced Energy Programs Department
D.E. Perry	Vice President and General Manager	General Electric Company – Industrial Sales Division
T.J. Wright	President	Texasgulf Chemicals Company
B.N. Soderman	Vice President and General Manager	Texasgulf Sulfur Operations
C. Karnes	Director – Research & Development	Burlington Industries
C. Massopust	Corporate Vice President of Technical & Regulatory Services	Dart & Kraft, Inc.
Charles Mauk	Coordinator, Solar and Conservation Programs	Texas Energy and Natural Resources Advisory Council
R. Wood	Executive Vice President	Fort Stockton Chamber of Commerce
W. Baxter	Manager – Industrial Sales and Research	West Texas Utilities

Table 2-6
PROJECT REVIEW PANEL

PURPOSE

- Review Progress at Appropriate Intervals
- Provide Guidance and Perspective
  - Pilot Plant
  - Commercial Plant

COMPOSITION

- Potential Industrial Users
- Senior GE Management
- State and Local Officials
- Electric Utility Representative

ACTIVITIES

- First Meeting (December 3, 1980)
  - Program Familiarization
  - Early Guidance/Perspective
- Second Meeting (March 25-26, 1981)
  - Review Conceptual Design Results
  - Tour DOE Central Receiver Test Facility
  - Guidance/Perspective for Future Activities

Table 2-7

FINAL REPORT ORGANIZATION

Program Task	Report Section
Task 1 - System Specification	Appendix A
Task 2 - Selection of Preferred System	Section 3
Task 3 - Conceptual Design - Subsystem Characteristics	Section 4 Section 5
Task 4 - System Performance	Section 4.5
Task 5 - Cost Estimates - Economic Analyses	Sections 4.7 and 4.8 Section 6
Task 6 - Development Plan	Section 7

Section 3
SELECTION OF PREFERRED SYSTEM

Section 3

SELECTION OF PREFERRED SYSTEM

This section describes both the proposal and the program efforts undertaken to select the site-specific system configuration for the Texasgulf Solar Cogeneration Facility.

3.1 INTRODUCTION

The general solar cogeneration concept, illustrated in Figure 3-1 and involving a solar steam supply in parallel with a fossil-fired steam supply, was selected during the proposal phase of the program. The criteria for selecting the general system concept were based on the understanding that cogeneration was evisioned as a near-term application of solar energy to the industrial community. Furthermore, it was believed that the selected concept should be adaptable to a wide range of industrial applications. The selection criteria that evolved from this understanding are listed in Table 3-1.

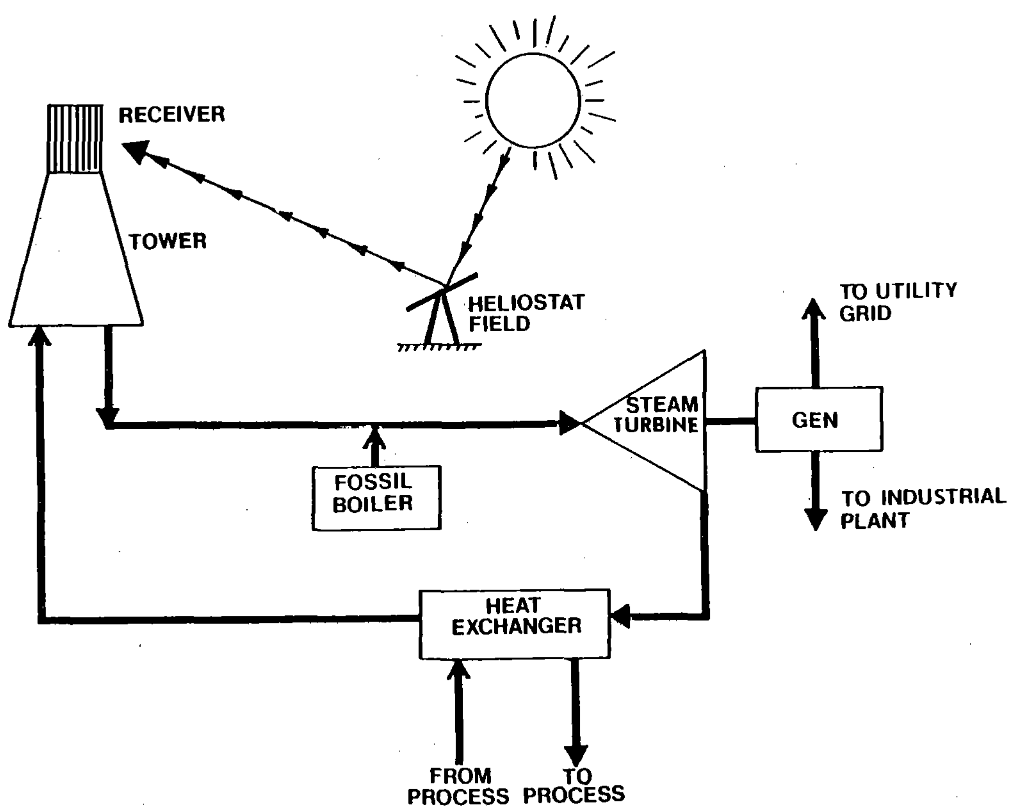


Figure 3-1. Proposed Solar Cogeneration Concept

In order to ensure a wide industrial applicability for the solar cogeneration facility, data used came from a study performed by General Electric for DOE/NASA-Lewis, titled "Cogeneration Technology Alternatives Study - CTAS."(3.1) This data allowed the selection of a process heat temperature range and a power-to-heat ratio with large market potential.

Table 3-1

BASELINE CONCEPT SELECTION CRITERIA

DOE Program Objectives	GE Selection Criteria
• Effective Use Of Solar Energy • Central Receiver Configuration	• Maximize Solar Contribution • Provide Electricity And Process Heat • Central Receiver Configuration
• High Reliability • Operation By 1986	• Near Term Technology • Minimize Development Needs • Maximum Use Of Off-Shelf Equipment • Minimize Complexity
• Best Possible Economics	• Minimize Capital And O&M Costs • Maximize Fuel Savings • Maximize Capacity Factor
• Large Potential Market	• Widely Applicable Concept • Competitive Economics
• Significant Savings In Oil/Gas	• Displace Oil And/or Gas • Maximize Solar Contribution - Cost Effectively
• Power/Heat Ratio Between 10-1000%	• Power/Heat Ratio Between 10-1000%
• Size Unconstrained - Small Preferred	• Measurable Solar Contribution • Meaningful To Site Operator • Compatible With DOE Objectives

The CTAS effort considered cogeneration within the six largest energy consuming industrial groups in the nation during the time frame of 1985-2000. The energy consumption of these groups represents 85% of all U.S. manufacturing industries, and approximately 94% of this energy usage involves processes requiring low to intermediate temperatures of less than 246 °C (475 °F), as shown in Figure 3-2. This temperature range was selected for the baseline concept because of its large potential market, which is 80% (0.85 × 0.94) of the entire U.S. manufacturing industry. Furthermore, this temperature range poses few technology problems, will allow the use of cheaper materials, and will minimize the associated development activities.

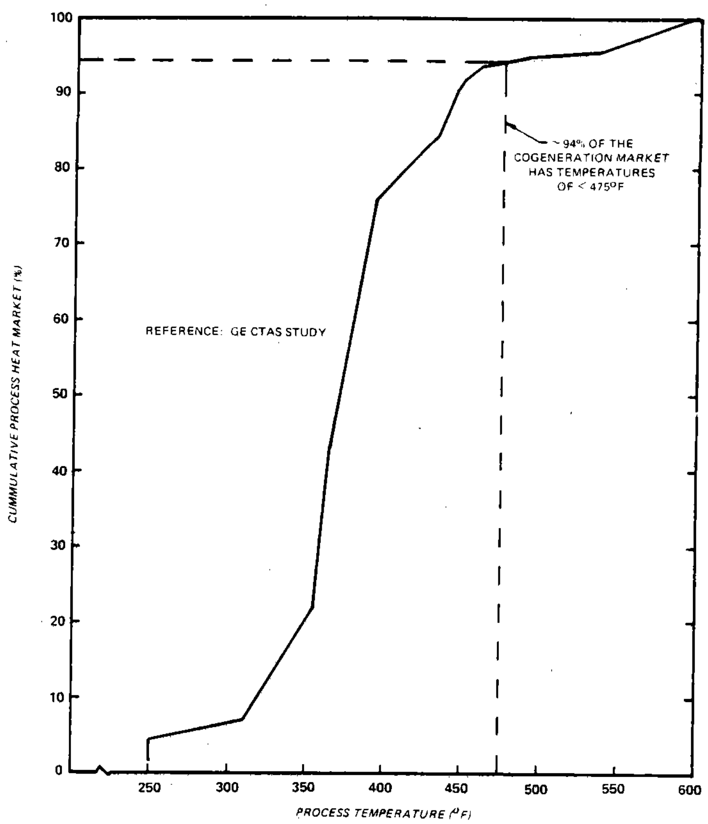


Figure 3-2. Process Temperature Applications in the Cogeneration Market

Power-to-heat (P/H) ratios for the industries considered in the CTAS effort are shown in Figure 3-3. Approximately 70% of the industrial processes studied in CTAS fall in the P/H range of zero to 0.15. Therefore, this P/H range was selected as a design goal for our baseline concept since it represents 60% (0.85 × 0.70) of the national industrial market.

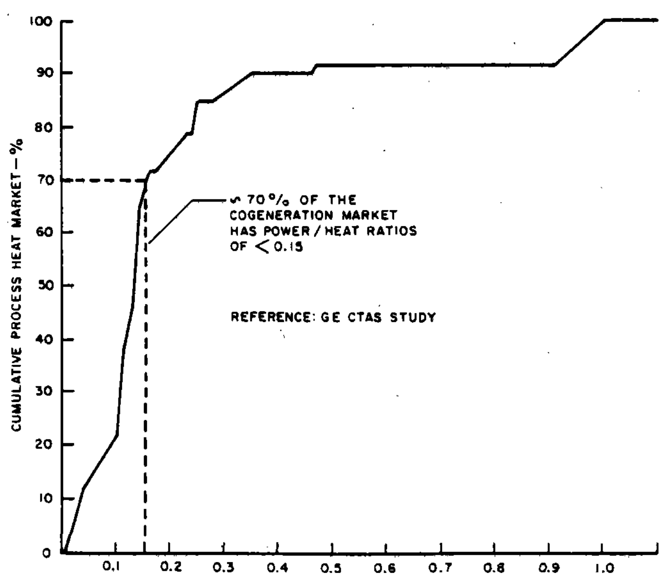


Figure 3-3. Power/Heat Applications in the Cogeneration Market

The many industries that fall within these selected ranges of temperature and P/H ratio include, among others: sulfur mines, ethanol and petroleum refineries, sugar mills and refineries, textile mills, lumber mills, paper mills, and plants for producing alumina, vinyl chloride, and phosphoric acid. The design of solar cogeneration systems exhibiting these selected temperature and P/H ratios will be influenced primarily by process heat requirements, with the electrical requirements playing a secondary role.

3.2 TECHNOLOGY

When trying to adapt any generic concept to a specific application, each individual subsystem or component has certain associated design alternatives. Table 3-2 presents a list of design alternatives that were considered during the proposal. The rationale for selecting these alternatives is discussed below.

Table 3-2

CONCEPT DESIGN ALTERNATIVES

Subsystem	Options
Collector Subsystem	Flat vs Focused Heliostats North Field vs Surround Heliostat Aiming Strategy
Receiver Subsystem	Cavity vs External Sodium vs Water/Steam vs Salt Single Pass Boiler vs Recirculation Natural vs Pumped Circulation Evaporator & Superheater vs Evaporator Only
Electric Power Generation Subsystem	Topping vs Parallel vs Bottoming Superheated vs Saturated Inlet Steam Heat Rate Operation out of Storage
Process Heat Subsystem	Direct Flow vs Intermediate Heat Exchanger
Fossil Energy Subsystem	New vs Existing Plant

3.2.1 Collector Subsystem

Focused heliostats were not used in this study because high fluxes were not needed to achieve acceptable receiver efficiencies at the low temperature levels proposed. Furthermore, focusing would present problems in receiver design because of the high peak fluxes. According to the receiver flux studies from the Alternate Central Receiver Program, multipoint aiming would be required even with flat heliostats in order to keep the incident fluxes below 1 MW/m^2 at representative receiver ratings.

Field configuration studies performed during the Solar Repowering Program have shown that for receiver ratings up to 60 MW_t there is a definite economic advantage in using a north field collector arrangement. Therefore, the north field arrangement was selected for this cogeneration program.

3.2.2 Receiver Subsystem

Cavity receivers present a more difficult design problem than external receivers due to the uncertainty in estimating the distribution of absorbed flux and the total convection loss. Because of the very near-term application goal (1986), the risk involved in developing a cavity receiver was considered unacceptable. Thus, only flat, external receivers have been considered.

Steam can be generated in a recirculatory flow evaporator with a drum separator on top. This approach draws upon a large body of package boiler experience. Recirculation is either natural (by gravity feed) or forced (by pumping). The natural circulation concept was selected because it is self-controlling, i.e., "the water flow goes where the flux is" and because of the low pressure levels required.

Superheat was not selected because of the attendant complexity of the solar receiver, which would not be justified by the marginal gain in turbine efficiency. Thus, based upon the criteria, a saturated water/steam receiver was selected.

3.2.2.1 Receiver Working Fluid

The selection of a receiver working fluid was based upon the following criteria:

- Low to intermediate temperature
- Minimum thermal losses
- Material cost
- Degree of development required
- System complexity
- Storage adaptability

The specific coolants evaluated were sodium, molten salt, and water/steam. Sodium offers very high flux capability, but that capability is not as important in this cogeneration application as it is in large central station power plants. This is because with the lower receiver temperatures 150-425 °C (300-800 °F) as compared with 593 °C (1100 °F), the receiver flux does not have to be high to achieve acceptable receiver efficiencies of 90% or more.

The use of either molten salt or sodium as a receiver coolant would require a sodium- or salt-to-steam heat exchange that would add cost to the system. In addition, trace heating would be required in both cases to maintain a minimum temperature: sodium above 121 °C (250 °F) and salt above 204 °C (400 °F). The trace heating would ensure that the coolant does not freeze during nonsolar operation. For these reasons, both molten salt and sodium have been rejected as a receiver working fluid for this low-temperature application.

3.2.3 Electric Power Generating Subsystem

The configurations already studied range from parallel to topping, depending upon the ratio of power to heat. For very low power-to-heat ratios, parallel arrangements will be required because the turbine exhaust does not supply sufficient heat. For high ratios, all of the heat may be derived from the turbine exhaust, which may occur in two or more streams at different pressure/temperature levels. The turbine heat rate is not an issue in this study except where it affects the power/heat ratio.

Referring to the system concept shown in Figure 3-1, the most direct way to provide both electrical and thermal power is by expanding steam in a turbine with a back pressure of about 1.38 MPa (200 psia). An alternate way is to use a steam turbine that permits the extraction of most of the steam at 1.38 MPa (200 psia) and expands the rest of the steam to 17.9 kPa (2.6 psia). Then the higher-pressure extraction supplies heat for the higher temperature process, and the low-pressure exhaust provides heat at the lower temperature. The two condensate streams are at different pressures and need to be combined. Since the higher-pressure liquid will flash to wet steam at the lower pressure, this process would probably be done along with a deaerating system.

The results of preliminary cycle calculations for both types of systems show an increase of moisture content at discharge with an increase of throttle pressure. High moisture content increases erosion problems and decreases turbine efficiency. The maximum moisture percentage tolerable at the turbine discharge is about 15%. By that criterion, peak throttle pressure is about 5.5 MPa (800 psia) for the extraction turbine and 8.6 MPa (1250 psia) for the back pressure turbine (Figure 3-4).

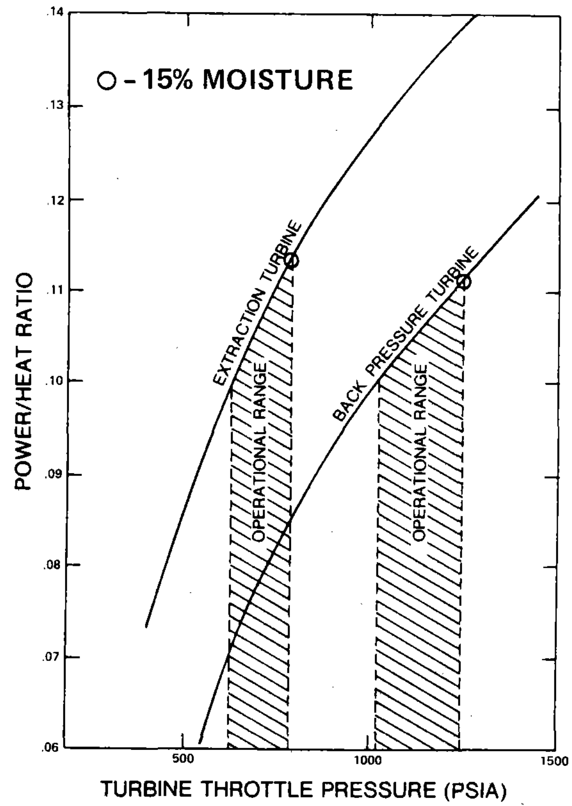


Figure 3-4. Power/Heat Ratio vs Steam Turbine Throttle Pressure

To fulfill both criteria (a power/heat ratio of at least 0.1 required by DOE and a moisture content of no more than 15%), the optimum operating ranges of throttle pressure are 4.1 to 5.5 MPa (600 to 800 psia) for the extraction turbine and 6.9 to 8.6 MPa (1000 to 1250 psia) for the back pressure turbine. Both cases have power/heat ratios of from 10 to 12%. The difference for the two types is the operating throttle pressure level. However, high pressure tends to increase the erosion problem if moisture is present. Therefore, an extraction turbine has been selected for this study.

3.2.4 Process Heat Subsystem

Steam can be supplied to the process directly from either the receiver or the turbine, or indirectly through an intermediate heat exchanger (IHX). Direct supply has an advantage in delivering steam without any temperature drop. However, direct supply couples the receiver and turbine not only to the process temperature but also to the process pressure, and requires continuous makeup of large quantities of boiler-quality water. The poor quality of the Texasgulf raw water thus makes direct supply very impractical due to the extensive water treatment that would be required. Therefore, only indirect heat supply through an IHX has been considered in this study.

3.2.5 Fossil Energy Subsystem

All of the industries surveyed have fossil-fired boilers already in place. If these boilers were sufficiently responsive, the solar plant could work in parallel with the existing boilers. However, the Texasgulf facility uses water heaters that cannot generate the steam requirements of the turbine. This site-specific concept will therefore require an appropriate boiler. Such boilers are readily available as package units.

3.3 SYSTEM CONFIGURATION

Based on the selected range of criteria for wide applicability and the previous technology discussion, a baseline cogeneration concept was derived. This concept was presented in the proposal and formed the basis for the trade-off studies conducted to select the site-specific configuration. The use of superheat steam was initially discarded because its higher temperature capability was not needed to meet the stated concept criteria. However, the use of superheat has been reevaluated and is now found to be economically desirable.

3.3.1 Baseline Configuration

The baseline configuration is shown schematically in Figure 3-5. It involves a north-field arrangement of second-generation heliostats reflecting solar insolation onto a flat, external tower mounted receiver. The receiver is a natural convection, saturated water/steam boiler designed to operate at a temperature of 266 °C (511 °F). The steam is collected in a steam drum above the receiver, from which dry saturated steam is supplied to the rest of the system. A steam accumulator is located at the base of the tower to provide 2-5 minutes of buffer storage. A parallel fossil boiler, maintained in a rapid-response condition, is used when needed to maintain a level energy supply 24 hours per day for the sulfur mine. The steam for electrical generation is expanded through a steam turbine that drives a generator to provide electricity either for use in the plant or for sale to West Texas Utilities. The steam for process heat is obtained from an extraction port in the steam turbine through a high-pressure condenser to generate superheated water required for the process. Additional process heat or preheat is obtained by passing the turbine exhaust steam through either a back-pressure or subatmospheric condenser cooled by the process water. This concept makes maximum use of available energy and does not require cooling towers, which would increase cost and waste energy.

Trade studies were limited to those areas that would enhance the cost-effectiveness of the baseline configuration, specifically:

- Solar System Size
- Thermal Energy Storage
- Field Piping

Each of these studies is discussed in Sections 3.4 through 3.6.

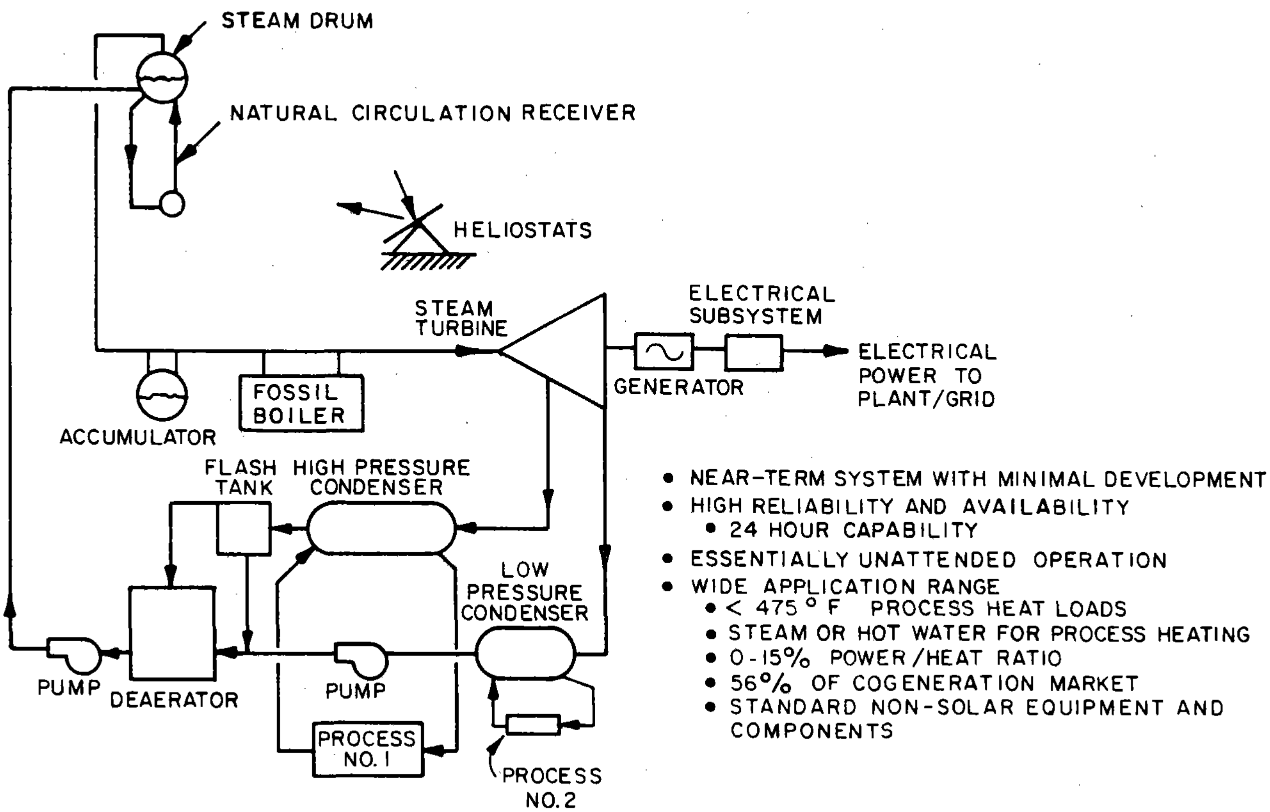


Figure 3-5. Baseline Configuration

3.3.2 Superheat Configuration

Section 3.7 describes the superheat trade-off study, which indicated that the use of superheat is economically desirable. Thus, the baseline configuration was changed to include a separate gas-fired superheater. Except for changing the steam turbine, the basic differences between the two configurations are in the fossil energy subsystem and the collector subsystem. The output from the accumulator is now fed directly to the superheater whose output is fed to the turbine, and there are signficantly fewer heliostats. A more complete description of the superheat configuration is presented in Section 4.1.

3.4 SYSTEM SIZE TRADE-OFF STUDY

The purpose of this trade study was to determine the economy of scale by assessing the cost and performance impacts of varying the thermal power input to the steam turbine between 10 MW_t and 130 MW_t. The upper end of this power range covers the complete requirements of the entire mining operation. By maintaining a power-to-heat ratio greater than 10% and by selling all excess electricity to the local utility, an economic rate of return analysis should indicate the most cost-effective system size.

The Sandia-developed DELSOL[3.2] computer code was used as the primary analytical tool in this trade study, and Table 3-3 lists the main input parameters for the analysis. Note that long-term thermal storage was not considered except as part of the storage trade-off study discussed in Section 3.5.

Appropriate cost models (Table 3-4) were developed for all components with the exception of the heliostats. A heliostat cost of $260 per square meter ($24/ft^2) was used in accordance with Sandia's directive on the costs to assume for heliostats for the program. Models for the other components were based either upon the results from those Repowering Program Studies using similar equipment or upon estimates from General Electric's Industrial Sales Division.

Table 3-3

SYSTEM SIZE STUDY INPUT VALUES

Parameter	Input Value
Design Point	Equinox, Noon
Design Point Isolation	950 W/m^2
Site Altitude	913 m (2995 ft)
Heliostat Size	49.12 m^2
Heliostat Reflectivity	90%
Receiver Absorbtivity	95%
Radiation and Convection Losses	4%
Receiver Flux Limitation	0.85 MW/m^2
Solar Multiple	1.0

Table 3-4

SYSTEM SIZE STUDY COST MODELS

Parameter	Cost Model
Heliostats	CH = 260.0 ($/m^2)
Land/Site Preparation	CL = 2.4 ($/m^2)
Tower	$CTOW = 3.487 \times 10^6 - 7.928 \times 10^4\,(THT) + 594.9\,(THT^2)$
Receiver	$CREC = 8.3 \times 10^5 \left(\frac{AREA}{48}\right)^{0.923}$
Storage	CSTOR = 0.0
All Other	GE - Industrial Sales Division Estimates

The results of the DELSOL optimization analysis are presented in Table 3-5, which shows the recommended field configuration and capital costs for each rated size in the range 10-130 MW_t.

Parametric turbine envelope diagrams were used to determine the available power distribution for each size. Then the fuel consumption requirements were calculated both for the existing mine water heaters and for the add-on fossil boiler.

Table 3-5

DELSOL FIELD SIZE RESULTS

Rated Size (MW_t)	No. Heliostats	Tower Height (m)	Receiver Size Width × Height (m)	Land Area (Acres)	Annual Solar Energy (MWh/yr)	Capital Cost ($M)
10	380	70	8 × 8	18.3	23300	12.58
20	686	70	10 × 10	40.8	47700	18.92
30	1017	80	10 × 10	61.0	72500	25.75
40	1317	90	12 × 12	77.1	96500	32.23
50	1636	100	12 × 12	95.1	121000	39.03
60	1963	110	12 × 12	108.2	146000	45.97
70	2295	120	12 × 12	121.6	170000	53.11
80	2667	120	12 × 12	152.5	196000	60.95
90	2926	130	14 × 14	158.6	220000	66.19
100	3247	140	14 × 14	174.0	244000	73.82
110	3604	140	14 × 14	202.1	270000	81.27
120	3935	150	14 × 14	232.0	295000	88.23
130	4236	150	16 × 16	243.6	319000	92.70

Based upon an evaluation of the Comanche Creek power requirements for the 18-month period of May 1979 through October 1980, the peak power demand was 3.0 MW_e. The available electricity for each rated size was factored into the analysis in terms of the reduced purchases and the sales of excess (defined as over 3.0 MW_e) electricity. The sale of excess electricity was assumed at a rate of 0.6 times the purchase rate. The fuel and electricity consumption are summarized in Table 3-6.

Typically, the primary evaluation criterion for trade study decisions is the discounted rate of return (DCRR) on the capital investment. In addition to capital cost, the DCRR analysis considers capitalized O&M costs as well as the savings in fuel consumption and the buying/selling of electricity. The O&M costs were taken as 1.5% of the capital cost per year over the plant life. The fuel and electricity costs along with other economic assumptions are listed in Table 3-7.

Table 3-6

FUEL AND ELECTRICITY CONSUMPTION

Rated Size (MW_t)	Water Heaters (MBtu/yr) × 10^{-6}	Fossil Boiler (MBtu/yr) × 10^{-6}	Electricity (kWh/yr) × 10^{-6}
10	3.224	0.261	17.083
20	2.952	0.518	7.917
30	2.672	0.773	0.883
40	2.401	1.032	(8.333)*
50	2.141	1.288	(20.833)
60	1.857	1.542	(26.667)
70	1.607	1.801	(41.667)
80	1.344	2.051	(53.333)
90	1.081	2.309	(65.0)
100	0.812	2.568	(75.0)
110	0.538	2.818	(83.333)
120	0.272	3.072	(94.167)
130	0	3.331	(103.333)

* ( ) indicates excess electricity

Table 3-7

ECONOMIC ASSUMPTIONS*

Factor	Value
Annual Inflation Rate	0
Federal & State Income Tax Rate	50%
Tax Depreciation Method	Straight Line
Tax Depreciation Life	7 Years
Salvage Value	0
Investment Tax Credit	10% + 15%
Local Real Estate Taxes & Insurange	3%
Useful Life of Investment	20 Years
First Full Year of Operation	1986
Cost of Fuels and Power:	
Natural Gas	$2.50/10⁶ Btu
Purchased Power	$0.033/kWh
Escalation of Fuels and Power Above Inflation:	
Natural Gas	3%
Purchased & Exported Power	1%

*All Costs are in 1980 $
NOTE: Price of surplus power exported to utility = 0.6 x purchased power rate

Figure 3-6 summarizes the results of the economic analysis and shows the real rate of return (with zero general inflation) versus the rated size of the solar system. The solid lines represent various heliostat costs ranging from the DOE-specified $260/m^2 down to $100/m^2, a cost at which DOE expects heliostats to be available in the future.

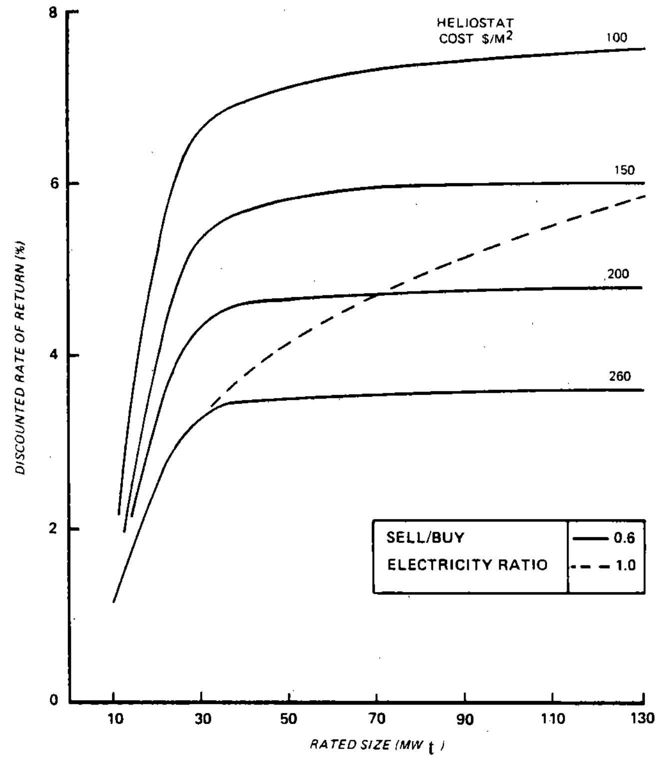


Figure 3-6. Results of System Size Trade-Off Study

The first observation is that, since the collector field represents at least 50% of the total capital cost, there is a significant increase in the rate of return with decreasing heliostat cost. Second, there appears to be a general leveling off at system sizes in excess of 30 MW_t. It is believed that this leveling is caused by the fact that in this size range there begins to be an excess of electricity available for sale to the utility, and this electricity is generally sold at a rate less than it can be purchased for. In general, you would expect to see an economy of scale as you get larger in size. This expectation would be true if you were able to sell the electricity at the same rate at which you buy it, as shown in the dashed curve with a heliostat cost of $260/m^2.

Based on the above analysis, the optimum system size should be in the range of 25-40 MW_t, since the initial indications are that the electricity sell/buy ratio will be less than 1.0. More specifically, after consulting with Texasgulf, the solar system size selected for the conceptual design efforts was one that provides 3.0 MW_e, the peak electrical demand. For the saturated steam approach, this output is equivalent to a 30 MW_t rated solar system.

3.5 THERMAL ENERGY STORAGE TRADE-OFF STUDY

The proposal baseline configuration provides only buffer storage, which is sufficient to allow the gas-fired boiler to pick up the load in an orderly manner, should the solar insolation be interrupted.

During this trade-off study, the cost-effectiveness of providing additional long-term storage to increase the solar contribution has been investigated.

Table 3-8 summarizes the different storage media and applications of storage that were evaluated in this trade study. The evaluation used the baseline proposal concept as a reference case and assumed that there is no selling of electricity. A simplified sun model that assumed a levelized uniform solar input to the receiver for ten hours per day has been used, with the balance of the required process energy to be supplied either from storage or from the gas-fired boiler.

Table 3-8

STORAGE TRADE STUDY APPLICATIONS

Storage Media	Storage Uses
• Pressurized Hot Water	• Preheating Feedwater
• Molten Salt	• Process Heat/Buy Electricity
• Oil or Oil/Rock	• Generate Steam for Turbine

Six long-term thermal storage concepts have been evaluated for application to the solar cogeneration facility. The storage concepts consist of two basic types: cases 2 through 5 all use thermal energy storage in pressurized hot water (PHW), while cases 5 through 7 have a storage medium other than water (oil plus rock or molten salt).

The available daily solar energy and the corresponding capital cost investment for the collector field, the receiver, and the tower were determined by DELSOL as a function of the solar multiple. Only these component costs will be considered in addition to the cost of the storage system, since they are the only ones that vary with storage system size. Tables 3-9 and 3-10 use these data to summarize the preliminary storage trade study results.

A comparison of the various combinations of storage media and uses is shown in Table 3-9, which includes the 24-hour daily energy balance consisting of the receiver output, boiler fuel consumption, and electricity purchased. Also shown is the corresponding solar contribution and comments on the additional equipment that may be required to implement the storage concept. Table 3-10 shows the physical description of the various storage concepts in terms of the required number and size of tanks, along with the probable method of constructing these tanks.

Using storage for feedwater heating at night (cases 2 and 5) appears to be the most simple and least costly method of applying storage. The amount of new equipment is relatively small, and storage can be discharged in parallel with heat input from the receiver to augment the solar steam supply. The disadvantage of this storage mode is that it is limited to a maximum solar input fraction of 34%.

Table 3-9
ENERGY BALANCE FOR STORAGE CONCEPTS

Case No.	Storage Medium	Use of Storage	Diurnal Energy Balance* Rec'r (MWh)	Boiler (MWh)	Elec. Purch. (MWh)	Waste Heat (MWh)	Total Input (MWh)	% Solar Input	Comments
1	–	–	170	469	0	0	639	27	Baseline Concept
2	PHW	FW Heating	215	416	0	0	631	34	No New HX Can Run Parallel
3	PHW	Process Heat	400	175	58	0	633	63	2 New HX Cannot Parallel
4	PHW	Flash for Turbine and Process Heat	500	155	0	64	655	76	2 New HX Cannot Parallel 1 New Turbine
5	Oil and Rock	FW Heating	205	427	0	0	632	32	2 New HX Can Run Parallel
6	Oil and Rock	Process Heat	400	176	58	0	634	63	3 New HX Cannot Parallel
7	Oil and Rock	Boil for Turbine and Process Heat	510	155	0	74	655	77	3 New HX Cannot Parallel 1 New Turbine

*Assumes constant solar input for 10 hours followed by no lar input for 014 hours, based on average day solar input.

Table 3-10
PHYSICAL DESCRIPTION OF STORAGE CONCEPTS

Case No.	Solar Mult.	Storage Tanks Volume (ft^3)	Dimensions (ft)	Construction Method	Heat Exch. Area (ft^2)
2	1.2	7 × 3800 1 × 23,000	8D × 78L 35D	Factory Field	0
3	2.0	20 × 3800 1 × 61,000	8D × 78L 49D	Factory Field	1 × 1800 1 × 200
4	2.5	28 × 3800 1 × 85,000	8D × 78L 55D	Factory Field	1 × 4000 1 × 500
5	1.2	1 × 41,000	30D × 59H	Field	1 × 5700 1 × 14,000
	1.2	1 × 29,000	26D × 53H	Field	1 × 1200 1 × 3500
6	2.0	1 × 99,000	40D × 80H	Field	1 × 19,000 1 × 27,000 1 × 2700
7	2.5	1 × 224,000	52D × 104H	Field	1 × 25,000 1 × 23,000 1 × 38,000

If storage is used to provide process heat at night while the turbine is shut down and electricity is purchased (cases 3 and 6), then the solar contribution can be increased to 63%. However, this concept requires electricity to be purchased and increases the investment for storage tanks and heat exchanger equipment.

Cases 4 and 7 use storage to provide steam to run the turbine at night, thus eliminating the need to buy electricity and increases the solar contribution to 76%. However, these systems are quite large and expensive, and they produce excess heat at night which must be dumped if it cannot be absorbed by the process.

Each of the six storage concepts was designed to accommodate the largest storage capacity that can be effectively utilized. Then they all were compared against the baseline proposed case that has only buffer storage.

To determine whether a storage concept is cost-effective, its investment cost must be compared to the savings* in operating costs over the plant lifetime. In making this comparison, one must remember to account for the time value of money (discounting) and for the effects of corporate taxes as shown in Table 3-11. For particular values of the fuel cost savings, ΔF, and the purchased electricity expense, ΔE, and a stated value of the rate of return, r, this equation gives the amount of the initial investment which can be justified by the savings.

Table 3-11

CALCULATION OF LIFETIME SAVINGS

$$\Delta I = \frac{\Delta F \cdot LEVF - \Delta E \cdot LEVE}{FCR}$$

where:	ΔI	=	lifetime savings
		=	investment in storage which would have a return, r, based on the savings ΔF and expenses ΔE
	ΔF	=	annual savings in fuel cost with respect to case 1. (\$/year) at 2.50 \$/MBtu
	LEVF	=	fuel cost levelization factor
	ΔE	=	annual expenses for purchased electricity (\$/year) at 3.3¢/kWh
	LEVE	=	Elec. cost levelization factor
	FCR	=	fixed charge rate
		=	$\frac{1}{(1-t)}\left\{(1-k)(CRF)_L + p(1-t) + \frac{2t}{r(L+1)}(CRF)_L \frac{1}{L}\right\}$
	t	=	corporate income tax rate (50%)
	k	=	investment tax credit (25%)
	$(CRF)_L$	=	capital recovery factor
	p	=	property tax rate (3%)
	r	=	discounted rate of return
	L	=	plant lifetime (20 years)
	LEV	=	$\frac{1-\left(\frac{1+e}{1+r}\right)^L}{(r-e)\ 1-(1+r)^{-L}}$
	e_f	=	fuel escalation rate over GNP inflation = 3%/yr
	e_e	=	electricity escalation rate over GNP inflation = 1%/yr

* Savings equals the operating cost of the reference plant minus the operating cost of the plant with storage.

Figure 3-7 plots the results of this equation for each of the cases analyzed. Also shown are the storage system cost estimates determined in Appendix B.

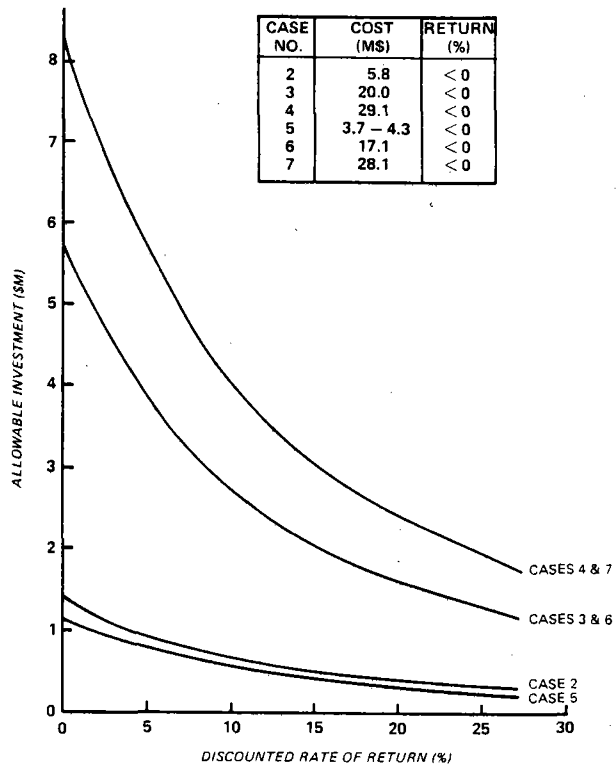


Figure 3-7. Thermal Storage Trade-Off Study Results

Compared with the system cost estimates, none of the storage systems produce a positive return. Since none of the storage systems appears to offer any economic advantage over the reference case, it has been concluded that long-term thermal storage should not be incorporated in the solar plant. This conclusion stems primarily from the high cost of the solar components. If there were a significant decrease in the cost of heliostats, the storage trade-off study might produce a different result.

3.6 FIELD PIPING TRADE-OFF STUDY

The solar collector field is located to the south of the existing Comanche Creek Plant for the following reasons:

- The prevailing wind is from the south and this location will minimize collector soiling.
- This location is the only unrestricted land, since sulfur mining is done on land to the east and west while land to the north is broken by a railroad spur line and overhead transmission lines.

In this location the tower is on the side of the collector field that is opposite from the sulfur mine. The purpose of this trade-off study was to determine the best location for the steam-turbine generator and process heat exchangers, i.e., whether they should be at the tower base or adjacent to the existing plant. The major variables are field piping and electrical transmission lines.

The field piping schematic (Figure 3-8) illustrates the six different piping runs that must be considered along with their respective operating temperatures. From Figure 3-8, there are three possible choices for the location of the turbine and process heat exchangers. They are:

- Baseline (Proposed System):
  Turbine/Generator and Heat Exchangers located near tower.
- Alternate 1:
  Turbine/Generator and Heat Exchangers located near existing plant.
- Alternate 2:
  Turbine/Generator located near tower;
  Heat Exchangers located near existing plant.

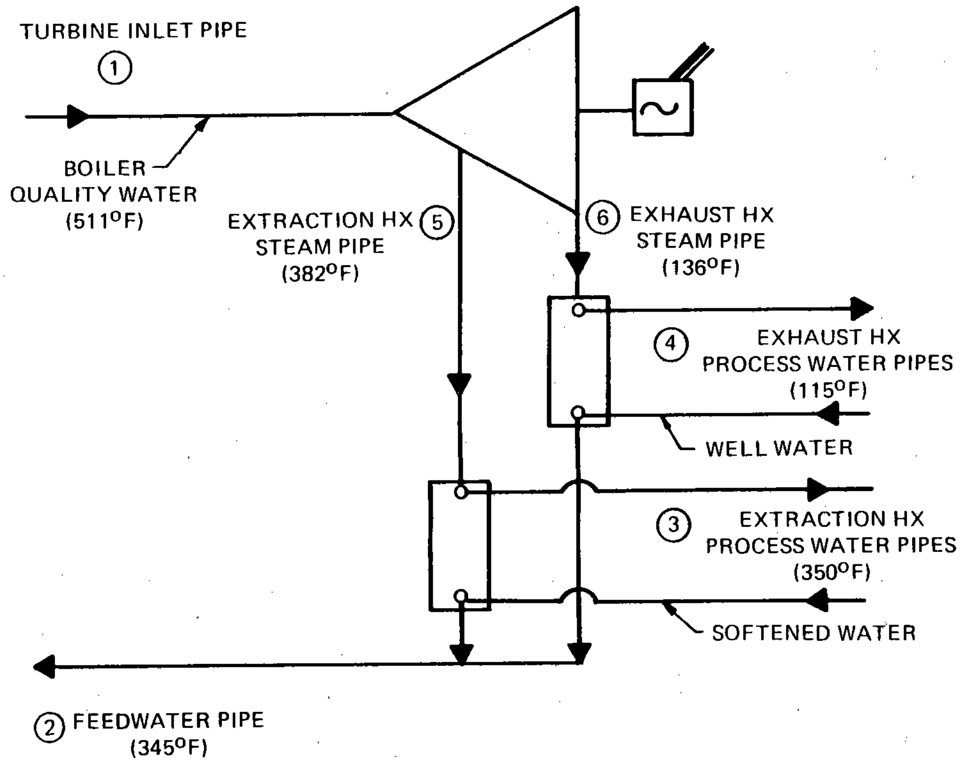


Figure 3-8. Field Piping Considered in Turbine/Generator and Heat Exchanger (HX) Location Trade-Off Study

The approach used in this trade study is to maintain constant performance, and thus the optimum choice will be the one that has the lowest cost. Constant performance includes keeping the moisture at the turbine inlet equal to or less than 0.5%, maintaining less than 2 ° temperature drop in all water lines, and maintaining the pressure drop in each piping run independent of pipe length. These characteristics will determine the required pipe size and insulation thickness. The pertinent costs to be considered are those of the piping, insulation, electrical transmission lines, installation, and O&M charges. The specific cost parameters are listed in Table 3-12.

In evaluating the three options for steam turbine/heat exchanger location, a computer program written for calculating the required pipe size and insulation thickness for the stated constant performance conditions was used. Table 3-13 shows the corresponding results; Table 3-14 shows the corresponding cost estimates.

Table 3-12

PIPING TRADE-OFF STUDY COST PARAMETERS

- Piping
  - Schedule 40 carbon steel piping for sizes over 2 in. nominal OD
  - Schedule 80 carbon steel piping for sizes 2 in. and under
  - 20 ft. lengths, field welded
  - Expansion "U" bend (20% pipe length adder)
  - Pipe support piers every 20 ft
  - Sliding type pipe hangers
  - Field piping traverses the perimeter of the heliostat field

(See Figure 3-9 for installed pipe costs as a function of diameter and insulation thickness.)

- Insulation
  - Certainteed* with aluminum jacket
- Electric Transmission Line
  - Class II wood pole with 10 ft wood across arm, 45 ft long
  - 3 insulators, ASA Class 55-5
  - Poles installed every 200 ft
  - 3-400 MCM aluminum wire with steel strand
  - 1-2/0 steel ground wire
  - Transmission line traverses the perimeter of the heliostat field
- Installation
  - All costs considered include the cost of installation.
- O&M Costs
  - Insulated Piping: 1.5%/year of installed capital cost
  - Transmission Line: 2.0%/year of installed capital cost
- Additional Data
  - All costs are 1/1/80.
  - Plant life - 30 years; interest - 8%; present worth factor - 11.258
  - Valves, transformers, etc. (i.e., end conditions) are considered constant for the 3 concepts and, therefore, are not included in the trade-off study costs.

*Certainteed is a registered trademark for the Certainteed Corporation, P.O. Box 860, Valley Forge, PA, 19482.

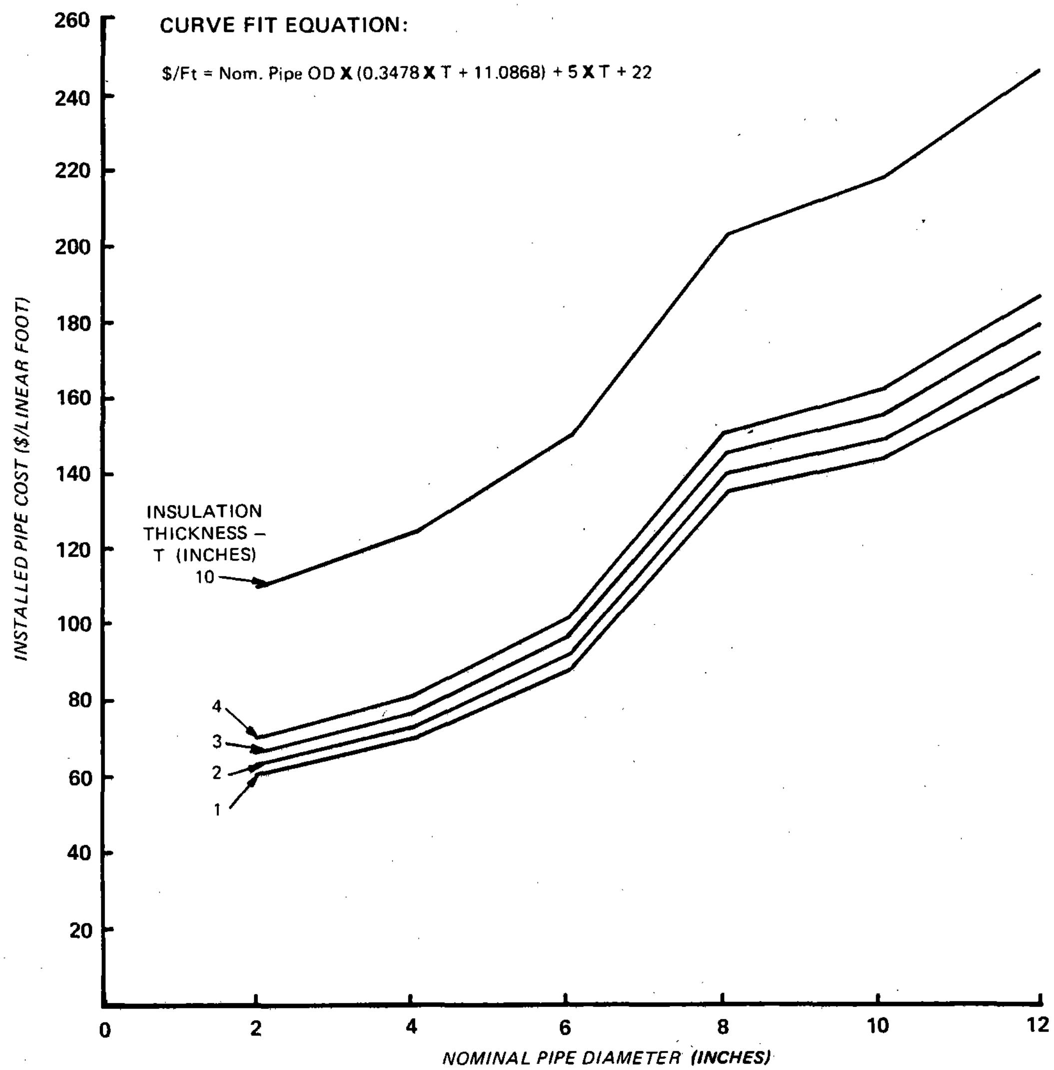


Figure 3-9. Installed Pipe Costs

Alternate concept 1, with the steam turbine and heat exchangers located near the existing plant, was chosen because of its minimum cost along with the following subjective (not costed) benefits.

- Minimum number of long distance pipes required (2)
- Minimum pipe maintenance, since long-distance piping will be carrying boiler quality steam or water
- Loss of vacuum in line 6 minimized due to short length (as compared with the length in Alternate Concept 2)
- Minimum length transmission line has less potential for forced outages due to lightning strikes, etc.
- Minimum length of turbine/generator control wiring required
- Reduced maintenance time spent on turbine/generators and heat exchangers, since they are located near the main plant repair and parts supply centers

Table 3-13

PIPING SUMMARY

Concept	Length (ft)	SCH. 40 Diameter (in.)	Insulation Thickness (in.)
Baseline			
1. Turbine Inlet	400	8	1
2. Feedwater Return	400	3	1
3. Supply	4000	10	2
Return	4000	10	2
4. Supply	4000	8	0
Return	4000	8	1
Alternate 1			
1. Turbine Inlet	4000	10	9
2. Feedwater Return	4000	5	2
Alternate 2			
1. Turbine Inlet	400	8	1
2. Feedwater Return	4000	5	2
5. Extraction - HX	4000	8	4
6. Exhaust - HX	4000	3.5	2

Table 3-14

SUMMARY - PIPING COSTS

Concept	Installed Capital Cost ($)	Present Worth O&M Costs ($)	Total
Baseline			
• Piping	2,187,200	369,200	
• Transmission	35,600	8,000	
			2,600,000
Alternate 1			
• Piping	1,198,000	202,000	
• Transmission	0	0	
			1,400,000
Alternate 2			
• Piping	1,217,500	214,900	
• Transmission	35,600	8,000	
			1,530,000

3.7 SUPERHEAT TRADE-OFF STUDY

The previous trade-off studies were all based on the baseline configuration, which incorporated a steam turbine with saturated steam inlet conditions. The use of superheat had been rejected during the proposal phase because its inherent higher temperature capability was not required in order to satisfy the selected process heat market. However, upon the recommendation of the Project Review Panel, a superheat system was reevaluated and the results of the trade-off study are presented below.

The Texasgulf requirement of providing their peak power demand of 3.0 MW_e was imposed on the superheat solar system. A preliminary heat balance indicated that the solar receiver/fossil boiler should be rated at 18.2 MW_t and that a 5.2 MW_t superheater would be required.

The collector field analysis was performed with the DELSOL program using the same parameters and cost models described in Section 3.4. Tables 3-15 and 3-16 present a comparison of the resulting superheat system and the saturated system.

Table 3-15

SYSTEM CONFIGURATIONS

	Saturated	Superheat
Number Heliostats	913	592
Tower Height (m)	80	70
Receiver Size, H x W (m)	9.3 x 11.0	6.8 x 8.0
Land Area (acres)	50	35
Electricity (MW_e)	3.0	3.0
Thermal Energy (MW_t)	25.7	19.3
Power/Heat Ratio	0.117	0.156
Solar Contribution/Turndown (%)	28.3/23.3	22.0/17.7
Fuel Consumption (MBtu/Yr)	3.45 x 10^6	3.52 x 10^6
Capital Cost (1980 - $M)	26.0	18.6

Table 3-15 shows that both systems would consume approximately the same amount of fuel each year. However, the superheat system has a significantly lower capital cost primarily due to the reduced number of heliostats. Furthermore, Table 3-16 shows that there is a greater fuel savings for each dollar invested with the superheat system.

The reduced capital investment required for the superheat system should ease the future cost sharing requirements of both Texasgulf and the DOE. This result, in turn, would enhance the probability of eventual facility construction. Therefore, the superheat system has been selected for the conceptual design activities to be discussed in Sections 4, 5 and 6 of this report.

Based upon a trade-off study performed by Foster Wheeler,[3.3] a separate gas-fired superheater is used instead of a solar superheater. The Foster Wheeler study showed that with heliostats at $230/$m^2$ ($21/$ft^2$), the equivalent cost of energy for a solar superheater was $18/MBtu. On the

Table 3-16

SYSTEM COMPARISON

	Saturated	Superheat
(1) Electricity Savings at Utility Eff. = 32%	274.5×10^6 ft³/yr	274.5×10^6 ft³/yr
(2) Turndown at Tg	23.3%	17.7%
(3) Gas Savings at Water Heater	797.0×10^6 ft³/yr	606.8×10^6 ft³/yr
(4) Solar Thermal Supply	74.3×10^6 kWh/yr	45.1×10^6 kWh/yr
(5) Gas Consumed by Boiler	741.3×10^6 ft³/yr	449.5×10^6 ft³/yr
(6) Gas Consumed in Superheater	—	179.1×10^6 ft³/yr
Total Savings (1) + (3) - (5) - (6)	330.2×10^6 ft³/yr	252.7×10^6 ft³/yr
Total Capital Cost	\$26.0 M	\$18.6 M
Gas Saved (ft³ per \$ invested)	12.7	13.6

other hand, with natural gas at \$2.50/MBtu (1980 \$), the gas-fired superheater will be superior as long as the fuel escalation rate (including inflation) remains below 16 percent.

REFERENCES

3.1 *Cogeneration Technology Alternatives Study (CTAS),* General Electric Company Report (GE80ET0102) Prepared for DOE/NASA-Lewis, May, 1980.

3.2 *DELSOL: A Computer Code for Calculating the Optical Performance, Field Layout and Optimal System Design for Solar Central Receiver Plants,* T.A. Dellin and M.J. Fish, Sandia National Laboratories, SAND79-8215, June, 1979.

3.3 *Solar Industrial Retrofit System for the Provident Energy Company Refinery,* Foster Wheeler Development Corporation, Livingston, NJ, Final Report FWDC No. 9-41-3131, July 15, 1980.

Section 4
CONCEPTUAL DESIGN

Section 4

CONCEPTUAL DESIGN

This section discusses the Solar Cogeneration Facility (SCF) design for the Texasgulf Comanche Creek sulfur mining operation. The system level description is provided, and the functional requirements, operational characteristics and system performance are discussed. System costs, operation and maintenance considerations, safety and environmental and regulatory issues are included. Individual subsystems are discussed in detail in Section 5.

4.1 SYSTEM DESCRIPTION

The SCF configuration integrated with the existing plant is shown schematically in Figure 4-1. It consists of a north field arrangement of 588 heliostats, each 52.77 m^2 (567.8 ft^2), reflecting solar insolation onto a 6.8 m high × 8.0 m wide (22.31 ft × 26.25 ft) flat-panel, external receiver mounted atop a 70 m (229.7 ft) tower. The natural-circulation receiver generates 5.65 MPa (820 psia) saturated steam, which is conducted down the tower and fed into the accumulator. The output of the gas-fired boiler (minimum turndown of 5%) is fed into the accumulator in parallel with the receiver output to insure uniform, continuous 24 hours per day operation.

The accumulator output is directed into a gas-fired superheater that will produce 5.17 MPa, 482 °C (750 psia, 900 °F) superheated steam for the uncontrolled extraction, condensing superheat steam turbine. Steam exhausted from the turbine will be routed through a low pressure heat exchanger, where cold water from the existing water supply will be preheated to 46 °C (115 °F). An extraction port on the steam turbine feeds a high pressure heat exchanger that raises the process water temperature to 177 °C (350 °F) which is combined with water from the mine heaters and delivered to the sulfur wells.

The SCF will provide 100% of the mining operation's electrical requirements (3.0 MW_e) and 19.85% of the process heat requirements (21.6 MW_t) to yield a power-to-heat ratio of 0.139. The impact on the existing sulfur mine is limited to piping tie-ins and controls modifications. The master control subsystem (not shown) responds to signals from the receiver, boiler, accumulator and superheater, directing the steam supply to provide the required quantity of hot water to the process.

4.2 FUNCTIONAL REQUIREMENTS

The following sections provide a top level discussion of the functional requirements imposed on the cogeneration facility. The requirements include provisions for the desired output and specifications by the user for satisfactory integration with the existing plant.

Details of individual subsystems and component requirements are included in the System Specification, Appendix A.

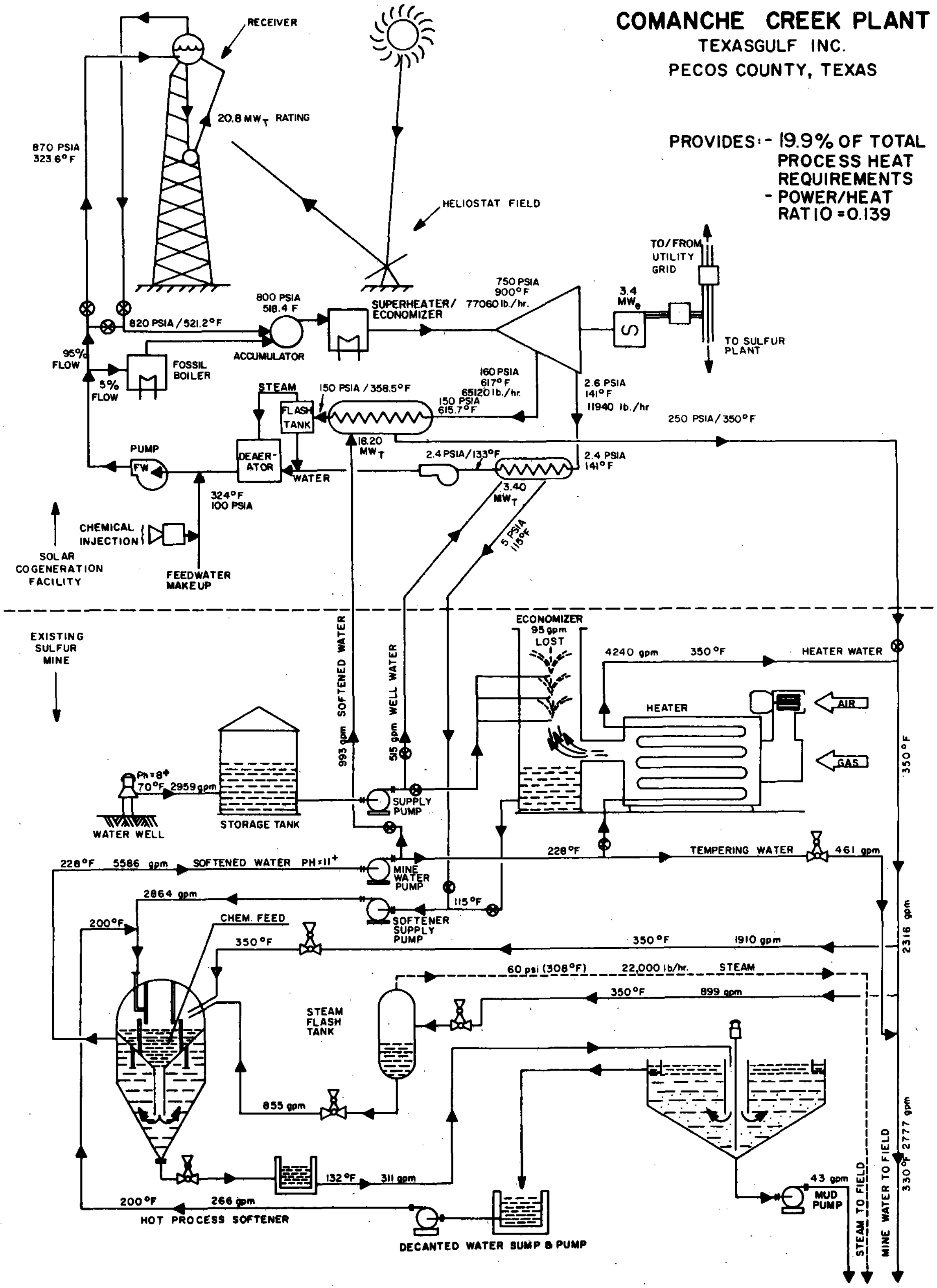


Figure 4-1. Texasgulf Solar Cogeneration Facility Configuration

4.2.1 Design Life

The 20-year design life of the solar system is consistent with Texasgulf design practices. Major subsystem components are designed for a 20-year life.

4.2.2 System Performance Requirements

The system performance requirements listed in Table 4-1 are those necessary to meet operating limitations of the existing plant and proposed equipment. Annual solar energy collected and solar fraction are shown as projected values for information rather than as requirements, because we have no direct normal insolation data for the site.

Table 4-1

SYSTEM PERFORMANCE REQUIREMENTS

Site Location	Fort Stockton, Texas
Design Point	Vernal Equinox, Noon
Design Point Insolation	950 W/m^2
Design Point Power	20.4 MW_t (69.6 MBtu/hr)
Design Point Steam Flow	9.7 Kg/s (77060 lb/hr)
Annual Solar Energy Collected*	53GWh (181000 MBtu)
Solar Fraction*	19.1 %
Receiver Delivery Pressure	5.65 MPa (820 psia)
Receiver Delivery Temperature	272 °C (521 °F)
Turbine Inlet Pressure	5.17 MPa (750 psia)
Turbine Inlet Temperature	482 °C (900 °F)
Environmental Operating Conditions	
Temperature	-18 °C to 49 °C (0 °F to 120 °F)
Wind	18 m/s (40 mph)
Environmental Survival Conditions	
Wind	40 m/s (90 mph)
Snow	240 Pa (5 lb/ft^2)
Ice	5.08 cm (2 in.)
Hail	5.08 cm (2 in) @ 36.5 m/s (75 mph)
Seismic Environment	Zone 2 (UBC)

*Projected values - not requirements

The instrumentation and control philosophy is to incorporate the minimal provisions to assure safe and efficient operation. This requires maintenance of steam pressure at the interface with the superheater while delivering steam at the maximum available rate, up to the demand. Sufficient instrumentation to facilitate control of this output and to warn the operator of out-of-plan conditions will be incorporated.

4.2.3 Operating Requirements

The operating requirements listed in Table 4-2 are those imposed by Texasgulf to ensure satisfactory integration of the solar system into the existing Comanche Creek Mine.

Table 4-2

OPERATING REQUIREMENTS

Mode of Operation	Requirement
Hybrid	Capability to startup or shutdown either solar or fossil system with the other operating; steady output during solar transients; responsive to mine demand.
Fossil Only	No performance degradation of existing mining operation.
Controls	Redundant master control and critical distributed control facilities; manual overide capability; hard wiring of controls for critical components.
Emergencies	Automatic response to emergencies to put facility in safe shutdown mode and to prevent casualty from impacting other components.

4.3 DESIGN AND OPERATING CHARACTERISTICS

This section includes a discussion of the Comanche Creek cogeneration facility design and operating characteristics established to satisfy the specified functional requirements.

4.3.1 Modes of Operation

Definition of the method of operating the proposed facility and the associated control and instrumentation requirements is considered a critical element in the conceptual design. The solar cogeneration facility will be operational in several interconnecting modes. Described below are five major modes of operation:

- Normal Nighttime Operation
- Solar Startup
- Normal Daytime Operation
- Cloud-Cover Transients
- Emergency

4.3.1.1 Normal Nighttime Operation

During normal nighttime operation the cogeneration system electrical and thermal loads are maintained at full load design point levels under steam supply from the gas-fired fossil boiler which operates at full capacity. A receiver warm up line will circulate saturated steam from downstream of the accumulator to the lower water wall header of the receiver. This will create a natural circulation upward through the risers of the receiver by the difference in density from the colder liquid in the downcomer tubes. Flow in the warm up line will commence after the normal evening shutdown of the solar receiver, during extended cloud coverage and prior to a startup after an extended outage of the solar receiver. Thus, the receiver remains, throughout the night, in a state of readiness for automatic startup in the morning.

It is anticipated that the receiver warm up line will consume very little energy. However, since it was incorporated in the design late in this study, its effects have not been included in the performance and/or economic analyses. These effects should be accounted for in any future studies.

4.3.1.2 Solar Startup

At sunrise the heliostats are focused on the flat-panel receiver tubes. The incident heat flux generates steam and starts the natural circulation process. As drum pressure rises, a steam outlet valve will be opened to supply steam to the accumulator. The fossil boiler will sense the change in flow and pressure and turn down accordingly. Firing of the boiler is controlled so that the outlet steam temperature is always at 270 °C (518 °F).

4.3.1.3 Normal Daytime Operation

In this mode, the cogeneration facility always operates as a hybrid (i.e., combined solar and fossil energy). During daytime operation saturated steam is generated by the receiver at 5.65 MPa (820 psia) and is throttled to the accumulator, where it is combined with saturated steam from the fossil boiler. The output from the accumulator is directed to the gas-fired superheater where it is superheated to 482 °C (900 °F) and admitted to the steam turbine.

At the design point, the receiver generates 9.21 kg/s (73210 lb/hr) steam. The fossil boiler is operated at minimum turndown (5%) providing 0.49 kg/s (3850 lb/hr) steam. The output of the boiler is modulated by the control system such that there is a constant steam supply to the steam turbine. At times other than the design point, the boiler is slowly ramped up to compensate for the decrease in solar steam generation due to reduced insolation.

4.3.1.4 Cloud-Cover Transients

As a cloud starts covering the heliostat field, the receiver flux will decay, resulting in a drop in flow and pressure at the steam outlet. The control system responds by ramping the fossil boiler to bring the pressure and flow up to normal. The accumulator equivalent steam capacity of 0.89 MWh_t is sufficient to allow the boiler to ramp up to full output (from 5%) within 5 minutes in the case of severe cloud transients.

With the departure of the cloud, the heat flux is again incident on the solar receiver, starting steam generation. With rising drum pressure, the steam outlet valve is opened and steam is fed to the accumulator. With the admission of this steam, the fossil boiler is turned down accordingly and the solar system is back in the normal daytime operating mode.

4.3.1.5 Emergency Operation

In the event of an emergency that requires immediate cessation of steam production, the heliostats are defocused from the receiver. This is done to protect the receiver from potentially damaging flux or to keep from over-pressurizing the system following a previous failure. If further safety precautions are required, the system can be depressurized by venting the steam drum.

In the event of loss of electrical power (turbine-generator outage), the ability to feed water to the receiver and to focus heliostats away from the receiver will be lost. The sun's motion will cause the reflected beam to gradually leave the receiver. Approximately 15 minutes is required for the absorbed power to reach 10% of the original value. Since this time is more than that required for the steam drum to empty, the West Texas Utilities grid tie-in will drive the feed pump to ensure sufficient coolant is available to the drum. This electric supply will allow for complete shutdown of the solar system and fossil only operation with turbine bypass. As mentioned in Section 5.3.5 the superheater is vented and flow is maintained for cooldown control until shutdown.

4.3.2 Thermal Energy Balance

This section describes the balance of input and output energies to the cycle along with the water/steam system state parameters (flow, pressure and temperature). Figure 4-2 illustrates the design point (equinox, noon) mass and energy flows during operation.

The energy flows are designated as Q_x and the energy balance is detailed in Table 4-3. The water and steam flows, pressures and temperatures are listed for 13 locations, designated A through M in Table 4-4.

4.3.3 Control Concept

Monitoring and control instrumentation hardware will be basically a pneumatic analog control system comparable with the existing plant controls. The exception will be the solar receiver and heliostat field instrumentation and controls which are planned to be a conventional electric digital signal system, due to the remote location of the solar receiver and heliostats from the existing control system.

4.3.3.1 Steam Pressure Control

Two modes of operation, selectable from a master switch on the central control panel, will be designed into the system: nonsolar and hybrid.

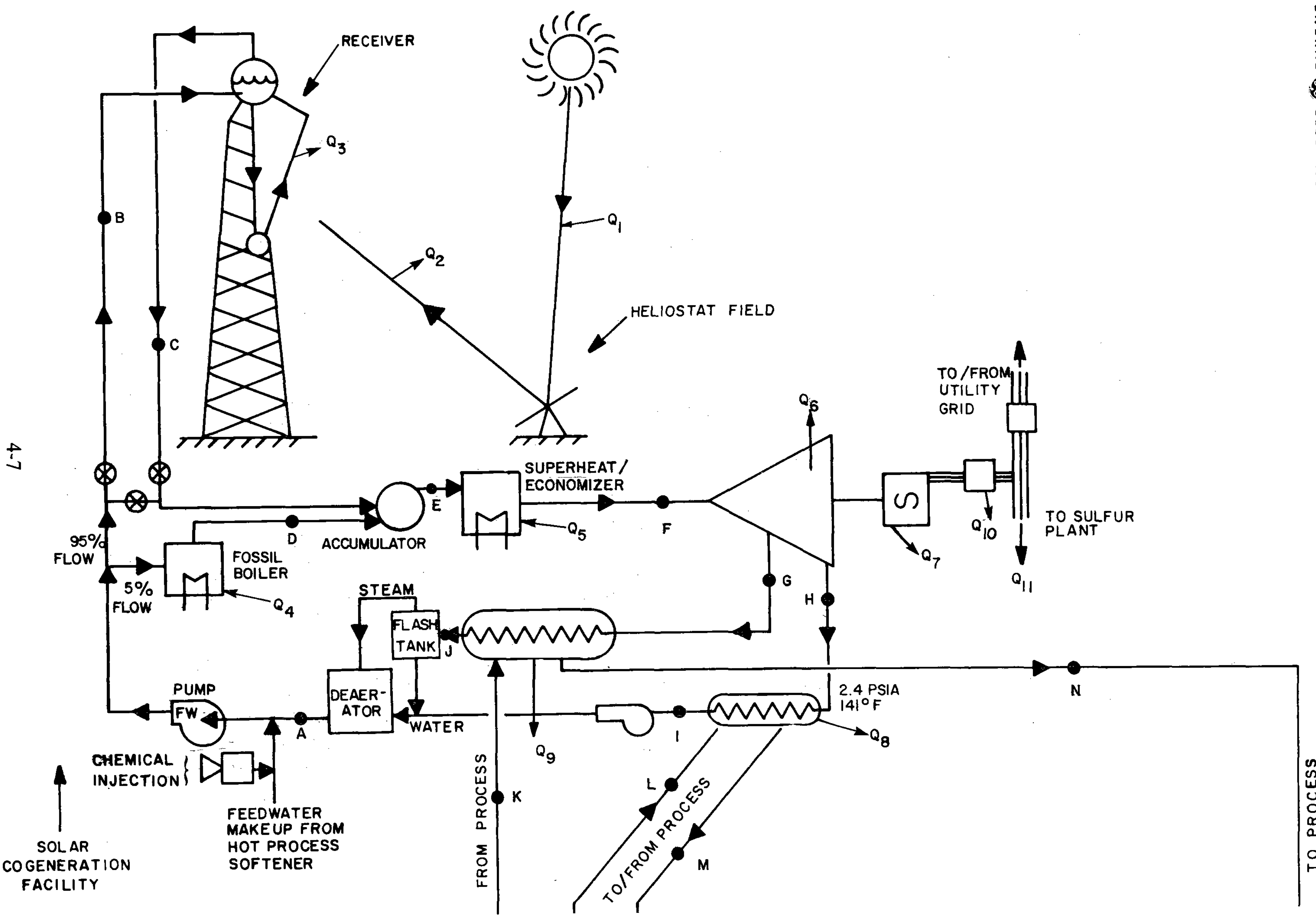


Figure 4-2. Mass Flows and Energy Balance

Table 4-3

DESIGN POINT ENERGY BALANCE

- Energy Inputs

Designation	Description		MW_t
Q1	Energy Incident on Heliostat Field		29.5
Q4	Saturated Boiler		1.0
Q5	Superheater		5.8
	Total		36.3

- Energy Outputs

Designation	Description		MW_t
Q2	Field Losses		7.1
Q3	Receiver Losses:	Thermal	1.6
		Flow	1.0
Q6	Turbine Losses		1.6
Q7	Generator Losses		
Q8	L.P. Condenser		3.4
Q9	H.P. Condenser		18.2
Q10	Aux. Power Requirements		0.4
Q11	Power to Mine		3.0
	Total		36.3

Table 4-4

DESIGN POINT THERMAL STATE PARAMETERS

- Steam Side

Designation	Location	Flow kg/s (lb/hr)	Pressure MPa (psia)	Temperature °C (°F)
A	Feedwater Pump Inlet	9.69 (77060)	0.69 (100)	162 (324)
B	Receiver Inlet	9.21 (73210)	5.99 (870)	162 (324)
C	Receiver Outlet	9.21 (73210)	5.65 (820)	272 (521)
D	Boiler Outlet	0.48 (3850)	5.51 (800)	270 (518)
E	Accumulator Outlet	9.69 (77060)	5.51 (800)	270 (518)
F	Turbine Inlet	9.69 (77060)	5.17 (750)	482 (900)
G	Turbine Extraction	8.19 (65120)	1.10 (160)	325 (617)
H	Turbine Exhaust	1.50 (11940)	0.02 (2.6)	61 (141)
I	L.P. HX Outlet	1.50 (11940)	0.02 (2.4)	56 (133)
J	H.P. HX Outlet	8.19 (65120)	1.03 (150)	183 (359)

- Water Side

Designation	Location	Flow m^3/s (gpm)	Pressure MPa (psia)	Temperature °C (°F)
K	H.P. HX Inlet	0.062 (989)	1.73 (250)	109 (228)
L	L.P. HX Inlet	0.003 (54)	0.04 (5)	21 (70)
M	L.P. HX Outlet	0.003 (54)	0.04 (5)	46 (115)
N	H.P. HX Outlet	0.062 (989)	1.73 (250)	177 (350)

4.3.3.1.1 Nonsolar Operation. This mode is selected during nighttime hours or during extended cloud covers. The primary steam source will be from the fossil boiler only with the solar receiver isolated from the main cycle.

Fossil boiler combustion control (air and fuel modulation) will be indexed from the steam pressure signal monitored at the outlet of the accumulator. The boiler will follow the turbine during this mode. Feedwater regulation will be by single element (drum level) control by modulating control valve in the feedwater inlet line to the fossil boiler drum.

The fossil boiler will maintain the required steam flow plus the additional amount needed for the water treatment system. The furnace safeguard system will be supplied by the boiler supplier as a packaged equipment.

4.3.3.1.2 Hybrid Operation. This mode is selected during daylight hours provided sufficient insolation is available. Transients during intermittent cloud covers will also be handled during this mode.

Fossil boiler combustion control (air and fuel modulation) will be primarily indexed from the steam pressure signal monitored at the outlet of the solar receiver drum but upstream of the isolation non-return valve. The fossil boiler will follow the solar receiver system and hybrid combination will follow the turbine.

The fossil boiler will be maintained at a minimum firing rate to maintain the boiler in a state of readiness. Solar receiver and fossil boiler feedwater regulation will be by respective single element (drum levels) controls. Recorders and indicators will be provided for the steam and feedwater streams of solar receivers, the fossil boiler and the accumulator.

4.3.3.2 Accumulator Level Control

The accumulator drum will be maintained at a preset level by modulation of the feedwater control valve and the blowdown valve. The level falling signal will open the feedwater inlet valve while the level rising signal will adjust the blowdown valve opening.

4.3.3.3 Superheat Steam Temperature Control

The superheat steam temperature control will be a closed loop feedback metering system with steam flow as a feed forward anticipatory signal to control the firing rate of the superheater boiler. The steam flow signal will be obtained from first stage pressure of the turbine.

A turbine trip will constitute a master fuel trip for the superheat boiler.

4.3.3.4 Exhaust Heat Exchanger Control

Primary objective of the control system is to maintain a constant well water outlet temperature 46 °C (115 °F) in conjunction with providing sufficient condensing capability for the heat exchanger so that turbine back pressure is maintained within safe limits.

The outlet temperature of the secondary (heated water) fluid will be monitored. Rising temperature will indicate that water flow demand to the softeners is decreased, at which time a 3-way control valve will be modulated to by-pass the water to existing economizers such that water flow on the tube side is maintained at a constant rate.

Conversely, decreasing temperature will indicate that the turbine exhaust steam flow has decreased. A turbine steam by-pass valve, with saturated steam from the accumulator outlet, will be modulated open to provide additional heating source to the heat exchanger.

The hotwell level will be maintained by modulation of make-up and overflow control valves.

4.3.3.5 Extraction Heat Exchangers Control

A similar control philosophy for the mine water temperature control will be adapted, as described in Section 4.3.3.4.

Heater drain levels will be maintained by modulation of the level control valve located in the heater drain pumps discharge line to the evaporator.

4.3.3.6 Deaerator Level Control

Conventional single element level control will be adapted by modulating inflow from the condensate pumps.

4.3.3.7 Recirculation Pumps Control

Condensate recirculation pumps will be provided through a fixed restriction orifice because of very low miniflow requirements.

Minimum recirculation flow of heater drain pumps and boiler feed pumps will be maintained by individual back-pressure regulators.

4.3.4 Summary of Subsystem Characteristics

The major subsystem characteristics are summarized in Tables 4-5 through 4-11. All subsystems are described in detail in Section 5.

Table 4-5

NOMINAL SECOND GENERATION HELIOSTAT CHARACTERISTICS

Reflector Shape, m (ft)	Rectangular, 7.39 × 7.44 (24.2 × 24.4)
Reflector Area, m^2 (ft^2)	53.51 (576)
Number of Mirror Modules	12
Mirror Module Size, m (ft)	1.22 × 3.66 (4 × 12)
Mirror Reflectivity	0.90
Total Reflective Area, m^2 (ft^2)	52.77 (568)
Reflector Configuration	Canted
Pointing Error (1 σ)	0.75 mrad each axis
Surface Error (1 σ)	1.0 mrad each axis

Table 4-6

RECEIVER CHARACTERISTICS

Peak Power Input, MW_t	22.4
Fluid	Water/Steam
Pressure, MPa (psia)	5.65 (820)
Nominal Inlet Temperature, °C (°F)	162 (324)
Nominal Outlet Temperature, °C (°F)	272 (521)
Design Flow Rate, kg/s (lb/hr)	9.70 (77060)
Aperture Width, m (ft)	8.0 (26.3)
Aperture Height, m (ft)	6.8 (22.3)
Losses, MW_t	1.57
Rated Power, MW	20.8
Receiver Efficiency	0.93
Design Point	Noon, Vernal Equinox
Operating Life, years	20
Tower Height, m (ft)	70 (230)
Peak Flux, MW/m^2	0.685
Peak Metal Temperature, °C (°F)	319 (606)

Table 4-7

FOSSIL BOILER CHARACTERISTICS

Peak Power, MW_t	20.8
Fluid	Water/Steam
Design Flow Rate, kg/s (lb/hr)	9.81 (77836)
Inlet Pressure, MPa (psia)	5.99 (870)
Outlet Pressure, MPa (psia)	5.51 (800)
Inlet Temperature, °C (°F)	162 (324)
Outlet Temperature, °C (°F)	270 (518)
Fuel	Gas
Efficiency (%)	0.84

Table 4-8
FOSSIL SUPERHEATER CHARACTERISTICS

Peak Power, MW_t	5.8
Fluid	Steam
Design Flow Rate, kg/s (lb/hr)	9.70 (77060)
Inlet Pressure, MPa (psia)	5.51 (800)
Outlet Pressure, MPa (psia)	5.17 (750)
Inlet Temperature, °C (°F)	270 (518)
Outlet Temperature, °C (°F)	482 (900)
Fuel	Gas
Efficiency (%)	0.84

Table 4-9
STEAM ACCUMULATOR CHARACTERISTICS

Thermal Capacity, MWh	0.89
Outlet Pressure, MPa (psia)	5.51 (800)
Outlet Temperature, °C (°F)	270 (518)
Design Flow Rate, kg/s (lb/hr)	9.70 (77060)

Table 4-10
CONTROL CHARACTERISTICS

Heliostat Array Controller (HAC)	Based on the Digital Equipment Corporation Model LSI 11/23 computer system; dual redundant microprocessors and peripherals; 256K bytes protected user memory.
Heliostat Field controller (HFC)	Based on INTEL Model 8085 microprocessor; 2K bytes PROM, 16K bytes RAM.
Heliostat Controller (HC) (Ref. only - part of heliostat assembly)	Based on INTEL Model 8049 microprocessor; 2K bytes PROM, 120 bytes RAM.
Data Acquisition Module (DAM)	Digital Equipment Corporation Model ADK11-KT, 12 bit A/D converter.

Table 4-11

TURBINE-GENERATOR CHARACTERISTICS

Maximum rating	3500 kW
Generator rating	4375 kVA at 0.80 pf
Generator voltage	4160 V
Steam inlet	5.175 MPa/482°C(750 psia/900°F)
Extraction	1.104 MPa (160 psia) uncontrolled
Exhaust	17940 Pa (2.6 psia)
Throttle flow	9.69 kg/s (77060 lb/hr) at rating
Extraction flow	8.19 kg/s (65120 lb/hr) at rating
Extraction enthalpy	1318 Btu/lb at rating
Exhaust enthalpy	1097 Btu/lb at rating
Turbine speed	8000 rpm
Number turbine stages	8

4.4 SITE REQUIREMENTS

This section describes those elements of the overall cogeneration effort, (shown on the plot plan, Figure 4-3) necessary to prepare the Texasgulf Comanche Creek site for the addition of the facilities to integrate into the solar plant. These include:

- General site preparation
- Site Facilities

4.4.1 General Site Preparation

Areas designated for buildings, roads, and outdoor equipment such as heliostats, power transformers, etc., other structures, and structural or nonstructural fills will be stripped of brush and top soil and graded to provide a surface suitable for construction of the solar cogeneration facility. Areas not affected by construction activity will be left in their natural state.

4.4.1.1 Heliostat Field

The initial site preparation activity will consist of clearing and grubbing the approximately $1.42 \times 10^5 m^3$ (35 acres) of land required for the heliostat field. All vegetation will be stripped to at least a 10.2 cm (4 in) depth to remove surface soil containing organic materials.

The second phase in preparation of the site will be the rough grading and compaction of the native soils for construction and installation of an array of heliostats and a receiver tower. The field will be rough graded to a uniform slope approximating the existing natural slope (less than 1%) from the tower down to the northern edge of the field. All fill material will be placed in 15.2 cm (6 in) maximum lifts, processed to near optimum moisture, and compacted to 95% of maximum dry density (ASTM Designation: D698-70).

Soil stratigraphy and conditions are uniform across the site. The soils generally grade from sandy silts to silty sands and range in relative density from loose to depths on the order of 0.6 m (two feet), medium dense to an average depth of 3 m (10 feet), and very dense below this zone.

The soil is free draining (highly permeable) and will readily accept standing water. Therefore, an important consideration in site preparation will be the provision of adequate drainage. Grading for site drainage will be on the basis of overland sheet flow. Surface swales, catch basins and connecting storm drains will be designed for the 9.9 cm (3.9 in) maximum 24-hour rainfall rate and will carry the collected storm water to the nearest natural drainage channel for disposal.

Upon completion of construction of the drainage system and heliostat foundations, the surface will be scarified, compacted and brought to final grade. A final surface treatment of rock chips and asphalt sealer will be applied to the surface of the graded field to minimize erosion and to allow occasional vehicular maintenance traffic between the heliostat rows without raising dust.

A "no dust" two-lane all weather service road will be constructed extending south from the existing sulfur plant area, paralleling the new pipe rack, to the solar receiver tower. The road will continue around the east side of the heliostat field and will connnect with the existing road to the north of the field.

The road will have two 3.7 m (12 ft) wide lanes with 1.85 m (6 ft) wide shoulders. The road surface will consist of 5.08 cm (2 in) of asphaltic concrete over a 30.5 cm (12 in) compacted crushed stone base and a 15.2 cm (6 in) compacted soil subbase. The shoulders will consist of 15.2 cm (6 in) of compacted soil with a single bituminous surface treatment.

Drainage ditches will be constructed on both sides of the road. These ditches will require cement stabilized slopes to prevent wind and water erosion of the loose soils.

At road-pipe rack intersections, the pipes will pass under the road through a corregated metal pipe tunnel. Native soil will be used for the fill material required to raise the road elevation.

4.4.1.2 Comanche Creek Plant

Any area within the existing plant to receive a fill, structural foundation on grade or paving, etc., will be stripped of vegetation to a depth of at least 10.2 cm (4 in). The area(s) will be scarified to a minimum depth of 15.2 cm (6 in), processed to near optimum moisture and compacted to 95% of maximum dry density. Placement of fill will be limited to a maximum of 15.2 cm (6 in) lifts.

Facilities requiring at least limited site preparation will include the areas for the new turbine-generator building, control building expansion and the area around the auxiliary boiler and accumulator/superheater.

4.4.1.3 Landscaping

Landscaping will be limited to leveling the ground surface upon completion of construction. No allowance has been made for vegetation.

4.4.1.4 Utilities

The existing Comanche Creek plant's utilities that will be extended to serve the new solar cogeneration facility include:

- The fire protection water system
- Plant and instrument air

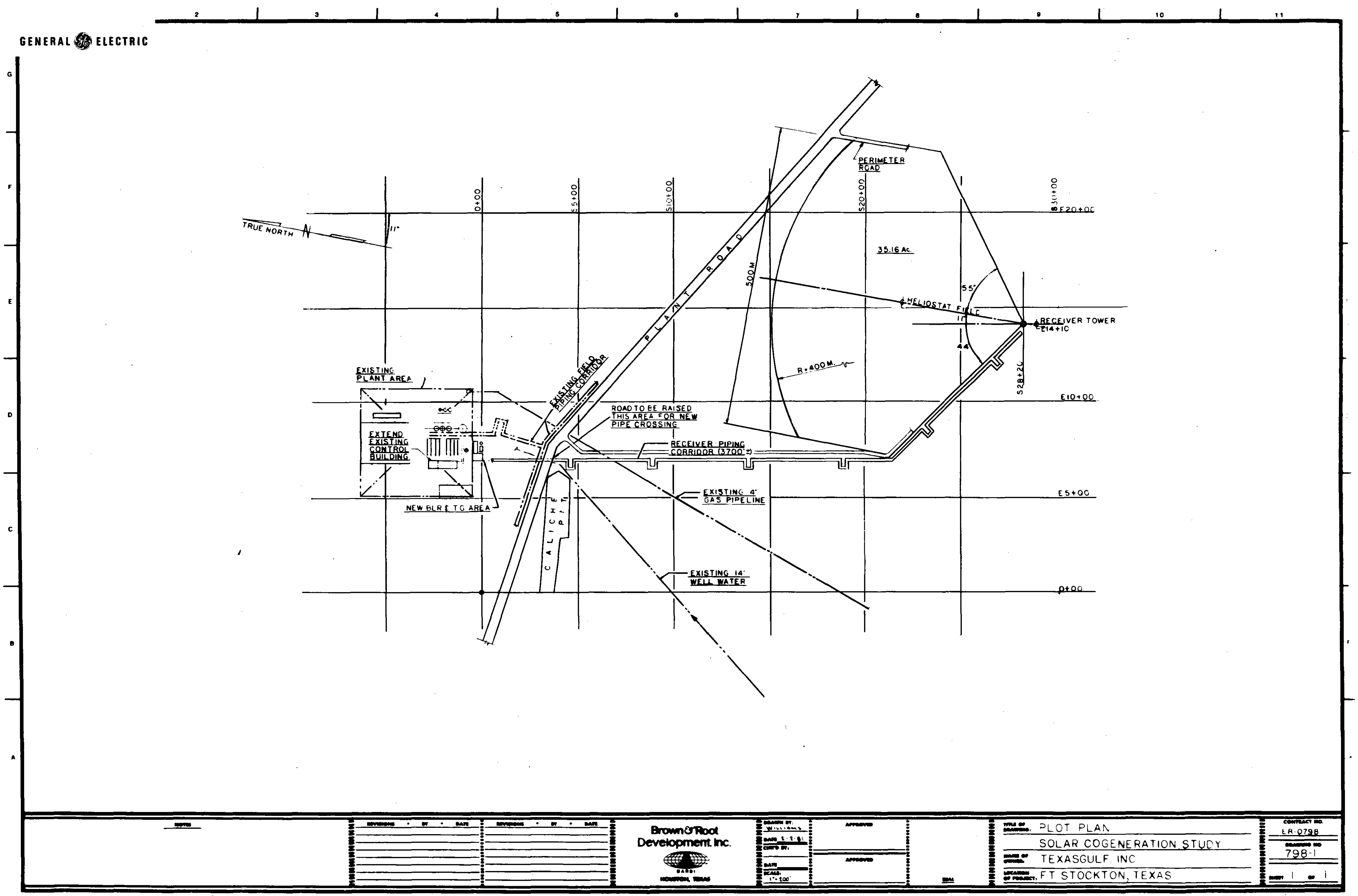


Figure 4-3. Solar Cogeneration Facility Plot Plan

- Communication systems
- Drain and waste collection system

4.4.1.4.1 Fire Protection Water. The fire protection water requirements for the solar cogeneration facilities will be provided by an extension of the existing plant supply and distribution system. The extension of the fire protection system will be designed in conformance with the National Fire Codes of the National Fire Protection Association for an occupancy classification of Ordinary Hazard (Group 1). Portable extinguishers mounted in wall recesses or enclosed cabinets will be strategically located in building corridors and working spaces.

Documents applicable to the system design include:

- DOE Design Criteria Appendix 6301
- National Fire Codes of the National Fire Protection Association (NFPA)
- Standards listed in DOE Manual, Chapter 0552, Industrial Fire Protection

4.4.1.4.2 Plant and Instrument Air. The existing plant and instrument air system will be extended to supply compressed air at a nominal pressure of 0.7 MPa (100 psia) to utility stations and maintenance tools as well as dry, oil-free air at reduced pressure for instruments, controls, and operators in the utility systems and the heating, ventilating, and air conditioning systems.

4.4.1.4.3 Communication Systems. Communication for the solar cogeneration facilities will consist of a combined telephone-intercommunication system of dial-type telephones served from the local telephone exchange incorporated into the existing plant communication system. The fire alarm system will be activated by ionization smoke detection or fire alarm pull boxes. The fire alarm signals will be transmitted over the paging systems to the central control room.

4.4.1.4.4 Drain and Waste Collection System. The industrial drain and waste collection systems for the interior of the buildings will collect liquid wastes and discharge them into an extension of the existing system for transport to the existing treatment facilities. Roof drains will discharge storm water to surface drainage.

The waste from floor drains will be drained by gravity through building waste systems that will be connected to underground waste systems piping at a point 1.52 m (5 ft) outside the building walls.

4.4.2 Site Facilities

Site facilities include those new structures and facilities required to support the operation of the solar cogeneration facility. Included are:

- Buildings
- Security

4.4.2.1 Buildings

The solar cogeneration facilities will include both new structures and modifications to existing structures within the Comanche Creek facility. The proposed facilities include the following:

- Turbine/Generator Building
- Control Building Extension

All buildings will conform to DOE and Texasgulf Sulphur architectural requirements.

4.4.2.1.1 Turbine/Generator Building. The turbine/generator building will house the solar cogeneration facilities' turbine/generator, deaerator, heat exchangers, water treating unit and other auxiliary equipment. As shown in Figures 4-4 and 4-5, it will consist of a two-story 12.2 m by 14.6 m by 11.6 m high (40 ft by 48 ft by 38 ft) structural steel framed building with metal siding and roof.

The ground floor will consist of a slab on grade and will support the water treating unit and other light weight miscellaneous pieces of equipment. Building columns and the larger heat exchangers located at this level will be supported on spread footings. The operating room floor will be a composite designed structural concrete slab. This approach minimizes the amount of concrete and steel required by stud weld bonding slab and floor framing steel beams into one unit.

The operating floor will support the deaerator, heat exchangers and all other miscellaneous equipment located at this level with the exception of the turbine-generator, which will be supported on a concrete pedestal and mat foundation. The turbine aisle will be serviced by a pendent operated 9072 kg (10-ton) capacity bridge crane with a 2722 kg (3-ton) auxiliary hook.

Adequate maintenance space will be provided around all equipment. Tube pull space will be provided through the use of removable panels in the sides of the building. Interior platforms and stairs will be provided, as required, for equipment access and maintenance activities.

Gravity ventilation will be provided for natural air flow through the building. Electrical resistance type local heating will be provided, as required, in selected work areas.

Fire protection within the turbine/generator building will consist of ionization type smoke detectors. In addition, non-aqueous portable extinguishers or dry chemical equipment will be provided. Areas used for storage of combustibles, i.e., turbine lube oil storage, will be provided with a sprinkler system served by the existing plant water system.

4.4.2.1.2 Control Building Extension. A structural steel metal clad building extension 7.6 m by 12.2 m (25 ft by 40 ft), as shown in Figure 4-6, will be provided to house the switchgear and controls for the new solar cogeneration facility. A conventional slab-on-grade floor and foundation system similar to the existing one will be provided to support the structure.

Steel channels will be set true and level in the floor slab. These channels will provide support for the switchgear and control panels and will assure that draw-out equipment can be removed and installed without binding. The finished floor will be smooth and level to provide a good rolling surface for circuit breaker elements that will occasionally be moved to a local panel for operating tests and adjustments. Adequate aisle space will be provided for the operating and servicing of equipment.

Cable raceways will be overhead. Cable tray, and entry to equipment will be from above. Ionization type smoke detectors will be provided, and portable insert gas type extinguishers or dry chemicals will be provided for fire protection.

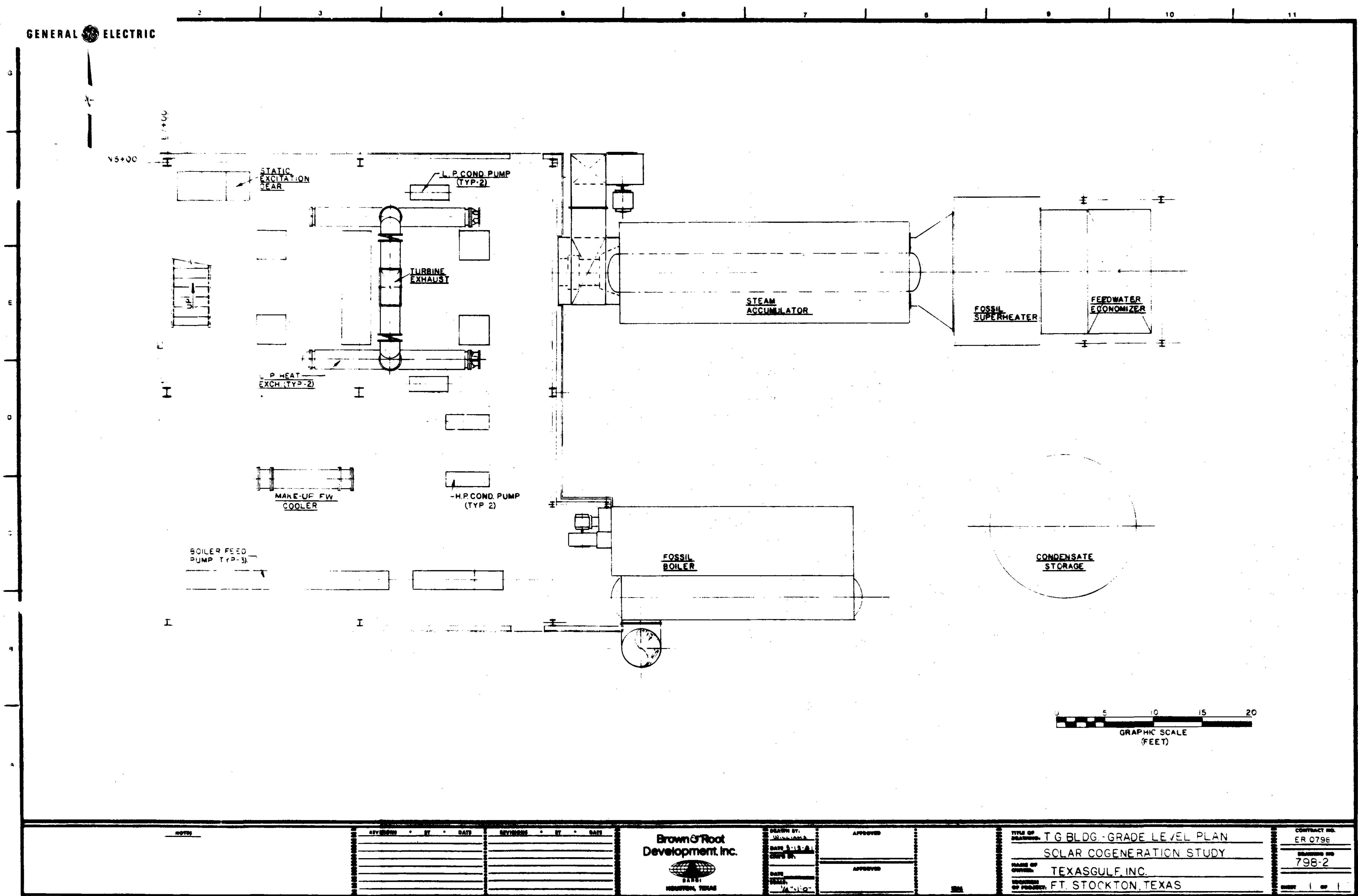


Figure 4-4. Turbine/Generator Building Plan View

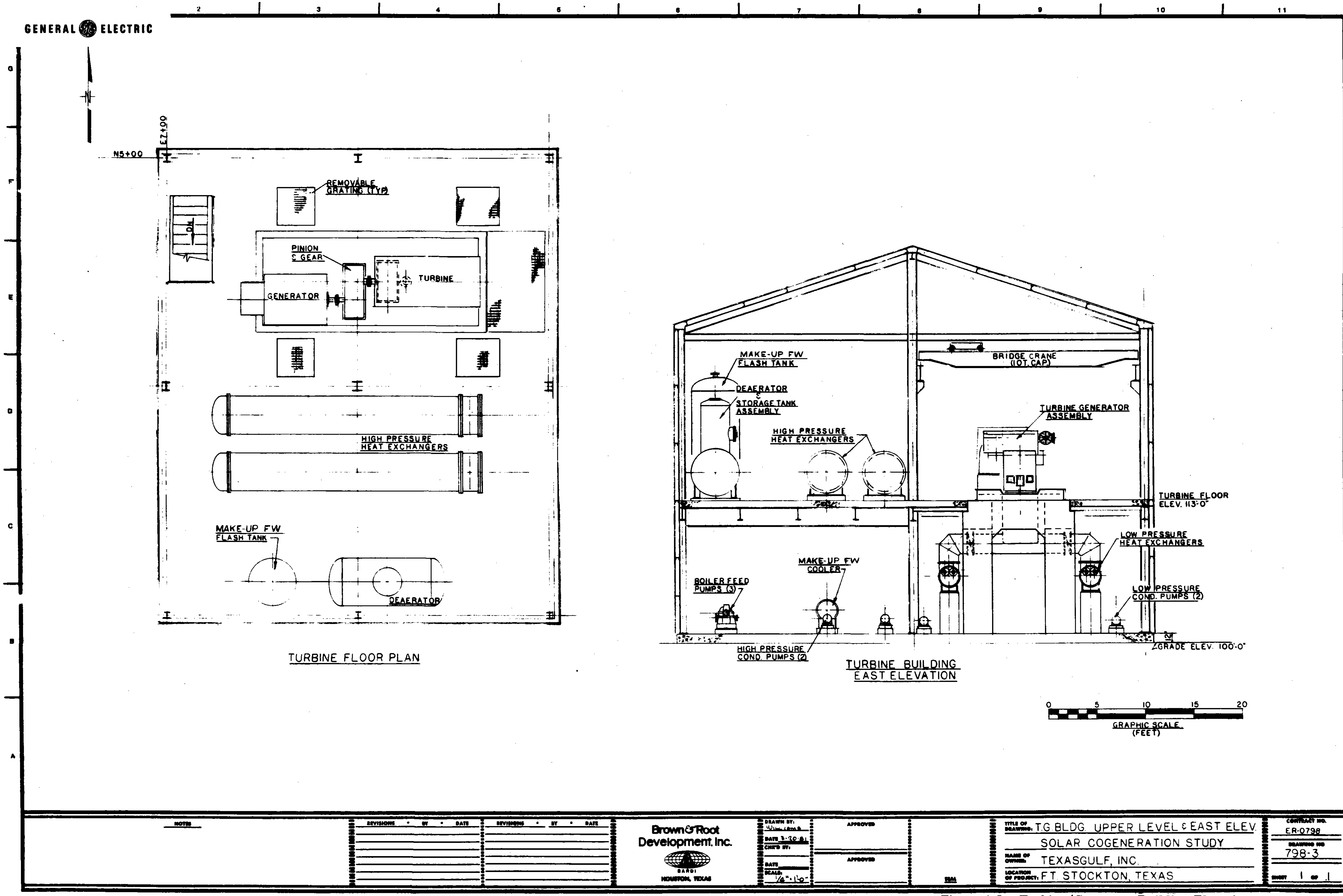


Figure 4-5. Turbine/Generator Building Elevation

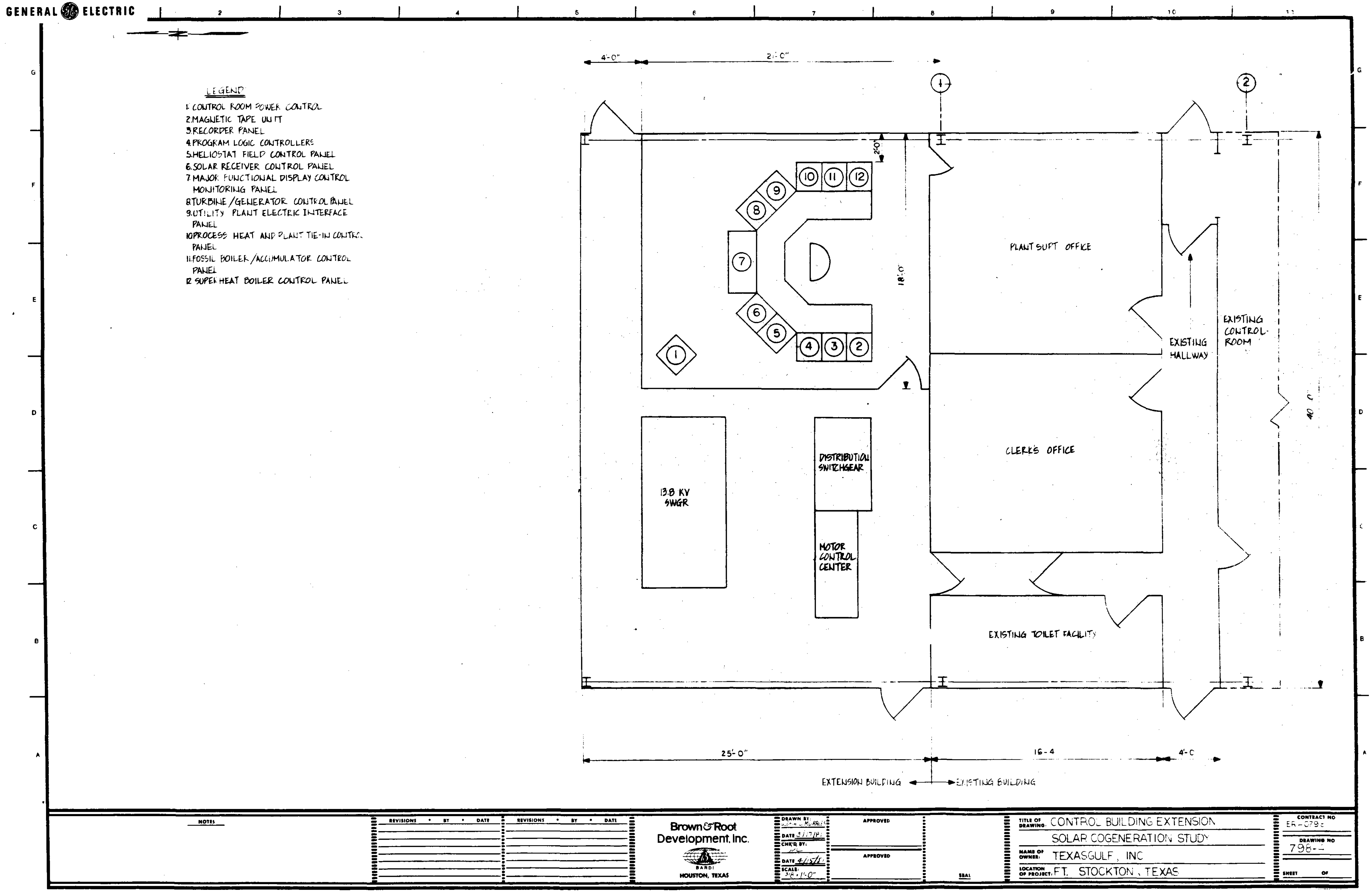


Figure 4-6. Control Building Extension

4.4.2.2 Security

4.4.2.2.1 Fencing. A chain link fence 2.4 m (8 ft) high topped with three strands of barbed wire on brackets, angled outward, 0.3 m (1 ft) high, for a total height of 2.7 m (9 ft) will be provided around the heliostat field shown in Figure 4-3. Swing type vehicular gates will be provided at the two service road entrances to the heliostat field to limit and control access to authorized personnel. Man barriers will be provided at points where the perimeter fence crosses drainage ditches.

The existing fencing around the Comanche Creek plant is assumed to be adequate and will not require modification. All fencing will be grounded in accordance with the following codes:

- IEEE Standard 80 (1976), Section 10, "Guide for Safety in Substation Grounding"
- National Electric Safety Code (1981), Section G

4.4.2.2.2 Lighting. Security lighting for the heliostat field will be provided by pole mounted high pressure sodium vapor flood lights located on the perimeter of the field.

4.5 SYSTEM PERFORMANCE

System and subsystem performance has been calculated for the cogeneration facility at the design point and on an annual basis. This allowed the determination of the fossil fuel conserved by the incorporation of the solar system. The results are discussed in the following sections.

4.5.1 Design Point Performance

The design point was chosen as equinox noon because it provides the maximum thermal input to the receiver for the north field collector arrangement (see Figure 4-7). This choice satisfies Texasgulf's requirement that the system be designed to supply their maximum electrical power demand (3.0 MW_e).

System performance at the design point has been evaluated with two computer models, MIRVAL and WSRLOSS. MIRVAL (Ref. 4.1), developed by Sandia, is a Monte Carlo ray trace program for evaluating collector field performance. WSRLOSS is the GE receiver loss code which is discussed further in Section 5.2.

As described in Section 5.2, the receiver was conservatively designed for full flow conditions of 9.69 kg/s (77060 lb/hr). However, with the boiler operating at minimum turndown (5%) there is only 95% flow through the receiver. The resulting design point system performance stairstep diagram is shown in Figure 4-8 which includes the 5% receiver flow loss. This loss is balanced by the contribution of the boiler. Assuming a reference direct normal insolation value of 950 W/m^2 (301.2 $Btu/hr\text{-}ft^2$) the solar system efficiency at the design point is 67.1%

4.5.2 Annual Performance

The annual performance of the cogeneration facility was calculated using MIRVAL and the Sandia generated computer code STEAEC (Ref. 4.2). The principal output of these codes is the net annual thermal energy production from the solar portion of the facility. The energy production required from the fossil portion of the facility is simply the difference between the energy load profile (described in Section 4.6) and the solar production. This information is required as a major input for the calculation of the value of the cogeneration concept, described in Section 4.5.3.

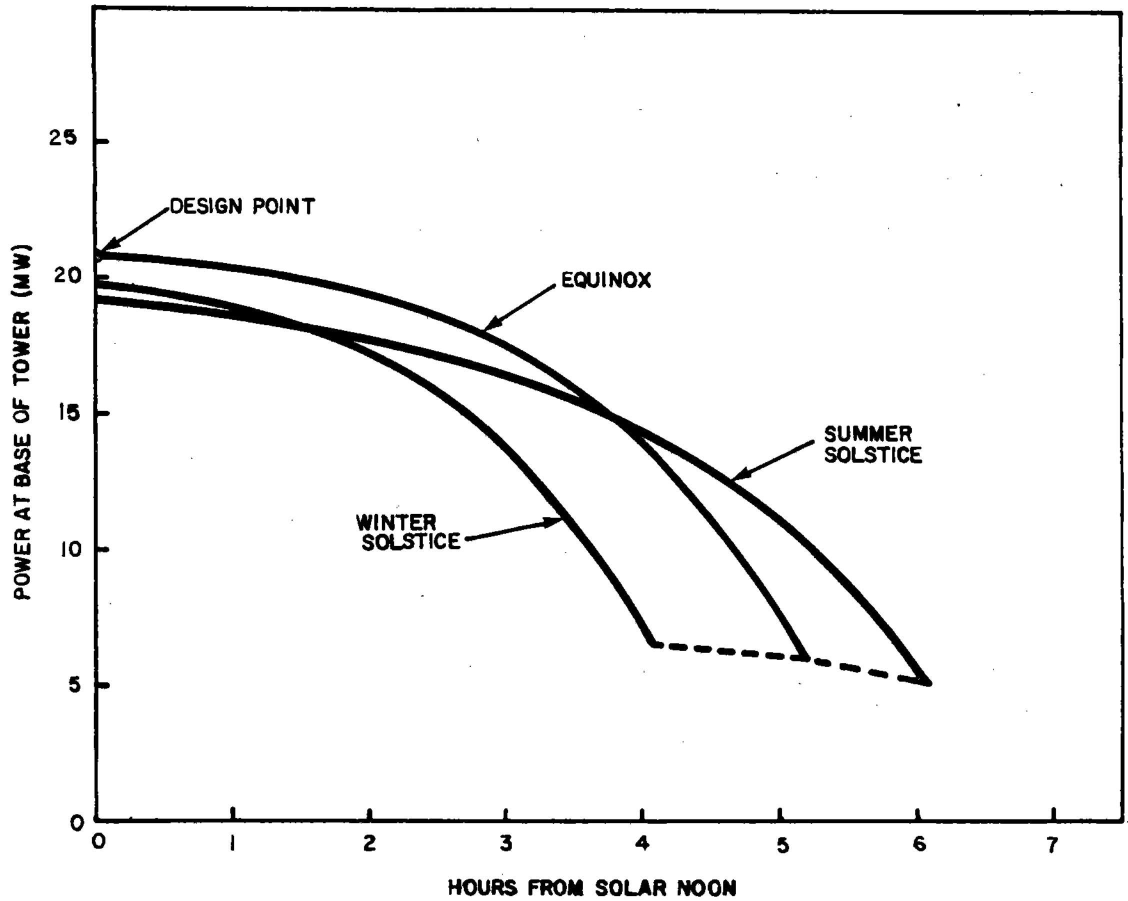


Figure 4-7. Receiver Daily Output Variations

Inputs to the analysis are illustrated in Figure 4-9. Development of those inputs is described in the following sections.

4.5.2.1 Field Efficiencies

The efficiency of the heliostat field in transmitting incident energy to the receiver is dependent on sun position and field configuration. MIRVAL was used to determine field efficiencies based on the field configuration described in Section 5.1. Field efficiency, defined as the ratio of solar radiation entering the receiver to the total available insolation incident on the collector area, was calculated for a matrix of seven sun azimuth angles and six sun elevation angles. The results are listed in Table 4-12.

The field efficiencies generated by the MIRVAL code do not account for wind speed effects. In actuality, the wind has a significant effect on the performance of an unenclosed heliostat, and this effect is accounted for by the correction factors listed in Table 4-13. The values are obtained from the STEAEC default input, which was developed for the Barstow field and is applicable to the second generation heliostats proposed for the cogeneration facility.

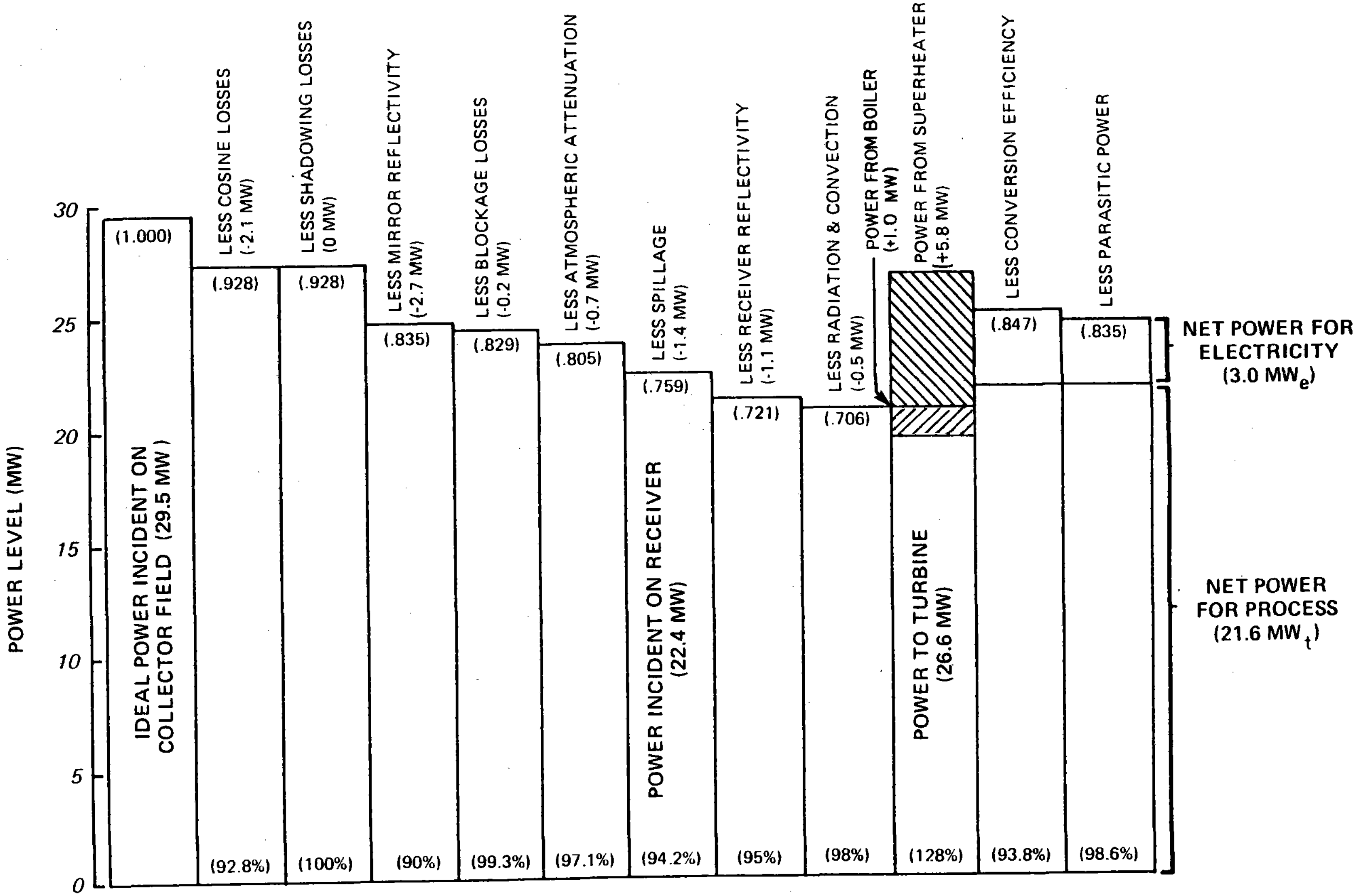


Figure 4-8. Equinox Noon Design Point Power Cascade

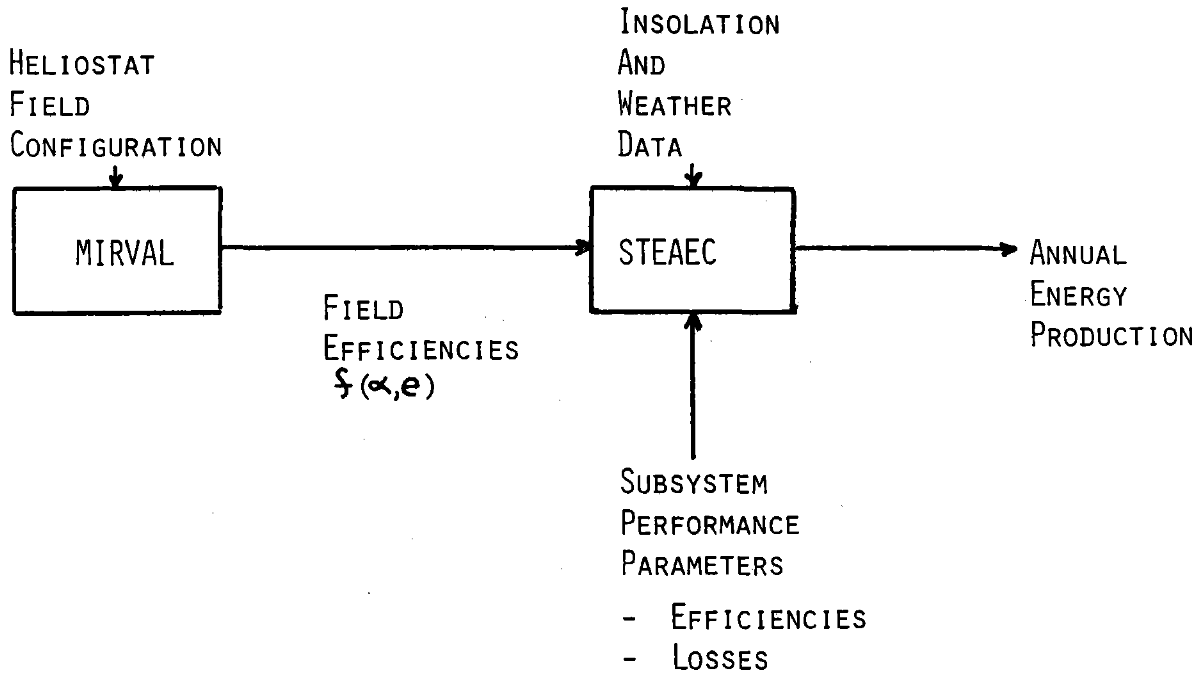


Figure 4-9. Annual Performance Block Diagram

Table 4-12

COLLECTOR FIELD EFFICIENCIES

Azimuth Angle	Elevation Angle 10 °	20 °	30 °	45 °	65 °	85 °
0 °	0.4760	0.6688	0.7531	0.7627	0.7571	0.6671
30 °	0.4872	0.6520	0.7334	0.7365	0.7145	0.6615
40 °	0.4660	0.6339	0.6903	0.7439	0.6974	0.6710
70 °	0.4333	0.5348	0.6537	0.6797	0.6923	0.6654
90 °	0.4070	0.5326	0.5945	0.6275	0.6317	0.6397
105 °	0.3782	0.4801	0.5432	0.5916	0.6276	0.6638
115 °	0.3465	0.4622	0.5023	0.5630	0.6010	0.6520

4.5.2.2 Insolation and Weather Data

Since no complete weather data (insolation, wind speed and direction, temperature and pressure) is available for the Comanche Creek site (Fort Stockton, Texas), the SOLMET (Ref. 4.3) weather data for El Paso, Texas, was used. El Paso is approximately 454 km (245 miles) west of Fort Stockton, but is nonetheless representative of the site region. However, the two locations are at different altitudes and, therefore, an adjustment must be made in the magnitude of direct insolation. As described in Section 5.5 of the System Specification (Appendix A) the altitude correction factor is 0.98. Thus, the El Paso insolation data was reduced by 2% and input to the STEAEC performance model.

Table 4-13

WIND SPEED CORRECTION FACTOR

Wind Speed (m/s)	Correction Factor
0	1.0
2	0.999
4	0.998
6	0.996
8	0.994
10	0.985
12	0.964
13.4	0.942

4.5.2.3 *Receiver Efficiencies*

A portion of the energy impinging upon the receiver is reflected back to the surroundings. It is assumed that 5% of the incident energy is reflected, based on data from receiver coating tests using Pyromark paint. Of the energy absorbed, losses occur by convection and radiation from the receiver surface. Radiation is a function of receiver size and metal temperature, both of which are constant. Convection losses are functions of wind speed and ambient temperature. WSRLOSS, the receiver loss program described in Section 5.2, was used to assess the receiver losses. The results are shown in Table 4-14 as a function of wind-speed and ambient temperature. Note that the saturated water/steam receiver concept, which operates at approximately 315 °C (600 °F), has corresponding relatively high efficiencies.

Table 4-14

RECEIVER EFFICIENCIES

Temperature °C (°F)	Wind Speed (m/s, mph)				
	0	4.47(10)	8.94(20)	13.41(30)	17.88(40)
-17.8 (0)	0.932	0.931	0.928	0.925	0.922
-2.2 (28)	0.933	0.931	0.929	0.926	0.923
13.3 (56)	0.934	0.932	0.929	0.926	0.924
28.9 (84)	0.934	0.933	0.930	0.927	0.925
44.4 (112)	0.935	0.933	0.930	0.928	0.926
60.0 (140)	0.936	0.934	0.931	0.929	0.927

4.5.2.4 Annual Performance Results

The preceding sections have defined the inputs to the STEAEC program. Use of a fossil boiler in a hybrid configuration was not included in STEAEC, since it was designed to calculate net electrical output from solar central receiver systems only. Therefore, the STEAEC thermal output up to the accumulator (see Figure 4-10) was used in combination with the calculated fossil energy required to supply the mining operation with its required annual energy based on the load profile described in Section 4.6.

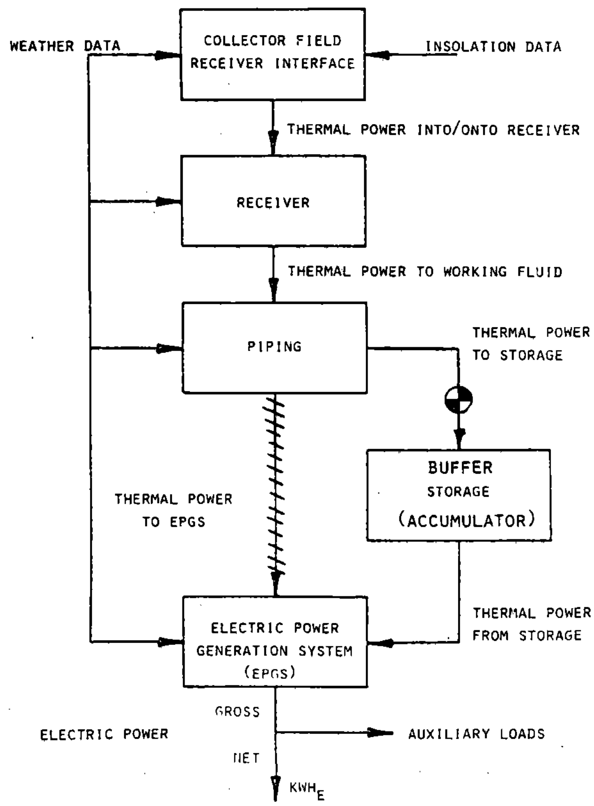


Figure 4-10. STEAEC Block Diagram

The resulting energy cascade for the cogeneration facility annual performance is illustrated in Figure 4-11. The annual solar energy available for delivery to the steam turbine, as shown in the figure, is 48.39 GWh (165,150 MBtu), yielding an annual net solar system efficiency of 59.9%.

4.5.3 Fuel Displacement Analysis

The existing Comanche Creek sulfur mine currently purchases all of its electrical power needs from West Texas Utilities and consumes 99.2×10^7 m^3 (3.5×10^9 ft^3) of natural gas per year to supply its required thermal energy. The addition of the solar cogeneration facility will eliminate the need to purchase electricity and provide 19.85% of their thermal power requirements.

For the uniform load profile throughout the year, with the fossil boiler and superheater operating at an annual average efficiency of 84%, the yearly fuel consumption is as shown in Table 4-15. Fuel savings have been calculated by subtracting the annual fossil energy required during operation of the cogeneration facility from the annual fossil energy required for the existing plant. The West Texas Utilities fuel savings is based on a 32% delivery efficiency, which includes distribution losses. Thus, the solar addition will displace 6.5×10^6 m^3 (228×10^6 ft^3) of natural gas per year.

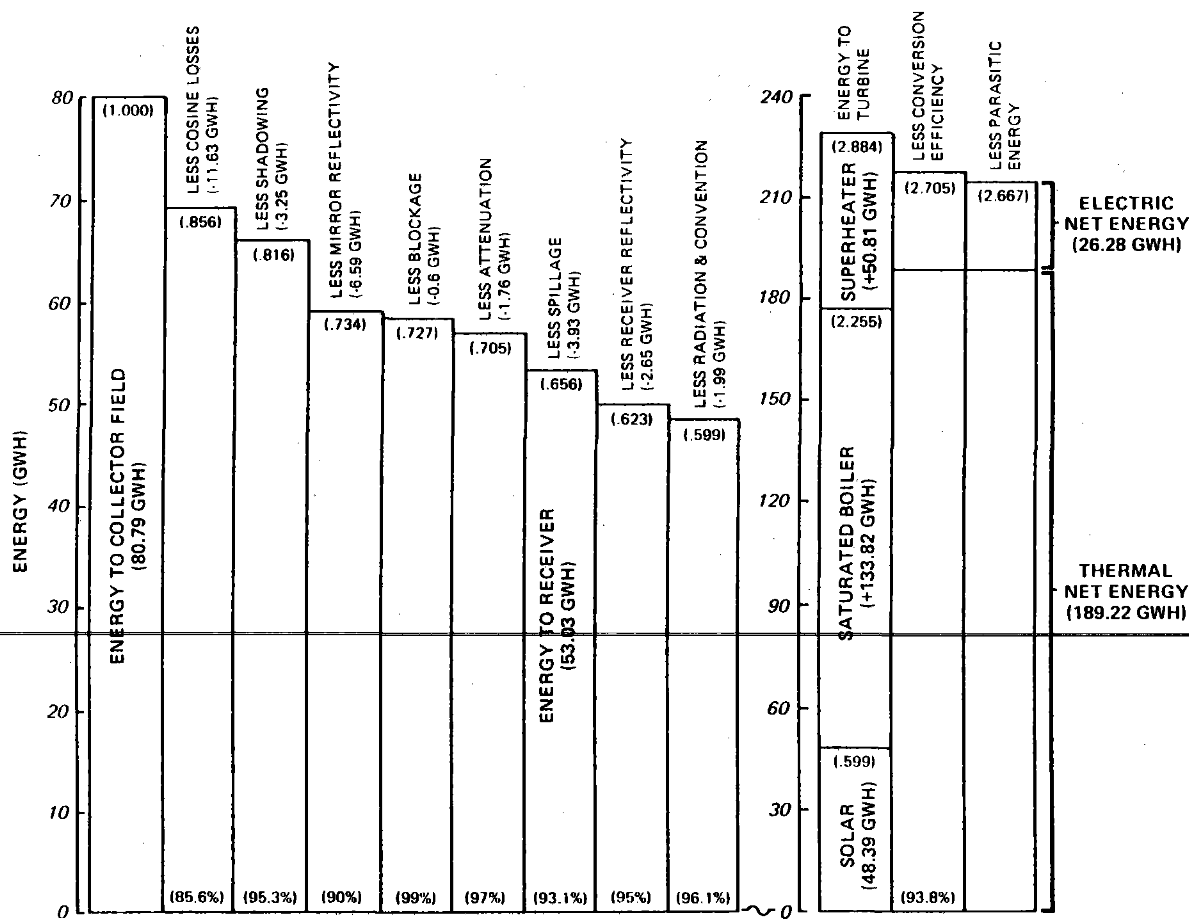


Figure 4-11. Energy Cascade – Annual Summary

Table 4-15

ANNUAL CONSUMPTION AND SAVINGS OF NATURAL GAS

	Existing Plant Mcm (Mcf)*	Solar Facility Mcm (Mcf)*	Savings Mcm (Mcf)*
WTU @ 32%	7.6 (268)	-	7.6 (268)
Tg Heaters	99.1(3500)	79.4(2805)	19.7 (695)
Boiler	-	15.1 (533)	-15.1(-533)
Superheater	-	5.7 (202)	-5.7(-202)
Total	106.7(3768)	100.2(3540)	6.5 (228)

*Mcm = million cubic meters
Mcf = million cubic feet

4.5.4 Cogeneration Utilization Efficiency

DOE has defined a Cogeneration Utilization Efficiency (CUE) as the ratio of the sum of the net useful energy (electrical, mechanical, and thermal) to the total energy input using annual energy in megawatt-hours. From Figure 4-11, the net useful energy consists of 26.28 GWh electrical and 189.22 GWh thermal. There is no net useful mechanical energy since it was not considered in this conceptual design. The total energy input consists of the solar input of 53.03 GWh to the receiver and the fossil input to the boiler and superheater. The fossil energy shown in Figure 4-11 is after boiler conversion. Thus, at 84% efficiency the fossil energy input is 219.80 GWh. Finally, the Cogeneration Utilization Efficiency is

$$\text{CUE} = \frac{26.28 + 189.22}{53.03 + 219.80} = 0.790 \text{ or } 79.0\%.$$

4.6 ENERGY LOAD PROFILE

The energy load profile for the Comanche Creek sulfur mine is basically constant throughout a typical 24-hour day and throughout the seasons. Infrequently, small variances occur which are the result of water supply limitations and changes in the mining process heat demands. Typical daily load demands are shown in Figures 4-12 and 4-13.

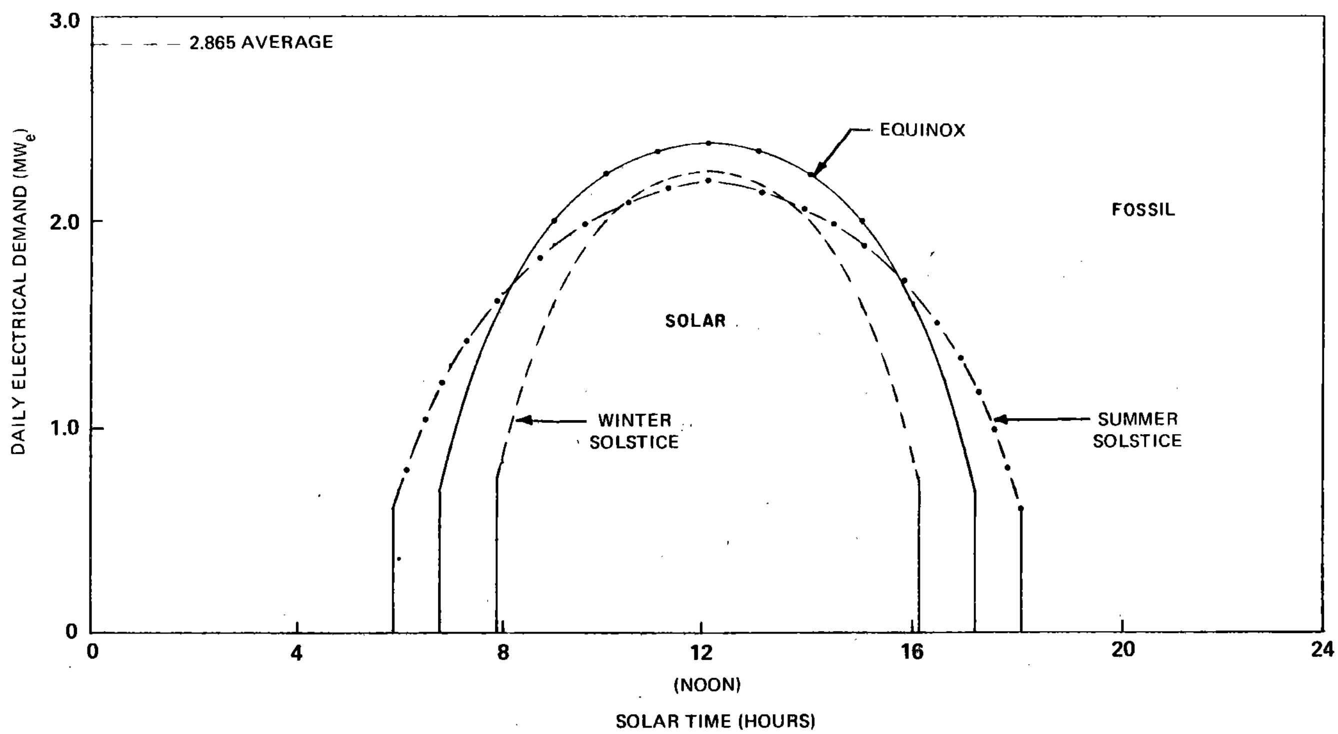


Figure 4-12. Daily Electrical Load Demand

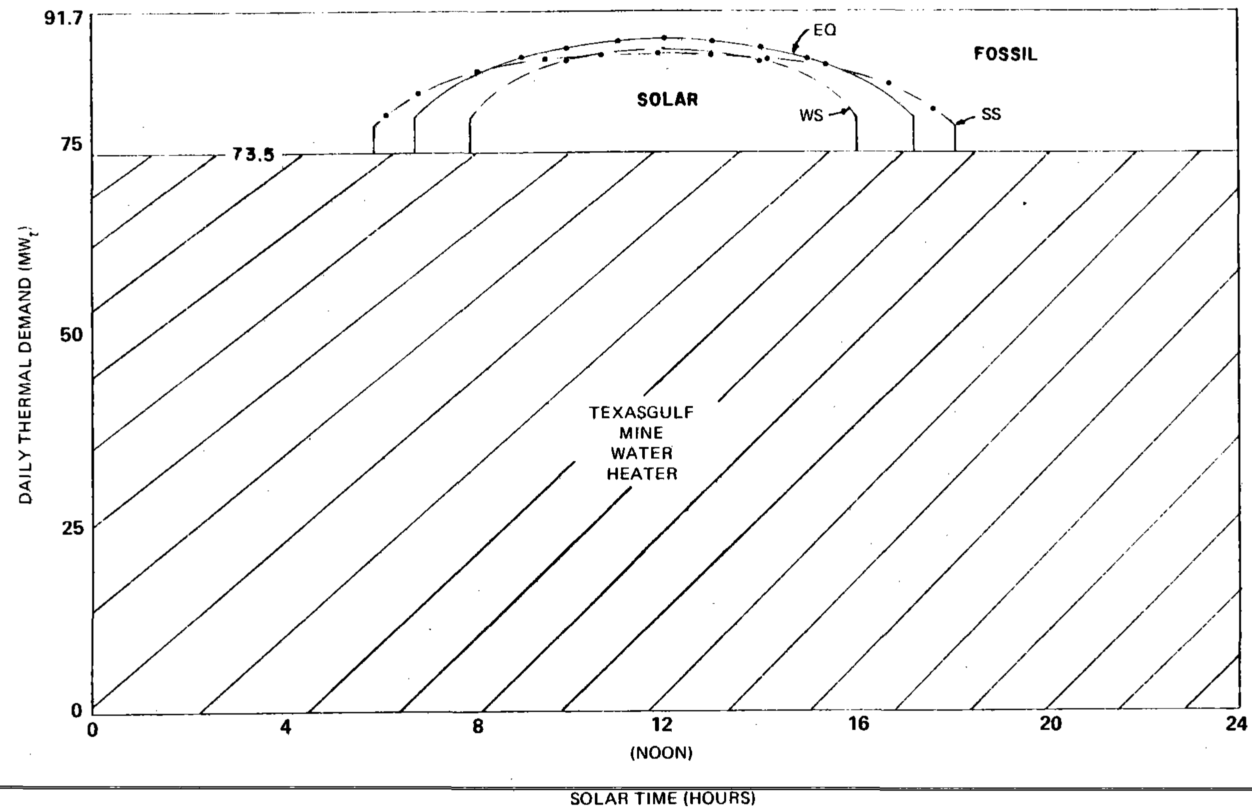


Figure 4-13. Daily Thermal Load Demand

The average daily electrical load demand is 2.865 MW_e. Occasionally, the daily demand will peak at 3.0 MW_e. Currently, the electrical demand is satisfied by West Texas Utilities. With the addition of the solar cogeneration facility, this electrical energy will be supplied by the hybrid (solar/fossil) system during daylight hours and by the fossil system at night and during periods of insufficient insolation. Shown in Figure 4-12 is the solar contribution (the area beneath the curves) for three days considered representative of the entire year. The solar energy collection is assumed to start and end at a solar elevation of 10 degrees above the horizon.

The daily thermal load demand for a typical 24-hour day is shown in Figure 4-13. It is based on the existing mine water heaters, which currently consume approximately 2.72×10^5 m^3 (9.6×10^6 ft^3) of natural gas per day. The cross-hatched area represents the thermal energy to be supplied by the water heaters after being turned down to accommodate the addition of the solar facility. The clear area at the top represents the thermal energy to be supplied by the cogeneration facility with the solar contribution (area under curves) shown for the same three days as in Figure 4-12.

4.7 CAPITAL COST SUMMARY

Section 5.3 of the System Specification (Appendix A) contains the basis for the capital cost and also the detailed cost breakdown. The cost estimates are summarized in Table 4-16. The geographic boundaries for the cost accounts are depicted on a plot plan in Figure 4-14 and the functional boundaries are depicted on a schematic in Figure 4-15. The cost estimates include all design and construction costs, as well as adjustments for labor productivity at the site. A detailed breakdown of the owner's cost is also presented in Section 5.3 of Appendix A.

Table 4-16

CAPITAL COST SUMMARY

Cost Element	Capital Cost* (10^6\$)
5100 Site Improvements	0.695
5200 Site Facilities	1.198
5300 Collector Subsystem	8.446
5400 Receiver Subsystem	3.068
5500 Master Control Subsystem	0.751
5600 Fossil Energy Subsystem	1.754
5800 Electric Power Generating Subsystem	1.514
5900 Other Subsystems	3.096
Total Construction Cost	20.522
Owner's Cost	0.149
Total Project Cost	20.671

*All costs expressed in 1980$

4.8 OPERATING AND MAINTENANCE COSTS AND CONSIDERATIONS

This section presents a summation of the annual operating and maintenance cost estimate for the solar cogeneration facility at the Fort Stockton site. The personnel required for operating and maintaining the facility, as well as the maintenance materials, have been estimated and costed separately on the cost worksheets given in Section 5.3 of Appendix A.

The annual operating and maintenance cost estimates are summarized in Table 4-17. Each of the major recurring cost items is discussed in the following sections.

4.8.1 Operating Personnel

The manning requirements for the cogeneration system are identified as operating personnel and maintenance personnel. A level of 4.5 operators for three shifts each day of the year (including holidays) was estimated to be required for system operations, plus one additional maintenance person working a standard 40-hour week for maintenance tasks.

4.8.2 Maintenance Materials

This account includes the normal spare parts and materials for the collector equipment, receiver equipment and balance of plant equipment.

4.8.3 Scheduled Maintenance

This account includes periodic maintenance for the turbine-generator and heat exchanger cleaning as well as heliostat washing. Heliostat washing frequency is an unknown at this stage of the study;

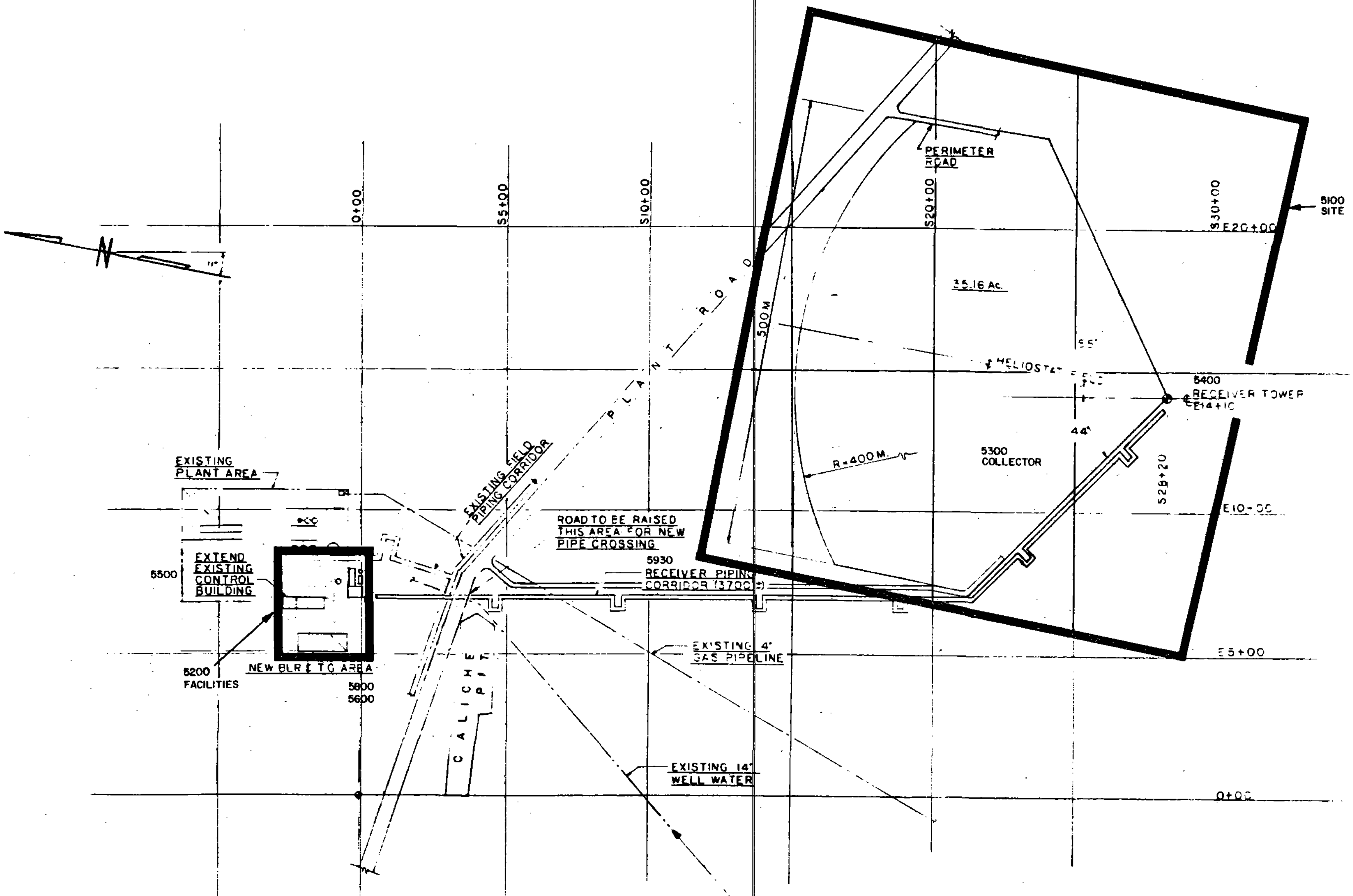


Figure 4-14. Geographic Boundaries for Cost Accountants

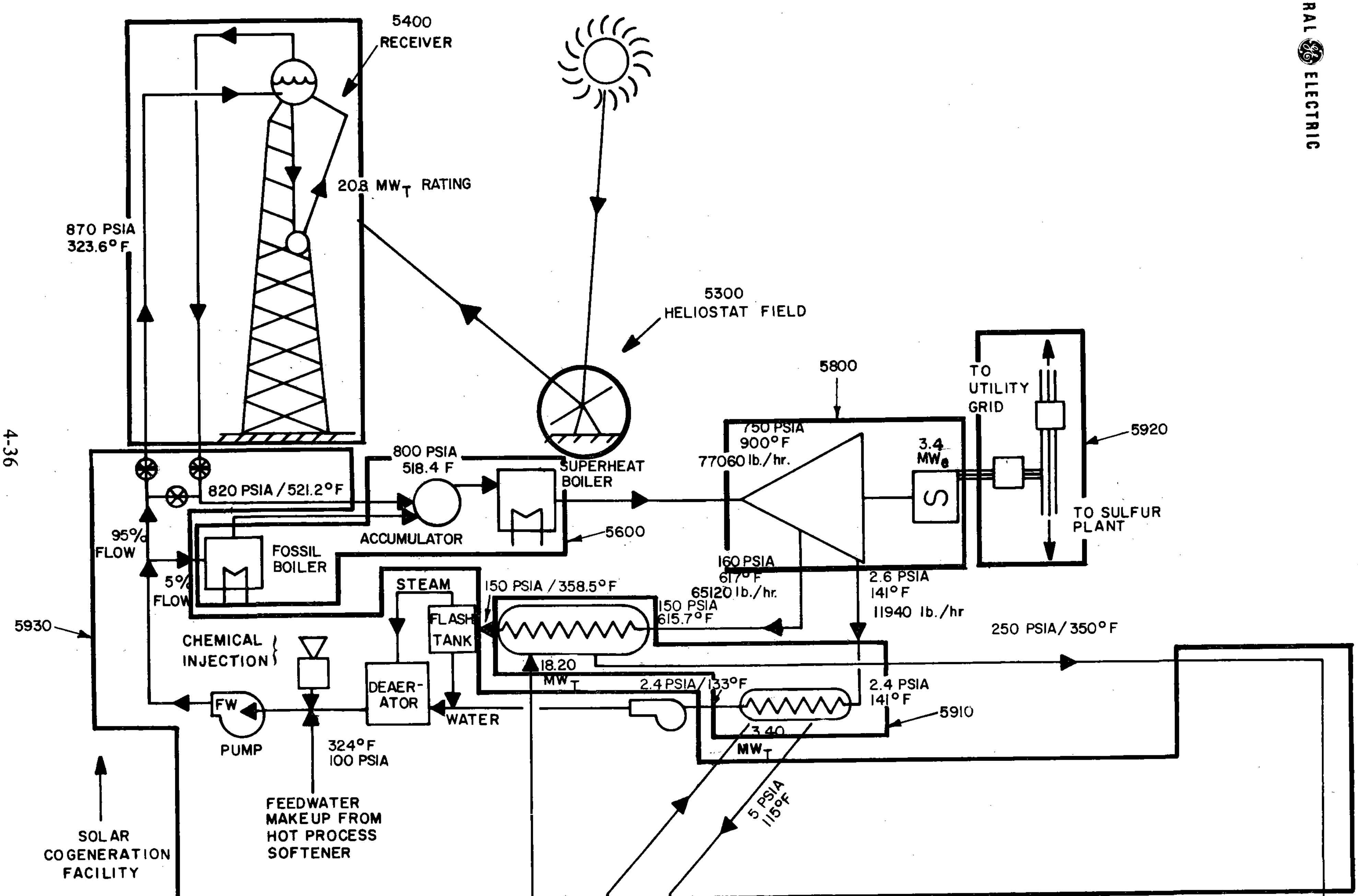


Figure 4-15. Functional Boundaries for Cost Accounts

however, based on existing literature on heliostat washing costs, an estimate of $50 per heliostat per year has been included.

Table 4-17

OPERATIONS AND MAINTENANCE COST SUMMARY

OM100	Operations	
	OM110 Operating Personnel	$186,150
OM200	Maintenance Materials	
	OM210 Spare Parts and Materials	$26,514
OM300	Maintenance Labor	
	OM310 Scheduled Maintenance	$39,400
Total Annual O&M Cost		$252,064

4.9 SUPPORTING SYSTEM ANALYSES

4.9.1 Reliability, Availability and Maintainability

The design of the solar cogeneration plant utilizes fundamental power plant design concepts. This approach provides a system of equipment redundancy and maintainability where experience has shown it to be necessary and which trained operators will find familiar.

Plant mechanical equipment such as boiler feed pumps are sized (at 50%) and supplied in such numbers (3) to allow for an unscheduled equipment outage without affecting the plant's capability to operate at full power. Two (2) 100% LP heat exchangers for heating well water enable full capacity operation when the normal tube cleaning is performed approximately every six months. Where equipment capacity and number of units is equal to 100%, such as the two 50% high pressure heat exchangers for heating process water, power plant practice has shown redundancy to be unnecessary or cost ineffective. Such equipment is usually known to be reliable or easily repairable.

Maintainability is achieved by making equipment accessible and as standard off-the-shelf as possible. Examples of accessability is a minimum of three feet clearance around instrument cabinets to permit full opening of drawers and sufficient aisle space in front of heat exchangers for access to or for removal of tube bundles.

The standardization concept is exemplified in the use of purchaseable pumps and motors with the exception of the boiler feed pump rotating element. The availability of replacement parts for standard equipment minimizes the stocking of spare costly components but allows for such maintenance supplies as valve stem packing. Consideration may be given to the purchase of a boiler feed pump impeller section or spare diodes for the Generator Alterex System because these items are more apt to have long deliveries.

In general, the spares supply philosophy of Texasgulf will govern in establishing the quantity of such supplies. This attitude is established through their experience and the level of maintenance capability possessed by the plant personnel.

4.9.2 Installation

Installation of the plant equipment and construction of the power plant is estimated to take approximately 11 months with the heliostat field being the area of most concern. The fossil cogeneration plant itself can be constructed in approximately nine months and can conveniently be assembled while the heliostat field, tower and receiver are being erected.

Long lead items such as the turbine generator, fossil boiler and superheater/accumulator may require early procurement to prevent construction delays. Because the fossil plant is a basic power plant design, there will be no unusual construction practices to be followed. The plant building and extension to the existing control building will be conventional structural steel metal clad design conducive to rapid construction.

Piping, fittings and valves will be standard carbon steel requiring normal welding and nondestructive testing practices. A maximum amount of shop welded assemblies of the main steam piping will be purchased to minimize field costs, with field welding limited to smaller pipe sizes.

The construction schedule and interface connections will be designed to minimize any interruption in the operation of the existing plant. such connections are presently considered to be possible without any effect on the sulfur mine's operation.

As the plant construction proceeds, Texasgulf operating personnel will become familiar with the installed equipment and operation of the systems. The start-up and testing phase will be conducted by these same crews so that complete familiarity will have been achieved by the time that the plant is ready for operation.

4.9.3 System Safety

The potential system safety implications of the solar cogeneration facility are to operating and maintenance personnel from the following three major concerns:

- Visual hazards of reflected solar energy
- Releases of pressurized water and steam
- Catastrophic failure of equipment, including pressure vessels

To minimize the danger of stray reflected solar energy, an "always focused" operations strategy similar to that used at the CRTF would be employed. This strategy also results in limiting the area of concentrated energy to no more than twice the tower height, thus eliminating danger to aircraft.

During operations, plant personnel will be excluded from the field and tower area. All nonemergency maintenance and operating activities in these areas will be done at night.

The receiver fluid (water) poses no toxic threat. Failure of receiver pressure parts during operation poses little danger since personnel will not be present. All equipment and pressure parts will be designed and built in strict accordance with the ASME boiler and Pressure Vessel Code to minimize the possibility of failure. The failure of a tube in the receiver would release pressurized water that would flash and cool before hitting the ground.

Safety valves, overpressure alarms, a low-water-level sensor in the steam drum, and overtemperature alarms will be used to alert the operator to take appropriate action or to initiate automatic corrective action.

In the receiver tower, ample platforms, stairways, and ladders will be provided in accordance with OSHA regulations to permit convenient access to all areas requiring regular maintenance.

The tower will be lighted in accordance with FAA regulations. Field maintenance operations will be carried out only during periods when the solar system is not operating.

4.9.4 Environmental Impact

Prior to construction of a large facility with significant air emissions, ambient air monitoring for one year is usually required to determine whether the plant will be in an attainment area, and with the additional emissions, whether the area will remain within attainment limits. The Comanche Creek Plant is in Pecos County, which is an attainment area along with all the surrounding counties. There is no record of any extensive ambient air monitoring in the immediate area because there are no large industrial or petrochemical plants within a 80 km (50-mile) radius. The nearest area having a significant density of population and industry is the Midland-Odessa area about 145 km (90 miles) north-east of Fort Stockton.

The air pollutants (SO_2, CO, O_3, and NOx) are normally generated from large fuel burning plants, hydrocarbon emitting petrochemical plants, and automobiles. Fuel burning plants in West Texas (generating plants and sulphur mines) all burn natural gas, an exceptionally clean fuel emitting primarily nitrogen oxides and some carbon monoxide but no sulphur dioxide. Ozone pollution comes from petroleum emissions plus automobile exhaust. Although the air around the Comanche Creek Plant is not pristine in purity, it can be logically assumed that it is far from approaching nonattainment status.

The natural gas burned at the Comanche Creek Plant will remain essentially the same with the installation of the solar cogeneration facility. Therefore, the solar plant addition will not increase or decrease the air pollutants at the sulphur mine. The solar addition, however, will generate 3 MW_e, allowing West Texas Utilities to reduce their generation by 3 MW_e and their gas consumption and resulting emissions. This, in overall effect, will improve the air quality in West Texas.

The solar facility will have no waste water discharge to area streams or lakes. The only apparent detrimental impact to the environment is the removal of the indigenous plants and animals for installation of the heliostat field. There appears to be no problem of time or expense in obtaining the proper permits for plant construction.

4.9.5 Institutional, Regulatory, and Other Considerations

The primary regulatory consideration involved in this cogeneration plant is the burning of natural gas in a new boiler and superheater to produce electricity. Under the Act, Section 8311, it states "(1) natural gas or petroleum shall not be used as a primary energy source in any new electric power plant; and (2)no new electric power plant may be constructed without the capability to use coal or any other alternate fuel as a primary energy source." The electric power plant definition under the Act is given under Section 8302 (a) (7)(A) to "mean any stationary electric generating unit, consisting of a boiler, a gas turbine, or a combined cycle unit, which produces electric power for purposes of sale or exchange and ... ."

Solar is a source of "fuel" for the project but the *primary* source is still natural gas. Most cogeneration facilities, especially the smaller units, use the very fuels that national energy objectives are attempting to replace — oil and gas. However, an awareness has been established with the energy regulatory agencies that use of these types of fuels in cogeneration facilities just may be the most efficient use available for these fuels.

This is evident in the Power Plant and Industrial Fuel Use Act (FUA), which includes as one of its major purposes in Section 102 (6)(2), the conservation of natural gas and oil for uses, other than electric utility or other industrial or commercial generation of steam or electricity, for which there are no feasible alternative fuels or raw material substitutes. The Fuel Use Act provides a permanent exemption from its prohibitions against use of oil and gas by new and existing electric power plants and major industrial fuel burning installations (MFBI) for cogeneration facilities in Section 212(c) and 312 (c). These exemptions have been implemented by the Economic Regulatory Administration in interim rules which will be finalized later this year.

Under the Public Utility Regulatory Policies Act (PURPA), Sections 201 and 210 define small cogeneration facilities and establish guidelines for utilities in setting nondiscriminatory power exchange rates and stand-by rates. The regulations under this act are highly encouraging toward the construction of cogeneration plants. Another incentive is found in P.O. 96-223, which provides a 10% business energy tax credit for investment in cogeneration equipment.

A study of the recent energy legislation and rule promulgations has not found any barriers to construction of the solar cogeneration facility; the Legislation actually seems to encourage such projects.

REFERENCES

4.1 "A User's Guide for MIRVAL – A Computer Code for Comparing Designs of Heliostat-Receiver Optics for Central Receiver Solar Power Plants," P.L Leary and J.D. Hankins, Sandia National Laboratories, Report No. SAND77-8280, February 1979.

4.2 "STEAEC – Solar Thermal Electric Annual Energy Calculator Documentation," J.B. Woodard and G.J. Miller, Sandia National Laboratories, Report No. SAND77-8278, January 1978.

4.3 "SOLMET – Hourly Solar Radiation and Surface Meteorological Observations," NOAA Report No. TD-9724, August. 1978.

Section 5

SUBSYSTEM CHARACTERISTICS

Section 5

SUBSYSTEM CHARACTERISTICS

This section provides details of the design, operating and performance characteristics of the major subsystems in the solar cogeneration facility:

- Collector Subsystem
- Receiver Subsystem
- Master Control Subsystem
- Fossil Energy Subsystem
- Electric Power Generating Subsystem
- Process Heat Subsystem
- Electrical Subsystem
- Fluid Circulation Subsystem

5.1 COLLECTOR SUBSYSTEM

The collector subsystem functions to reflect the incident insolation to the tower-mounted receiver. To adequately perform this function, the individual heliostats must track the sun and position themselves properly to reflect the energy to the intended target. The following sections discuss the development of the collector subsystem design for the Texasgulf Solar Cogeneration Facility.

5.1.1 Functional Requirements

To attain the desired 3 MWe design point net output from the turbine/generator, the collector field will be required to deliver $\sim$22.0 MW_t power to the receiver at noon on the equinox. In addition to this requirement, the collector subsystem must also meet the requirement that the maximum flux shall not exceed 0.85 MW/m^2 which is a receiver operating limitation necessary to avoid exceeding structural limits on the receiver.

With respect to individual heliostat performance, the requirements of a typical second generation heliostat have been imposed for design point performance. These requirements, summarized in Table 5-1, were provided by DOE (Ref. 5.1) and are not meant to be representative of any specific second generation heliostat program. However, these requirements do form the basis for the collector subsystem design described below.

5.1.2 System Design Description

The collector subsystem will consist of 588 heliostats in a 35-acre northfield configuration located southeast of the existing Comanche Creek Plant. A layout of the proposed field is shown in Figure 4-3. The evolution of this field design is described in the following section.

Table 5-1

HELIOSTAT DESIGN PERFORMANCE REQUIREMENTS

Parameter	Requirement
Total mirror module area	53.51 m^2 (576 ft^2)
Heliostat dimensions	7.39 m wide x 7.44 m high (24 ft 3 in x 24 ft 5 in)
Heliostat area	55.01 m^2 (592.1 ft^2)
Total reflective area	52.77 m^2 (568.02 ft^2)
% Reflective Area $\left(\frac{\text{Total reflective area}}{\text{Heliostat area}}\right)$	96%
Mirror reflectivity (clean 92%) Nominally	90%
Heliostat 1 - standard deviation angular errors for pointing	0.75 milliradians each axis
Surface normal 1 - standard deviation errors	1 milliradian each axis
Minimum distance center to center (heliostat spacing)	10.79 m (35.4 ft)
Height of elevation axis centerline	4.04 m (13 ft 3 in)

5.1.2.1 Collector Field Design Model

The analysis used the same heliostat, solar and receiver parameters described in Table 3-3 (with two exceptions), and the same cost models described in Table 3-4. One exception is the site latitude. The natural slope of the land is one degree down from south to north. It was desired to minimize site preparation costs by maintaining the natural slope. Therefore, this was approximated by using a site latitude that was one degree further north. The second exception is the heliostat characteristics which are now taken from Table 5-1.

This information was input to the DELSOL computer code optimization routine. The code is designed to optimize the system configuration in terms of the collector field size and arrangement, with the tower and receiver sizes as a function of the overall cost of energy.

5.1.2.2 Collector Field Design Results

The collector field configuration developed by DELSOL consisted of 592 heliostats reflecting energy to an 8 m by 8 m (26.2 ft × 26.2 ft) flat panel receiver mounted on a 70 m (230 ft) tower. This optimized field, shown in Figure 5-1, covers 0.119 k/m^2 (29.4 acres) and delivers 22.7 MW_t to the receiver.

To assess this field configuration, the DELSOL performance code was run to obtain the receiver flux pattern, which in turn could be analyzed with WSRLOSS, the GE Receiver Loss Code. This code calculates receiver panel performance based on incident flux and detailed receiver design characteristics. Further discussion of this code is in Section 5.2.

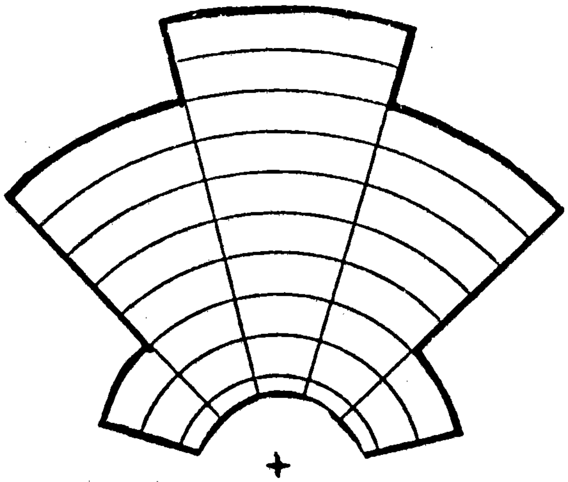


Figure 5-1. DELSOL – Optimized Field Configuration

The performance analysis indicated that at the design point (equinox, noon) the power delivered to the working fluid (21.2 MW_t) slightly exceeded the design requirement. Using fewer heliostats and a slightly smaller receiver will reduce the power to the receiver. To minimize the field losses, the Sandia computer code MIRVAL (Ref. 5.2) was used so that variable heliostat spacing could be employed. The resulting collector field layout is shown in Figure 5-2 and described in Table 5-2. Finally, the X, Y coordinates relative to the tower position for each of the 588 heliostats were obtained from MIRVAL and are presented in Appendix C.

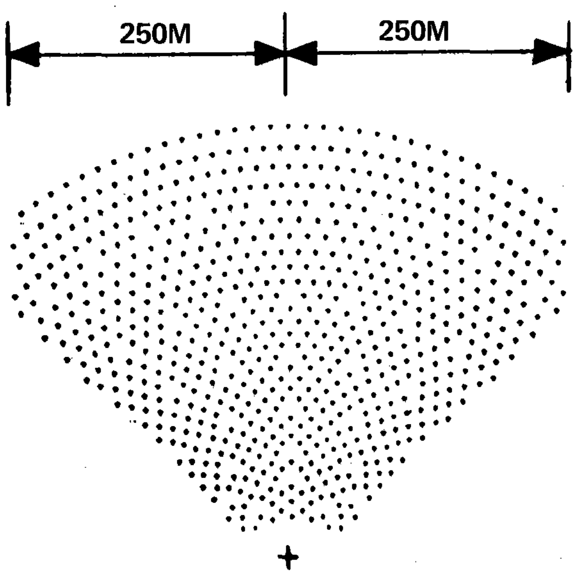


Figure 5-2. MIRVAL – Collector Field Configuration

Table 5-2

REVISED COLLECTOR FIELD DESIGN

Parameter	Design Value
Noon Equinox Power	20.8 MW_t
Number of Heliostats	588
Tower Size	70 m (230 ft)
Receiver Size	8.0 m (width) x 6.8 m (height) (26.2 ft x 22.3 ft)
Peak Flux	0.685 MW/m^2
North Field Radius	400 m (1312 ft)

5.1.3 Component Description

Development of components for the collector subsystem is a part of the overall DOE heliostat development program. Rather than duplicate the efforts of that program, the heliostat and collector subsystem performance assumptions provided by DOE for the cogeneration conceptual design were utilized. These assumptions are discussed in Section 5.1.1 (Heliostat Performance) and Section 5.1.4 (System Performance). For the detailed design and construction phase of the program, an evaluation of available hardware will be required to select the physical equipment to be used.

5.1.4 Operating Characteristics

Since the collector subsystem component design is not a part of this program, the operating characteristics of the subsystem have been based on the DOE assumptions provided together with published data available for second generation heliostats. Those operating characteristics that will affect the design of the remainder of the cogeneration facility and the assumed values are shown in Table 5-3.

5.1.5 Performance Estimates

The collector subsystem performance can be described in terms of the receiver flux distribution and the field efficiency variation with time. These two parameters allow the effect of the collector field design on the overall system performance to be calculated. The flux impacts the structural

Table 5-3

COLLECTOR SUBSYSTEM OPERATING CHARACTERISTICS

Parameter	Performance	Source
Defocus Time	2 min/heliostat	DOE/Sandia
Tracking	35 W/heliostat	McDonnell Douglas
Stow	657 W/heliostat	McDonnell Douglas
Emergency Slew	335 W/heliostat	McDonnell Douglas

integrity of the receiver and the field efficiency variation allows calculation of system energy performance.

5.1.5.1 Receiver Flux

The collector field design for the Comanche Creek cogeneration facility, described in Section 5.1.2, will deliver a peak flux of 0.685 MW/m^2 at the design point (noon, equinox). This flux level is based on a multiple point aiming strategy. The distribution of the flux over the receiver surface at the design point is listed in Figure 5-3.

E						℄						W	
0.1170	0.1645	0.1865	0.1980	0.2140	0.2305	0.2360	0.2290	0.2134	0.1980	0.1870	0.1670	0.1190	
0.2125	0.3115	0.3550	0.3958	0.4140	0.4200	0.4165	0.3967	0.3748	0.3530	0.3530	0.3060	0.2075	
0.2795	0.4075	0.4690	0.4975	0.5230	0.5460	0.5535	0.5485	0.5250	0.5968	0.4660	0.4020	0.2740	
0.3170	0.4575	0.5250	0.5582	0.5940	0.6225	0.6310	0.6225	0.5930	0.5576	0.5250	0.4555	0.3140	
0.3375	0.4840	0.5550	0.5916	0.6300	0.6620	0.6730	0.6620	0.6290	0.5910	0.5550	0.4825	0.3355	
0.3430	0.4920	0.5650	0.6019	0.6410	0.6735	0.6850	0.6730	0.6403	0.6016	0.5640	0.4915	0.3420	
0.3310	0.4780	0.5500	0.5896	0.6215	0.6535	0.6625	0.6525	0.6220	0.5897	0.5500	0.4790	0.3315	
0.3040	0.4450	0.5150	0.5444	0.5760	0.6035	0.6115	0.6035	0.6775	0.5451	0.5150	0.4475	0.3075	
0.2530	0.3785	0.4405	0.4645	0.4901	0.5105	0.5130	0.5070	0.4884	0.4654	0.4435	0.3855	0.2600	
0.1725	0.2615	0.3015	0.3146	0.3324	0.3475	0.3490	0.3465	0.3323	0.3150	0.3025	0.2645	0.1765	
0.0815	0.1165	0.1305	0.1347	0.1433	0.1540	0.1595	0.1567	0.1452	0.1349	0.1285	0.1125	0.0780	0.6182
E						℄						0.6154 W	

Figure 5-3. Design Point Incident Flux (MW/m^2)

5.1.5.2 Field Efficiency

Field efficiency is defined as:

$$\text{Field Efficiency} = \frac{\text{Power Incident on Receiver}}{\text{Total Reflector Surface Area} \times \text{Normal Flux}}$$

At the design point, the field efficiency is 75.9%. The variation of field efficiency with time is shown in Figure 5-4.

5.1.6 Heliostat Cost Estimate

The collector subsystem cost estimate was based on the DOE-provided assumption of $260/m². This cost is an installed cost for the heliostat field including the field wiring and control computer equipment. This direct cost totals $8,067,478.

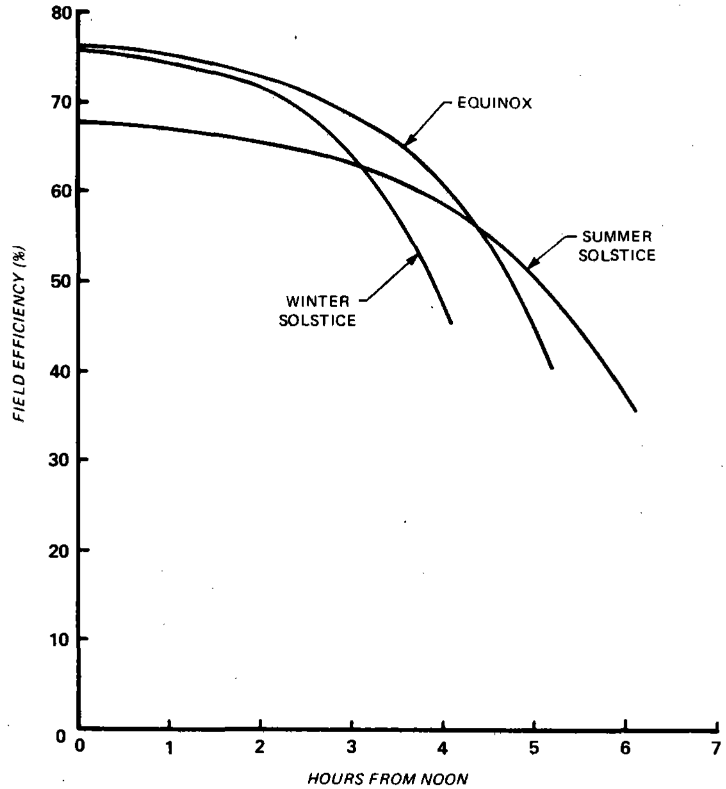


Figure 5-4. Field Efficiency Variation with Time

Because the heliostat installation will in essence be a turnkey effort on the part of the collector field vendor, the approach taken in calculating indirect costs was different from other subsystems. Lump sum estimates of the cost of engineering (field layout and specification work) and construction management (monitoring of vendor performance) were made as opposed to the conventional percentage approach. The lump sum estimates are General Electric best guesses based on time and material considerations for these efforts. The results are summarized in Table 5-4. No contingency is included for the collector subsystem since they are based on DOE projections based on numbers that already include some contingency.

Table 5-4

COLLECTOR SUBSYSTEM COST SUMMARY (5300)

Collector Subsystem Purchase	$8,067,478
Engineering	245,000
Construction Management	134,000
Total	$8,446,478

Additional cost details are provided in Appendix A, System Specification.

5.2 RECEIVER SUBSYSTEM

The Receiver Subsystem includes the receiver, the steam drum, the riser/downcomer piping and the tower. The basic function of this subsystem is effective interception of radiant solar flux directed from the Collector Subsystem and the efficient transfer of as much of that thermal energy as possible into the receiver boiler water for conversion to steam.

A natural-circulation system was selected because of its history of high reliability in fossil-fueled boilers. Natural circulation reduces capital and maintenance costs, increases reliability, and eliminates power consumption associated with a forced-circulation pump. The diameter of the boiler tubes is relatively large. No small orifices, which are prone to plugging, are needed to control flow distribution. Flow circuitry and valving are inherently uncomplicated. The receiver is relatively tolerant of impure feedwater because of its large tubes and sizeable water inventory. Circulation is inherently self-compensating for energy input variations. The plot plan (Figure 4-3) shows the location of the receiver and tower in the southeast sector of the facility.

5.2.1 Functional Requirements

Table 5-5 provides a list of receiver subsystem design requirements. These requirements evolve from the overall plant performance requirements and also from the collector subsystem design discussed in Section 5.1.

Table 5-5

RECEIVER SUBSYSTEM DESIGN REQUIREMENTS

Parameter	Requirement
Nominal Power	20.4 MW_t
Receiver Size	8 m (width) x 6.8 m (height) (26.2 ft x 22.3 ft)
Tower Height	70 m (230 ft)
Working Fluid	Water/Steam
Inlet Temperature	162 °C (324 °F)
Outlet Temperature	272 °C (521 °F)

In addition to the design requirements listed in Table 5-5, the following operational requirements were imposed on the design of the receiver subsystem:

- Provide for the safe, efficient collection of energy redirected by the heliostat field under all operating modes and conditions
- Be capable of remote automatic operation
- Be capable of operating during the worst combination of:
  - Ambient Temperature −18 to 49 °C (0 to 120 °F)
  - Wind Velocity at 10 m (30 ft); 17.88 m/s (40 mph)
- Survive maximum winds of 40 m/s (90 mph) measured at the 10 m (30 ft) level

- Survive U.B.C. Zone 2 earthquake
- Be designed for a 20-year life

5.2.2 Description

As presented herein, the receiver design is based on full flow operation instead of the 95% flow as shown in Figure 4-1. This is a conservative approach since it does not consider the contribution from the fossil boiler which operates in parallel with the receiver. This approach was adopted because early in the conceptual design the boiler minimum flow operation level vacillated between zero and 10%. The choice of 5% minimum boiler flow was made approximately half way through the program and the resulting effect on the receiver design and even the collector field design was believed to be small. This effect should be reevaluated in the next phase of the program.

The Receiver Subsystem consists of six major components:

- Receiver Panel
- Steam Drum
- Support Structure
- Tower
- Up/Down Piping
- Controls

A brief description of these receiver components is provided in the following sections.

5.2.2.1 Receiver Boiler Panel

The natural-circulation water/steam receiver absorbs heat in an exposed north-facing flat panel that is tilted down 20 degrees from the vertical to face the heliostat field at an optimal angle. The boiler panel consists of tubes that are joined along their length by continuous weld integral fins to form a flat MONO-WALL™.

This type of construction typically consists of carbon steel boiler tubes 50.8 mm (2 in) in diameter with a fin width of 6.4 mm (0.25 in). The panel is coated with PYROMARK™ absorbtive coating. The 6.8 m (H) × 8.0 m (W) (22.3 ft × 26.3 ft) receiver is consistent with the system power requirement of 20.8 MW_t (71.0 × 10^6 Btu/hr) and a peak heat-flux limit of 0.8 MW/m^2 (254,000 Btu/hr-ft^2). Figure 5-5 is an artistic rendering of the panel receiver. The design characteristics of the receiver are shown in Table 5-6.

Boiler water from the drum is distributed directly from the bottom of the downcomers to a lower distribution header via feeder tubes. From the lower header, water flows upward inside the boiler tubes, becoming a mixture of steam and water after absorbing the incident heat flux. The resultant steam/water mixture is collected at the upper header and is carried by riser tubes to a horizontal steam drum. In the drum the water is separated from the steam and, after mixing with makeup feedwater, enters the downcomer for a return trip around the boiler circuit. The dry saturated steam is delivered to a steam accumulator. Figure 5-6 shows the general arrangement of the boiler with the panel downcomer, risers, feeders and drum.

Receiver size and materials are listed in Section 5-1 of Appendix A. The north face of the receiver, surrounding the boiler panel, is insulated with KAOWOOL™ insulation board. Recent

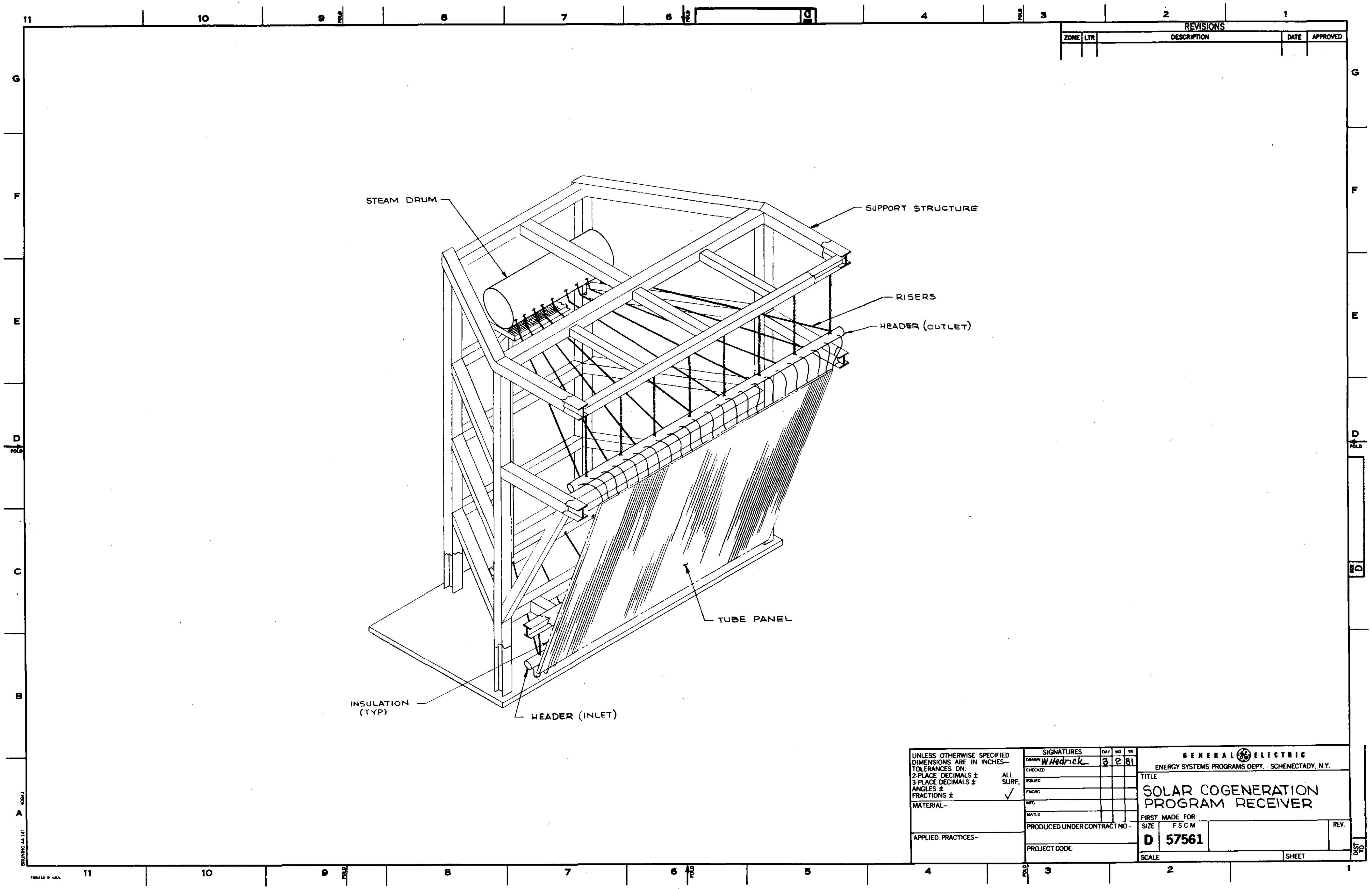


Figure 5-5. Panel Receiver

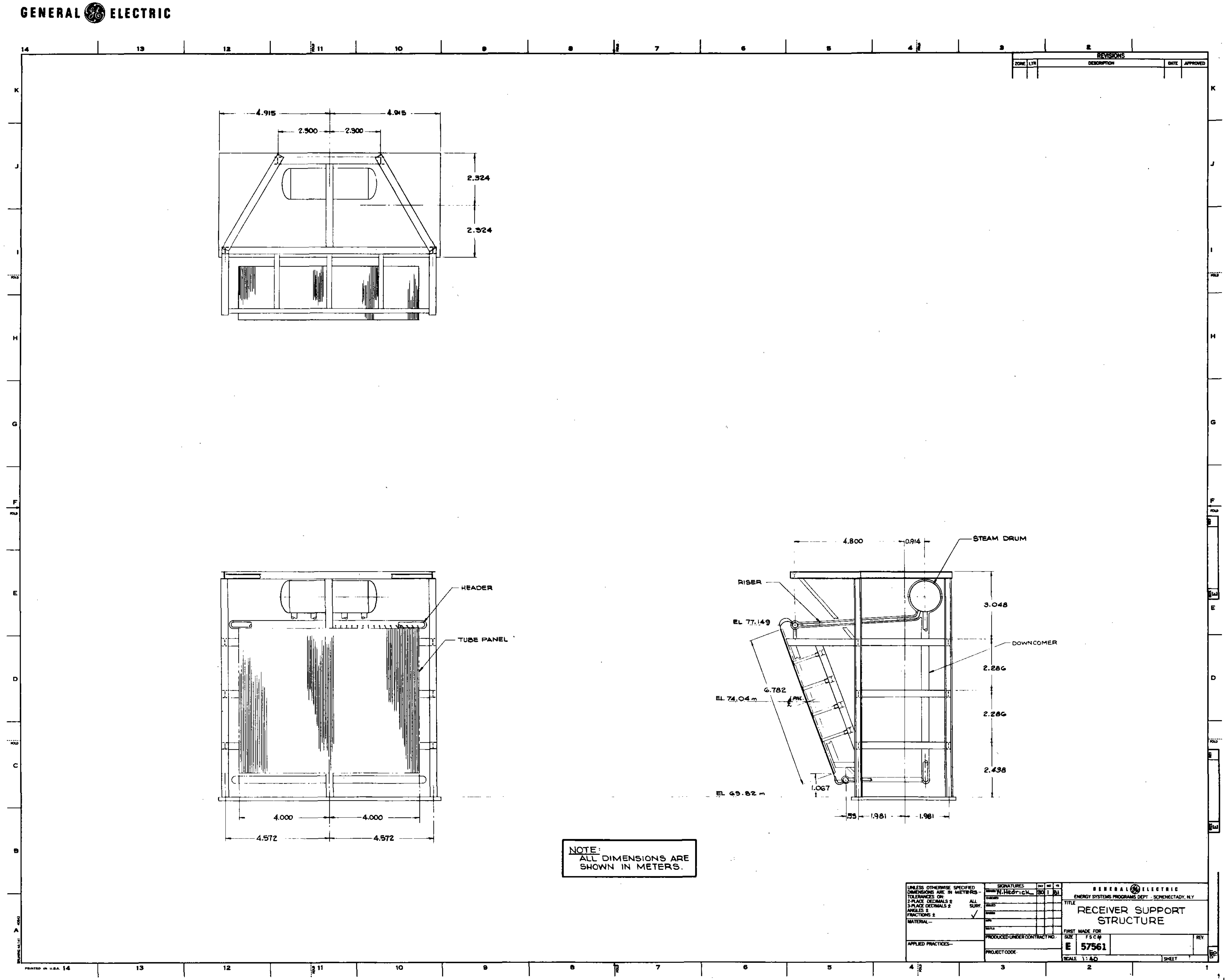


Figure 5-6. Receiver Support Structure

Table 5-6

RECEIVER CHARACTERISTICS

Peak Power Input, MW_t	22.37
Fluid	Water/Steam
Pressure, MPa (psia)	5.64 (820)
Nominal Inlet Temperature, °C (°F)	162 (324)
Nominal Outlet Temperature, °C (°F)	272 (521)
Design Flow Rate, kg/s (lb/hr)	9.7 (77,060)
Aperture Width, m (ft)	8.0 (26.3)
Aperture Height, m (ft)	6.8 (22.3)
Losses, MW_t	1.58
Useful Power, MW_t	20.8
Receiver Efficiency	0.93
Design Point	Noon, Equinox
Operating Life, years	>20
Thermal Cycles	>10,000
Fatigue Life, cycles	>100,000
Peak Metal Temperature, °C (°F)	319 (606)
Design Pressure, MPa (psia)	6.2 (900)

work by Sandia (Ref. 5.3) shows this insulation can withstand flux as high as 0.6 MW/m^2 (190,000 $Btu/hr\text{-}ft^2$) without any appreciable deterioration.

5.2.2.2 Steam Drum

The steam drum, which serves as a water reservoir for the steam-generating circuits, contains steam separating equipment and internal piping for feedwater distribution, and continuous blowdown. A cross section of the drum showing arrangement of the steam-separating components (drum internals) is depicted in Figure 5-7.

The function of the steam separating equipment is to provide steam-free water for the circulation system and water-free steam for the superheater. The entrainment of steam in the downcomers reduces the gravitational head available and thus adversely affects the circulation rate. Excessive moisture in the steam leaving the drum will result in superheater deposits. These effects are controlled by appropriate selection and arrangement of drum internals.

The feedwater pipe, located in the water space of the drum above the downcomer openings, extends for the length of the drum shell. The feedwater is discharged uniformly along the length of the pipe through holes located in its upper surface.

The continuous blowdown line is located below the expected lowest operating water level, close to the horizontal separator drains, where the boiler water concentration is highest.

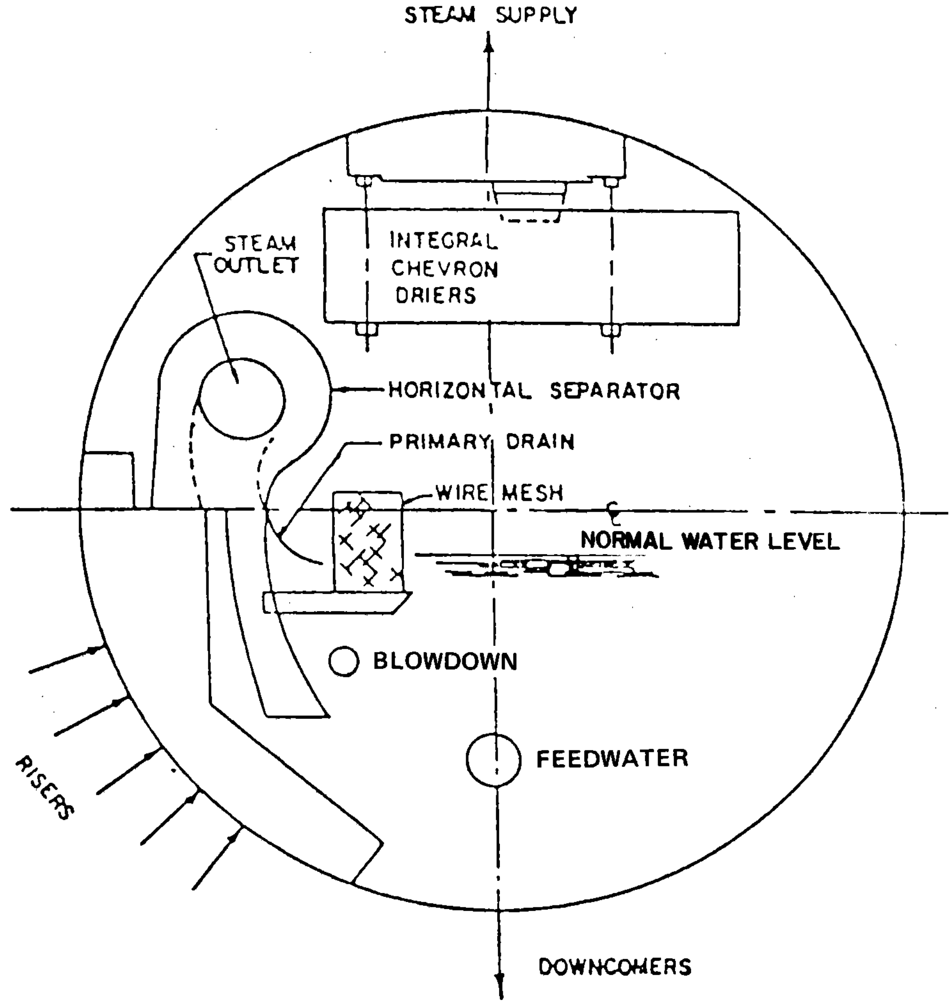


Figure 5-7. Arrangement of Steam Drum Internals

Referring again to Figure 5-7, an internal circumferential baffle extending almost the full length of the shell forms an annulus along the bottom half of the steam drum on one side. The steam-water mixture from the risers enters the drum in this annulus and then passes through the horizontal steam separators, where the first stage of steam separation from the water is accomplished. As the mixture follows the curved contour of the separator, the heavier water particles are forced to the outside, discharging first through the primary drain and then through the wire mesh located at the primary drain outlet into the bottom of the drum. The wire mesh dissipates the discharging water velocity and allows any entrained steam to escape. The separated steam flows from openings on both sides of the separators into the chevron driers.

The final separation of moisture in the steam takes place as the steam meets the W-shaped chevron elements that form the drier assemblies. Steam enters the driers at a low velocity and makes several abrupt changes in flow direction. These changes cause the entrained moisture to adhere to the large surface area presented by the chevrons. The water film then drains by gravity to the lower part of the drum. The separated steam flows into the dry box and leaves the drum through the steam line at the top. The line supplies steam to the fossil-fired superheater. Water separated from the steam falls into the water space of the drum and then to downcomer pipes that carry the water to the bottom of the unit for distribution to the waterwalls.

5.2.2.3 Support Structure

The boiler panel is 6.8 m (22.3 ft) long. Provision must be made for intermediate horizontal supports to withstand wind and seismic loads.

The panel is supported from the structure at the top by spring mounts and held in place by means of links that connect it with the support structure at different elevations. This connection allows the panel both lateral and vertical downward movement for thermal expansion. Figure 5-6 shows the support arrangement. Structural support members facing the heliostat field are insulated. Areas surrounding the receiver have a thermal insulation shield to prevent any stray heat flux from being incident in areas behind the boiler panel.

There are platforms at the top of the tower and at drum level for easy maintenance and inspection.

5.2.2.4 Tower

Support for the receiver will be provided by an approximately 70 m (229 ft 7 in) tall structural steel tower as shown in Figure 5-8. This tower will be constructed of standard hot rolled A-36 steel shapes with high strength bolted connections. The tower will taper from a maximum base dimension of 16 m by 16 m (52 ft 6 in by 52 ft 6 in) to 4.0 m by 9.2 m (13 ft 1-1/2 in by 30 ft 2-1/4 in) at the top. The receiver structure will add approximately 10 m (32 ft 10 in) to the overall tower height for a total of approximately 80 m (262 ft 5 in).

Access platforms will be provided, as required, for valves or other equipment. Access to the top of the tower will be provided by both a stairway and a 907 kg (2000 lb) capacity elevator. The elevator will be capable of stopping at intermediate locations for maintenance and repair, as required. At each location, adequate safety provisions will be made for personnel.

The receiver and its support structure will be fabricated in sections and bolted together in the field. The field assembly will be done on the ground, and the total unit will be lifted to the top of the tower by high-capacity long reach cranes.

A summary of the weights of major structural elements of the tower used in its design is given in Table 5-7. These weights were based on preliminary estimates and are higher than actual component weights.

The tower structural design will comply with applicable federal government and current state, and local and industry building construction codes. The principal codes and design criteria for the tower are summarized in Table 5-8.

The deflection at the center line of the receiver will be limited to 15 cm (5.9 in) under an operating condition wind speed of 17.88 m/sec (40 mph). Wind loads, being greater than earthquake loads, will control the design.

Based on the soil report developed for the existing Texasgulf Sulphur Plant, the soil in the area of the receiver tower is of a high strength and relatively incompressible. Therefore, the foundations for the tower will consist of concrete spread footings of sufficient size and weight to resist uplift forces generated by wind or earthquake.

5.2.2.5 Up/Down Piping

The up/down piping within the tower will consist of the upward flow feedwater and warm-up lines and the downward main steam and drain pipes. All are seamless carbon steel, ASTM A106 GR. B

Table 5-7

TOWER WEIGHT SUMMARY

Element	Weight 1000 kg	(1000 lb)
Receiver Support Structure	15.9	(35.0)
Steam Drum	8.5	(18.7)
Aperture Tubes	5.0	(11.0)
Other Piping (riser, downcomer, etc.)	4.4	(9.7)
Tower Structural Steel	336.6	(742.0)
Stairs	9.8	(21.5)
Elevator	2.7	(6.0)
Subtotal	382.8	(843.9)
Tower Foundations	310.4	(684.3)
Tower Tower Weight*	693.2	(1528.2)

*Excluding Soil Overburden

Table 5-8

SUMMARY OF TOWER STRUCTURAL DESIGN CRITERIA

A. Natural Phenomena	
Earthquake	U.B.C. Zone 2
Wind Gusts	Up to 40 m/s (90 mph)
Snow	0.24 KPa (5 lb/ft^2)
Ice	5.08 cm (2 in) thick buildup
B. Material Strength	
Tower Structural Steel - fy	248 MPa (36 ksi)
Tower Foundation Concrete - f'c	20.7 MPa (3,000 psi)
Tower Reinforcing Steel - fy	276 MPa (40 ksi)
Soil Bearing - q	696.2 kPa (15.3 ksf)
C. Codes	
1. UBC - 1981	
2. NRC - Regulatory Guides 1.60 and 1.61	
3. ACI 319-77 Building Code Requirements for Reinforced Concrete	
4. AISC 8th Edition Manual of Steel Construction	

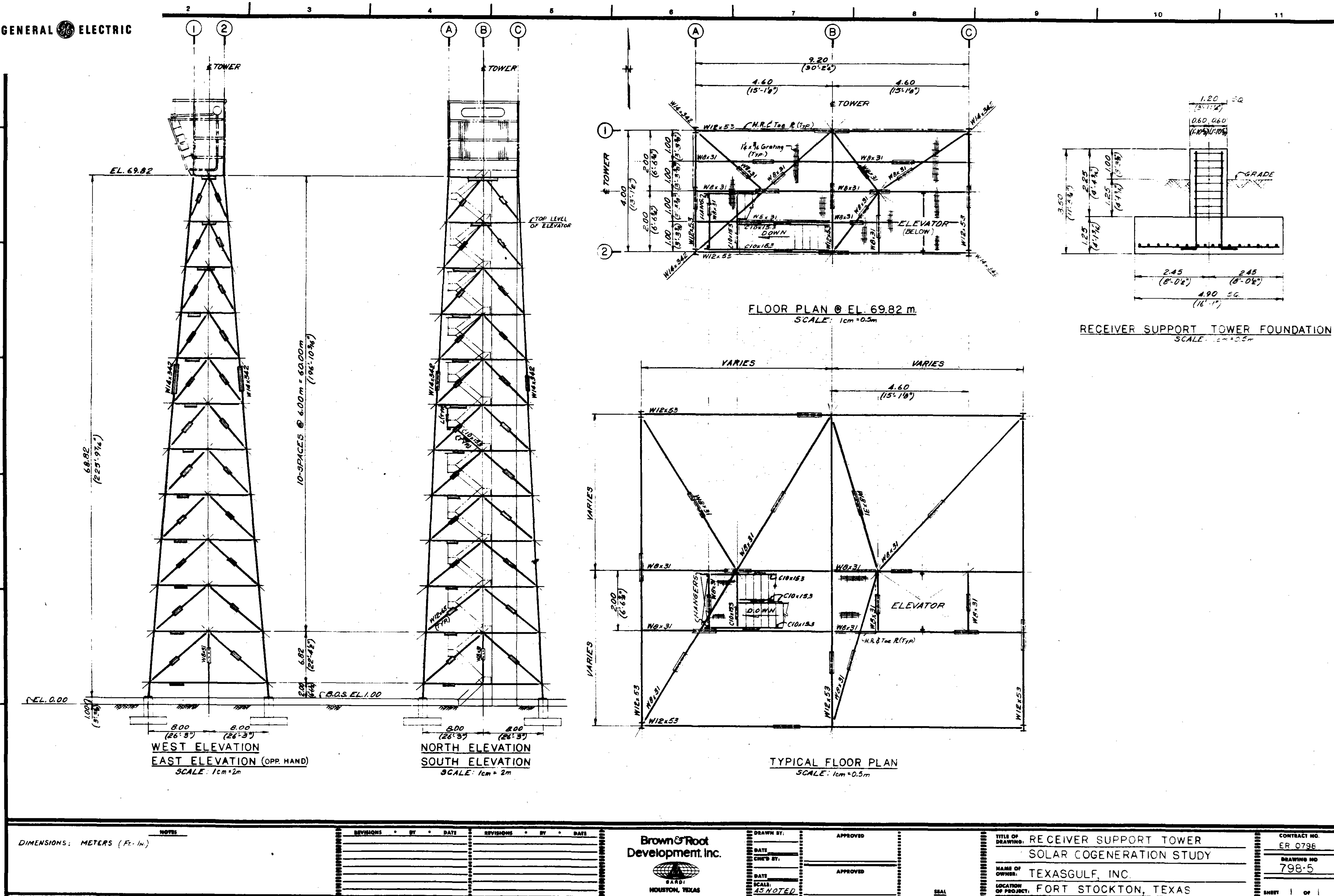


Figure 5-8. Receiver Support Tower

with standard wall thickness. The nominal diameters chosen primarily for moderate velocity, pressure drop and mechanical strength are:

Main Steam	15.24 cm	(6 inch)
Feedwater	7.62 cm	(3 inch)
Warmup steam	7.62 cm	(3-inch)
Drain	5.08 cm	(2 inch)

Differential expansion between the up/down piping and the tower will be accommodated by all welded three-plane, square cornered expansion loops. Each line will be supported from the tower structure by a separate system or spring loaded constant support pipe hangers.

5.2.2.6 Receiver Control

Receiver water inventory is maintained at the desired level by controlling the flow rate of the water so that it equals the steam flow generated (plus an allowance for blowdown) with drum level correction. This system is capable of holding the level within acceptable limits under all operating conditions, including the sudden reduction in steam generation caused by a passing cloud. High- and low-water level alarms alert the operator to large excursions. A low-level cut-out relay sends a signal to the master control to defocus the heliostat field in the event the water level decreases to the emergency level.

Receiver tube temperatures are monitored by several sensors. A high-temperature preshutdown alarm alerts the operator to an impending problem. A further increase in temperature signals the master control to defocus some of the heliostats and cut off the heat input.

The solar receiver generates steam at 5.65 MPa (820 psia). The pressure at the receiver discharge is regulated by a let-down valve located between the inlet and outlet connections of the accumulator. This valve is set to maintain the desired 5.65 MPa (820 psia) by releasing more or less steam to the lower pressure line downstream of the valve. It is monitored from the main control room.

A high-pressure preshutdown alarm is provided to alert the operator in the main control room. A high-pressure cut-out signal is also provided to defocus the heliostat at a pressure slightly lower than the safety valve settings on the receiver drum.

Remote manual operation from the main control room is provided for the solar receiver stop valve and the drum vent valve.

A minimum flow through the feedwater pumps will be maintained by flow measurement in the common pump discharge by opening a valve to return the flow to the blowdown line in the event the water for the solar receiver and the accumulator drops below the minimum flow.

5.2.3 Operating Characteristics

Receiver operating modes include normal operation, startup and shutdown. They are described below.

5.2.3.1 Normal Operation

During the course of the day, the steam outlet will automatically remain at 5.65 MPa (820 psia), and the amount of process steam will be proportional to the heat absorbed.

In the event of a cloud passage, the steam flow rate falls. To partially compensate for the drop in steam flow, the steam outlet control valve will allow the drum pressure to fall. The steam outlet control valve will close when the drum pressure falls below a preset value. The receiver will be on standby until the solar heat input resumes. After a short cloud passage, the receiver will produce steam and the steam outlet pressure will rise to 5.65 MPa (820 psia).

5.2.3.2 Startup

The receiver is placed into service each day by activating the controllers and properly positioning the stop and drain valves by remote control. The controller set points will be:

Drum Level	–	0 (operating level)
Steam Pressure	–	5.65 MPa (820 psia)
Blowdown	–	0.5%
Maximum Drum Pressure	–	2 MPa (287 psia)

The feedwater pump is turned on. Normally the receiver is filled with water from the previous day's operation, but if it were empty, the feedwater controller will automatically fill the receiver.

The operator will inspect the indicators and readouts on the controller panel to ensure that the receiver system is functioning properly before commanding heliostats onto the receiver. The receiver will absorb all the heat that is redirected by the heliostats during startup and will start producing process steam within 15 minutes for a typical diurnal startup and within 30 minutes for a cold startup. Typical receiver startup will be from a drum pressure of 0.69 MPa (100 psia).

During startup, the water within the panel is heated to the drum saturation pressure, the water within the panel begins to boil, and steam bubbles rise causing the boiler to circulate. The water/steam mixture from the panel flows into the drum, some steam condenses, and the drum pressure rises. The steam outlet control valve will open and regulate drum pressure to supply steam to the line at 5.65 MPa (820 psia).

5.2.3.3 Normal Shutdown

At the end of the day, the receiver will shut down automatically. The drum pressure and the steam outlet flow rate will fall, and the steam outlet valve will close when the drum pressure falls below preset values. The operator will close all receiver stop valves, turn off the water pump and valve control systems, and remove the heliostats from the receiver. As described in Section 4.3, a receiver warmup line will be utilized to maintain the receiver in a state of readiness for startup the following morning.

5.2.3.4 Emergency Shutdown

An overpressure controller is used to protect the system from dangerous pressure levels or extreme heat flux on the receiver. This controller signals the heliostat controller to defocus the heliostats, which occurs within 30 seconds of the command. The operator can then proceed through a normal shutdown or evaluate the condition.

5.2.4 Receiver Performance

All receiver performance is based on the work done by Foster Wheeler (see Ref. 5.4). Aside from sizing the receiver to develop the appropriate amount of thermal energy needed for the Texasgulf facility, no receiver design work has been performed. To keep the overall program costs low and still develop an acceptable conceptual receiver design, the receiver developed by GE is well within FW design limits.

5.2.4.1 Receiver Coating

The receiver coating, also used on the Barstow pilot plant receiver, is manufactured under the trade name PYROMARK™ by the Tempil Corporation, 2901 Hamilton Boulevard, South Plainfield, New Jersey. PYROMARK has been used for various commercial and aerospace high-temperature applications for many years.

The spectral reflectance (equal to 1-spectral absorptance) was measured at wavelengths between 0.25 and 2.5 μm, as shown in Figure 5-9. These data are for PYROMARK on stainless steel; however, measurements have shown no difference in PYROMARK absorptance using Incoloy 800, carbon steel, and stainless steel as substrates. In the wavelengths corresponding to the region of maximum solar radiation, the reflectance is below 0.05 μm, giving a solar absorptance of 95+%.

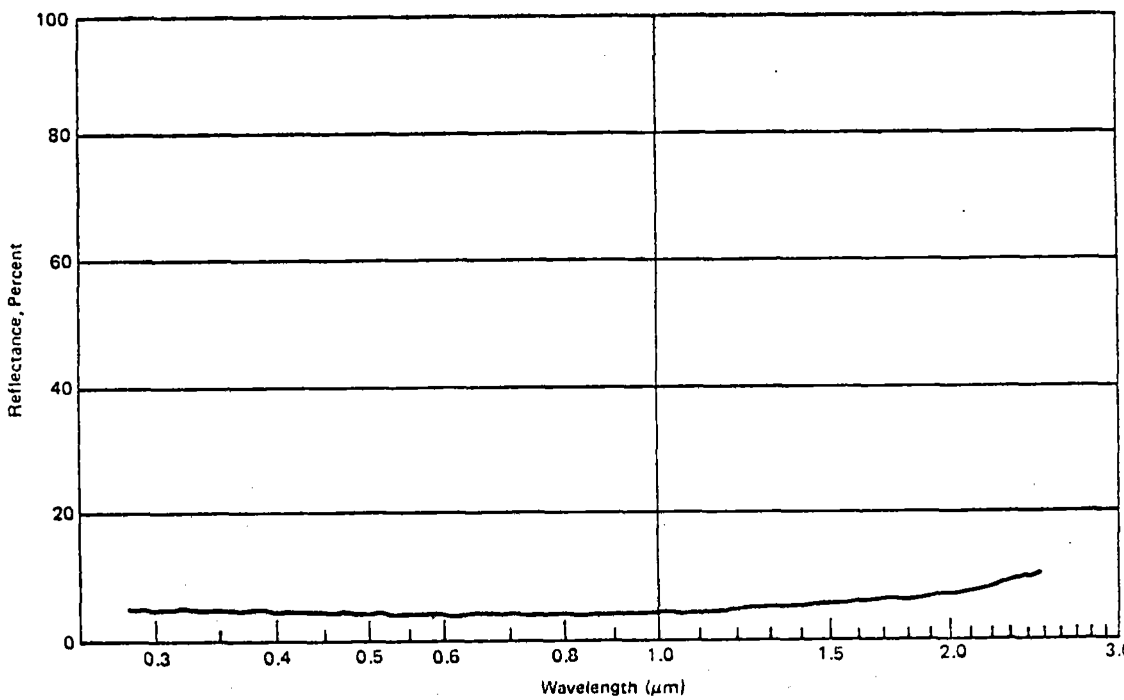


Figure 5-9. Spectral Reflectance of PYROMARK

5.2.4.2 Thermal Performance

The receiver thermal performance analysis was based on the DELSOL generated receiver flux pattern modified to account for fewer heliostats and tailored flux limits. The resulting incident flux is shown in Figure 5-3. Peak incident flux is 0.685 MW/m^2 (217,185 Btu/hr-ft^2) corresponding to an absorbed flux of 0.637 MW/m^2 (201,982 Btu/hr-ft^2). Receiver design is thus very conservative, leaving a large heat flux margin of safety.

Absorbed flux is derived from the incident flux by the following relationship:

$$\text{Absorbed flux} = 0.93 \text{ (Incident flux)}$$

This is based on an analysis using the GE developed *W*ater *S*team *R*eceiver *Loss* (WSRLOSS) computer code. This code is a modified version of a similar code used previously on the GE Alternate Central Receiver and Solar Repowering programs. The code has been modified to reflect a water/steam working fluid instead of sodium as before. A more complete description and listing of WSRLOSS is presented in Appendix D. The resulting overall receiver thermal performance is shown in Table 5-9.

Table 5-9

RECEIVER THERMAL PERFORMANCE

Incident Energy	22.37 MWth
Reflection Loss	1.12 MWth
Radiation Loss	0.25 MWth
Convection Loss	0.20 MWth
Absorbed Energy	20.8 MWth
Receiver Efficiency	0.9301

5.2.5 Receiver Cost Estimate

The Receiver Subsystem cost, including materials, labor, and construction is:

Code	Item	Amount
5400	Receiver Subsystem	$3,068,110

5.3 MASTER CONTROL SUBSYSTEM

The control and instrumentation subsystem incorporates the system master controller plus six subsystem controllers for the heliostat field, integrated boiler and superheater, turbine/generator, process water flow/temperature control, and the condensate/feedwater subsystem. The master controller provides a complete operational interface with the system including implementation of both manual and automatic unattended control. The subsystem controls operate under the command and operational monitoring functions of the master controller. Instrumentation necessary for the subsystem controls, for master control operating mode selection, and for general system monitoring is provided.

A system schematic diagram which indicates the instrumentation, flow control valves, and level control valves needed for system control and operational monitoring is presented in Figure 5-10. Not shown is the heliostat field, which is outside the system steam/water flow circuit.

5.3.1 Functional Requirements

The Master Control Subsystem design is based on a philosophy of flexibility and reliability resulting in the following general design requirements:

- Capability for complete automatic operation, semi-automatic operation, and manual operation
- Solar-fossil controls separated to permit totally independent operation
- Data acquisition of all major operating parameters with display at operator control panel
- Critical/emergency functions and data hardwired to operator control panel
- Redundant critical/emergency function controls and data acquisition

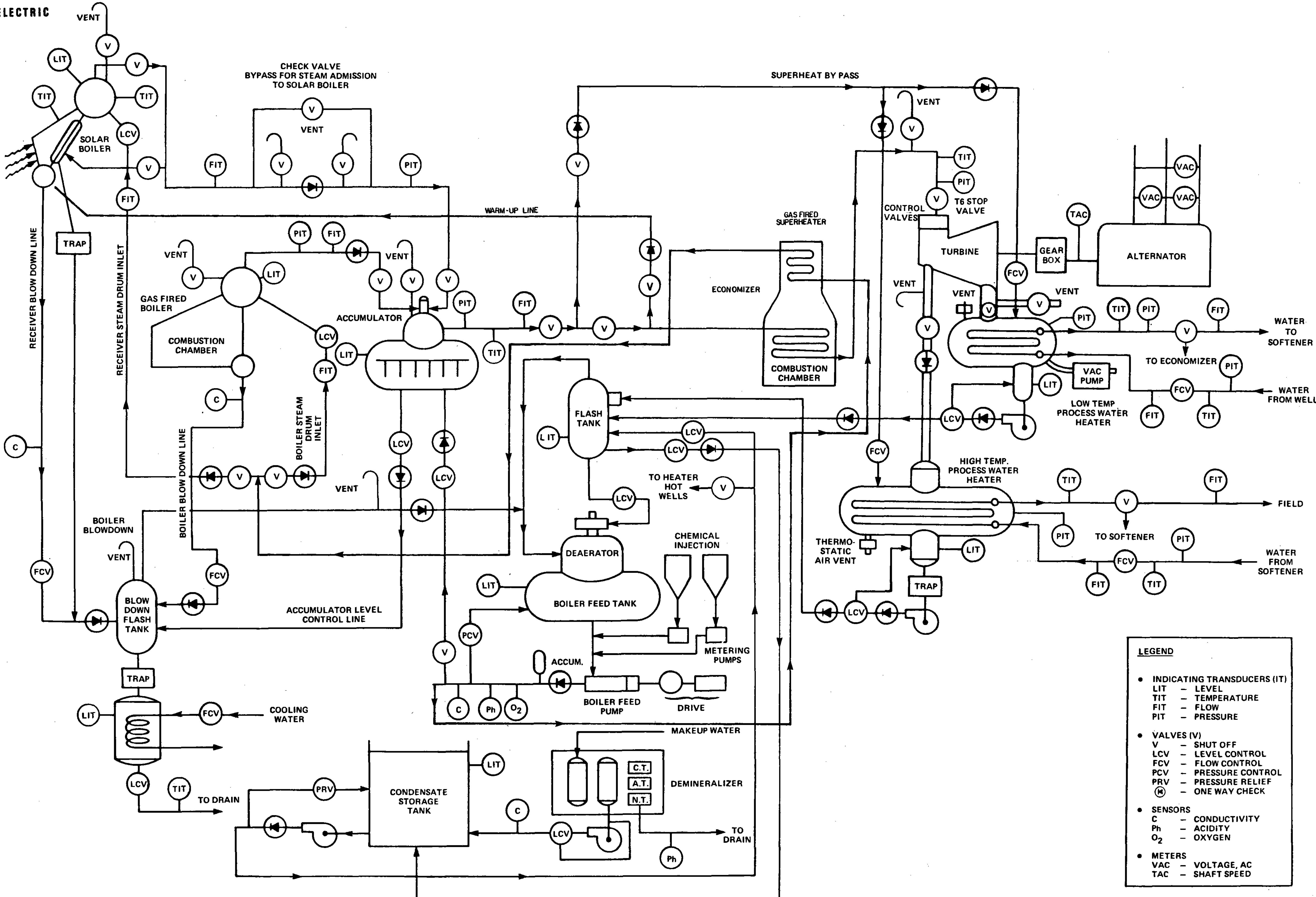


Figure 5-10. Piping and Instrumentation Diagram

5.3.2 Design Description

The design of the control subsystem is based on proven hardware components that will provide high reliability, cost-effectiveness, and overall simplicity. The hardware/software system selected to implement the facility control and monitoring system is shown functionally on the diagram of Figure 5-11. All communication between the master control subsystem (MCS) and other subsystems is via redundant input/output (I/O) busses.

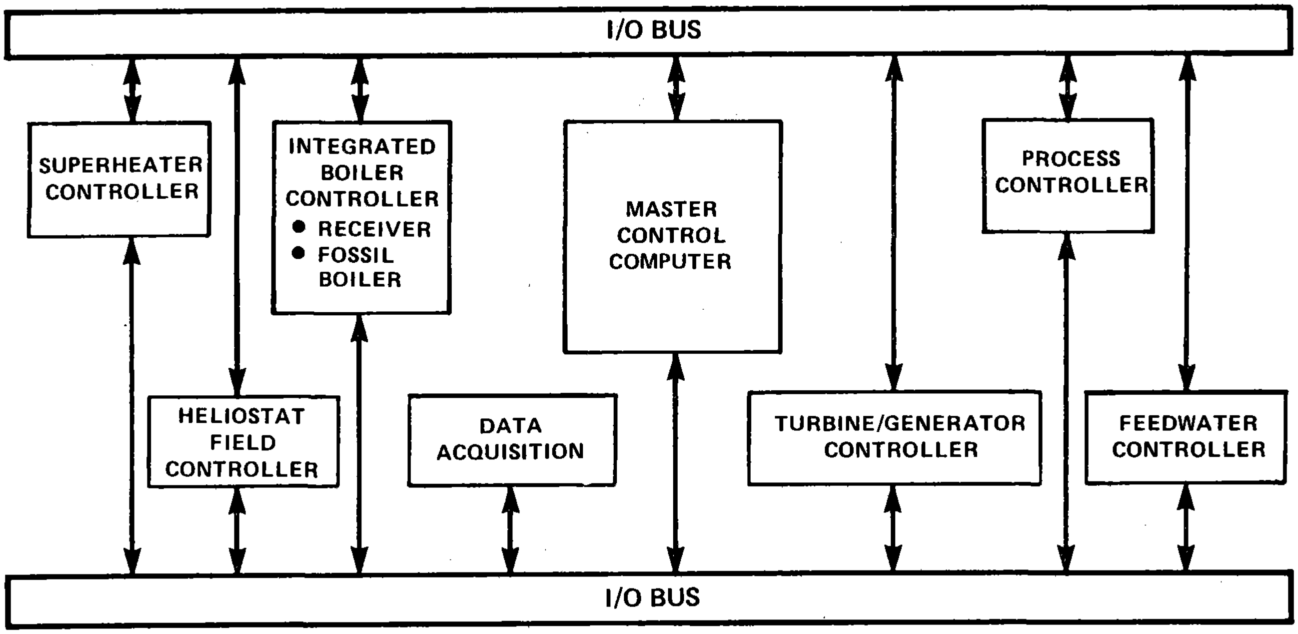


Figure 5-11. Functional Control Diagram

The heart of the master control subsystem is a microcomputer system. This system performs process calculations based on measured plant parameters and determines transitions between operating modes, performs calculations, provides steering signals to the heliostat drives, matches steam flow with feedwater flow, and sequences and coordinates other control functions.

The system currently being considered is a Hewlett-Packard 9800 series microprocessor-based system. Features include a 64 K random access memory (RAM), analog and digital input/output, peripheral interface, hard copy output and interrupt capability.

The computer has dual I/O port capability and will utilize redundant sensors to minimize single point failures where cost effective. In general, critical sensors and controls will be only dual redundant with computer logic determining the failed sensor by monitoring sensor performance indirectly using other sensors. In a few critical cases, such as fossil boiler pressure and solar receiver panel temperature, triple redundancy will be used in conjunction with a "voting algorithm" to determine the failed element. In all cases, sufficient manual hard-wired backup will be provided to the operator to safely shutdown the facility if required, or if possible, to operate it until the problem has been cleared up.

The data acquisition and alarm system monitors and records key plant operating parameters on a periodic time basis and records certain signals whenever they exceed a predetermined value. These functions can be accomplished by a programmable data system such as the Esterline Angus Model PD2064. This model is a standard self-contained, key programmable 64-channel microprocessor-based unit with expansion to 248 channels included. It features an on-board printer, analog and digital input circuitry, and alarm options, such as set point dump and initialization. It is also capable of interfacing with a data link system, such that signals can be transmitted to a remote location by standard telephone circuits or where specific signals can be requested by the remote operator. There will be other peripheral devices associated with the data acquisition system, such as a magnetic tape drive unit and strip chart recorders.

The programmable logic controllers, such as General Electric's Logitrol 550 model, will perform specific control functions primarily associated with individual plant components, such as water level control. Each controller has 128 inputs and 128 outputs, with functions for relays, latches, timing, counting and arithmetic operations. Options include switchable dual RAM/PROM CPU (for program development capability), programmable read-only memory (ROM) for on-line control, and a separate CRT programmer module with a five-inch CRT display and capability for data exchange with the serial interface data part of the controllers.

As described in Section 4.4, the cogeneration facility control room will be located in an extension to the existing control room. An artist's concept of the control room extension is shown in Figure 5-12. Sizes and locations of components are represented for illustrative purposes only; actual size and location will be determined during the preliminary and final design phases. The overall design concept will, however, remain the same; namely, separation of the solar and fossil parts of the plant on an operator interface level with overall integration of control of the hybrid plant (solar and fossil) remaining the responsibility of the master control subsystem.

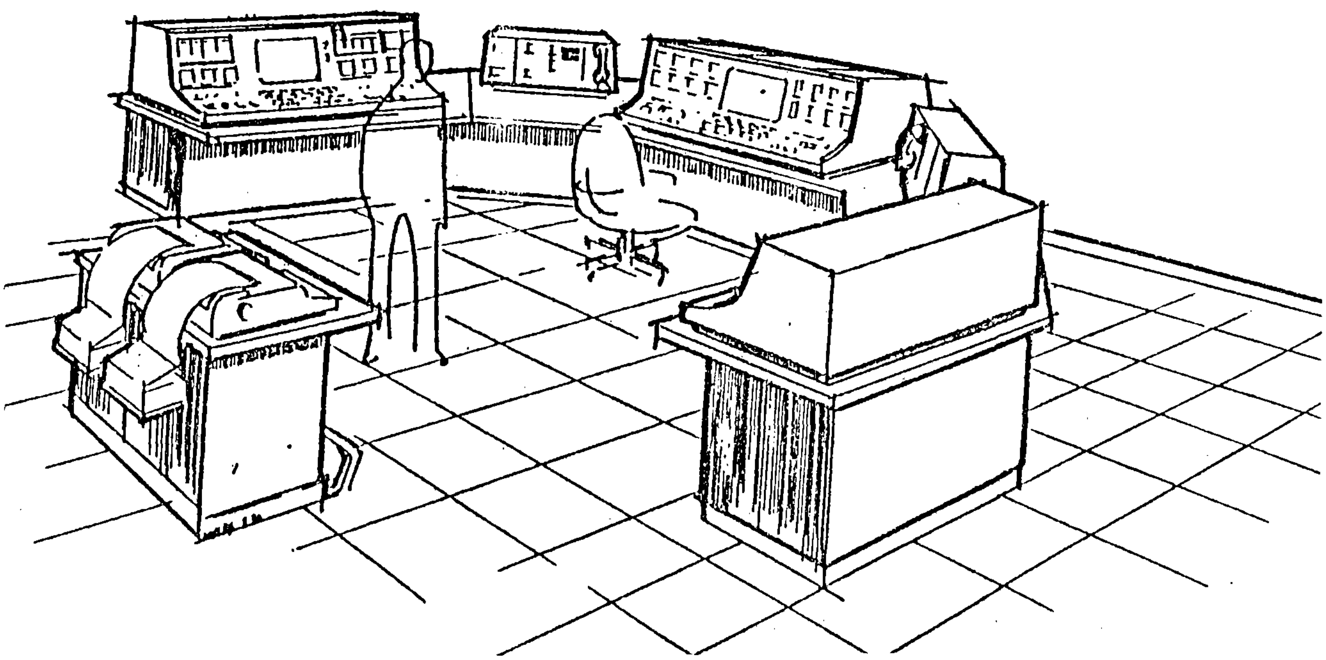


Figure 5-12. Artist's Concept of Control Room Layout

Operator interface with the computer system is via H/A control stations, push-buttons, and switches located on the operator's consoles and through the I/O typer located on the engineer's console. Subsystem response can be monitored from status lights, indicators, and recorders on the operator's console and the CRT displays generated by the data acquisition computer. A hard copier will be used to provide permanent record of these displays.

5.3.3 Subsystem Major Elements

The organization of the overall control system is indicated in Table 5-10 which lists the principal input and output signals for the master control and for the subsystem controls. As this chart indicates, the operation of the system is directed by the master control, either automatically, or under guidance of manual inputs, which can override the automatic decisions of the computer. In response to input signals including insolation status, functional and operational status of the subsystems, wind velocity, utility grid interface status, and cogeneration system thermal load interface status, the master control computer generates and issues to the subsystems the sequential signals necessary for establishing and transitioning the system operating modes. These include normal daytime operation, nighttime or zero insolation daytime operation, operation with turbine shut down, operation without utility tie-in, system startup, and system shutdown. In addition, the master control continuously monitors the operation of the subsystems, and provides readouts of subsystem instrumentation upon command. Inputs from subsystem instrumentation also activate the generation of malfunction alarm signals by the master control and the initiation of appropriate system operating mode changes. Set points for principal system operating parameters, such as steam pressure, steam temperature, and process water temperature are transmitted to the subsystem controls from the master control. These set points can be manually adjusted at the master control operating station.

The subsystem controls, which are individually described below, regulate the subsystem operation in the modes established by commands from the master control. These controls are a combination of feedback type regulators of the principal subsystem operating parameters, and sequencing controls for subsystem startup and shutdown. Other features include feed forward controls which are integrated with the feedback control in order to speed response and reduce transient excursions, and automatic protective controls which initiate shutdown independently of the master control upon sensing abnormal situations.

5.3.3.1 Integrated Boiler Controls

The integrated boiler controls perform the following functions:

- Maintain steam delivery pressure at accumulator discharge at 5.51 MPa (800 psia) $\pm 1\%$ during 24-hour continuous plant operation under all normal and abnormal variations of insolation and solar receiver output and under variations of steam delivery flow rate which may be associated with a transition between grid-connected and grid-independent operation.
- Provide sequencing required for startup/shutdown of the gas-fired boiler, and the solar receiver, in response to commands from master control which coordinate these processes for the integrated boiler, superheater, turbine/generator, process water heat exchanger, condensate/feedwater, and heliostat field subsystems.
- Provide protective controls for safe handling of contingencies including:
  - loss of burner flame
  - drum level out of limits
  - accumulator level out of limits
  - solar receiver drum pressure within 0.17 MPa (25 psi) of atmospheric pressure during a noninsolation period
  - solar receiver riser water temperature below 7 °C (45 °F)

- Provide continuous blowdown of boiler drum water at a controlled rate proportional to boiler steam delivery flow. Blowdown water is passed to a flash tank from which steam is extracted for the deaerator and from which water is passed to the drain through a trap and cooler.
- Transmit subsystem instrumentation signals to master control.

Implementation of these functions is accomplished by a pressure regulating feedback combustion control on the fossil boiler supplemented by a feed forward control which responds to solar receiver steam flow and insolation change rate. In addition, two element drum level controls, blowdown flow proportioning controls, startup/shutdown sequencing, protective controls, and instrumentation transmitters are provided.

5.3.3.2 Superheater Controls

The superheater controls perform the following functions:

- Maintain steam temperature at the turbine inlet at 482 °C (900 °F) ±1% during 24-hour continuous operation under variations of steam delivery flow rate that may be associated with transitions between grid-connected and grid-independent operation.
- Provide sequencing required for startup/shutdown of the superheater in response to commands from master control which coordinate these processes for all the subsystems.
- Provide protective controls for safe handling of contingencies including loss of burner flame and steam temperature out of limits
- Transmit subsystem instrumentation signals to master control

The superheater control includes a feedback type temperature regulating combustion control supplemented by a feed forward control responding to steam flow rate out of the accumulator. Also provided are startup/shutdown sequencing and protective controls.

5.3.3.3 Turbine/Generator Controls

The turbine/generator controls perform the following functions:

- Start/synchronize/load valve control sequencing for turbine/generator startup in response to commands from master control
- Reduce load/trip sequencing valve controls for turbine/generator shutdown
- Protective trip controls which provide safe handling of contingencies including:
  - turbine overspeed
  - high shaft vibrations
  - loss of bearing lubricant flow
  - loss of alternator coolant flow
  - high back pressure
- Alternator excitation control providing power factor control during grid-connected operation and voltage control during grid-independent operation

Table 5-10
MASTER CONTROL SUBSYSTEM ORGANIZATION CHART

MASTER CONTROL

INPUTS

- MANUAL OPERATING MODE COMMANDS
- MANUAL ADJUSTMENTS TO SET POINTS FOR SUBSYSTEM CONTROLS
- PROCESS WATER INLET PRESSURES AND TEMPS
- INSOLATION LEVEL SIGNAL
- GRID INTERFACE CIRCUIT BREAKER POSITION SIGNAL
- SUBSYSTEM OPERATIONAL STATUS/DETAILED DATA SIGNALS

OUTPUTS

- SEQUENCED OPERATIONAL COMMAND SIGNALS TO SUBSYSTEM CONTROLS
- EMERGENCY BACKUP SYSTEM/SUBSYSTEM SHUTDOWN COMMANDS
- DISPLAYED SYSTEM OPERATING MODE SIGNALS
- DISPLAYED SYSTEM/SUBSYSTEM MALFUNCTION SIGNALS IDENTIFYING SOURCE OF TROUBLE
- DETAIL INSTRUMENTATION READOUTS DISPLAYED UPON MANUAL COMMAND

HELIOSTAT FIELD CONTROLS

INPUT COMMANDS

START NORMAL (DAYTIME) OPERATION

SHUTDOWN NORMAL OPERATION

STOW INDIVIDUAL MALFUNCTIONING HELIOSTAT

EMERGENCY FIELD DEFOCUS

TRANSITION TO SYNTHETIC TRACKING

TRANSITION TO FINE TRACKING

TRANSITION TO/FROM PARTIALLY DEFOCUSED FIELD OPERATION

TRANSITION TO/FROM EMERGENCY POWER

EMERGENCY TRANSITION TO STOW POSITION

OUTPUTS

FIELD OPERATING MODE STATUS SIGNALS

INDIVIDUAL HELIOSTAT ACTUAL VS DIRECTED POSITION SIGNALS

EMERGENCY POWER SOURCE STATUS SIGNALS

INTEGRATED BOILER CONTROL

INPUT COMMANDS

FILL ACCUMULATOR

START FOSSIL BOILER

ADMIT STEAM TO ACCUMULATOR

VENT AIR FROM ACCUMULATOR

ADMIT STEAM TO SH AND TURBINE INLET PIPING/VENT AIR FROM LINES

SHUT DOWN FOSSIL BOILER

FILL SOLAR BOILER

VENT SOLAR BOILER DRUM

ADMIT STEAM TO PIPING FROM SOLAR BOILER TO ACCUMULATOR VENT AIR FROM LINE

START/STOP STEAM TO SOLAR BOILER DRUM

START/STOP STEAM TO SOLAR BOILER DOWNCOMER JACKET

DRAIN BOILERS, ACCUMULATOR, AND LINES

STEAM PRESSURE SET PT

OUTPUTS

STEAM DELIVERY PRESSURE SIGNAL

STEAM DELIVERY FLOW RATE FROM SOLAR BOILER, FOSSIL BOILER AND ACCUMULATOR

FEEDWATER FLOW RATE SIGNALS

BOILER DRUMS AND ACCUMULATOR WATER LEVEL SIGNALS

GAS/AIR FIRING RATE SIGNALS

FLAME DETECTOR SIGNALS

STACK TEMP SIGNALS

OTHER DETAILED OPERATIONAL DATA FROM SOLAR BOILER, FOSSIL BOILER, AND ACCUMULATOR INSTRUMENTATION

SEQUENTIAL STATUS SIGNALS DURING START/STOP OPERATIONS

SUPERHEATER CONTROL

INPUT COMMANDS

START NORMAL OPERATION

SHUT DOWN FIRING

DRAIN DESUPERHEATER

STEAM TEMP SET PT

OUTPUTS

STEAM DELIVERY TEMPERATURE SIGNAL

STEAM DELIVERY PRESSURE SIGNAL

STACK TEMPERATURE SIGNAL

COMBUSTION AIR AND GAS FLOW SIGNALS

FLAME DETECTOR SIGNALS

SEQUENTIAL STATUS SIGNALS DURING START/STOP OPERATIONS

TURBINE/GEN CONTROL

INPUT COMMANDS

CLOSE/OPEN TB DRAINS

ADMIT STEAM TO SEALS

START/SYNCHRONIZE

SET TB VALVES FOR 50% FLOW

FULLY OPEN TB VALVES

TRIP TB

SHUT TB GEN DOWN

CLOSE TB DISCHARGE VALVE

TB SPEED SET PT FOR GRID – INDEPENDENT OPERATION

OUTPUTS

ELECTRICAL OUTPUT SIGNALS – LINE VOLTS LINE AMPS KW KVAR FREQUENCY

PROTECTIVE RELAY OUTPUT SIGNLAS

TURBINE OPERATIONAL DATA SIGNALS

LUBRICANT FLOW, TEMPERATURE, LEVEL

SHAFT VIBRATION

EXH PRESSURE

SEQUENTIAL STATUS SIGNALS DURING START/STOP OPERATIONS

PROCESS WATER FLOW/TEMP CONTROL

INPUT COMMANDS

START WATER FLOW THRU LT PW HX

ADMIT BYPASS STEAM TO LT PW HX

START WATER FLOW THRU HT PW HX

ADMIT BYPASS STEAM TO HT PW HX

ADMIT EXTR STEAM TO HT PW HX

CLOSE EXTR STEAM ADM VALVE TO HT PW HX

SHUT DOWN SUBSYSTEM

PROCESS WATER TEMPERATURE SET PTS

OUTPUTS

PROCESS WATER STREAM IN/OUT TEMP, PRESSURE, FLOW

PROCESS WATER BYPASS VALVE POSITIONS

BOILER FEEDWATER CONTROLS

INPUT COMMANDS

FILL HOT WELLS AND BOILER FEED TANK TO MIN START LEVELS

REGENERATE DEMIN BEDS

DRAIN/PUMP ALL CONDENSATE INTO CONDENSATE STORAGE TANK

WATER QUALITY LIMIT SET PTS (CONDUCTIVITY, O_2, P_h)

OUTPUTS

HOT WELL/TANKS LEVEL SIGNALS

CONDENSATE CONDUCTIVITY

FEEDWATER P_h

FEEDWATER O_2 CONC

DEMINERALIZER OPERATING MODE STATUS

- Protective relays for safe handling of alternator overcurrents and internal faults.
- Provide isochronous frequency governing for operation in grid-independent mode
- Transmit subsystem instrumentation signals to master control

The turbine valve controls during normal operation of the system respond to signals from the automatic start/synchronize/load control unit and to emergency trip signals. Following synchronizing and loading, the control valves normally remain wide open and the speed governor is disconnected.

For grid-independent operation speed error signals conditioned by a proportional plus rate plus reset controller are fed to the valve controls. The alternator is a brushless machine with a rotating rectifier type of field excitation.

5.3.3.4 Process Water Flow/Temperature Controls

The functions of the process water temperature controls are the following:

- Maintain temperature of process water stream to softener at 46 °C (115 °F) ±1% and maintain flow rate to softener at 32.5 l/s (515 gpm) −0 +10%, during 24-hour continuous operation under variations of 10 degrees in water supply temperature, and under variations of turbine exhaust stream flow rate, temperature, and pressure associated with changes in turbine operating mode
- Maintain temperature of process water stream to field at 177 °C (350 °F) ±1% and maintain flow rate to field at 62.6 l/s (993 gpm) −0 +10%, during 24-hour continuous operation under variations of 10 degrees in water supply temperature and under variations of turbine extraction stream flow rate, temperature, and pressure associated with changes in turbine operating mode
- Provide startup/shutdown sequencing in response to commands from the master control (see below for details)
- Transmit subsystem instrumentation signals to the master control

The process water flow/temperature controls include a closed loop water temperature control which regulates the heater tube side discharge temperature by variations of water flow rate through the heater with a flow control valve. As the heater inlet water temperature rises the water flow rate is increased in order to maintain a nearly constant outlet temperature. (A small rise in steam side pressure and temperature will also occur.) In addition there is provision for high pressure steam bypass admission to the heater shells. This is necessary for carrying the system thermal loads during operation independent of the grid or with the turbine shutdown. Under these conditions the turbine steam flow is variable or missing and supplementary steam injection is necessary to maintain pressure in the shells. Under the direction of the master control, steam injection control is activated during these modes of system operation. Steam is admitted to the heater shells through controlled throttling valves at a rate such that the shell pressure is scheduled as a function of process water inlet temperature.

Bypass steam injection is also employed during system startup, as described below, prior to startup of the turbine.

5.3.3.5 Condensate/Feedwater Controls

The condensate/feedwater controls consist of the following:

- Automatic level controls for the process water heat exchanger hot wells, the flash tank, deaerator reservoir, and the condensate storage tank
- An automatic control for chemical injection of sodium sulfite and ammonia into the feedwater in order to maintain O_2 concentration at 0.005 ppm max and Ph levels between 8.5 and 9.5
- An automatic regeneration cycle control for the makeup demineralizer which is designed to maintain the resistivity level of the condensate storage tank water above a minimum level of 250,000 ohm cm (1.6 ppm dissolved solids)
- Automatic sequencing controls for valve operation during startup/shutdown
- Transmitting type instrumentation for input of subsystem status data to master control

5.3.3.6 Heliostat Field Controls

The functions of the heliostat field controls include the following:

- Both coarse open loop (synthetic), and fine closed loop sun tracking for all heliostats
- Provide startup/shutdown sequencing for heliostat movement between stowed or defocused positions and operational position under fine tracking control
- Provide rapid defocusing of all or scheduled portions of the field. (The need for this could arise during startup of the solar boiler under high insolation, following loss of water in solar boiler, or other system emergency shutdown situations, or as a result of system operation without turbine or without grid connection under high insolation conditions.)
- Provide switching between plant control bus and emergency power source
- Transmit individual heliostat position status signals to master control

5.3.4 Performance

During normal 24-hour operation of the system, the turbine is supplied with a constant flow of superheated steam at 5.18 MPa, 482 °C (750 psia, 900 °F). This is achieved through maintenance of constant steam pressure at the accumulator discharge by variation of the fossil boiler firing rate in order to compensate for variations in insolation, and through control of the steam temperature at the outlet of the fired superheater. The fossil boiler steam output varies between 5% of the total steam flow under maximum insolation conditions and 100% of the steam flow at zero insolation. The turbine/generator net electrical output is, in this manner, maintained essentially constant at 3 MWe over the 24-hour period. Constant electrical load is maintained at the generator terminals by interconnection with the utility grid.

Cogeneration system thermal loads consist of two process water streams which are maintained, respectively, at 46 °C (115 °F) and 177 °C (350 °F) at the tube side discharge of the condensing heat exchangers receiving steam from the turbine exhaust and from an uncontrolled extraction port at which the pressure is 1.1 MPa (160 psia) under turbine full load conditions. The process water stream temperatures at the heat exchanger outlets are controlled by variation of water flow rates to compensate for variations in inlet water temperature.

The process water heat exchangers are provided with hot wells for condensate collection. These discharge through condensate pumps into a flash tank from which both steam and condensate are delivered to the deaerator. Water levels are maintained in the heat exchanger hot wells by means of controlled recirculation from the condensate pump discharges. The deaerator water reservoir level is controlled by means of a flow control valve located in the condensate line between the flash tank and the deaerator. The flash tank water level is controlled by transfer of condensate between the condensate storage tank and the flash tank.

Additional controls required for the system operation include the following:

- Steam bypass control for admission of accumulator steam to the process water heat exchangers. This is required, as explained below, during system startup and also during abnormal system operating modes
- Solar receiver and fossil boiler blowdown control, accomplished by admission of water flow from the boiler drums to a flash tank at a rate proportional to the flow rate of steam from the individual boilers. The flash steam is piped to the deaerator, and the water is passed to the drain after cooling
- Accumulator level control, accomplished by discharge of accumulator water to the boiler blowdown flash tank and by admission of water to the accumulator from the boiler feed pump discharge
- Operation of vents, bypass valves and shutoff valves in the manner described below for startup, shutdown, and various abnormal system operating modes; this includes admission of steam to the solar receiver for pressure maintenance and prevention of freezing
- Turbine speed control through an isochronous governor during system operation independent of the utility grid
- Automatically sequenced regeneration of the makeup water demineralizer resins at intervals determined by a measurement of total water volume passed through the unit. The condensate storage tank must be sized to provide makeup requirements without replenishment during regeneration periods
- Condensate storage tank level control through control of flow from the demineralizers sufficient to maintain a full tank except during demineralizer regeneration periods
- Heliostat field control including synthetic coarse tracking, fine tracking under feedback position control, acquisition, emergency and scheduled defocusing, and stowing. These functions are performed under the direction of the master control which, in turn, responds to signals indicating insolation, wind velocity, receiver operational status, and individual heliostat functional status, and also to manual command inputs

5.3.5 Operating Characteristics

The Solar Cogeneration Facility may be operated in the following modes:

- Normal daytime operation
- Normal nighttime operation
- Operation during prolonged periods of zero insolation during cold weather

- Operation independent of the utility grid
- Operation with turbine shutdown

Each of these operating modes is discussed below. In addition, there is a discussion of system operation during possible severe insolation transients and a description of the system cold start and shutdown sequences.

5.3.5.1 Normal Daytime Operation

During normal daytime operation the cogeneration system thermal and electrical outputs are maintained at full load design point levels by the combined steam outputs of the solar receiver and fossil boiler, which feed in parallel to the accumulator, from which steam flows to the fired superheater and to the turbine. The alternator is tied to the utility grid and works into what may be approximated as an infinite bus. The turbine valves are wide open and the speed follows the grid frequency.

At the design point (equinox, noon), steam generation is almost entirely supplied by the solar receiver, the fossil boiler being cut back to a level of approximately 5% load. At all other times, as the insolation varies during the day the fossil boiler firing control responds to changes in the receiver steam output in order to maintain a constant flow of steam to the accumulator. The accumulator provides a large thermal inertia in the integrated boiler steam supply, which facilitates the maintenance of essentially constant steam pressure at the turbine inlet even under sever insolation transients which may result in fairly rapid changes in steam output from the receiver. This inertia eases the response requirement of the fossil boiler combustion control, and minimizes the transient steam pressure undershoots and overshoots. In the evening as insolation drops to zero the receiver steam flow declines to zero, and the check valve in the delivery line to the accumulator closes. As this process proceeds, the fossil boiler takes over the complete steam supply load under the automatic action of its combustion control. Similarly, in the morning as insolation increases the receiver drum pressure rises, the check valve opens, and receiver steam delivery to the accumulator begins. The normal morning rate of insolation rise is slow enough that no significant thermal stresses are expected in the receiver structure during daily startup, and normally no special provisions for heliostat control during this period should be required.

Heliostat field control actions during the daily insolation cycle include movement in the morning from the stowed position to fine tracking as the synthetic tracking controlled open loop positioning system takes over. In the evening reverse movements occur as insolation falls to zero.

5.3.5.2 Normal Nighttime Operation

During normal nighttime operation the cogeneration system electrical and thermal loads are maintained at full load design point levels under steam supply from the fossil boiler which operates at full capacity. Pressure in the solar receiver drum and in the steam delivery lines on the receiver side of the check valve will be maintained well above one atmosphere by the thermal inertia of the water in the insulated drum. Thus, no air intrusion into the boiler or connecting line will occur, and the receiver remains throughout the night in a state of readiness for automatic startup in the morning.

5.3.5.3 Cold Weather/Zero Insolation Operations

During prolonged periods of zero insolation the solar receiver can cool to the extent that the drum pressure will drop below atmospheric pressure. Under such conditions, undesirable air in-leakage is possible. Also, in winter it is possible that during prolonged receiver down periods, freezing of the water in the tubes and drums can occur.

To forestall these contingencies a steam warmup line has been provided as shown in Figure 5-10. The warmup line is from downstream of the accumulator to the bottom header of the receiver. This makes it possible to inject small amounts of steam into the receiver thereby inducing normal circulation of heated water through the tubes and drum, thus preventing freezing.

5.3.5.4 Grid-Independent Operation

The Solar Cogeneration Facility is designed to permit operation independent of the utility grid. For this mode of operation the following design features are provided:

- A turbine speed governor is provided which regulates turbine valve position to maintain constant turbine speed and alternator frequency under variations of electrical load
- High pressure steam bypass lines are provided, together with flow control valves, to maintain steam flow and temperature in the shell side of the process water heaters adequate for carrying the system thermal loads when the turbine steam flow and pressure available at the turbine exhaust and at the extraction port are reduced by control valve action
- If this mode of operation results in a significant drop in steam flow to the turbine, the fossil boiler firing rate may be forced to its minimum setting by an excess of solar receiver output above system requirements. To handle this situation, when the fossil boiler reaches minimum setting (5%), the master control directs a partial defocusing of the heliostat field. This will reestablish a control margin for maintaining steam pressure

5.3.5.5 Operation With Turbine Shutdown

With power available from the utility grid, the cogeneration system electrical and thermal loads can be supplied with the turbine/generator shutdown. This is accomplished through bypass of high pressure steam into the process water heater shells in the manner described above. In this mode of operation partial heliostat defocusing, also described above, will become necessary during periods of high insolation. In addition, the superheater will be shutdown during this mode of operation.

In the event of a turbine/generator shutdown the following commands are automatically sequenced by the control subsystem to properly shut down the superheater:

- Close turbine main stop valve and main control valve
- Open relief valve to vent steam from superheater
- Shut off superheater controlled firing
- Maintain flow through superheater for controlled cooldown
- Shutdown superheater after residual heat has been removed

5.3.5.6 Cold Start Procedure

The sequential steps involved in a cold start of the Solar Cogeneration Facility are listed below. These operations will take place under the automatic direction of the master control by properly sequenced commands to the subsystem startup controls involved.

- Check/establish operating levels in the condensate storage tank, heater hot wells, boiler feed tank, flash tank, and boiler drums
- Establish cold start level in accumulator
- Start boiler feed pump
- Check water quality at feed pump discharge (Conductivity, O_2, Ph)
- Start gas-fired boiler; build up pressure to operating level over a period of (approximately) one hour per manufacturer's instructions; carry out venting (steam space) and purging (combustion space) procedures
- Admit steam to accumulator and build up temperature, pressure, and level to operating values under action of automatic level control
- Vent off air from boiler/accumulator connecting piping and from accumulator vessel
- Start vacuum pump and pull down condenser pressure to 0.017 MPa (5 in Hg). (Valve between low pressure heater shell and turbine exhaust is closed.)
- Start process water flows at low rate (10% of operating level) through low temperature and high temperature process water heaters. Direct discharge to drain (or return to source) during startup period when the heater discharge water temperature is out of control limits
- Admit steam from accumulator to steam bypass lines to process water heaters. Air in lines and in high temperature heater vessel will vent through the thermostatic air vent and through the vacuum pump. Increase process water flows to full load levels and allow process water discharge temperatures to stabilize under action of temperature control. Direct water discharge flows to softener and field
- Admit saturated steam from accumulator to turbine. Close drains and vents and open valves admitting steam to process water heaters.
- Synchronize alternator under action of automatic synchronizing valve control; continue operation of turbine at low load on saturated steam; process water temperatures will be maintained by flows of bypass steam into heater shells
- Start superheater firing and bring turbine inlet steam temperature up to operational level under superheat temperature control
- Fully open turbine valves and bring alternator output to normal operating level
- Cut off bypass steam flows to heaters
- Conditional upon existence of minimum (or greater) operating level of insolation, transition heliostats from stowed position to normal operation under fine tracking control. Allow solar receiver steam drum pressure to rise at rate limited by insolation or by scheduled automatic startup (heliostat defocusing) control (slower of two)
- When receiver drum pressure reaches 0.34 MPa (50 psia) warm lines connecting solar boiler to accumulator (check valve is closed) and vent air from lines
- When receiver drum pressure reaches operational level the check valve will open and steam will flow to the accumulator
- System is now fully started

5.3.5.7 Shutdown Procedure

- Defocus/stow heliostats
- Shutdown fired superheater
- Shutdown fired boiler
- Close turbine valves to low flow position; open circuit breaker tie between alternator and utility; trip turbine
- Open turbine drains
- Close steam valves between turbine and process water heaters
- Shutoff process water flows to heaters
- After cooling, drain hot wells, flash tank, boiler drums, accumulator, and all steam piping. (If prolonged shutdown is intended)
- Turn up existing mine water heaters to supply complete thermal load demand
- Satisfy electrical load demand by closing circuit breaker tie between utility grid and existing plant
- Original mine system now fully operational as before

5.3.5.8 Effects of Abnormal Insolation Transients

Abnormal insolation transients are associated with rapid changes in cloud cover over the heliostat field. Preliminary calculations indicate that the accumulator steam pressure control can, with a reasonable size accumulator water volume, limit the steam pressure transients associated with even 100% step function changes in insolation (a situation having very low probability) to very low, acceptable values. The effects of such transients upon thermal stresses in the receiver structure will require detail design investigation at a later phase of the program. However, since all boiler containments are partially full of saturated water, and since the receiver maximum flux level is modest, with a correspondingly small ΔT through heat transfer surfaces, the structural effects of sudden positive or negative changes in insolation during daily operation are not expected to be severe. In the unusual, but possible, case of a sudden large increase in insolation, starting from a cold condition of the receiver, the heliostat control system will provide for rapid partial defocusing of the heliostat field in order to limit the rate of change of receiver surface temperature to an acceptable value.

5.3.6 Cost Estimate

The controls cost, including materials, labor, and construction is

Code	Item	Amount
5500	Master Control Subsystem	$751,420

5.4 FOSSIL ENERGY SUBSYSTEM

This section describes the additonal fossil (gas fired) facilities that will be required to permit satisfactory operation of the solar cogeneration equipment, both in the fossil mode (only) and the hybrid (fossil-firing/solar receiving) mode. Major pieces of equipment under this subsystem are shown on Figures 4-4 and 4-5 and consist of the following:

- Fossil Boiler
- Fossil superheater
- Saturated steam accumulator (included with the fossil superheater package)
- Boiler feedwater economizer (included with the fossil superheater package)

5.4.1 Design Requirements

The fossil energy subsystem will be designed to have the following capabilities:

- Automatic or manual startup regardless of whether the solar system is operating
- Operation in a "Fossil Alone" mode, which will not impact any operations on the solar portion of the plant
- Operation in a hybrid mode in either a "Boiler Follow" or "Turbine Follow" configuration
- Ability to maintain a constant plant output by compensating for solar transients while operating in the hybrid mode
- Respond to functional commands from master control subsystem computers

5.4.2 Operating Characteristics

Two modes of operation, namely non-solar operation and hybrid operation, will be incorporated into the design of the plant control systems. The non-solar mode will permit fossil boiler operation independent of the solar portion of the plant during nondaylight hours or during periods of extended cloud cover. In this mode, the Fossil Energy Subsystem will follow the Electric Power Generating Subsystem (EPGS) and the Process Heat Subsystem. In the hybrid mode, the Fossil Energy Subsystem will follow the Receiver Subsystem and the combination will satisfy the steam generation demand established by the turbine and the process heating cycles. The feedwater control valves will split the flow between solar receiver and fossil boiler by receptive single element (drum level) feedwater controls. This mode will be selected during daylight hours.

5.4.3 System Component Descriptions

5.4.3.1 Fossil Boiler

One 100% capacity natural gas-fired boiler will be provided to furnish the required saturated steam to the cogeneration plant during the fossil firing only mode, plus provide (on maximum turndown) approximately 5% of the required saturated steam to the cogeneration system during the solar/fossil-fired hybrid mode of operation. The boiler will be a package-type steam industrial boiler rated approximately 605 kg/s (80,000 lb/hr) of 5.52 MPa (800 psia) steam. It will be furnished complete with FD fan, breeching, stack, burner controls and furnace of membrane water-wall construction for high pressure furnace operation.

5.4.3.2 Fossil Superheater

One 100% capacity natural gas-fired superheater will be provided to heat all saturated steam from the fossil boiler/solar receiver to dry, superheated steam acceptable for reliable turbine operation. The superheater will be a package type unit, with a refractory-lined furnace with buried water wall tubes at the furnace burner throat/exit for minimum circulation to an oversized steam drum (accumulator), radiant secondary superheater section, convection primary superheater section, plus a convection feedwater economizer section in the flue gas breeching. The superheater will be furnished with an FD fan, burner controls stub stack etc. Steam controls between accumulator and superheater will not be furnished with this unit but will be contained within the combustion control system.

5.4.3.3 Saturated Steam Accumulator

One 100% capacity saturated steam accumulator drum will be provided as part of the fossil superheater package to receive (below drum level) design flow sparged saturated steam from both the fossil boiler as well as from the solar receiver. The accumulator will be sized to retain, in energy storage, the thermal equivalent of 5 min of turbine design throttle flow or 0.89 MWh thermal energy.

5.4.3.4 Feedwater Economizer

One 100% capacity feedwater economizer section will be provided (as part of the fired superheater package) to heat up the boiler feed pump discharge flows approximately 9.4 °C (15°F). This economizer section will recover approximately 6% of the fossil superheater output by absorbing 0.35 MWh thermal energy in the exiting flue gases

5.4.4 Cost Estimate

The Fossil Energy Subsystem cost, including installation is:

Code	Item	Amount
5600	Fossil Energy Subsystem	$1,754,050

5.5 ELECTRIC POWER GENERATING SUBSYSTEM

This section describes the functional requirements, design, operating characteristics and cost of the Electric Power Generating Subsystem (EPGS).

5.5.1 Functional Requirements

The requirements for the EPGS are based on the parametric analyses discussed in Sections 3.4 and 3.7. Those analyses established the steam cycle conditions and the electrical load requirements for the turbine/generator. The turbine receives high pressure steam from the superheater and provides steam to the two sets of heat exchangers connected at the extraction port and the exhaust. The generator provides all of the net electrical power required by the sulfur mining operation. The design of the EPGS shall permit steam inlet from the accumulator during superheater bypass.

5.5.2 Design Description

The overall design of the EPGS is similar to the design of a conventional fossil-fired power plant of equal size. In fact, the EPGS is completely independent of the solar components. The primary interface between the EPGS and other sections of the solar/hybrid facility consists of the high-pressure steam inlet, supply lines the process heaters, auxiliary power systems, the control subsystem and the electric power output of the facility.

Superheated steam at 5.175 MPa (750 psia) and 482 °C (900 °F) is supplied to the turbine control valves from the superheater. The turbine drives the alternator through a reduction gear. Turbine extraction steam at 1.104 MPa (160 psia) flows through a heat exchanger to raise the softened water temperature from 109 °C (228 °F) to 177 °C (350 °F). The remaining steam exhausts from the turbine at 17940 Pa (2.6 psia) and also flows through a heat exchanger to raise the well water temperature from 21 °C (70 °F) to 46 °C (115 °F). Steam flow, throughout the turbine stages, stays in the superheated region (ie. no moisture).

5.5.2.1 Physical Arrangement of Components

The EPGS components are arranged on one base. On the turbine skid (Figure 5-13), the turbine generator is mounted in an elevated position which provides space for the turbine discharge plenums below the turbine from which the extraction and exhaust steam ducting carries steam to the heat exchangers located outside the turbine base. The deaerator is mounted in an elevated position above the boiler feed pump. The turbine lubrication oil cooler is mounted beside the alternator on the turbine base.

5.5.2.2 Turbine/Generator Foundation

The turbine-generator unit will be supported by a reinforced concrete pedestal and mat foundation using high strength concrete, 27.6 MPa (4000 psi). The foundation will be computer designed to assure that the natural frequency of the foundation (and of the soil supporting the foundation) will be outside the operating range of the turbine-generator unit.

5.5.2.3 Turbine/Generator Installation

The turbine/generator unit will be unloaded, installed, aligned, and tested in accordance with the turbine manufacturer's recommendations. The turbine-generator erector will utilize the services of a field technical representative (from the turbine manufacturer) for the erection of the turbine-generator unit.

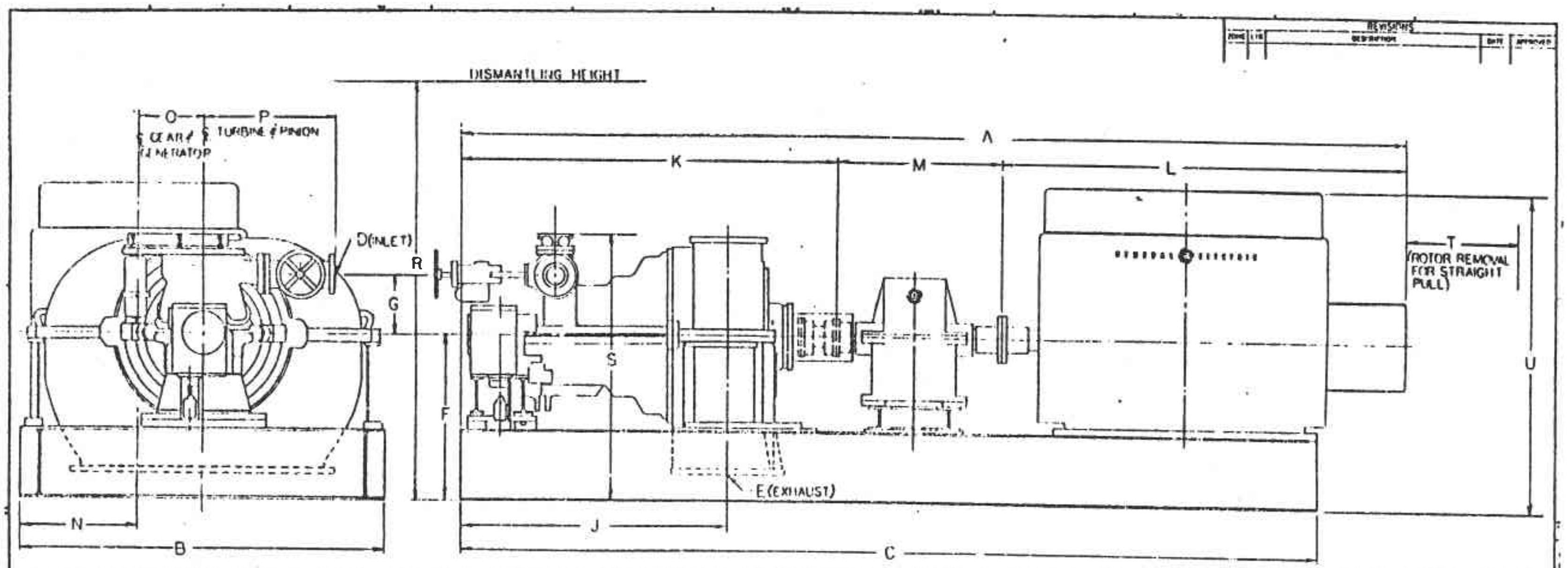
5.5.2.4 Steam Turbine/Generator

The turbine is an eight-stage, single-row, axial flow impulse machine with a speed of 8,000 rpm. It was selected for this application because it has the following characteristics.

1. The design has been proven to have excellent reliability especially in industrial power service.

2. The efficiency of this turbine design is equal to that of any comparable commercially available turbine. The design allows for:

- Inlet pressures in the range of 4.14 to 10.00 MPa (600-1450 psia)
- Throttle temperatures in the range of 399 to 500 °C (750-950 °F)
- Power levels in the range of 1500 to 10000 kW



IDENTIFICATION	KW	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	R	S	T	U		TOTAL DRY WGT
ALTERNATE B	3000	287	111	259	6	44x24	53	21	40	8	104	124	120	42	34	21	43	107	93	88	104		80,000

NOTES:
1. DO NOT USE FOR CONSTRUCTION—ALL DIMENSIONS AND WEIGHTS ARE APPROXIMATE.
2. ALL DIMENSIONS ARE IN INCHES, WEIGHTS IN POUNDS.

CUSTOMER — DOE/SOLAR COGEN
PROP. NO. — 091-X-209B

OUTLINE/PROPOSITION
TURBINE - GENERATOR (S C)
D 4066016-60RE

Figure 5-13. Turbine/Generator Outline Drawing

3. The machine is integrated with a co-designed gear reducer and synchronous generator. The entire package complete with turbine, generator auxiliaries, and controls is shown in Figure 5-14.

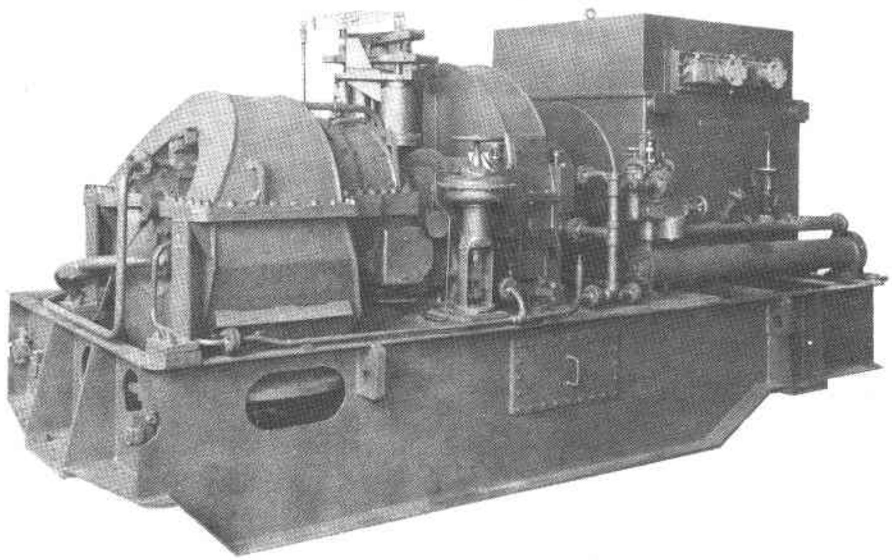


Figure 5-14. Turbine Generator Unit

4. The eight-stage turbine is readily adaptable to the incorporation of uncontrolled steam extraction at the fifth shell position. The pressure at this location is close to the optimum level for the extraction heat exchanger.

5. Special features of this machine include:

- The heat chamber bayonet steam inlet, which thermally isolates the inlet steam plenum/valve chests from the casing and permits unconstrained differential expansion of these parts
- The relatively high first-stage pressure ratio, resulting in relatively low temperature and pressure exposure of the high-pressure end of the casing
- The solid one-piece machined forging rotor, making the design mechanically tolerant of frequent thermal transients.

The turbine design incorporates high-pressure and low-pressure shaft seals, as well as interstage seals. There is an automatic steam seal regulator which protects the turbine from in-leakage of air and also prevents significant loss of steam at the end of the high-pressure rotor.

The high-pressure end of the 8,000 rpm turbine rotor is coupled to an 1800 rpm salient pole, air-cooled, synchronous alternator through a helical reduction gear. The alternator is a brushless rotating rectifier design complete with voltage regulator. Turbine generator auxiliaries include the lubrication system with both shaft-driven and motor-driven lube oil pumps, a water-cooled lube oil cooler, and a magnetic filter. The turbine governor is electro-hydraulic, which provides for pressure governing modified for temperature override. There are three independently controlled admission valves and a stop/throttle valve. An independent emergency governor, protective trip/alarm features, and automatic synchronizing equipment are provided.

5.5.2.5 Auxiliary Power Requirements

The estimated auxiliary power requirements for the EPGS are shown in Table 5-11 for normal daytime operation.

Table 5-11

AUXILIARY POWER REQUIREMENTS

Item	Quantity	Rating	KW
Heliostats	588	35 W	20.58
Boiler Feed Pumps	3	150 HP	335.57
Heater Drain Pumps	2	25 HP	37.29
Condensate Hotwell Pumps	2	7.5 HP	11.19
Condenser Air Removal Pump	1	15 HP	11.19
Total Auxiliary Power			415.82

5.5.3 Operating Characteristics

The load demand of the Comanche Creek sulfur mine is basically uniform throughout the day and year. Therefore, the turbine/generator will be continuously operating at capacity. A summary of the EPGS operating characteristics is presented in Table 5-12.

5.5.4 Cost Estimate

The EPGS cost estimate including labor and installation is:

Code	Item	Amount
5800	Electric Power Generating Subsystem	$1,514,460

5.6 PROCESS HEAT SUBSYSTEM

This section describes the facilities of the cogeneration plant which will input heat energy to the industrial process (sulfur mining) at the existing plant. Heat energy transfer will be made at a design steady-state condition regardless of whether steam production is produced under fossil-firing only mode or under the hybrid fossil-firing/solar receiving mode. Major pieces of equipment under this subsystem are shown on Figures 4-4 and 4-5 and consist of the following:

- Low Pressure Heat Exchangers (to heat well water)
- High Pressure Heat Exchangers (to heat process water)

5.6.1 Functional Requirements

The process heat subsystem will be designed to have the following capabilities:

- Receive turbine exhaust and turbine extraction steam flows and condense such flows to proper temperature condensate and feedwater in accordance with the design turbine-generator cycle heat balance
- Efficiently transfer the latent heat (and slight super heat) energy of the turbine cycle exhaust and extraction flows to the plant process water condensing flows, thereby displacing heat energy required in the existing plant operation

Table 5-12

EPGS OPERATING CHARACTERISTICS

Maximum rating:	3500 kW
Generator rating:	4375 kVA at 0.80 p.f.
Generator voltage:	4160 V
Steam inlet:	5.175 MPa/482°C(750 psia/900°F)
Extraction:	1.104 MPa (160 psia) uncontrolled
Exhaust:	17940 Pa (2.6 psia)
Throttle flow:	9.69 kg/s (77060 lb/hr)at rating
Extraction flow:	8.19 kg/s (65120 lb/hr)at rating
Extraction Enthalpy:	1318 Btu/lb at rating
Exhaust Enthalpy:	1097 Btu/lb at rating
Turbine Data:	8000 rpm
	8 stages
	electrohydraulic control system
	solid forged rotor
	multi (5) inlet control valves
	trip/throttle emergency inlet valve
	baseplate mounted
	integral lubrication system
Reduction Gear Data:	double helical tooth
	solid forge pinion
	flexible couplings
Generator Data:	salient pole design
	rotating brushless exciter
	solid state voltage regulator

5.6.2 Operating Characteristics

The process heat subsystem will work in parallel with the operation of the turbine cycle; therefore, it is expected that heat transfer from the turbine cycle to the process systems of the existing plant will be affected at or very close to the maximum turbine rating.

The process heat subsystem will be completely independent of the steam generation modes.

5.6.3 Design Description

5.6.3.1 Low Pressure Heat Exchangers

Two (2) 100% capacity, separate shell, steam surface low pressure heat exchangers will be furnished, each sized for condensing full exhaust flow to 16.5 kPa (2.4 psia), with 5 minutes of hotwell storage and air cooling zones for air removal. Each heat exchanger will be equipped with removable waterbox/waterbox covers for mechanical/hydraulic cleaning of the straight tubes. The heat exchangers will be piped/valved parallel for steam, condensate, cooling water and air removal piping enabling one heat exchanger to be operating while the other is in a standby mode available for tube cleaning. The tubes will be 22.2-25.4 mm (7/8"-1") OD Admiralty Model designed for 1.8-2.1 m/s (6-7 fps) tube velocity. The low pressure heat exchangers will be uninsulated and mounted on pedestal/spread footing foundations penetrating the grade level turbine-generator building floor slab.

5.6.3.2 High Pressure Heat Exchangers

Two (2) 50% capacity U-tube, tube and shell type heat exchangers will be furnished to condense the turbine extraction steam flow to 1.034 MPa (150 psia) saturated steam and saturated water at 181 °C (358 °F) and heat process mine water from 109 °C (228 °F) to 177 °C (350 °F) on the tube side. These heat exchangers will not require desuperheating or subcooling zones. Both heat exchangers will be floor anchored to the turbine operating floor. Heater drains will cascade to the suction of the heater drain pumps located below the heaters on the grade floor level.

5.6.4 Cost Estimate

The process heat subsystem cost including materials, labor and installation, is:

Code	Item	Amount
5910	Process Heat Subsystem	$386,785

5.7 ELECTRICAL SUBSYSTEM

This section describes the requirements, design, operating characteristics and cost of the electrical subsystem. This subsystem consists of that equipment necessary to monitor and control the flow of power between the generator, the utility grid and the existing plant. The major equipment utilized in this subsystem is shown schematically in Figure 5-15.

5.7.1 Functional Requirements

The Solar Cogeneration Facility shall be capable of normal operation independent of the utility source. To attain full operating independence, a four unit set of metal clad switchgear will be installed. The feeder for the existing plant, which is now connected to the utility switchyard, will be relocated to the new switchgear. Complete independence is not possible since the utility/grid tie-in is required for system startup.

5.7.2 System Design

All components of the electrical subsystem are of standard design and conform to applicable standards. Their long standing and current use by utilities assures that the plant reliability will be the best available under the present day state-of-the-art in equipment manufacture.

5.7.3 Major Components

5.7.3.1 13.8 KV Class Metalclad Switchgear

The switchgear is rated at 1200 amperes continuous and 18,000 amperes RMS symmetrical with four (4) circuit breakers rated at 1200 amperes (see Figure 5-15).

Circuit breaker No. 52-1 is the tie to West Texas Utilities. Power and demand are metered either in the "in" or "out" direction. Metering also includes an ammeter and ammeter switch. Protective relaying consists of three instantaneous/time overcurrent relays, three directional time overcurrent relays and one residual ground overcurrent relay.

Circuit breaker No. 52-2 is the generator breaker. The unit contains only a watthour meter, the remainder of the metering and protective relaying, being associated with the generator, is located in the control room.

Circuit breaker No. 52-3 serves the solar facility auxiliaries and is equipped with a watthour meter, ammeter switch, ammeter, three instantaneous/time overcurrent relays, and one residual ground overcurrent relay.

Circuit breaker No. 52-4 serves the original plant auxiliaries and has the same equipment as circuit breaker 52-3.

Primary control of the circuit breakers will be from the control room; however, local control is possible. Bus differential overcurrent protection is provided. The switchgear is located indoors, adjacent to the control room, and is readily accessible to the plant operators.

5.7.3.2 Power Transformers

The generator transformer is rated 4375 kVA, 12.5 kV/4.16 kV, 3 phase, 60 hertz. The transformer steps up the generator voltage to utility voltage and also limits the generator fault contribution to the utility system.

The auxiliary transformer is rated 1000 kVA, 12.5 kV/480 volts, 3 phase, 60 hertz and steps the utility voltage down to plant utilization voltage for operation of pumps and motors. Both transformers are located outdoors, west of and adjacent to the control building. Standard accessories are provided.

5.7.3.3 Distribution Switchboard

The distribution switchboard is rated 600 volts, 3000 amperes continuous, 50,000 amperes RMS symmetrical and distributes solar facility auxiliary power to large motors and motor control centers. The unit is located indoors adjacent to the control room.

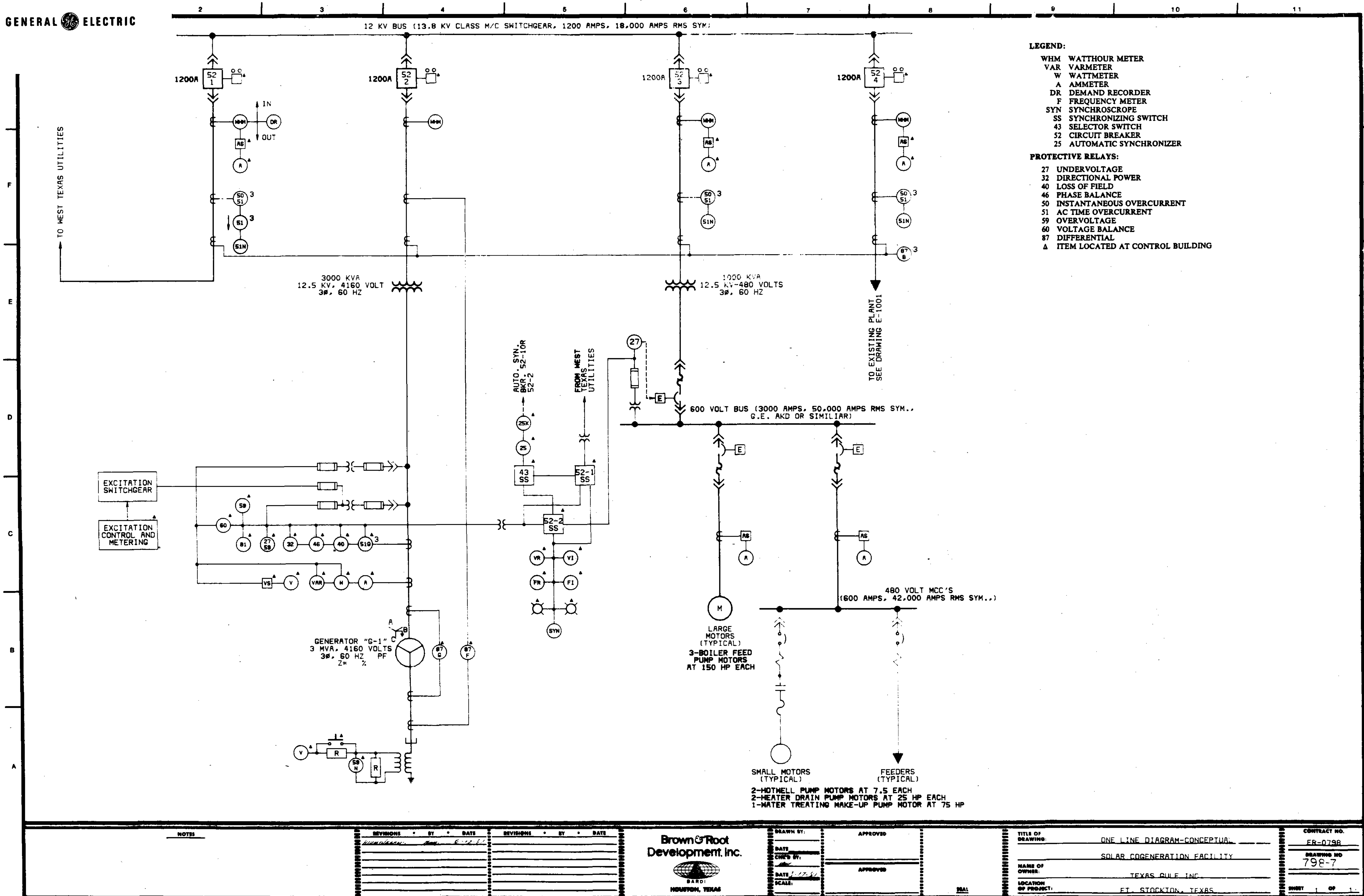


Figure 5-15. Electrical One Line Diagram

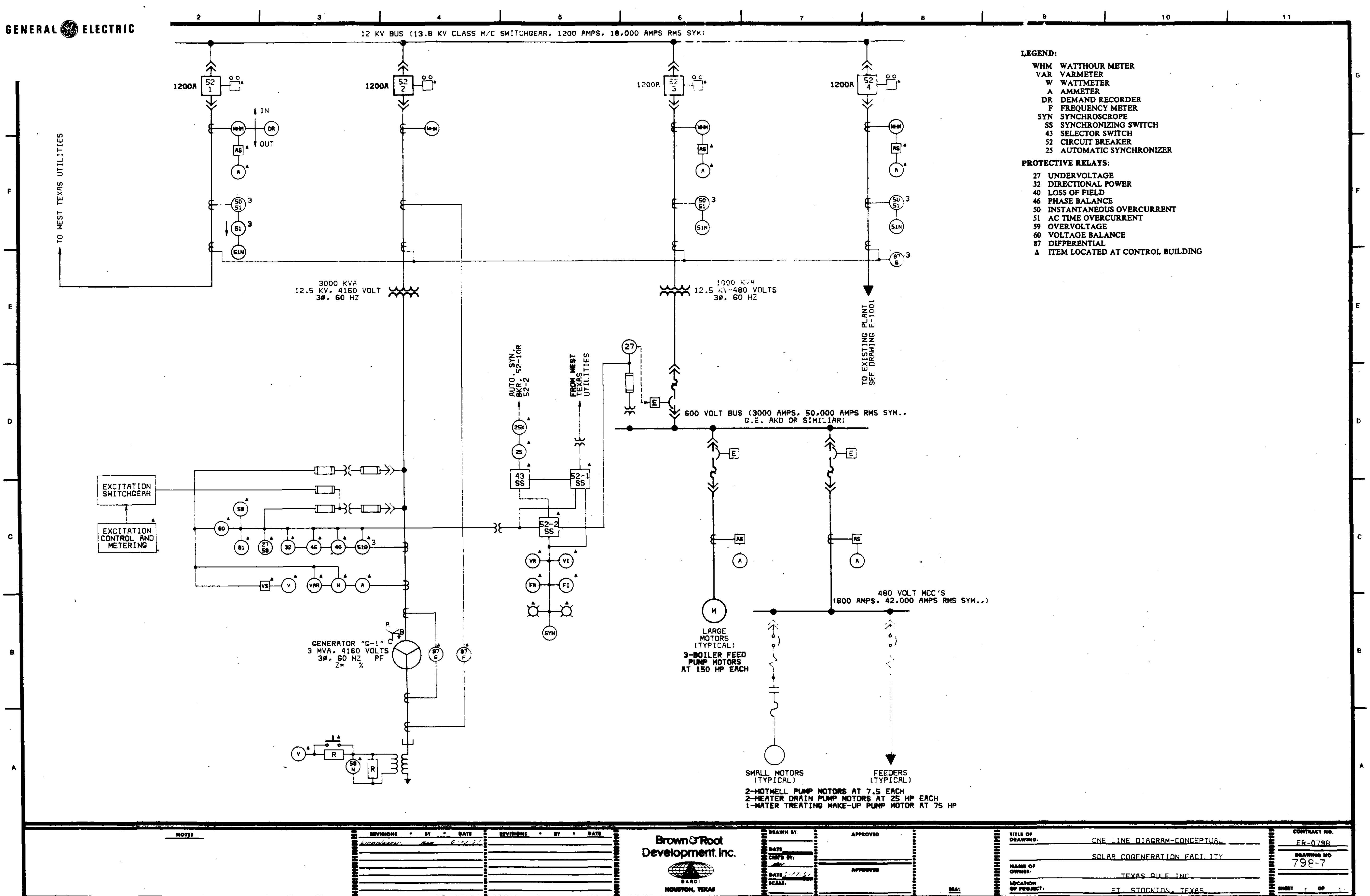


Figure 5-15. Electrical One Line Diagram

5.7.3.4 Motor Control Centers

The motor control centers are rated at 600 volts, 600 amperes continuous, 42,000 amperes RMS symmetrical and are equipped with combination motor starters for motors and circuit breakers for lighting and power feeders. The equipment is located indoors adjacent to the control room.

5.7.3.5 Metering, Protective Relaying, and Control Elements

Meters are provided to monitor generator volts, amperes, VARS, and watts. Ammeters and ammeter switches are provided to monitor current through circuit breakers 52-1, 52-3, and 52-4. These instruments are located in the control room.

Protective relaying for the generator includes overcurrent, loss of field, phase balance, reverse power, underfrequency, and overvoltage. Additionally, differential overcurrent protection is provided for the generator, the generator-transformer unit, and the metalclad switchgear. The zones of protection are overlapping and the relays are located in the control room.

The generator may be synchronized either manually or automatically. Components include an automatic synchronizer, running and incoming voltmeters, running and incoming frequency meters, synchroscope, and synchronizing lights and switches. Circuit breakers 52-1 and 52-2 are arranged for synchronized closing.

Circuit breaker control switches and indicating lights for all switchgear units, as well as all generator controls, are located on the control panel.

5.7.3.6 Plant Lighting

In general, fluorescent lighting will be used in office areas, incandescent in operating areas, and high pressure sodium vapor will be used for area lighting. Low level sodium vapor flood-lighting will be used for the heliostat field.

5.7.3.7 Communications System

Equipment will be provided to extend existing plant communications into new areas.

5.7.3.8 Plant Grounding

Plant grounding will be in accordance with ANSI C2-1981.

5.7.4 Operating Characteristics

With reference to the one line diagram (Figure 5-15) SCF operation will be as follows:

Closure of circuit breaker 52-1 will energize the switchgear from the utility. Closure of circuit breaker 52-4 will allow operation of the existing plant auxiliary system and closure of circuit breaker 52-3 will allow operation of the SCF auxiliaries. The turbine-generator may now be brought up to speed, synchronized and placed "on line" via circuit breaker 52-2.

The utility-tie breaker can remain closed allowing the export of any excess generation and to provide backup power in case of an unscheduled loss of generated power.

If too much power is drawn from the SCF, the utility tie breaker may be opened allowing the plant to operate independently. If the utility draws an excessive amount of power, a directional overcurrent relay will automatically open the tie breaker. The tie breaker may be reclosed at any time as it is arranged for synchronized closing.

5.7.5 Cost

The electrical subsystem cost estimate, including materials and labor, is:

Code	Item	Amount
5920	Electrical Subsystem	$588,075

5.8 FLUID CIRCULATION SUBSYSTEM

This section describes the facilities forming the fluid circulation subsystem or more specifically the equipment required in circulating fluids within the closed, nonregenerative, condensing turbine generator cycle. Major components of this subsystem are shown on Figures 4-4 and 4-5 and consist of the following:

- Makeup feedwater system
- Turbine cycle feedwater chemical system
- Flash-type, non-heated deaerator
- High pressure boiler feed pumps
- Heater drain pumps
- Condensate hotwell pumps
- Condenser air removal pump
- Field piping

5.8.1 Functional Requirements

The fluid circulation subsystem will be designed to have the following capabilities:

- Provide and store boiler quality water in sufficient quantity to satisfy both operating makeup (including blowdown) and startup fill and steam blowdown cleaning
- Provide in-cycle treatment of circulating feedwater to achieve acceptable rates of corrosion and fouling
- Reduce the oxygen and non-condensable gases to acceptable levels for prevention of general corrosion
- Provide high pressure boiler feedwater to both the fossil-fired subsystem as well as the solar receiver subsystem under either fossil or hybrid mode of operation across both transient and stable operating ranges
- Insure that condensed extraction flows will cascade forward to the deaerator by providing pumps to handle the saturated liquid effectively at any operating point
- Provide pumpage that will effectively pump the saturated liquid condenser flows forward in the cycle

- Utilize air removal equipment to draw-off air and other non-condensables from the condenser air-cooling zone effecting suitable deaeration of the condensed turbine exhaust steam flows
- Provide a system for intermittent (startup) and continuous blowdown of all steam drums, lower water wall headers, and non-drainable steam outlet headers to minimize collection of solids (and carry-over). Such a system should effectively recover a great proportion of both the energy as well as the water given up in blowdown

5.8.2 Operating Characteristics

The fluid circulation subsystem will operate across the entire operating range of the turbine cycle and will be completely independent of the steam generation modes.

5.8.3 Design Description

5.8.3.1 Makeup Feedwater System

The makeup feedwater system will provide and store boiler quality feedwater and consists of a flash tank, cooler, condensate recycle and transfer pumps and a condensate storage tank. Influent to the flash tank will be a side stream of softened and heated process mine water at 177 °C (350 °F) which will be flashed down to 137 kPa (20 psia) in the flash tank. During a daily operating period of approximately 100 minutes, 94.5 kg/s (12,500 lb/hr or 25 gpm) will be flashed off as feedwater effluent steam. The liquid effluent from the flash tank will be returned to the process water stream by the condensate recycle pump. The steam effluent will be condensed in the cooler to 51 °C (150 °F) saturated water, which will then be pumped by the condensate transfer pump to the 87 m^3 (23,000 gallon) condensate storage tank. Stored makeup condensate will enter the turbine cycle in the low pressure heater hotwell by static head and pressure differential.

5.8.3.2 Turbine Cycle Feedwater Chemical System

A skid mounted mixing and metering chemical injection system will be provided to reduce the oxygen level in the feedwater. In this way corrosion will be minimized by control of oxygen levels and maintenance of a proper pH level. An all, volatile treatment will be used to control the water chemistry of the closed, recirculating system of the turbine cycle, regardless of the steam generation operating mode. This treatment will consists of adding hydrazine for oxygen scavenging and ammonia hydroxide for pH control.

5.8.3.3 Deaerator

One (1) 100% capacity spray and tray flash-type deaerator column with integral feedwater storage tank will be furnished, designed and stamped in accordance with ASME Section VIII. Steam heating/deaeration will be from partial flash of incoming high pressure condensate pumped from the high pressure (HP) heat exchangers, deaerating both the HP condensate and the LP condensate (from the low pressure heat exchangers) sprayed above the tray section. Condensate will leave the deaerator with less than 0.005 cc O_2/liter of H_2O. The storage tank section of the deaerator will be sized for a minimum of 10 minutes of feedwater storage based on the maximum design rating feedwater flow. Startup or "pegging" steam will be flashed from the fossil boiler blowdown.

5.8.3.4 High Pressure Boiler Feed Pumps

Three (3) 50% capacity, 9-stage centrifugal boiler feed pumps will be furnished with each pump rated nominally at 7.5 x 10^{-3} m^3/s (120 gpm) at 762 m (2500 ft) total head, with required NPSH, at design, of 3.05 m (10 ft) for SG = 0.893. Pumps will be furnished complete with 111.8 KW (150 HP) motor drives, couplings, coupling guards, shaft sealing system, lubrication systems and common baseplates. Pump baseplates will be mounted on pedestal/spread· footing foundations penetrating the grade level Turbine Generator Building floor slab.

5.8.3.5 Heater Drain Pumps

Two (2) 100% capacity condensate-booster drainage control systems (pumps with appurtenances) will be installed to pump cascading HP drains to the deaerator. Each pump system will be nominally rated at 9.1 x 10^{-3} m^3/s (144 gpm) at 965 kPa (140 psi) differential and will be furnished with coupling, coupling guard, 18.65 KW (25 HP) motor drive and common baseplate. Pump baseplates will be mounted on pedestal/spread footing foundations penetrating the grade level Turbine Generator Building floor slab.

5.8.3.6 Condensate Hotwell Pumps

Two (2) 100% capacity condensate booster drainage control systems (pumps with appurtenances) will be installed to take suction from the low pressure heat exchangers to pump condensate forward to the deaerator. Each pump system will be nominally rated at 1.26 - 1.8 x 10^{-3} m^3/s (20-30 gpm) at 689-758 kPa (100-110 psi) differential and will be furnished with coupling, coupling guard, 5.6 KW (7.5 HP) motor drive and common baseplate. Pump baseplates will be mounted on pedestal/spread footing foundations penetrating the grade level Turbine Generator Building floor slab.

5.8.3.7 Condenser Air Removal Pump

One (1) 100% capacity liquid ring, eccentric rotary vacuum pump will be furnished to remove air and non condensible gases from the air cooling zone of the low pressure heat exchangers. This pump (evacuator) will be nominally rated to handle 29.7 kg (13.5 pounds) of air (estimated air leakage) saturated with water-vapor at 16.5 kPa (2.4 psig) and 52 °C (125 °F). The pump will be furnished with coupling, coupling guard, 11.2 KW (15 HP) motor drive, common baseplate, and condenser with muffler. Pump baseplate will be mounted on pedestal/spread footing foundation penetrating the grade level Turbine Generator Building floor slab.

5.8.3.8 Field Piping

The piping run between the receiver tower and power plant will consist of three (3) standard wall thickness pipes of ASTM A106, GR. B carbon steel. The nominal diameters of these pipes will be:

Main Steam	15.24 cm	(6 inch)
Feedwater	7.62 cm	(3 inch)
Warm-up Steam	7.62 cm	(3 inch)

This pipe run will be supported every 4.6 m (15 feet) on reinforced concrete sleepers and contain square cornered, expansion loops at 152 m (500 feet) intervals. It will pass under the plant road through a corregated metal pipe protected by a backfill of compacted soil.

5.8.4 Cost Estimate

The fluid circulation subsystem cost estimate, including materials and labor, is:

Code	Item	Amount
5930	Fluid Circulation Subsystem	$2,120,775

REFERENCES

5.1 Memo from J.S. Anderson of Sandia National Laboratories to H.E. Jones, General Electric Company, November 19, 1980.

5.2 "A User's Guide for MIRVAL — A Computer Code for Comparing Designs of Heliostat-Receiver Optics for Central Receiver Solar Power Plants," P.L. Leary and J.D. Hankins, Sandia National Laboratories, Report No. SAND77-8280, February, 1979.

5.3 L.K. Matthers, et al., "High Temperature High Flux Material Testng for Solar Application," *Solar Energy,* Vol. 23, 1979.

5.4 "Solar Industrial Retrofit System for the Provident Energy Company Refinery," Foster Wheeler Development Corporation, Livingston, NJ, Final Report FWDC No. 9-41-3131, July 15, 1980.

Section 6
ECONOMIC ANALYSIS

Section 6

ECONOMIC ANALYSIS

One of the most important considerations affecting an industry's decision as to which type of cogeneration system to install, or whether to put in a cogeneration system at all, is the relative economics of the alternatives. In general, a solar central receiver system relies on reductions in fossil fuel consumption to justify large capital investments. Therefore, for the economic assessment to be valid, it must consider not only the initial capital costs but also the remaining life cycle costs, and it must accurately reflect the industrial marketplace for which the solar application is intended. In this section, the analytical methodology is described, the economic assumptions are tabulated, and the results of the analysis are presented.

6.1 METHODOLOGY

Of primary concern, when industry is trying to decide between alternative methods of satisfying their power and process heat requirements, is the rate of return on investment. Here, the alternatives are the Solar Cogeneration Facility (SCF) along with its associated costs and equivalent savings on the one hand, and continuing the existing plant operation as is on the other hand. The procedure used to evaluate the near-term economic viability of the SCF is the discounted cash flow rate of return (DCRR) method as described in the GE-CTAS program final report.[6.1]

DCRR is defined as the discount rate which makes the difference, in the present worth of discounted after tax cash flows, for two alternatives over their economic life, equal to their difference in capital costs. Since one alternative is to leave the existing plant as is, the difference in capital costs is the required investment for the solar system.

In equation form, the DCRR relationship is

$$\sum_{J=1}^{N} \frac{\Delta \text{Cash Flow}}{(1 + \text{DCRR})^J} = \text{Investment}$$

where N is the economic life in years and the cash flow (after taxes) is given by

$$\text{Cash Flow} = \text{Revenues} - \text{Operating Expenses} - \text{Income Taxes}$$

Income taxes are defined by

$$\text{Income Taxes} = \text{Income Tax Rate} \times (\text{Revenues} - \text{Operating Expenses} - \text{Depreciation}) - \text{Investment Tax Credit}$$

The investment tax credit, obtained by multiplying the capital investment by the investment tax credit rate, is only applicable in the first year of operation. Each of the other items used in the cash flow calculation are described in the following sections.

6.1.1 Revenues (R_j)

For this project, the only revenue to be considered is the income derived from the sale of excess power to West Texas Utilities. The yearly revenue is given by:

$$R_j = kWh_e \times P_e \times (1 + e_p)^{(N^*-1980-0.5)+j} \quad (\$/yr)$$

where kWh_e is the total annual power sold to the utility, P_e is the price received for the power, e_p is a factor accounting for inflation plus escalation of power price above inflation, N^* is the first full year of operation, and j is the specific year of operation (1,2,3,...N).

6.1.2 Operating Expenses

The operating expenses are those due to purchases of power and fuel, operation and maintenance costs, taxes and insurance. The specific yearly calculation for each expense is described below.

6.1.2.1 Purchased Power Expense (PP_j)

When power is purchased from a utility, the yearly expense is:

$$PP_j = kWh_p \times P_p \times (1 + e_p)^{(N^*-1980-0.5)+j} \qquad (\$/yr)$$

where kWh_p is the total annual power purchased from the utility, P_p is the price paid for the power and the other terms are as before.

6.1.2.2 Purchased Fuel Expense (PF_j)

The expense per year, for purchased fuel is given by:

$$PF_j = F \times P_F \times (1 + e_f)^{(N^*-1980-0.5)+j} \qquad (\$/yr)$$

where F is the total amount of fuel purchased per year, P_F is the cost of fuel, e_F is a factor accounting for inflation plus the escalation of fuel price above inflation and the other terms are as before.

6.1.2.3 Operation and Maintenance Expense (OM_j)

This expense is the difference in O&M costs between the two alternative configurations which is assumed to be those O&M costs associated with just the retrofitted add-on equipment. Thus, the yearly O&M expense is obtained from

$$OM_j = E_{OM} \times (1 + e_{OM})^{(N^*-1980-0.5)+j} \qquad (\$/yr)$$

where E_{OM} is the estimated O&M costs for the first year of operation of the SCF, e_{OM} is a factor to account for the rate of inflation plus the escalation of O&M above inflation and the other parameters are as before.

6.1.2.4 *Taxes and Insurance Expense* (TI_j)

The following equation is used to calculate this expense

$$TI_j = C \times p \times (1+e_T)^{(N^*-1980-0.5)+j} \qquad (\$/yr)$$

where C is the capital investment, p is the fraction of capital investment for local real estate tax and insurance, e_T is a factor to account for the probable increase in real estate taxes and insurance with inflation, and other terms are as before.

6.1.3 Depreciation

Depreciation is calculated for each year of tax life using the double declining balance method over a period of ten (10) years with a zero salvage value.

6.1.4 Cash Flow Calculation

Annual cash flows for both alternatives are calculated for twenty (20) years of operation using the above equations. In this analysis, those cash flows common to both alternatives have not been evaluated since they would cancel each other when the difference is taken as required by the DCRR method.

This calculation methodology is an iterative procedure that has been programmed into a computer code allowing for variation of each parameter.

6.2 ECONOMIC ASSUMPTIONS

A primary consideration of this economic analysis is to assess the economic viability of the solar cogeneration concept to the user, Texasgulf. The economic parameters used in the analysis, developed with Texasgulf, are shown in Table 6-1.

Table 6-1

ECONOMIC ASSUMPTIONS

Factor	Value
Annual Inflation Rate	9%
Federal & State Income Tax Rate	46%
Tax Depreciation Method	DDB
Tax Depreciation Life	10 Years
Salvage Value	0
Investment Tax Credit	10% + 15%
Local Real Estate Taxes & Insurance	3%
Useful Life of Investment	20 Years
First Full Year of Operation	1986
Cost of Fuels & Power	
Natural Gas	$2.50/10^6 Btu
Purchased Power	$0.033/kWh
Escalation of Fuels & Power Above Inflation	
Natural Gas	3%
Purchased & Exported Power	1%

The investment tax credit is made up of the standard 10% federal investment tax credit plus the 15% federal energy tax credit as specified by the 1980 Windfall Profits Tax Act.

The portion of the investment that will be funded by the DOE is presently unknown. The analysis considers the DOE cost-sharing to vary from 0% to 100% of the investment. The funds obtained from the DOE are treated, for tax purposes, as an outright grant. The investment tax credit and depreciation are based solely on that portion of the costs contributed by Texasgulf.

The DCRR calculations in this study utilize constant dollars with the annual inflation rate set equal to zero. The economic analysis is more realistic when the inflation rate is set equal to zero because when inflation is included, the calculated rate of return is misleadingly high since future inflated savings or cash flows have less purchasing power than constant non-inflated dollars. Finally, inflation rates are changing rapidly so that comparison of the results of studies done at different inflation rates are difficult to compare and "rules of thumb" cannot be deduced. This whole problem is eliminated if the analysis is performed in constant dollars with zero inflation and, if desired, the results converted to current dollars with inflation.

DCRR is one of many methods of economic analysis that are used by industry to determine the projected return on investments. DCRR is considered by many to be the most accurate method since it correctly considers the time value of money. The DCRR calculations presented herein were accomplished using constant 1980 dollars with the annual inflation rate set to zero. Alternatively, the calculations could have used current dollars by incorporating an annual inflation rate of 9% which would be consistent with Texasgulf practices. However, this would not have been representative of the real return on investment as mentioned earlier. Therefore, for purposes of this report, the terminology DCRR will be used to indicate a zero inflation analysis in terms of constant 1980 dollars. The terminology ROI (return on investment) will be used to indicate a DCRR analysis calculated in terms of current dollars with a specified annual inflation rate. A simple conversion formula can be utilized:

$$\mathrm{ROI} = (1 + \mathrm{DCRR}) \times (1 + i) - 1$$

where i is the specified annual inflation rate.

6.3 FACILITY AND SYSTEM SIMULATION MODEL

As discussed in Section 4.5, the performance of the SCF has been analyzed using three computer models — MIRVAL, WSRLOSS, and STEAEC. The MIRVAL and WSRLOSS programs were used to model the performance of the collector field and receiver, respectively, from which performance parameters were developed for input to the STEAEC system simulation model.

The MIRVAL computer code is a Monte Carlo model that evaluates collector field performance. The model evaluates tower shadow, field cosines, reflectivity losses, shading and blocking, atmospheric attenuation and spillage losses, taking into account heliostat error parameters and aperture sizes and orientations.

The Water/Steam Receiver Loss (WSRLOSS) model, a General Electric-Mark III computer code was used to calculate receiver losses. Based on input incident heat fluxes over a user defined node pattern, the program estimates reflection, convection and radiation losses on the active surface.

The annual system performance and energy output were evaluated using the STEAEC program. This program simulates the system performance at one-hour intervals using site insolation and weather data as input. For the site weather data, a SOLMET data tape for El Paso, TX was modified for site compatibility and input to STEAEC.

The results of these analyses are further detailed in Section 4.5, with the net annual output summarized in the following section.

6.4 RESULTS OF ANALYSES

As discussed in Section 6.1, the evaluation performed during the economic analysis and presented here is an after tax discounted cash flow rate of return (DCRR) comparison between the SCF and the existing plant left as is. Table 6-2 summarizes the capital cost, yearly operating expenses and annual output for the two alternatives.

The economic analysis evaluates the SCF as an alternative to the existing plant. As such, Table 6-2 lists only the capital cost (Δ investment) and the additional O&M costs incurred as a result of adding the solar retrofit. The purchased electricity for the existing plant is based on the average daily demand of 2.865 MW_e as discussed in Section 4.6. The costs and performance are discussed in Sections 4.5 and 4.7 with detailed cost estimates given in the System Specification (Appendix A).

Table 6-2

COST AND PERFORMANCE SUMMARY (1980 $)

	Existing Plant	Solar Cogeneration Facility
Capital Cost	–	$20,671,468
Operations & Maintenance	–	$252,064
Purchased Electricty	25.1×10^6 kWh	–
Fuel Consumed	3.50×10^9 ft^3	3.54×10^9 ft^3
Net Annual Output	9.53×10^5 MWh	9.79×10^5 MWh

Using the methodology and the economic parameters discussed in the previous sections, the after tax discounted cash flow rate of return (DCRR) was evaluated. The significant results are discussed in the following sections.

6.4.1 DCRR Results

The SCF will provide both electricity and process heat. To do this it will require a slight increase in consumption of natural gas over that of the existing plant as shown in Table 6-2. However, this slight increase in gas consumption is more than offset by the savings from the electricity that no longer must be purchased which, in turn, allows for reduced gas consumption by West Texas Utilities. Furthermore, with the SCF designed to meet the peak electrical demand of 3.0 MW_e there will be a small amount of electricity available for sale to the local utility since the annual average demand is 2.865 MW_e. The exported power has been considered in the analysis at a sale price that is 70% of the purchase cost based on current information from West Texas Utilities.[6.2]

The Texasgulf practice with respect to fuel and electricity expenses is to escalate these costs up to the first year of operation and then hold them constant for the remainder of the plant life. Thus, if the current fuel cost of $2.50/MBtu (1980$) is escalated by 3% per year (escalation over and above general inflation) for six years, the 1986 fuel cost would be \$3.00/MBtu. Similarly, if the current electricity cost of \$0.033/KWh is escalated by 1% per year for six years, the 1986 electricity cost would be \$0.035/KWh. Substitution of this data along with the capital costs and the parameters of Table 6-1 into the cash flow equations of Section 6.1 give the results labeled curve A in Figure 6-1.

Because of the risks inherent in a natural resources business, Texasgulf could not specify a minimum rate of return it would require on any investment. Furthermore, all potential investments are evaluated against other current investment opportunities, each one competing for limited available funds. However, industry in general, typically requires a minimum rate of return (with zero inflation) of around 10%. Curve A of Figure 6-1 shows that this level of DCRR can be achieved only if DOE will cost share to the tune of 80% of the total capital cost.

If 9% general inflation is included, the 10% DCRR is equivalent to a return on investment (ROI) of 19.9%.

6.4.2 Variable Fuel and Electricity Costs

Various estimates (including 9% inflation) have been prepared representing a wide range of fuel costs in 1986 and there does not seem to be any consensus as to which is the more realistic. A General Electric estimate based on gas prices being linked to the price of imported oil sets the 1986 fuel cost at \$7.80/MBtu.[6.3] A Texasgulf estimate equating the cost of natural gas, rising with deregulation, to that of No. 2 heating oil gives \$11.80/MBtu.[6.4]

Since the DCRR analysis does not include inflation, the latter two estimates must be put on a zero inflation basis so that they can be compared to the \$3.00/MBtu case. By removing 9% inflation, the GE and Tg estimates become \$4.65/MBtu and \$7.04/MBtu, respectively. These values then determine the equivalent fuel escalation rate above the 1980 cost of \$2.50/MBtu. They are 10.9% and 18.8% annually, for the GE and Tg estimates, respectively. Based on the escalation rates given in Table 6-1 it was assumed that the cost of electricity will escalate at a rate that is one-third that of natural gas. Thus, the three sets of fuel and electricity costs are shown on Figure 6-1 with curves B and C representing the GE and Tg 1986 estimates, in terms of 1980 dollars.

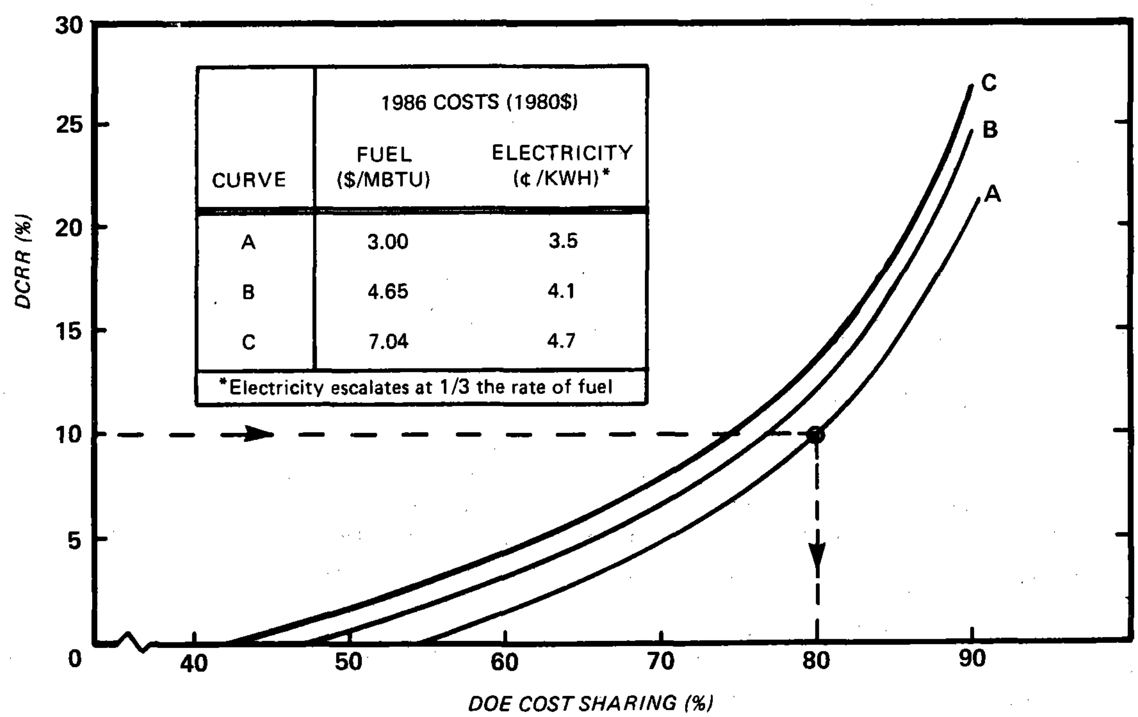


Figure 6-1. SCF Economic Results with Electricity at 1/3 Fuel Rate

As can be seen, the three curves in Figure 6-1 are relatively close together implying little benefit from the higher fuel costs. Since the major savings is due to electricity not being purchased, this is to be expected when the electricity is assumed to escalate at only one-third the rate of natural gas. If it is assumed that the electricity escalates at the same rate as the fuel then the results will be as shown in Figure 6-2.

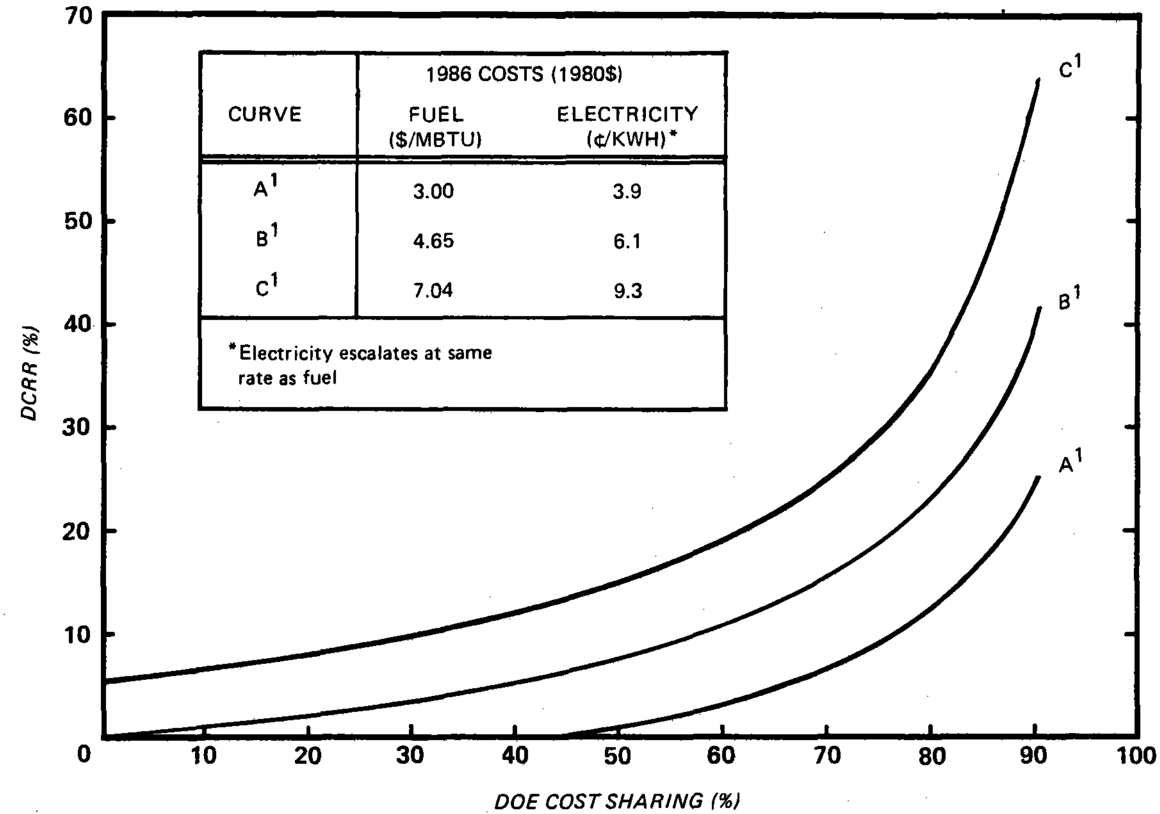


Figure 6-2. SCF Economic Results with Electricity Escalating at Fuel Rate

If a utility generates electricity entirely from natural gas, then the cost of that electricity might escalate at a rate approaching that of the fuel depending upon what portion of the generation cost was fuel based. As the utility moves toward other fuel sources, the cost of electricity will depend less and less on the cost of natural gas. West Texas Utilities currently is in the process of bringing a coal fired plant on line. Nevertheless, discussions with WTU indicate that the SCF will still displace natural gas generated electricity during its lifetime. Therefore, it is believed that the escalation rate for electricity relative to that of natural gas will fall between the two extremes just presented. Therefore, a comparison of the data in Figures 6-1 and 6-2 is presented in Table 6-3.

6.4.3 Effects of Investment Tax Credit Rate

As discussed in Section 6.2, the investment tax credit contains a 15% federal energy tax credit from the 1980 Windfall Profits Tax Act. There is some uncertainty as to the longevity of this tax credit and thus, an analysis was performed to examine the sensitivity of the results to this parameter. A total investment tax credit of 10% and also 50% was considered, and the results for both electricity escalation rates are shown in Table 6-4 for a DOE cost sharing level of 80%.

Table 6-3

SCF ECONOMIC RESULTS

Fuel Cost ($/MBtu)	3.00		4.65		7.04	
Electricity Cost (¢/kWh)	3.5	3.9	4.1	6.1	4.7	9.3
DCRR with 80% DOE Cost Sharing (%)	10.0	12.5	12.2	22.7	13.6	35.4
Required DOE Cost Sharing for 10% DCRR (%)	80.0	76.0	76.7	57.5	74.3	30.0
Required DOE Cost Sharing for 15% DCRR (%)	85.0	83.0	83.0	69.0	81.6	50.0

Table 6-4

EFFECT OF INVESTMENT TAX CREDIT*

Fuel Cost ($/MBtu)	3.00		4.65		7.04	
Electricity Cost (¢/kWh)	3.5	3.9	4.1	6.1	4.7	9.3
DCRR @ 10% ITC (%)	7.2	9.6	9.3	19.1	10.6	30.8
DCRR @ 25% ITC (%)	10.0	12.5	12.2	22.7	13.6	35.4
DCRR @ 50% ITC (%)	16.5	19.2	18.8	30.7	20.4	44.8
*Assumes 80% DOE Cost Sharing						

6.4.4 Annual Fuel and Electricity Savings

The annual savings for fuel and electricity is an important measure of the effectiveness of the Solar Cogeneration Facility. The projected annual electricity savings consists of the 25.1×10^6 KWh that no longer must be purchased plus the small excess amount (1.18×10^6 KWh) that can be sold to the local utility. At a cost of $0.035/KWh with a 70% rate for export power, this represents an effective income of $908,000. From this we must subtract the cost of the excess fuel consumption, which is 40,000 MBtu at $3.00/MBtu. Thus, the total annual savings is $788,000 in 1980 dollars. If inflation at 9% is considered, then the equivalent annual savings would be $1.32 million in 1986 dollars.

6.5 COMMERCIAL PLANT SCENARIO

The solar retrofit of Comanche Creek can be thought of as a pilot plant application on a small scale to demonstrate feasibility of the concept. On a larger scale, consider the design and construction of a Solar Cogeneration Facility that could provide all of the required process heat as well as the electricity needs of a sulfur mining operation such as Comanche Creek. Such an application would be thought of as a commercial plant whose size would be the equivalent of a 130 MW_t system as discussed in the System Size Trade-Off Study (Section 3.4). A commercial plant of this magnitude has been analyzed and the results are presented in the following sections.

Inherent in this commercial plant scenario is the assumption that Texasgulf has already decided to go ahead and build a new sulfur mining facility that would be the equivalent of the Comanche Creek operation. The new facility will be built in another location having essentially the same climatic and meteorological conditions. Therefore, the intent of this scenario is to evaluate whether or not it would be economically advantageous to incorporate the capability for cogeneration either by solar/hybrid or by fossil only.

6.5.1 Commercial Plant Capital Cost

Heat balance calculations indicate that, at the design point (equinox, noon), the commercial plant would produce 113 MW_t of process heat along with 17.6 MW_e of electricity. Thus, there would be in excess of 14 MW_e available for sale to the local utility. Additionally, it was determined that the commercial plant would require a superheater rated at 30.5 MW_t and a saturated boiler rated at 106.7 MW_t. To accommodate a minimum turndown of 5% for the boiler, the solar receiver should be rated at 101.4 MW_t. Using the DELSOL optimization code, the collector field will be a north field arrangement of 3247 heliostats covering 0.7 km^2 (173 acres). The flat plate receiver would be 14 m × 14 m (46 ft × 46 ft) and set atop a 140 m (459 ft) tower.

The capital cost estimate for the commercial plant has been determined by upward proportioning of the pilot plant costs on an account code basis. The proportional factors for the solar components are land area, number of heliostats, tower height and receiver width. For the fossil components, the proportional factors were the exponential expressions recommended by Park[6.5] based on MW ratings. The resulting capital cost estimate is shown in Table 6-5. It should be noted here that the mine water heaters have not been included in the commercial plant cost estimate because they are not required for a complete cogeneration facility.

Table 6-5

COMMERCIAL PLANT COST ESTIMATE (1980 $)

Account Code	Item	Cost (1000 $)
5100	Land	2,027
5200	Buildings	3,495
5300	Collectors	46,640
5400	Receiver	7,431
5500	Controls	2,625
5600	Fossil Energy	6,131
5800	EPGS	5,589
5900	Other	12,153
	Total Construction	86,091
	Owner's Cost	625
	Total	86,716

A reference base cost for a facility such as Comanche Creek is required since the economic analysis method is based on a comparison of alternatives. For the commercial plant analysis, the reference case will be assumed to be a duplicate of the Comanche Creek mining operation. To arrive at the appropriate capital cost, in 1980 \$, the actual cost of the Comanche Creek Plant (which was constructed in 1975) was increased by the ratio of the 1980 Consumer Price Index (CPI) to the 1975 CPI. Furthermore, it was assumed that approximately 50% of this cost was related to equipment not included in the solar facility estimate (e.g. office buildings, water treatment facilities, sulfur metering and distribution equipment, well head facilities, etc.). By this procedure the capital cost estimate of the reference case was calculated to be \$15M.

Table 6-6 gives a comparison of the commercial plant configurations that were considered along with their capital cost, fuel consumption and electricity either bought or sold. Presented are three cases: (1) the reference or base case which is a duplicate of Comanche Creek and requires the purchase of electricity; (2) the solar/hybrid cogeneration facility including the effects of different heliostat costs; and (3) a natural gas fired fossil only cogeneration facility with its capital cost obtained by subtracting the costs associated with account codes 5100, 5300 and 5400 from the total in Table 6-5. The third case was included in order to evaluate whether the economic results were due to the use of solar components or just due to the fact that cogeneration was incorporated.

Table 6-6

COMMERCIAL PLANT COMPARISON

	Reference Case 1	Solar/Hybrid Cogeneration Case 2	Fossil Only Cogeneration Case 3
Capital Cost (\$M-1980)	15	86.716 (260 \$/m^2) 75.953 (200 \$/m^2) 66.984 (150 \$/m^2) 57.835 (99 \$/m^2)	30.211
Fuel Consumed (MBtu/yr)	3.5×10^6	3.66×10^6	4.64×10^6
Electricity Consumed (kWh/yr)	25.1×10^6	124.4×10^6*	124.4×10^6*

* Available for sale to utility

6.5.2 Evaluation of Solar/Hybrid Configuration

In deciding whether to choose between the base case or the solar/hybrid alternative we performed the same economic evaluation as described in Section 6.1. However, note that Table 6-6 indicates a slightly larger fuel consumption in the solar case than in the base case. Furthermore, the major economic driver appears to be the difference between having to purchase electricity and being able to sell electricity. By ignoring the small difference in fuel consumption, Figure 6-3 illustrates the discounted cash flow rate of return (DCRR) as a function of heliostat cost and a variable cost of electricity.

To complete this evaluation, an economic scenario for the year 2000 has been projected. Using economic projections for the year 2000 can be interpreted either as having constant expenses over a twenty year life starting in 2000 (the Texasgulf practice), or as considering the year 2000 scenario as being the levelized average expense over a twenty year life starting in the year 1990. In either case, the economic scenario (in 1980$) contains the following:

- Heliostat cost of $136/m^2$ corresponding to a production level of 25,000 units/year.[6.6]
- Natural gas cost at $10.64/MBtu corresponding to the cost of imported oil.[6.3]
- Purchase cost of electricity at 11¢/KWh corresponding to above gas cost.
- Electricity sale price of 8¢/KWh corresponding to 70% of the electricity generation cost.[6.2]

Plotting this economic scenario on to Figure 6-3 gives the circled data point which yields an after tax DCRR of 17.5%. The corresponding ROI (at 9% inflation) is 28.1%.

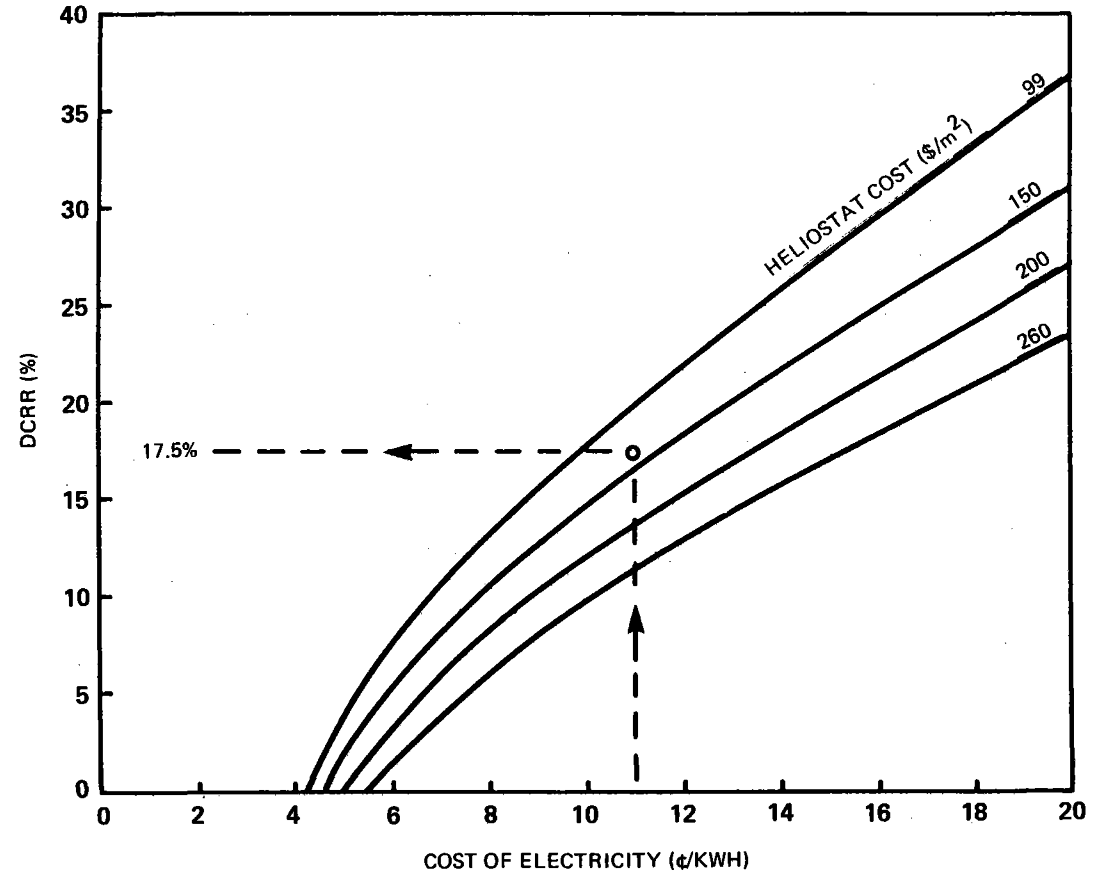


Figure 6-3. Solar/Hybrid Commercial Plant Economic Evaluation

6.5.3 Evaluation of Fossil Configuration

When comparing the fossil (natural gas fired) only cogeneration configuration to the reference case, Table 6-6 shows that the fuel consumption can not be ignored and must be considered in addition to the electricity differences. The economic analysis for this comparison is shown in Figure 6-4 where the DCRR is measured against variable costs for fuel and electricity. Plotting the year 2000 economic scenario, from the previous section, gives the circled datapoint in Figure 6-4. This yields an after tax DCRR of only 2% which corresponds to an ROI (with 9% inflation) of 11.2%.

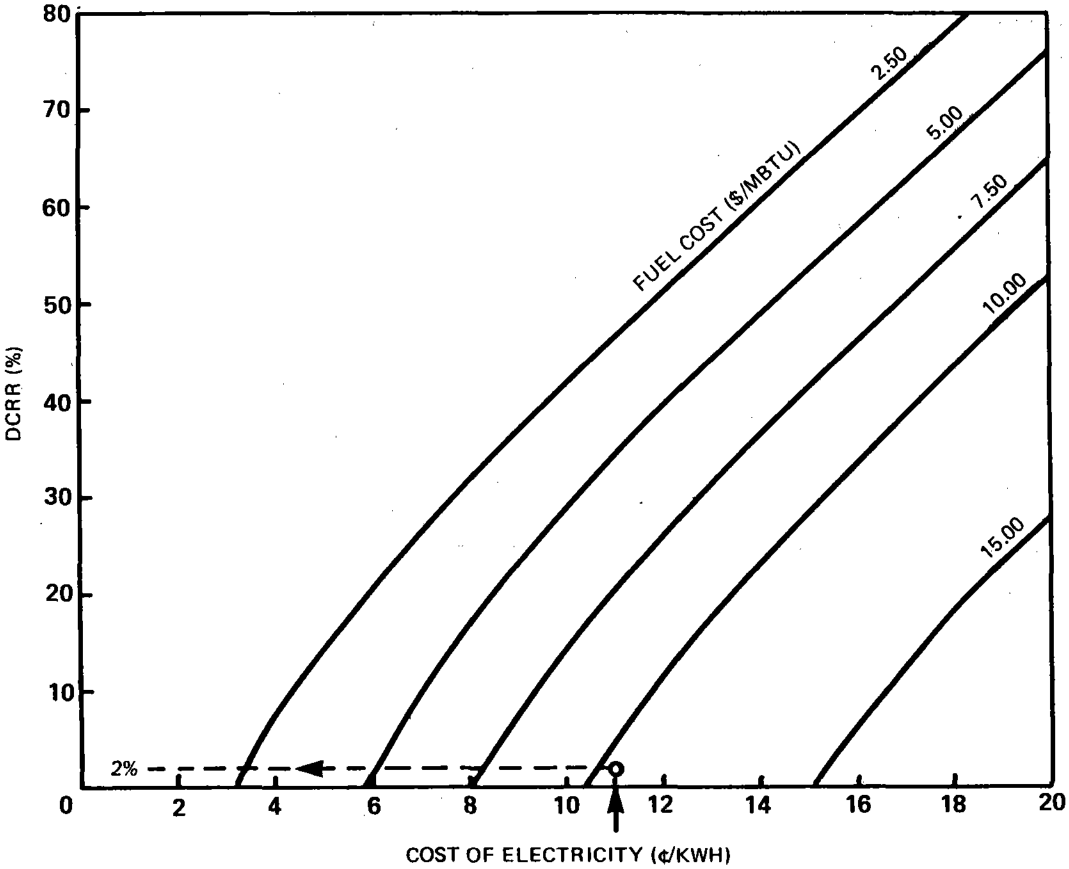


Figure 6-4. Fossil Commercial Plant Economic Evaluation

6.6 CONCLUSIONS

Some overall general conclusions for both the SCF pilot plant and the commercial plant scenario are presented below.

6.6.1 Pilot Plant

Based on the assumptions given in Section 6.2, the previous analyses have shown that a solar cogeneration facility retrofitted to the existing Comanche Creek sulfur mining operation may be economically attractive to the user, Texasgulf, only if there was significant investment cost sharing by the government. The required level of cost sharing would depend primarily on the costs of fuel and electricity but would also be affected by the allowable investment tax credit.

6.6.2 Commercial Plant

In contrast to the pilot plant assessment, the commercial plant evaluation does not include any government cost sharing. On this basis there is a strong indication that a solar/hybrid cogeneration facility would be much more attractive than a fossil only cogeneration facility. This can be seen more readily in Figure 6-5. Both of the solid curves for the solar and fossil facilities are based on a fuel cost of \$10.64/MBtu and the solar curve utilized a heliostat cost of \$136/m^2. As shown, the solar facility gives an after tax DCRR that is more than 15% greater than the fossil only facility.

From Figure 6-5 one might also conclude that if the cost of electricity was greater than 15¢/kWh then the fossil facility may be better than the solar facility. This conclusion is not quite correct because the cost of electricity is dependent on the cost of fuel. Thus, a 15¢/kWh electricity cost implies an increase in the fuel cost. Since Table 6-6 shows that the fossil facility consumes considerably more fuel than the solar facility, the rising energy costs will move the crossover point further and further to the right. This is illustrated in Figure 6-5 by the dashed curves which represent a fuel cost of \$15.00/MBtu and show that the crossover point is now in excess of 20¢/kWh. Therefore, the solar facility would always be more attractive than the fossil facility.

It is of interest to note that even if the current heliostat cost of \$260/m^2 were used the solar facility is still more attractive than the fossil facility. At a heliostat cost of \$260/m^2, Figure 6-3 gives an after tax DCRR of 11.3% with a corresponding ROI (with 9% inflation) of 21.3%.

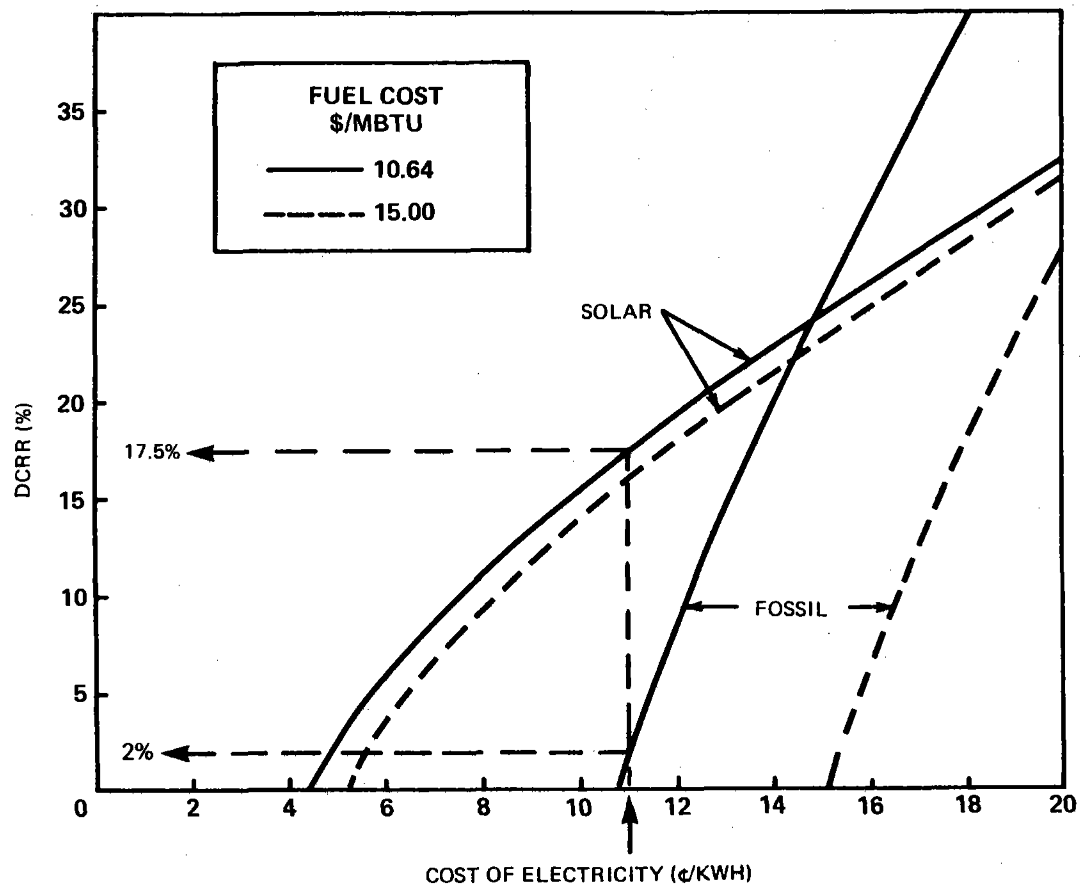


Figure 6-5. Commercial Plant Comparison: Solar Vs. Fossil

6.6.3 Electricity Sale Price

The economic analysis depends in part on excess electricity from the cogeneration facility which will be available for sale to the local utility. In the current study, the sale price for export power was taken as 70% of the purchase cost.(6.2) However, this percentage may not hold true for other applications in other regions of the country.

A significant increase or decrease in the electricity sale price would not change the results for the SCF (pilot plant) in that substantial cost sharing by the government would still be required. On the other hand, since there is a large quantity of available export power in the commercial plant scenario, even small changes in the sale price of electricity could have a strong impact on the economic results. This parameter should be considered carefully in any future studies.

REFERENCES

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6.3 General Electric Company Proprietary Report, "U.S. Energy Outlook," March 11, 1980.

6.4 Private Communication with Kenneth D. Bishop, Project Manager, Texasgulf Chemicals Company.

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6.6 "Heliostat Production Evaluation and Cost Analysis," General Motors Corporation, Warren, MI, Report No. SERI/TR-8052-2, December 1979.

Section 7
DEVELOPMENT PLAN

Section 7

DEVELOPMENT PLAN

A development plan for the Solar Cogeneration Facility (SCF) has been prepared with the major objective of efficiently achieving system operation by mid-1985. The DOE Solar Cogeneration Program objective was to start operation by 1986. However, an earlier startup will increase the attractiveness of the SCF to Texasgulf, since the resulting energy cost savings will help to extend the economical operating life of the sulfur mine.

In this section of the report, the activities planned for subsequent phases are summarized, a schedule and milestone chart is presented, and the potential roles of Texasgulf, the Federal Government and industry are discussed.

7.1 DESIGN PHASE

The design phase will consist of two separate activities: Advanced Conceptual/Preliminary Design, and Final Design. The Advanced Conceptual/Preliminary Design activity will have a duration of about nine months, with an assumed start date of September 1981. Key efforts planned for this activity are shown in Table 7-1. The Preliminary Design activities are included with the Advanced Conceptual Design activities so that the Solar Cogeneration Facility may be operational by mid-1985. Separation of these activities will result in a minimum delay in initial system operation of about six months, as well as adding additional cost to the program.

Table 7-1

MAJOR PROGRAM ACTIVITIES OF ADVANCED CONCEPTUAL/PRELIMINARY DESIGN PHASE

- Modify conceptual design and upgrade to preliminary design
- Obtain meteorological and environmental data
- Prepare and submit Environmental Information Document (EID)
- Prepare Environmental Impact Statement (EIS) if required
- Prepare and submit applications for other required permits
- Select receiver and heliostat contractors for engineering design efforts
- Conduct transient analyses and dynamic simulations
- Finalize system/subsystem requirements
- Prepare system/subsystem specifications
- Conduct subsystem/component development tests
- Prepare system/subsystem safety analysis
- Prepare preliminary construction plan
- Prepare preliminary test plan-checkout, startup, acceptance
- Prepare preliminary O&M plan
- Prepare layout drawings
- Identify long-lead items
- Update/revise development plan

Advanced Conceptual Design activities will occur early in this phase and will consist of evaluating minor changes to the current system configuration. Examples of changes that will be evaluated are:

- Superheat Solar Receiver
- Tube Type Tower
- Specific 2nd Generation Heliostat Configurations

Inputs from receiver and heliostat contractors will be solicited and appropriate contractors selected for participation during the Preliminary Design activities.

Meteorological and environmental data will be obtained at the site, starting early in this phase and will continue through the System Operation Phase. Early data will be utilized to prepare an Environmental Information Document (EID) for Environmental Protection Agency (EPA) approval. Based upon preliminary assessments, minimal adverse environmental impact is projected for the new Solar Cogeneration Facility; therefore, an EID should provide EPA with sufficient information for timely approval. However, should EPA determine, based upon review of the EID, that an Environmental Impact Statement (EIS) is required, facility construction and correspondingly, system operation, will be delayed by approximately six months.

Only minor engineering development is planned during this phase. The current system configuration consists of available state-of-the-art technology, with a large portion of the system components categorized as off-the-shelf. Preliminary discussions with receiver contractors have indicated that the natural circulation saturated water/steam receiver is well within the state of the art and that even panel tests will not be required. Minor engineering development of receiver attachments, etc., should allow for confident design and construction. Heliostat development is proceeding under parallel DOE Second Generation Heliostat Development Programs, and the assumption is made here that these programs will result in the timely availability of suitable heliostats for incorporation into this program. Preliminary assessments indicate that any of the current Second Generation Heliostats will meet the specific Texasgulf site requirements. However, this will be reviewed in greater depth during this phase to determine the desirability of any minor modifications relative to the Texasgulf site.

Procurement time for components will be reassessed during this phase to ascertain whether the placement of long-lead orders during the Final Design Phase, rather than following completion of the Final Design Phase as currently planned, will expedite the initiation of system operation.

The Final Design Phase will have a duration of about six months, with an assumed start date of October 1982. Key efforts for this activity are shown in Table 7-2.

Table 7-2

MAJOR PROGRAM ACTIVITIES OF FINAL DESIGN PHASE

- Prepare detailed engineering drawings
- Prepare procurement packages — Issue RFPs for heliostats and receiver, select vendors
- Finalize software package
- Finalize construction, test and O&M plans
- Prepare operation and maintenance manuals
- Obtain approval for site construction and hardware fabrication
- Prepare as-built drawings once system becomes operational
- Update/revise development plan

Detailed engineering drawings for fabrication and construction will be prepared. Procurement packages for hardware and materials will be prepared, including the issuance of competitive RFPs for the receiver and heliostats. Proposals in response to these RFPs will be evaluated and tentative contractors will be selected. Software packages will be finalized. Plans for construction, test and operation/maintenance will be finalized. Operation and Maintenance Manuals will be prepared. Approval for construction will be obtained from DOE. In addition, if not already accomplished, final approval by EPA and other regulatory agencies will be obtained. Once the Solar Cogeneration Facility becomes operational, drawings will be updated to the actual as-built configuration.

7.2 CONSTRUCTION PHASE

The Construction Phase will have a duration of about two years, with an assumed start date of April 1983. Key efforts planned for this activity are shown in Table 7-3.

Table 7-3

MAJOR PROGRAM ACTIVITIES OF CONSTRUCTION PHASE

- Issue procurement packages and select vendors
- Prepare site
- Modify existing facilities
- Install hardware and new facilities
- Checkout components/subsystems

Construction will be initiated once DOE approval has been received. Orders for the receiver and heliostats (longest lead item identified to date—requires about two years from order through checkout) will be placed with contractors selected during the Final Design activities. The steam turbine generator unit will also be ordered. Competitive procurement packages for other hardware. previously prepared during the Final Design activities, will be distributed and appropriate vendors selected.

Site preparation, modification of existing site facilities, and construction of new facilities and hardware (tower) will be initiated early in the Construction Phase.

The two-year schedule assumed here is for early planning purposes only, since the heliostats appear to be the long-lead item. Heliostat delivery times appear to vary greatly, depending on whether fabrication/assembly lines are operating prior to order placement and on the scheduling of competing orders. Heliostat delivery schedules will be defined in much more detail during the Design Phase and will play an important role, in addition to cost and performance, in the selection of a heliostat hardware contractor.

All subsystems will be checked out, to the maximum extent possible without full system operation, during the Construction Phase.

All construction activities, including existing facility modifications and Solar Cogeneration Facility/existing plant interfaces, will be accomplished on a noninterference basis with the normal around-the-clock, year-round operation of the existing plant. This will necessitate the use of such techniques as hot taps for plumbing connections and coordinated planning with site personnel. To facilitate training, site personnel will be involved to the maximum extent possible during the installation and checkout of the various subsystems.

7.3 SYSTEM CHECKOUT AND STARTUP PHASE

The System Checkout and Startup Phase will have a duration of about three months and will immediately follow completion of the Construction Phase. Texasgulf site personnel will be intimately involved during this Phase to ensure efficient training of operational and maintenance personnel.

The fossil boiler and superheater will be used initially to ensure proper rotation, alignment, balance and power delivery of the steam turbine/generator unit. In addition, heat exchangers, other balance of plant equipment and thermal energy delivered to the process will be checked out. The Fossil Mode will be utilized and control hardware and software modified as necessary. The output of existing plant process water heaters will be adjusted during checkout to maintain a constant energy supply to the sulfur mining operation.

Once proper Fossil Mode operation has been achieved, checkout of the solar portion of the system will begin. Heliostat focusing, alignment and control will have already been checked out during the Construction Phase. Proper flow rates to the receiver will be verified and a portion of the heliostats will then be used to initially generate steam. The Solar Cogeneration Facility will be operated in the Hybrid Mode during this portion of system checkout and related control hardware and software modified as required. As confidence of proper operation is achieved, more heliostats will be utilized until the entire heliostat field is operating. Following successful checkout and operation in the two major operating modes, Hybrid and Fossil, the Emergency Shutdown Mode will be checked out. Satisfactory system operation in all operating modes will complete this phase.

7.4 SYSTEM PERFORMANCE VALIDATION PHASE

The duration of this phase is relatively undefined at this time. A period between one month and one year is anticipated, with the actual duration to be established based upon more detailed test planning, which will be accomplished during the Design phase. Special tests desired by Texasgulf and/or DOE will be conducted. All tests during this phase will be scheduled at Texasgulf's convenience with DOE responsible for expenses over and above Texasgulf's normal operating expenses.

This phase will be completed with a system acceptance test during which the system will be operated in all modes. Proper operation in all modes, with acceptable performance, will be the criteria for acceptance.

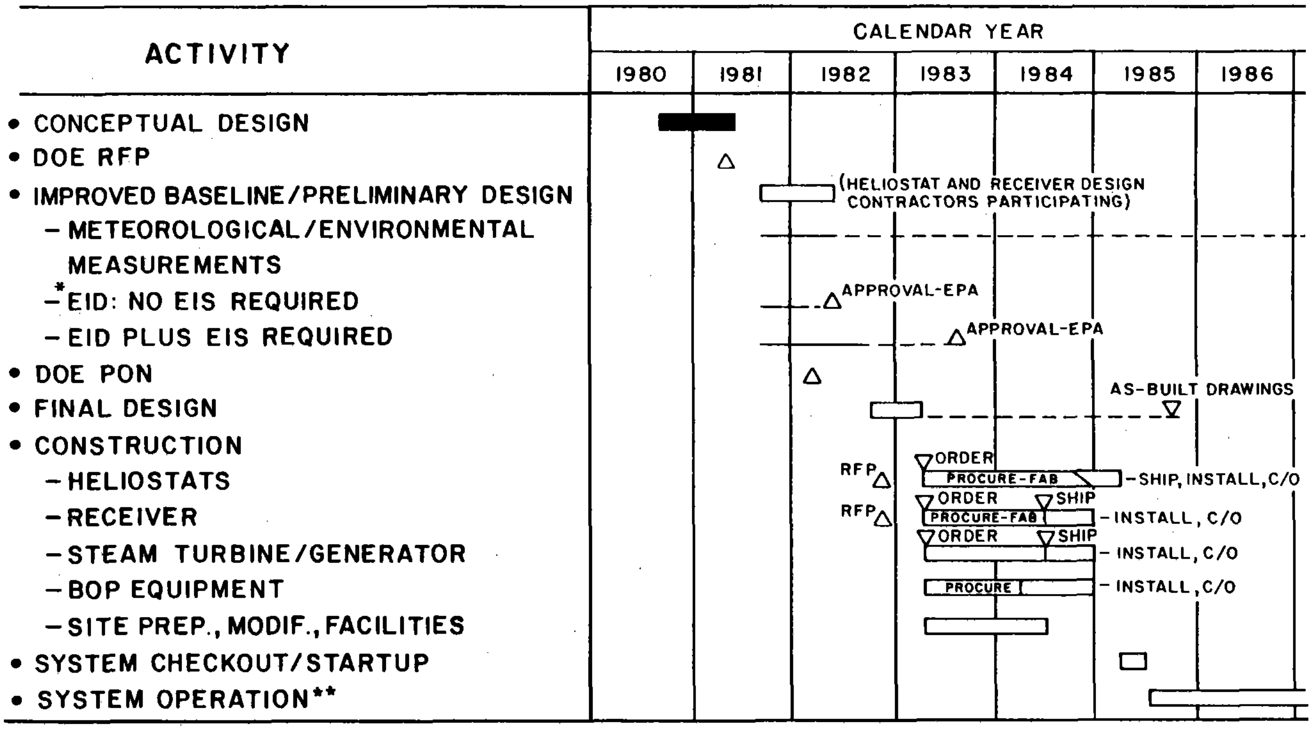
7.5 JOINT USER AND DOE OPERATIONS PHASE

The objective of this phase will be to assess the value of solar cogeneration as a viable option for industrial applications. The assessment will be performed by DOE while observing operation and communicating with Texasgulf's plant operation and maintenance personnel over a two-year period. DOE, along with its agents, as an agency familiar with the Solar Cogeneration Facility's design, and capable of influencing future solar activities, will be a recipient of all operational and maintenance data for the Solar Cogeneration Facility and will be able to observe the facility operation. During this period, the facility will be operated and maintained by Texasgulf personnel in a manner similar to the existing plant. DOE involvement with normal plant operations will be limited to observation of the Solar Cogeneration Facility operation and access to corresponding operation and maintenance records.

Following the two-year DOE observation period, Texasgulf will continue to operate and maintain the Solar Cogeneration Facility for as long as operation is economical.

7.6 SCHEDULE AND MILESTONE CHART

An overall schedule and milestone chart is shown in Figure 7-1. This schedule has been developed by GE, Texasgulf and Brown & Root Development, Inc. and reflects input from several equipment vendors. The schedule is based upon efficiently achieving system operation by mid-1985. Accordingly, an aggressive DOE program is assumed. The schedule will be modified and updated as the program proceeds with considerations for a possibly less aggressive DOE program incorporated as required. Key assumptions utilized to generate the development schedule and milestone chart are shown in Table 7-4.



* PROBABLE SITUATION – IF EIS REQUIRED, SCHEDULE FOR CONSTRUCTION, CHECKOUT/STARTUP AND OPERATION DELAYED ABOUT 6 MONTHS.

** SYSTEM OPERATION WILL CONSIST OF A 1-12 MONTH SYSTEM PERFORMANCE VALIDATION PHASE FOLLOWED BY A TWO-YEAR JOINT USER/DOE OPERATION PHASE. TEXASGULF WILL THEN CONTINUE TO OPERATE THE SYSTEM FOR AS LONG AS OPERATION IS ECONOMICAL.

Figure 7-1. Development Schedule and Milestone Chart

Table 7-4

KEY DEVELOPMENT PLAN ASSUMPTIONS

- DOE contract for Advanced Conceptual/Preliminary Design starting during 3rd quarter of calendar year 1981
- EPA approval based upon EID only. EIS not required
- Only minor engineering development required
- DOE contract for Final Design, Construction, Checkout/Startup initiated at start of 4th quarter of calendar year 1982
- No early procurement of hardware. Procurement initiated at completion of Final Design
- Two year time period from heliostat order through installation/checkout

7.7 ROLES OF SITE OWNER, GOVERNMENT AND INDUSTRY

Starting with the Preliminary Design Phase, Texasgulf plans to assume the prime contractor role from GE. Respective roles for Texasgulf, GE and Brown & Root Development, Inc. for the remainder of the program are summarized in Figure 7-2.

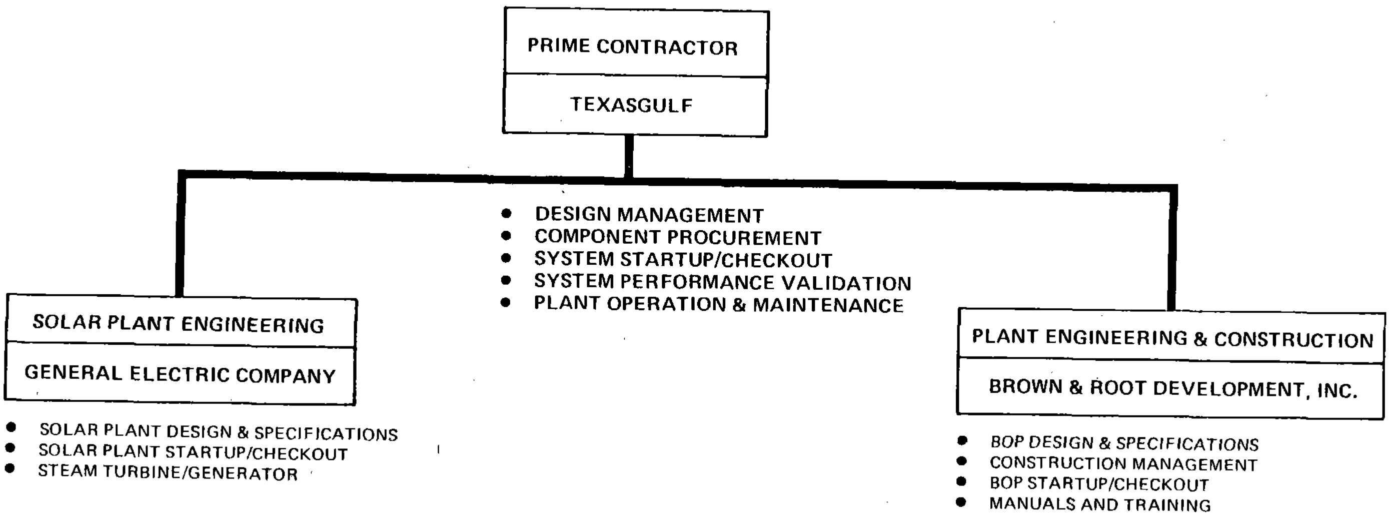


Figure 7-2. Program Organization

The overall objective of the planned program is to successfully evaluate the applicability of a Solar Cogeneration Facility for industrial use. Texasgulf plans to design, construct, operate and maintain the Solar Cogeneration Facility in a manner similar to that normally utilized by Texasgulf for any new plants. Important data regarding costs, operation, performance, reliability and maintenance will be developed during the program which will help to determine whether or not solar technology can satisfy the performance criteria of industry. Acceptable performance will help to encourage the commercialization of solar cogeneration as an energy alternative for industry. In addition, areas where additional research and engineering development could improve system performance and economics, thereby enhancing industry acceptance and commercialization, should be identified.

The collective efforts of Texasgulf, the Federal Government, and participating industries should result in a team effort that permits each entity to operate within its normal realm of expertise. It is mandatory that team members keep each other fully informed of activities to meet project objectives and to accomplish tasks initially agreed to. Each team member, functioning within its specified role, can best remove uncertainties which restrain current use of solar cogeneration plants.

Texasgulf will be expected to maintain the support of local officials for the project. Texasgulf's management and engineering staff will be responsible for the completion of the Solar Cogeneration Facility. The Federal Government and its agents will be expected to provide the necessary support of its agencies and supply information to justify partial DOE funding for the project. Industry will be asked to support the project with well-designed equipment manufactured in an efficient manner at a reasonable cost. Industry's support for the project could result in new free enterprise opportunities for commercialization of solar technology.

The role of the Federal Government in this development plan will be to define the objectives needed to accomplish the evaluation and commercialization of solar cogeneration within the framework of the Government's other activities. The definition of the objectives will include specifying tasks or direction but not detailed methodology; this should be accomplished by those who usually perform this type of activity.

The overall benefit of evaluating solar cogeneration is national in scope. The industrial use of solar could assist in energy independence. The Federal Government will select a contractor who can carry out the objectives of the program. The acceptance of a contractor will lead to construction of a Solar Cogeneration Facility to be operable within a certain time frame. During the design and construction of the facility, the Federal Government and its agents will review and report the progress of the project toward meeting its objectives. After construction and start-up, the Federal Government and its agents will observe facility operation and maintenance, collect data, and report on the performance of the facility. This will lead to decisions on additional development for commercialization of the solar cogeneration concept.

Industry's role in the program is to provide efficient manufacturing of components and equipment at a reasonable cost. This project will benefit most from industry's ability to reduce production cost and delivery time of solar equipment. Industry will act as a supplier providing services in the area of solar equipment selection and supply.

In summary, the authority to select the contractor rests with the Government. The authority to manage and complete the project should be with the contractor. The contractor's authority will be used to select and work with industry to complete a successful Solar Cogeneration Program.

The economics of the Solar Cogeneration Facility (SCF), which is based upon near-term costs of solar hardware (heliostats) and fossil/electrical energy, indicates that significant DOE cost sharing will be required in order for Texasgulf to receive a reasonable return-on-investment. Texasgulf requires a higher return-on-investment than many other industries due to the higher risk involved with a natural resource type of business. Texasgulf, like any business, has a limited amount of capital funding for investment purposes. Therefore, investment decisions must be made by considering all potential investment opportunities and selecting those investments which will maximize the return of owner's equity. Although Texasgulf could possibly receive a reasonable return-on-investment based upon funding a small portion of the capital cost of the SCF, the bulk of the capital cost would have to be provided by the taxpayer. The construction and operation of this SCF should provide a meaningful data base for future industrial usage of solar cogeneration that would most directly benefit industry, while indirectly benefitting the taxpayer. Texasgulf, therefore, feels that industry, the major potential beneficiary, should fund such activities rather than the taxpayer. Accordingly, Texasgulf has decided to terminate participation in the Solar Cogeneration Program at this time.

Texasgulf's participation in this current study has been a meaningful exercise which has established a good data base for the evaluation of solar cogeneration as a potential candidate for future installations. Participation in the study has eliminated Texasgulf's earlier concerns about the high risk of solar technology. Since visiting the DOE Central Receiver Test Facility at Albuquerque, New Mexico, their misgivings concerning safety and operational reliability have been eliminated. Almost by definition, a solar steam and electric plant will be a plus in environmental impact considerations. The solar cogeneration configuration developed during this study appears to be a practical application of solar energy in an industrial process requiring both low pressure steam or superheated hot water and electricity. This situation exists for most petrochemical and natural resource process industries, including Texasgulf's phosphate mine in North Carolina and the soda ash plant in Wyoming. Therefore Texasgulf will be able to utilize this study in the future to evaluate the economic competitiveness of solar cogeneration for new plants. As heliostat costs are decreased through mass production and other energy costs increase, it appears that solar cogeneration has good potential to become economically competitive with other more conventional energy systems.

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