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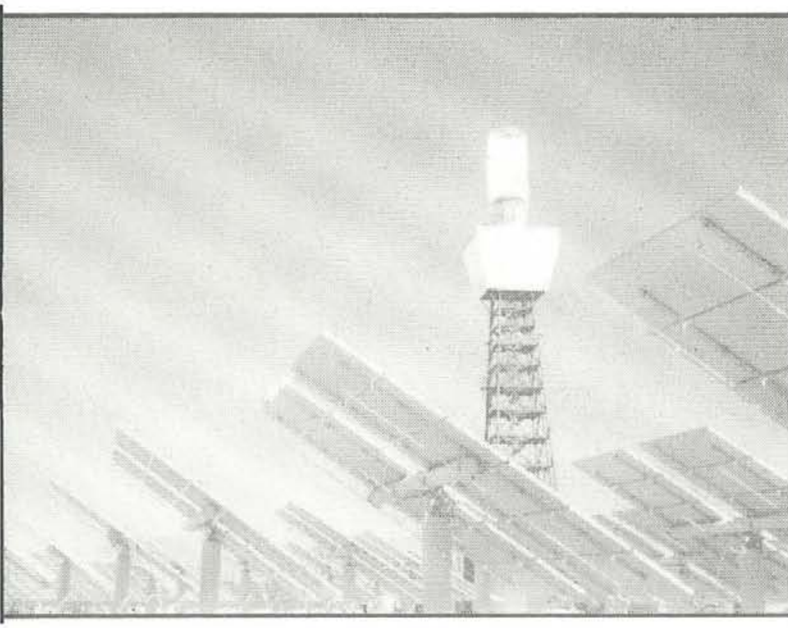
Reliability of the Solar One Plant During the Power Production Phase

August 1, 1984 — July 31, 1987



Gregory J. Kolb
Charles W. Lopez

Sandia National Laboratories

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Gregory J. Kolb
Division 6226
Sandia National Laboratories
Albuquerque, NM 87185-5800

Charles W. Lopez
Site Manager at Solar One
Southern California Edison Company
P. O. Box 800
Rosemead, CA 91770

ABSTRACT

The power production phase at Solar One spanned three years from August 1, 1984 through July 31, 1987. In that period the plant achieved an average availability, during hours of sunshine, of 81.7%. This report presents the frequencies and causes of the plant outages that occurred. The eleven most important causes composed 75% of the total outage time. Qualitative insights related to the origin and mitigation of these causes are provided. Also presented are insights and statistics regarding the reliability of the heliostat field. The quantitative and qualitative information presented in this report will be useful to studies aimed at improving the reliability of future solar central receiver power plants.

Acknowledgments

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CONTENTS

FOREWORD

The research and development described in this document was conducted within the U.S. Department of Energy's (DOE) Solar Thermal Technology Program. The goal of the Solar Thermal Technology Program is to advance the engineering and scientific understanding of solar thermal technology, and to establish the technology base from which private industry can develop solar thermal power production options for introduction into the competitive energy market.

Solar thermal technology concentrates solar radiation by means of tracking mirrors or lenses onto a receiver where the solar energy is absorbed as heat and converted into electricity or incorporated into products as process heat. The two primary solar thermal technologies, central receivers and distributed receivers, employ various point and line-focus optics to concentrate sunlight. Current central receiver systems use fields of heliostats (two-axis tracking mirrors) to focus the sun's radiant energy onto a single tower-mounted receiver. Parabolic dishes up to 17 meters in diameter track the sun in two axes and use mirrors to focus radiant energy onto a receiver. Troughs and bowls are line-focus tracking reflectors that concentrate sunlight onto receiver tubes along their focal lines. Concentrating collector modules can be used alone or in a multi-module system. The concentrated radiant energy absorbed by the solar thermal receiver is transported to the conversion process by a circulating working fluid. Receiver temperatures range from 100C in low-temperature troughs to over 1500C in dish and central receiver systems.

The Solar Thermal Technology Program is directing efforts to advance and improve promising system concepts through the research and development of solar thermal materials, components, and subsystems, and the testing and performance evaluation of subsystems and systems. These efforts are carried out through the technical direction of DOE and its network of national laboratories who work with private industry. Together they have established a comprehensive, goal directed program to improve performance and provide technically proven options for eventual incorporation into the nation's energy supply.

To be successful in contributing to an adequate national energy supply at reasonable cost, solar thermal energy must eventually be economically competitive with a variety of other energy sources. Components and system-level performance targets have been developed as quantitative program goals. The performance targets are used in planning research and development activities, measuring progress, assessing alternative technology options, and making optimal component developments. These targets will be pursued vigorously to insure a successful program.

Chapter 1

Introduction

1.1 Overview

The reliability of the Solar One power plant was commendable throughout the power production phase of its operation. During this three-year period (August 1, 1984 to July 31, 1987), the intent of plant operation was to maximize the amount of energy delivered to the Southern California Edison (SCE) utility grid. To achieve this, an availability goal of 90% was established. The plant was close to achieving this goal and registered values of 80%, 83%, and 82% in each of the three years (Radosevich 1988). Considering the fact that Solar One is a first-of-a-kind plant and that the 90% value is traditionally chosen for power plants based on old technology (e.g., fossil fuel and nuclear), the availabilities achieved at Solar One were truly outstanding.

Though the availabilities were commendable for a pilot plant, improvements are necessary to achieve the 90 to 95% goal the Department of Energy hopes to achieve for a mature central receiver system (Alpert and Kolb 1988). As part of our Annual Energy Improvement Study, Sandia Laboratories is performing a reliability analysis to identify ways to improve the design and operation of future central receiver plants to achieve this goal. This analysis requires a detailed understanding of the frequency and cause of equipment failure at a central receiver plant. The failure experience recorded in the Solar One log books during the power production phase is the best source of this information.

This report organizes the plant outages described in the Solar One logs, displays various failure statistics, and presents failure probability estimates needed for reliability studies. This work is described in Chapter 2. In that chapter we identify 65 different causes for plant outages. Eleven of them composed 75% of the total outage time. In Chapter 3 we describe these 11 outage causes and recommend ways for reducing their likelihood in future central receiver plants.

This report also presents failure statistics and qualitative insights regarding the reliability of the Solar One heliostat field. While failures of individual heliostats do not in general cause plant outages, their reliability is important to plant performance and maintenance costs. Future central receiver plants will therefore benefit from the information presented in Chapter 4. Conclusions and recommendations are presented in Chapter 5.

This is the second reliability analysis of Solar One. A previous report (Nagel 1986) documented the failure experience during the test and evaluation phase of the plant's operation

(January 1, 1983 to July 31, 1984). That report should be used to identify reliability problems that may occur during the "break-in" phase of a central receiver plant. The current analysis is more appropriate for the "useful life" phase (see Figure 1-1).

For those readers who are unfamiliar with the design and operation of the Solar One power plant, the following section serves as a brief primer.

1.2 Description of Plant Systems

In this section we provide a brief overview of the design and operation of the Solar One plant. A more detailed description can be found in Radosevich (1985) and US DOE (1982). Solar One, an electric generating pilot plant located in Barstow, CA, is the world's largest solar central receiver. It was designed to produce at least 10 MW for 8 hr on the best design day -- the summer solstice. The project is a joint undertaking of the US Department of Energy (DOE) and of Utility Associates. The latter consists of Southern California Edison (SCE) Company, the Los Angeles Department of Water and Power, and the California Energy Commission. In such a plant, large sun-tracking mirrors called heliostats concentrate sunlight onto a receiver mounted atop a tower. The receiver transforms the solar energy into thermal energy that heats water, turning it into superheated steam that drives a turbine to generate electricity (Figure 1-2). The heat can also be stored for later use.

Plant Design

Solar One consists of six major systems:

- The collector, including the heliostats and supporting components
- The receiver
- Thermal storage
- Plant control system
- Electric power generation system
- Beam characterization.

Supporting these six systems are auxiliary systems that provide raw water, fire protection, water treatment, cooling water, nitrogen, compressed air, liquid waste disposal, auxiliary steam, and air conditioning.

Collector--The heart of the collector system is an array of 1818 heliostats positioned 360° around the tower; the heliostats were designed and built by Martin Marietta. Each heliostat is an assembly of 12 slightly concave mirrors individually mounted on a geared drive that can be controlled for azimuth and elevation. The controlling system consists of a microprocessor for each heliostat, 64 field controllers (each for up to 32 heliostats) and two heliostat array controllers (HACs), one controlling the entire field and the other acting as a backup. Also included are the associated power supply and data transmission and control hardware.

Receiver--The receiver system uses reflected sunlight to heat water directly, creating superheated steam. The system consists of 6 preheating panels and 18 single-pass-to-superheat boiler panels. External tubing, tower, pumps, piping, wiring, valves, and controls are all part of the system that provides steam to the turbine or to the heat-storage system. Although the control-room operator can control delivery of steam, the system normally reacts automatically to changes in the amount of sunlight reaching the receiver.

Thermal Storage--The thermal storage system stores heat from solar-generated steam in a tank filled with rock and sand, using thermal oil as the heat transfer medium. The system thus extends the plant's power-generating capability into the night or during cloudy days. It also provides heat for generating low-grade steam to warm parts of the plant during off-hours and to start the plant the next morning. Components of the system are the charging subsystem, which heats the storage oil with superheated steam from the receiver; the extraction subsystem, which transfers the stored heat to water and generates medium pressure steam; the storage tank; and a ullage maintenance unit.

The thermal storage system at Solar One is no longer in use. On August 30, 1986, the system was damaged by fire. Because the storage system was functional for two years of the three-year time frame covered by this report, the above description was included.

Plant Control System--The plant control system consists of several computers responsible for monitoring and controlling the plant's individual systems and for collecting and storing plant operation and performance data. Most of the plant's functions are fully automatic, with operator override capabilities to make it possible for one operator to control the entire facility. The system has access to approximately 2500 channels of information from all over the plant and displays operating data and alarms on consoles and other graphic means within the control room. Three Beckman MV8000 distributed-process control systems are used to operate the receiver, thermal storage, and electric power generation systems. An interlock logic system consisting of three Modicon 584 programmable logic units contains the plant permissives required to safely operate the plant. Two red line units, which are also Modicon 584 programmable logic units, provide safety monitoring and control of the receiver and thermal storage systems to assure shutdown of the systems when criteria for safe operation are exceeded. Five remote stations process information between the operational control room and the operating equipment.

Turbine-Generator--The General Electric turbine-generator, a single-case design for cyclic duty, is rated at 12.5 MW. The turbine admits high-pressure steam generated by the receiver through one port and lower pressure steam generated by the thermal storage system through another. Circulating water from an evaporative cooling tower condenses the spent steam into water, which is then routed back to the receiver through a full-flow demineralizer and a series of feedwater heaters. Two other functions support the power-generating system: water chemistry control facilities and an uninterruptible power-supply battery system in case the main and backup power supplies to the control system fail.

Beam Characterization--The beam characterization system is coupled to the collector-control system and calibrates each individual heliostat's beam with respect to its aim point on the receiver, its shape, and its intensity. The system also helps identify heliostats requiring maintenance. It consists of four cameras, a minicomputer, and associated controls.

Plant Operation

The plant can be operated in eight steady-state modes, each characterized by different process flow paths between the plant's collector, receiver, thermal storage, and electric power generation systems (see Figure 1-3). The modes are

Mode 1 - Turbine Direct

In the turbine direct mode, all steam generated by the receiver passes directly to the turbine-generator, and the thermal storage system is bypassed. This is the most efficient mode for power production and is used on clear days when charging the thermal storage unit is not required.

Mode 2 - Turbine Direct and Charging

In this mode, steam from the receiver is directed simultaneously to the turbine-generator and to the thermal storage system. This operating mode would be used at midday on a clear day when the available solar energy exceeded the maximum capability of the turbine.

Mode 3 - Storage-Boosted

Steam generated by the thermal storage system is used to supplement steam generated in the receiver. This mode could be used on a clear day during early morning and late afternoon, when the available solar energy was less than the maximum capability of the turbine.

Mode 4 - In-Line Flow

Here, steam from the receiver is used to charge the thermal storage system, which then generates steam for the turbine-generator. When operating in this mode, the unit's tolerance of cloud transients is enhanced. Due to limitations on the temperature of the heat transfer oil and the temperature differences across the heat exchangers, plant efficiency and maximum power output are less than for Mode 1.

Mode 5 - Storage Charging

In this mode, the turbine-generator is not operating, and all steam generated in the receiver is delivered to the thermal storage system.

Mode 6 - Storage Discharging

Here, the heliostats and receiver are not operating and the thermal storage system generates steam for use in the turbine-generator. This mode would be used on overcast days or at night.

Mode 7 - Dual Flow

In this mode, steam from the receiver is delivered to both the turbine-generator and the thermal storage system. Simultaneously, steam from the thermal storage system is directed to the turbine-generator. This mode could be used on cloudy days since it allows the thermal storage system to dampen transients caused by passing clouds.

Mode 8 - Inactive

None of the major plant systems are in use in this mode during which only a portion of the plant's support systems is in operation. The support systems are used to generate auxiliary steam needed for start-up of the plant, building heating and ventilation, and other plant support functions.

Even though the plant could operate in the eight modes described above, only Modes 1, 5, and 8 were routinely used before the storage fire. Mode 2 was not used because the heliostat field was not large enough to supply simultaneously full power to the turbine and sufficient energy to the storage. The size of the heliostat field was reduced just before the plant was built to reduce costs. The remaining modes were not routinely used because the plant ran more efficiently in Mode 1. Before the fire, the storage tank was charged approximately every ten days (Mode 5). The energy stored in the tank was used to provide auxiliary steam during start up and at other times. After the fire, auxiliary steam was provided by the existing electric boiler.

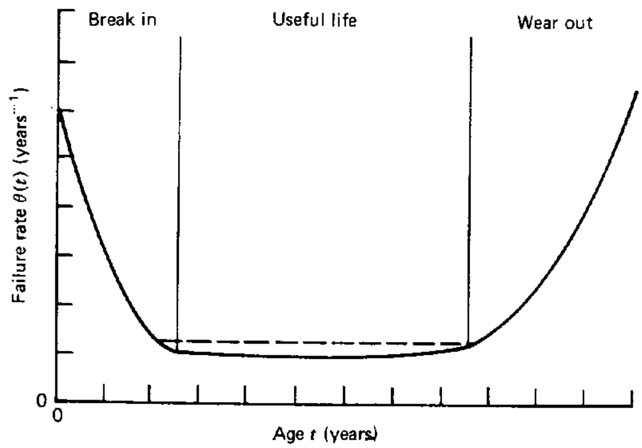


Figure 1-1 Failure Rate Characteristic of a Typical Engineering Device

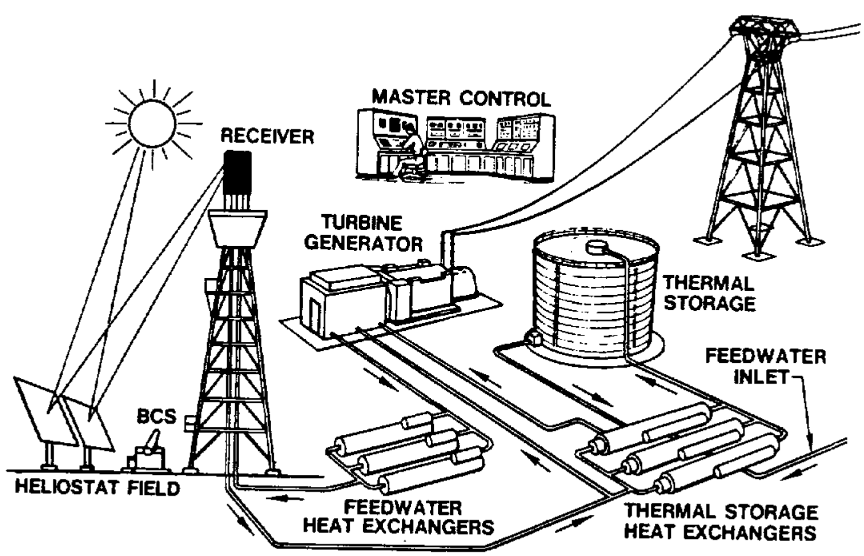
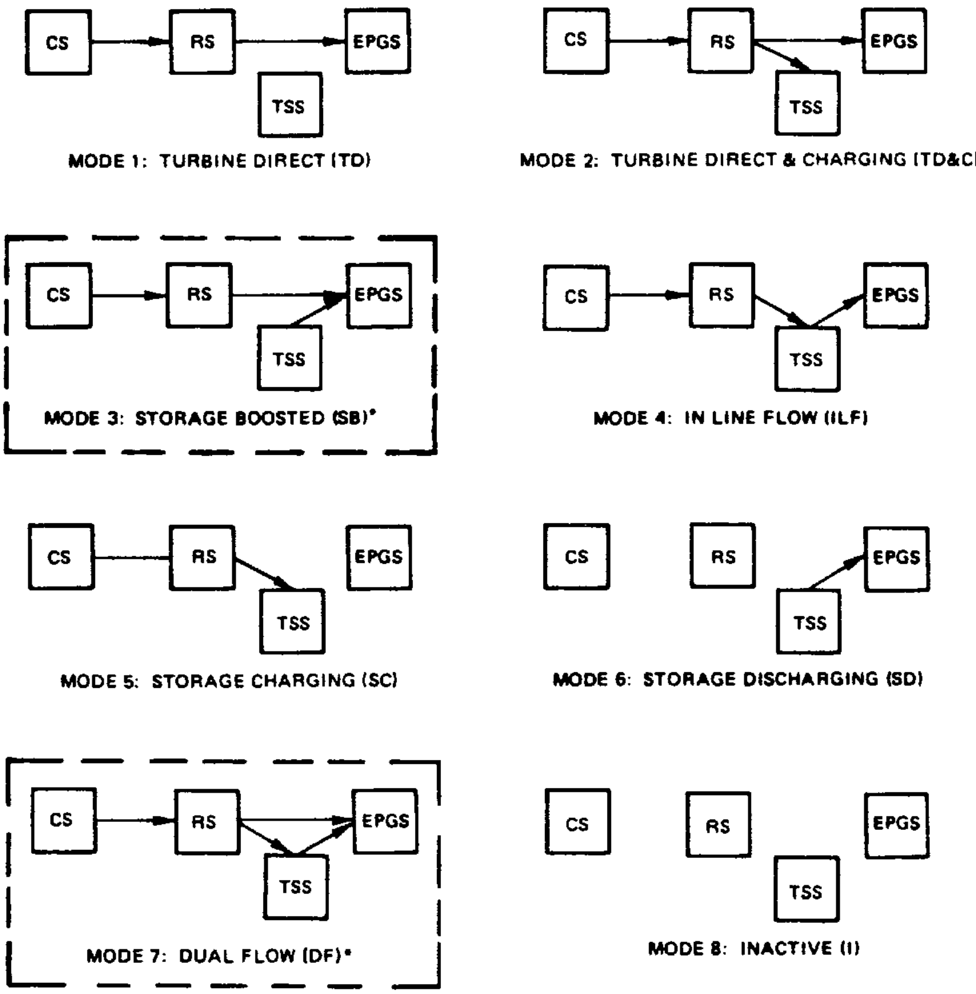


Figure 1-2 Solar One



Mode 1	Turbine Direct:	Receiver-generated steam directly powers the turbine.
Mode 2	Turbine Direct and Charging:	Receiver-generated steam powers the turbine and charges storage.
Mode 3	Storage Boosted:	Steam from the receiver and storage powers the turbine.
Mode 4	In-Line Flow:	Receiver steam charges storage, while storage steam is stimultaneously discharged powering the turbine.
Mode 5	Storage Charging:	Receiver steam charges the storage system.
Mode 6	Storage Discharging:	Steam generated by the storage system is used to power the turbine.
Mode 7	Dual Flow	A combination of Modes 2 and 3 (probably only achieved during transitions).
Mode 8	Inactive	Major systems are standing by for operation.

*Engineering Test and Transitory Modes

Figure 1-3 Operating Modes

Chapter 2

Causes for Plant Outages

In this chapter we present and categorize various failure statistics regarding the frequency and causes for plant outages at Solar One. Consequently, equipment failures that did not cause the plant to be unavailable for power production are generally not included in our analysis. The one exception is the failure of individual heliostats. Heliostat failures are discussed separately in Chapter 4.

2.1 Data Base of Plant Outages

The resources we used to understand the causes and frequency of plant outages are listed below:

1. Daily newsletters entitled "Daily Solar One Highlights."

2. Control room logbooks.

3. Interpretations by Solar One's maintenance and operations personnel.

4. Outage times recorded in a data base prepared by Sandia Livermore.

5. Maintenance orders recorded within an SCE data base.

The first four resources were used extensively. The last resource proved to be of limited value because a) equipment failure categories were often too general to determine the exact problem, and b) a maintenance order was not written for plant outages when the problem was corrected by the operations rather than the maintenance staff. The maintenance orders were used, however, to double check about one-third of the causes for outages described by the first three resources.

Table 2-1 summarizes all the outages that occurred at Solar One during the power production phase. The 261 outage events are listed in chronological order. It can be noted that some events caused the plant to be unavailable for more than one day. (For example, event 45 caused the plant to be out from February 10, through March 15, 1985.)

In column 3 we assign the outage cause to a particular system. The system boundaries and definitions employed were the same as defined in Appendix A of Nagel (1986); we have, however, added two new systems entitled "operators" and "utility grid" so that we could be more precise about the exact cause of the outage.

In column 4 we classify whether the outage was scheduled or unscheduled. A scheduled outage occurs if the plant is purposely shut down by the staff and not by an equipment failure. If equipment failure results in a trip condition (or if equipment is degraded so that trip should occur within a few hours) an unscheduled outage occurs.

Columns 5 and 6 list the total-outage hours and solar-outage hours, respectively. Total-outage hours are based on the number of daylight hours minus the time typically required to attach the plant to the utility grid after sunrise (approximately 90 minutes). Solar-outage hours are obtained by reducing the total-outage hours by the number of hours in which cloudy weather would have prevented operation. The availabilities presented in Chapter 1 and calculated in Radosevich (1988) are based upon the solar-outage hours. It is important that the reader understand the distinction between total and solar outage hours to be able to properly extrapolate the Solar One data to other plants. The solar-outage-hour data can only be directly extrapolated to another plant if the plant site receives approximately the same amount of direct-normal insolation as typically occurs at Solar One (i.e., 2.7 MWhrs/m^2/year). If the plant site receives significantly more annual insolation, solar-outage time for the new plant will be greater than the solar-outage time listed for Solar One and will approach the values listed for total-outage time. Conversely, if the plant site receives significantly less annual insolation, solar-outage time for the new plant will be less than that listed for Solar One. Users of the data presented here will therefore need to interpolate the solar-outage hour data for plant sites that have significantly different weather conditions. For the plant as a whole during the power production phase, the solar-outage time was 1289.5 hours and the total-outage time was 1765.5 hours.

Column 7 lists the outage category assigned to the event. The first four letters represent a component class; the last two letters represent a failure class. The naming scheme is explained in Table 2-2. It can be noted that not all component classes are at the same level of detail. For example, the "syst" class represents general system outage, whereas "flux" represents failure of a particular flux transmitter within a system. This occurred because either a) an outage report did not provide enough detail, or b) many different types of components within a particular system were repaired during the outage. The latter situation generally occurred during a scheduled outage when an entire system was overhauled (e.g. the scheduled turbine system outage in February 1985 and the scheduled receiver outage in December 1985).

Columns 8 and 9 contain notes regarding the component or subsystem that caused the outage and, in many cases, information related to the failure mode and the corrective action taken. It is important to note that the corrective actions listed only relate to the event that was the primary cause of the outage. The plant often performs corrective actions on other components that are degrading during the same outage. These other corrective actions are not listed.

2.2 Outage Summaries

The data base presented in Table 2-1 was analyzed with the help of the Rbase System V data base software (Microrim 1987) on a personal computer. The results of this analysis are presented in Figures 2-1 through 2-6. Each figure is discussed in turn below. It should be noted that all outage statistics are based on solar-outage hours.

Figure 2-1 Plant Outages By System

It can be noted that receiver unavailability accounted for approximately one-half of the plant outages. Unavailability of the turbine, storage, electric power, and control systems was also significant. Receiver and control system outages were due to several different types of problems. Unavailability of the other three systems was dominated by a single problem. The systems and system numbers listed are the same as those defined in Nagel (1986).

Figure 2-2 Plant Outages Caused by Receiver Problems

Figure 2-1 shows that receiver events caused the plant to be down for 662 hours. The pie chart in Figure 2-2 provides the specific causes for this down time. It can be noted that unscheduled and scheduled tube leaks account for about 25% of the receiver outages. Problems with various types of valves, flow and flux transmitters, and general receiver maintenance are also significant. Most categories were composed of several events, except for panel warpage. The latter category is dominated by a single event, which occurred in January 1987. These receiver problems are discussed in Chapter 3.

Figure 2-3 Plant Outages Caused by Receiver Leaks

The plant was down for 206.5 hours due to various types of receiver leaks. (This outage time can be determined from Table 2-3.) Receiver leaks occurred more often than in other systems because the receiver was exposed to a much more extreme operating environment. The pie chart provides the specific causes of these leaks. Tube leaks constitute 80% of the outages. It should be noted that Solar One routinely operates with some tube and valve leakage. We only included leakage events in our analysis if they were severe enough to cause a plant shutdown.

Figure 2-4 Plant Outages Caused by the Unavailability of the Turbine-Generator

The turbine-generator unavailability is dominated by a scheduled turbine inspection and overhaul that was performed during a 5-week period in February and March of 1985. SCE performs this activity at all its steam plants after the first year of operation and approximately every 4 years thereafter. This event is discussed in Chapter 3. The turbine-generator system experienced very few problems during the entire 3-year period. This was a pleasant surprise to the SCE maintenance staff. Prior to the power production phase, they were concerned that the daily thermal cycling experienced by the turbine would cause many problems.

Figure 2-5 Plant Outages Caused by Computer Failures

The heliostat array control computers (HAC) accounted for approximately one-half of the computer-related outages. HAC failures occurred regularly throughout the entire power production phase and the redundancy designed into the HAC system was generally not effective. Failure of the subsystem distributed process control (SDPC) for the receiver and the plant trip system (i.e., the programmable logic controllers contained within the interlock logic system and red-line unit) was also significant. Failures of these systems are discussed in Chapter 3.

Figure 2-6 Plant Outages Caused by Failures of Electrical Switchgear

Electrical switchgear outages were dominated by a failure of the heliostat interface switchgear that occurred in November of 1985. This event is described in Chapter 3. The remainder of the switchgear (4.16 KV, 480 V, and turbine) experienced only a few problems of short duration.

2.3 Component Failure/Outage Rates

With the help of the Rbase System V software, the outage events listed in Table 2-1 were grouped by systems, failure modes, and outage types. This allowed the calculation of component failure rates (Mean Failure Rate) and average outage times per event (Mean Time To Restore). The results of this analysis are presented in Table 2-3. The failure rates were determined by performing the following division:

$$\text{MFR} = \frac{\text{Number of Events}}{(\text{Fault Exposure Time})*(\text{Number of Components})}$$

The fault exposure times are based on an estimate of the number of hours a system was operating when the plant was either attached to the utility grid or charging storage. These estimates are listed in Table 2-4. The average outage times were determined by performing the following division:

$$\text{MTTR} = \frac{\text{Total Outage Hours}}{\text{Number of Events}}$$

The MFR and MTTR parameters are the required inputs to reliability analysis codes such as UNIRAM (EPRI 1985). We plan to use these values in the reliability improvement studies described in Chapter 1.

It should be noted that with the exception of the control systems, little redundancy exists within the power-production systems at Solar One. This facilitated the calculation of the failure rates since, in general, we did not need to consider the reliability of a redundant component/system.

It is important that the reader understand where redundancy existed at Solar One to properly extrapolate the system failure rates presented in Table 2-3 to other future system designs. For example, if system A at Solar One had redundant equipment, this system should have a lower failure rate than a similar system A at another plant that did not contain redundancy. The more important redundancies are listed below. The reliability block diagrams presented in Nagel (1986) also point out where redundancy exists.

1. There were two redundant HAC computers, with redundant data highways to the collector field, but computer interface problems caused automatic backup to be very unreliable. See discussion in Chapter 4.
2. There were main and backup power supplies to the computers and control systems. They were reliable except for the receiver control, since it was not attached to the uninterruptible power supply. This problem is discussed in Chapter 3.
3. Each of the subsystem distributed process control systems employed redundant data highways to the multivariable control units (MVCU) located at the remote stations. The data highways performed reliably.
4. Each of the 21 MVCUs located at the remote stations had redundant analog control channels to each process controller for bumpless transfer. This feature performed reliably.
5. The programmable logic controllers contained within the plant trip system contained redundant data highways and trip logic. This feature performed reliably.
6. The thermal storage system contained redundant charging trains and redundant extraction trains. Failure of redundant trains occurred infrequently.

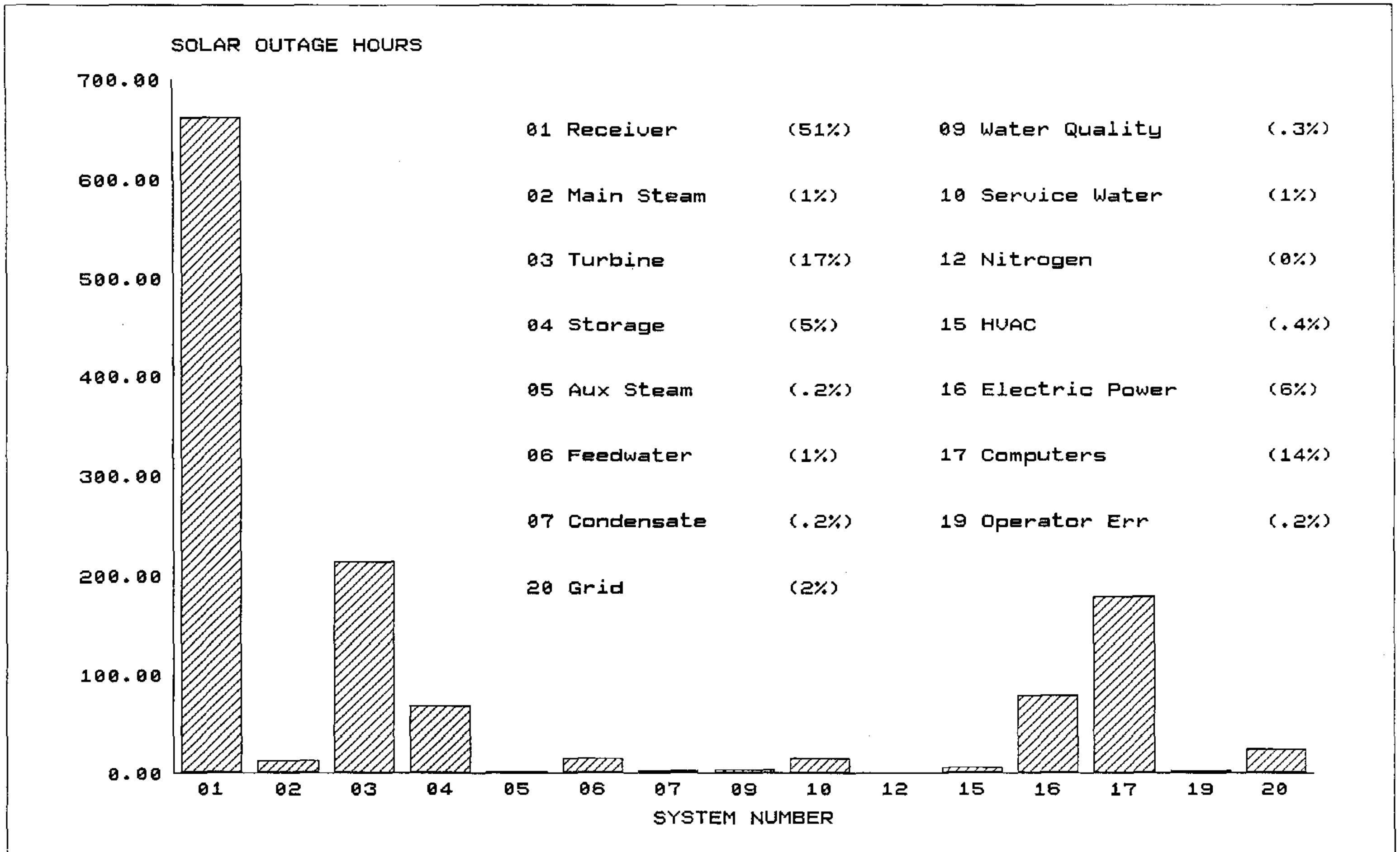


Figure 2-1 Plant Outages by System

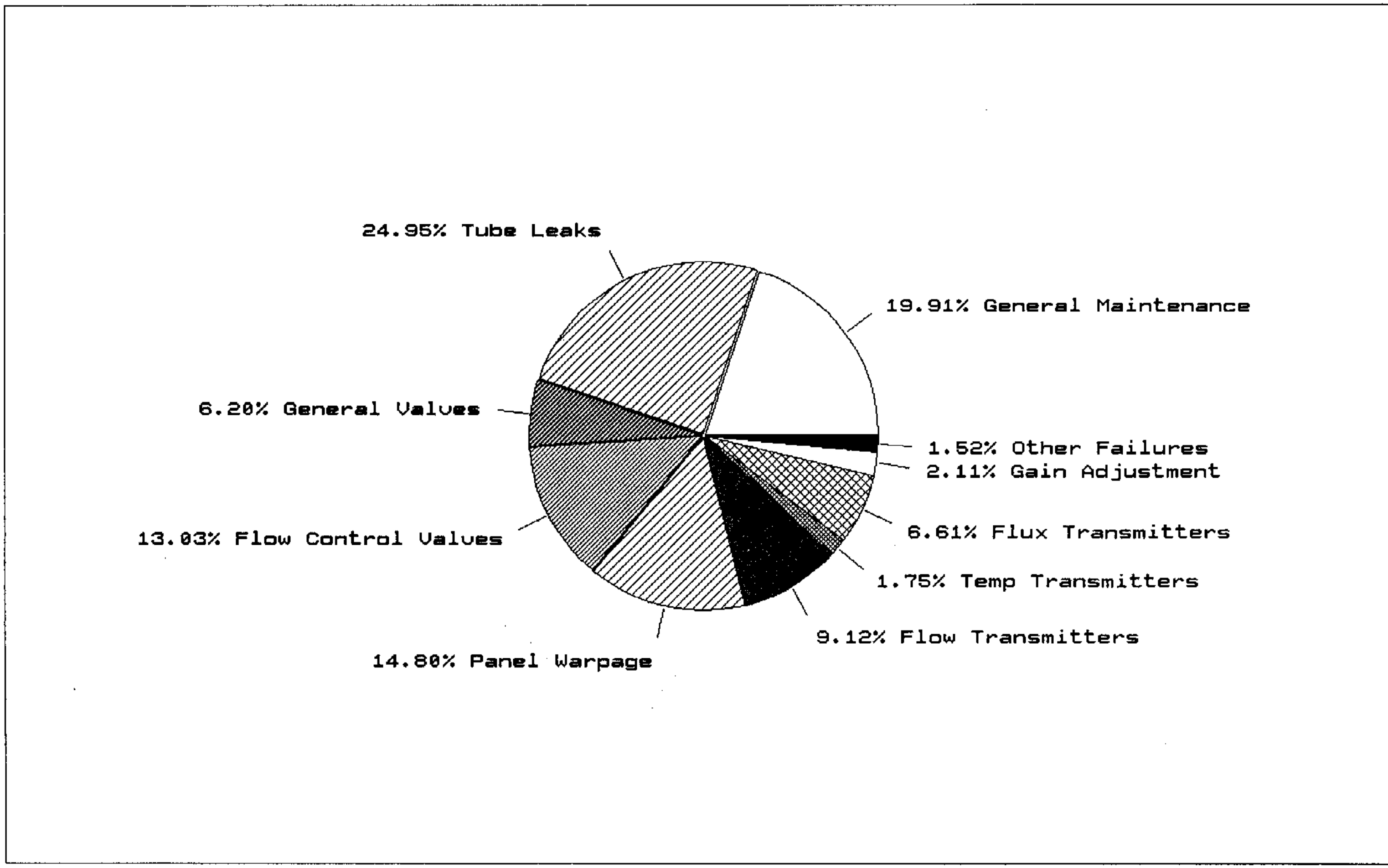


Figure 2-2 Plant Outages Caused by Receiver Problems

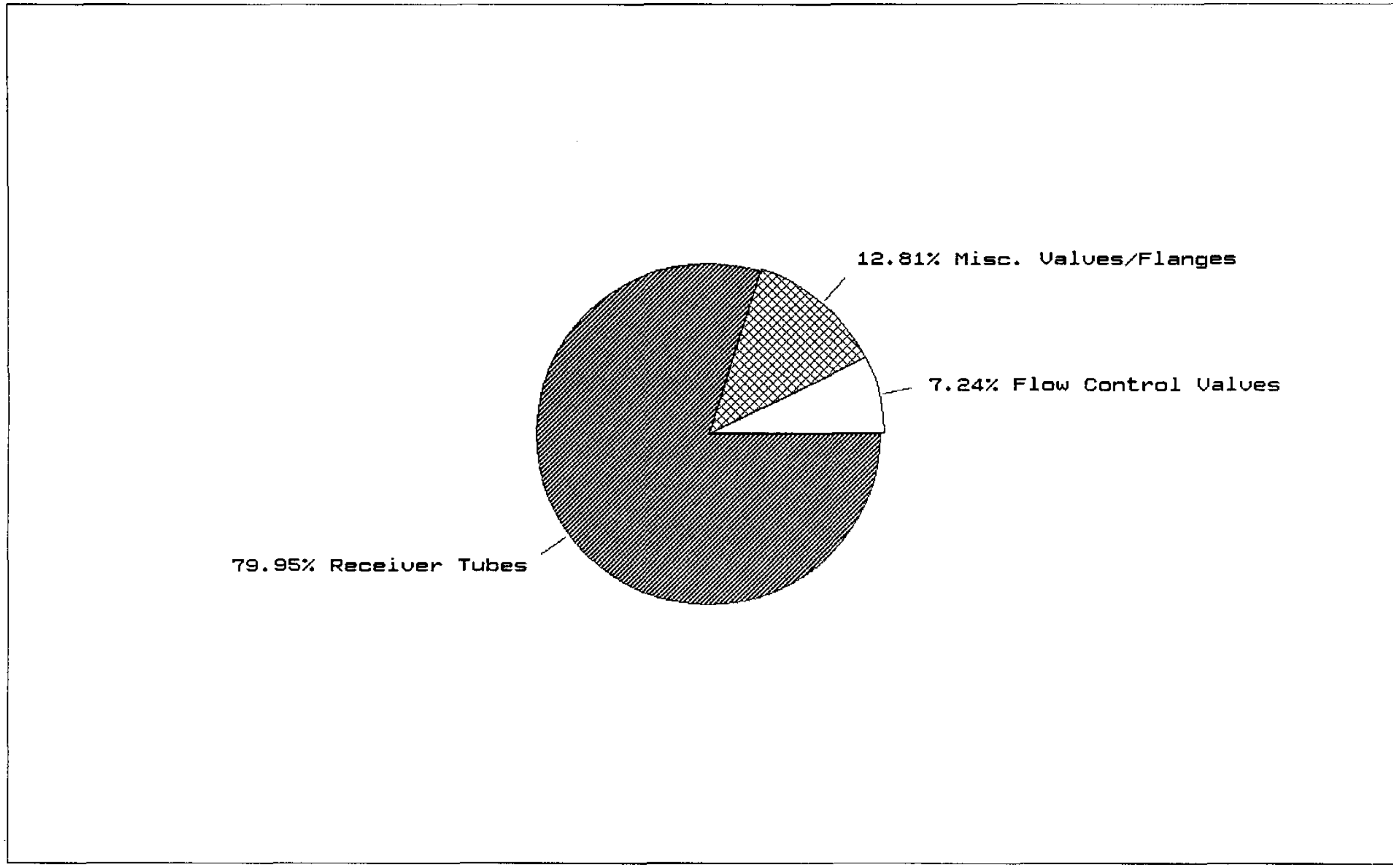


Figure 2-3 Plant Outages Caused by Receiver Leaks

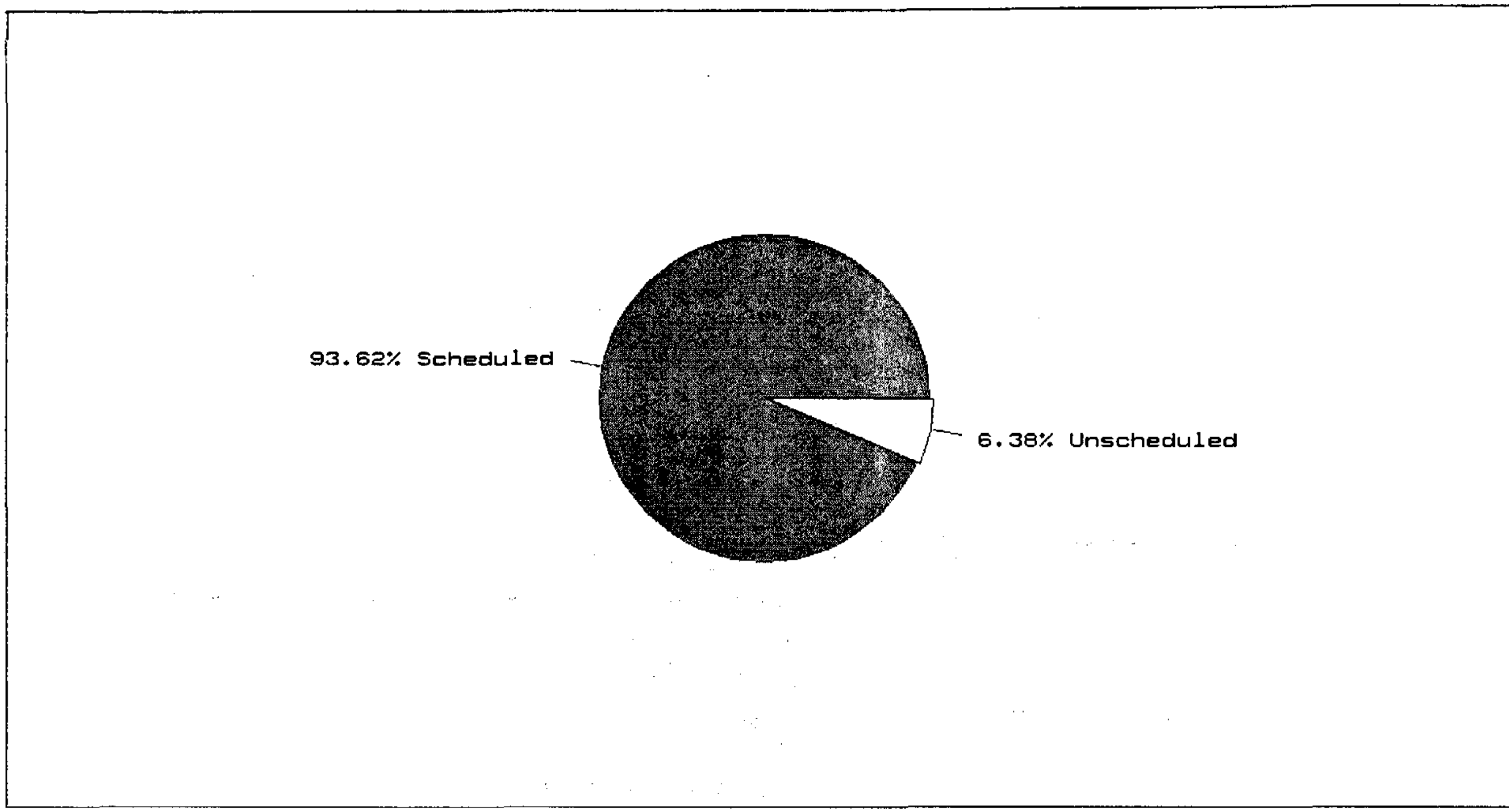


Figure 2-4 Plant Outages Caused by the Unavailability of the Turbine-Generator

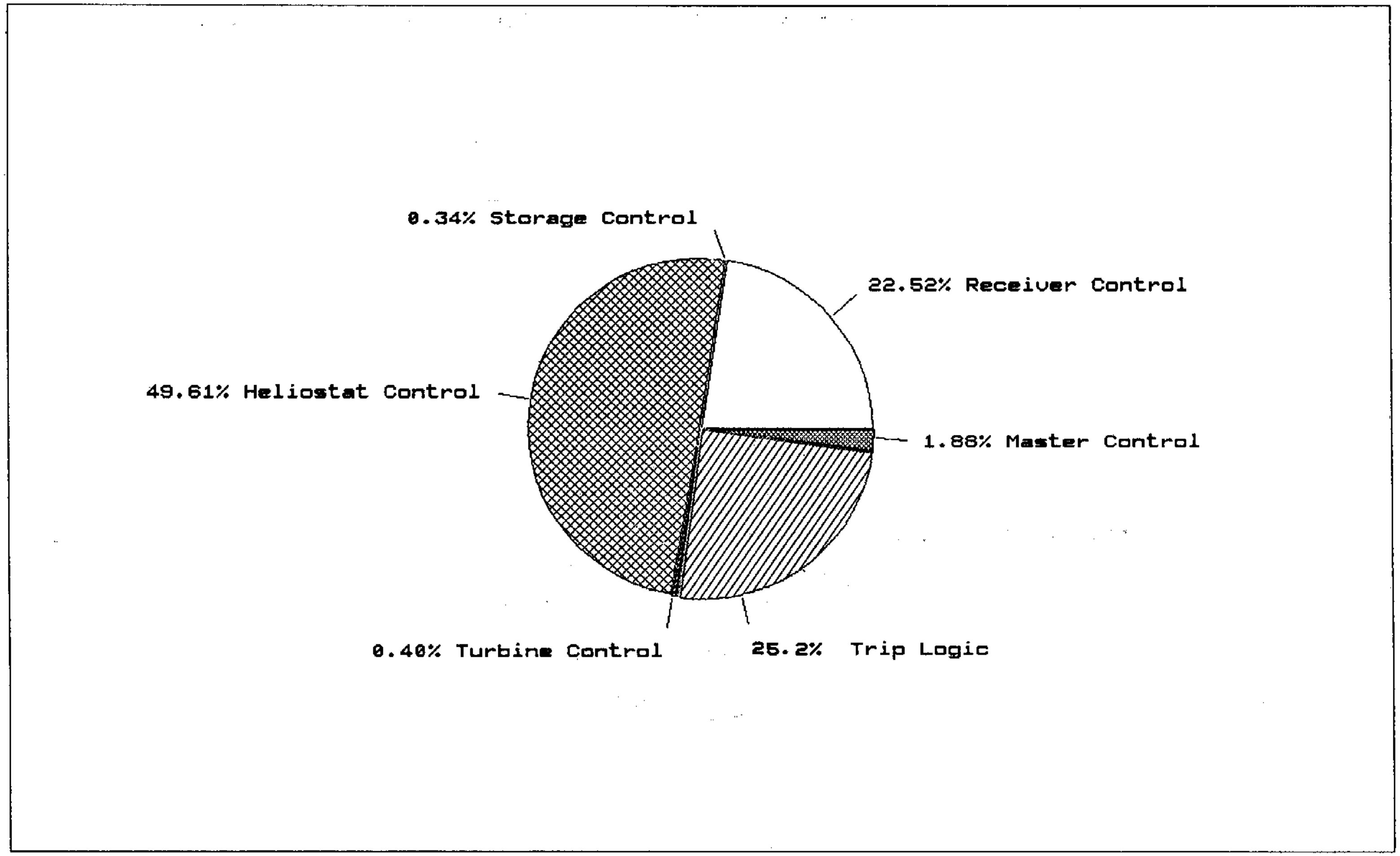


Figure 2-5 Plant Outages Caused by Computer Failures

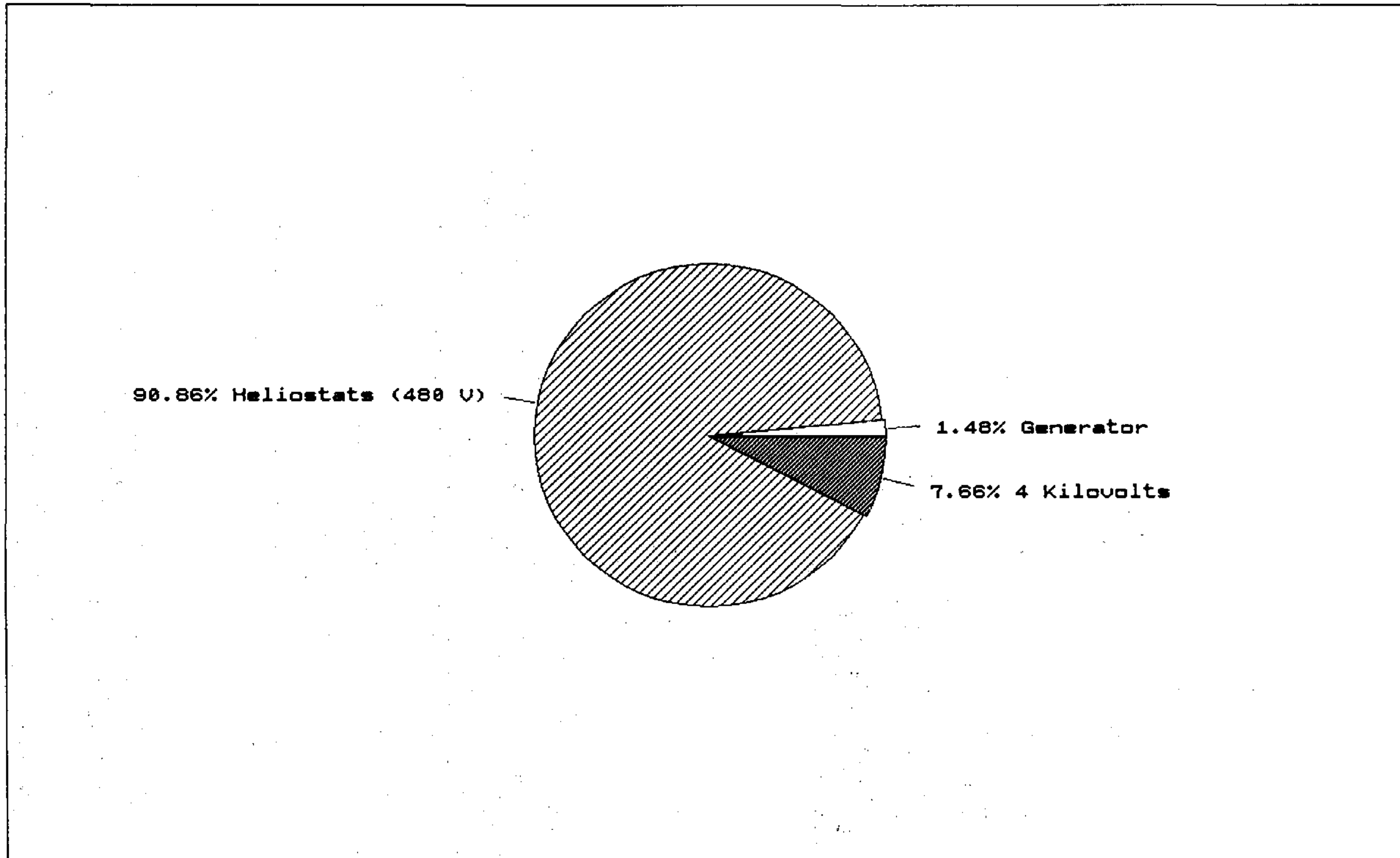


Figure 2-6 Plant Outages Caused by Failures of Electrical Switchgear

VENT	DATE	SYSTEM	OUTAGE TYPE	TOTAL HRS	SOLAR HRS	OUT CATEGORY	NOTES	
1	840803	RECEIVER	U	2.38	2.38	fcvvfa	TEMPERATURE CONTROL VALVE PANEL 11	MALFUNCTIONED
2	840803	RECEIVER	U	2.38	2.38	fcvvlk	TEMPERATURE CONTROL VALVE PANEL 13	LEAK
3	840811	RECEIVER	U	9.	9.	fcvvfa	TEMPERATURE CONTROL VALVE PANEL 11	PROBLEMS
4	840821	HVAC	U	5.77	5.77	rbunfa	AIR CONDITIONING UNIT IN REMOTE STATION #1	OVERHEATING
5	840910	ELEC POWER	S	1.4	0.	4kswgr	4 kV BREAKER	ROUTINES
6	840910	RECEIVER	S	1.4	0.	systgr	GENERAL RECEIVER REPAIRS	
7	840910	COMPUTERS	S	1.4	0.	systgr	COMPUTER ?	PROGRAMMING
8	840911	RECEIVER	S	4.17	0.	systgr	DYE PENETRATION	CHECKS
9	840912	RECEIVER	U	4.13	4.13	floxfa	RECEIVER PANEL CONTROLS PANEL 21	
10	840913	COMPUTERS	S	2.07	2.07	ocscgr	OPERATIONAL CONTROL SYSTEM	DISK DRIVE ALIGNMENT AND REPAIRS WILL CONTINUE BY CDC REP.
11	840913	ELEC POWER	S	2.07	2.07	4kswgr	4kV BREAKER	SERVICING
12	840913	RECEIVER	S	2.07	2.07	systgr	RECEIVER ABSORPTIVITY	TESTING CONTINUES
13	840914	RECEIVER	S	3.6	3.6	systgr	RECEIVER	LEAK INSPECTION
14	840914	ELEC POWER	S	3.6	3.6	4kswgr	4 kV AUXILIARY POWER	TRANSFER FROM BACKUP TO NORMAL FEED
15	840914	COMPUTERS	S	3.6	3.6	haccgr	HAC ERIN	LOOSE CABLE FROM PRINTER TO PERIPHERAL CABINET CAUSED FAILOVER
16	840928	RECEIVER	U	3.43	3.43	sdpcre	RECEIVER PANEL 16 AND 17	NOT RESPONDING NORMALLY·
17	841005	RECEIVER	U	7.25	7.25	fcvvfa	RECEIVER PANEL 17 FLOW CONTROLLER	
18	841008	SERV WATER	U	5.82	5.82	systlk	RUPTURED WELL LINE	BROKEN - CAUSED BY AGRICULTURAL WORK BEING PERFORMED
18	841009	SERV WATER	U	9.9	9.9	systlk	RUPTURED WELL LINE	REPAIRED
20	841010	RECEIVER	U	5.08	5.08	pdvvfa	DRAIN VALVE SOLENOID ON RECVR PREHEAT PANEL 3	FAILED AND REPLACED
21	841015	RECEIVER	S	3.82	3.82	gevvfa	AIR FILTER ON AOV2902	REPLACED
22	841017	CONDENSATE	U	1.43	1.43	condlk	WATER BOX VENT LINE ON EAST SIDE OF CONDENSER	BROKE OFF DURING WATER BOX VENTING
23	841030	COMPUTERS	U	8.12	8.12	haccfa	HELIOSTAT ARRAY CONTROLLER	PROB TRACED TO WRITTEN OVER OR DELETED INFO IN WINTER WIRE WALKS
24	841031	RECEIVER	U	9.12	9.12	floxfa	FLOWMETER PANEL 7	BAD - INSTALLED NEW ONE
25	841101	COMPUTERS	U	2.27	2.27	haccfa	LOST THE HAC	REBOOTED
26	841108	ELEC POWER	S	4.08	0.	tgbrfa	GENERATOR FIELD BREAKER	CLEANED AND LUBRICATED
27	841120	OPERATOR ERR	U	1.63	1.63	systfa	TRIP	OCCURRED WHEN 33kV LINE WAS REMOVED FROM SERVICE
28	841125	TURBINE	U	0.33	0.33	tanklk	LUBE OIL TO TURBINE GENERATOR	LOW
29	841129	COMPUTERS	U	0.5	0.5	ocscfa	RECEIVER TRIP	FALSE ALARM FROM OCS CONTRIBUTED TO TRIP
30	841205	TURBINE	U	8.27	0.	systlk	RUPTURE DIAPHGRAM	PULLING VACUUM ON THE CONDENSER FIXED LEAK ON RUPTURE DIAPHGRAM
31	841206	CONDENSATE	U	1.76	1.76	dminlk	INLINE DEMINERALIZER	AIR LEAKS
32	841206	TURBINE	U	1.76	1.76	systlk	BROKEN SIGHT GLASS ON THE TURBINE #2 BEARING	REPLACED
33	841225	ELEC POWER	U	1.18	1.18	tgbrfa	GENERATOR BREAKER	WOULD NOT CLOSE
34	841229	STORAGE	U	0.85	0.85	systfa	CHARGING AND EXTRACTION SYSTEM TRIPS	HIGH TSS FLASH TANK LEVEL
35	850101	COMPUTERS	U	2.24	2.24	haccfa	HAC	FAILURE
36	850101	COMPUTERS	U	2.24	2.24	tripfa	ILS TRIP	INTERLOCK LOGIC SYSTEM GLITCH
37	850103	RECEIVER	S	2.52	2.52	systin	RECEIVER PANEL INSPECTION	
38	850116	RECEIVER	U	8.42	8.42	fcvvfa	VALVE POSITIONER ON RECEIVER PANEL 21	TROUBLE
39	850131	RECEIVER	U	8.18	8.18	sdpcre	RECEIVER TEMPERATURE CONTROL VALVES	TOGGLING OUT OF CONTROL-reclass from revcfa
40	850201	RECEIVER	U	2.18	1.18	fcvvfa	PANEL 21 TEMPERATURE CONTROL VALVE	NOT ABLE TO CONTROL TEMP DUE TO CONTROLLER CALIBRATION PROBLEMS-recla
41	850204	RECEIVER	S	1.57	0.	systgr	JIB CRANE MODIFICATION	WILL INSTALL NEW MOTOR BRAKE
42	850207	RECEIVER	U	2.48	2.48	floxfa	RECEIVER PANEL 5 FLOWMETER	PROBLEM FLOWMETER WAS CHANGED OUT WITH NEW 14GPM
43	850207	COMPUTERS	U	2.48	2.48	haccfa	PRIME HAC LOCKED UP	REBOOTED TWICE
44	850208	NITROGEN	U	3.47	0.	systfa	PREHEAT PANEL NITROGEN SUPPLY SOLENOID VALVE	NOT OPERATING PROPERLY
45	850210	TURBINE	S	9.12	9.12	systgr	TURBINE OVERHAUL	
45	850211	TURBINE	S	9.15	9.15	systgr	TURBINE OVERHAUL	
45	850212	TURBINE	S	9.18	9.18	systgr	TURBINE OVERHAUL	
45	850213	TURBINE	S	9.22	9.22	systgr	TURBINE OVERHAUL	
45	850214	TURBINE	S	9.25	9.25	systgr	TURBINE OVERHAUL	
45	850215	TURBINE	S	9.28	9.28	systgr	TURBINE OVERHAUL	
45	850216	TURBINE	S	9.33	2.66	systgr	TURBINE OVERHAUL	
45	850217	TURBINE	S	9.35	0.	systgr	TURBINE OVERHAUL	
45	850218	TURBINE	S	9.38	0.	systgr	TURBINE OVERHAUL	
45	850219	TURBINE	S	9.42	0.	systgr	TURBINE OVERHAUL	
45	850220	TURBINE	S	9.45	0.	systgr	TURBINE OVERHAUL	
45	850221	TURBINE	S	9.48	9.48	systgr	TURBINE OVERHAUL	
45	850222	TURBINE	S	9.52	9.52	systgr	TURBINE OVERHAUL	
45	850223	TURBINE	S	9.57	9.57	systgr	TURBINE OVERHAUL	
45	850224	TURBINE	S	9.6	9.6	systgr	TURBINE OVERHAUL	
45	850225	TURBINE	S	9.63	9.63	systgr	TURBINE OVERHAUL	
45	850226	TURBINE	S	9.67	9.67	systgr	TURBINE OVERHAUL	
45	850227	TURBINE	S	9.7	7.45	systgr	TURBINE OVERHAUL	
45	850228	TURBINE	S	9.75	9.75	systgr	TURBINE OVERHAUL	
45	850301	TURBINE	S	9.78	8.15	systgr	TURBINE OVERHAUL	
45	850302	TURBINE	S	9.83	0.	systgr	TURBINE OVERHAUL	
45	850303	TURBINE	S	9.88	9.88	systgr	TURBINE OVERHAUL	
45	850304	TURBINE	S	9.92	9.92	systgr	TURBINE OVERHAUL	
45	850305	TURBINE	S	9.95	0.	systgr	TURBINE OVERHAUL	
45	850306	TURBINE	S	10.	10.	systgr	TURBINE OVERHAUL	
45	850307	TURBINE	S	10.03	0.	systgr	TURBINE OVERHAUL	
45	850308	TURBINE	S	10.07	0.	systgr	TURBINE OVERHAUL	
45	850309	TURBINE	S	10.1	6.23	systgr	TURBINE OVERHAUL	
45-	850310	TURBINE	S	10.13	0.	systgr	TURBINE OVERHAUL	
45	850311	TURBINE	S	10.17	3.14	systgr	TURBINE OVERHAUL	
45	850312	TURBINE	S	10.22	10.22	systgr	TURBINE OVERHAUL	
45	850313	TURBINE	S	4.47	4.47	systgr	TURBINE TEST	
45	850314	TURBINE	S	3.02	0.95	systgr	TURBINE TEST	
45	850315	TURBINE	S	10.32	0.	systgr	TURBINE TEST	
46	850317	RECEIVER	U	8.75	0.	floxfa	RECEIVER PANEL 5 FLOWMETER	WORK ON PROBLEM, CHANGED OUT FLOWMETER
47	850321	RECEIVER	U	1.72	1.72	floxfa	RECEIVER PANEL 20 TEMPERATURE CONTROL	PROBLEM EXPERIENCED WITH FLOW (DEBRIS LODGED IN FLOW TRANSMITTER)

Table 2-1 Outage Data Base

48	850322	RECEIVER	U	6.68	6.68	floxfa	PANEL 21	GREAT DIFFICULTY CONTROLLING TEMPERATURE, FLOWMETER REPLACED
49	850324	TURBINE	U	2.27	2.27	ehculk	TURBINE DEVELOPED ELECTROHYDRAULIC FLUID LEAK	AT THE MAIN STEAM CONTROL VALVE SEROO MECHANISM
50	850329	TURBINE	U	1.63	1.63	tanklk	ELECTROHYDRAULIC FLUID LEAK	REPAIRED AT THE V-1 CONTROL VALVE ACTUATOR RECIRCULATION LINE
51	850330	RECEIVER	U	5.83	5.83	floxfa	RECEIVER PANEL NUMBER 5 FLOWMETER	FAILED
52	850401	RECEIVER	U	4.35	4.35	floxfa	RECEIVER PANEL NUMBER 4 FLOWMETER	INDICATING A CONSTANT 4700 LB/HR FLOW
53	850402	RECEIVER	U	2.93	2.93	gevvlk	RECEIVER PANEL 11 AND 15 VENT VALV	PACKING LEAKS REPAIRED
54	850406	COMPUTERS	U	0.7	0.7	haccfa	HELIOSTAT ARRAY CONTROLLER COMMUNICATION	LINES 7&8 FAILOVER DURING UNSTOWING OF THE HELIOSTAT FIELD
55	850416	RECEIVER	U	1.92	0.	fluxfa	RECEIVER PANEL 21	LEAKS, FILTER HOUSING GASKETS REPLACED & FLUX SENSOR "B" REPLACED
56	850416	FEEDWATER	U	1.92	0.	pumplk	RECEIVER FEEDWATER PUMP	OIL LEAKS
57	850416	RECEIVER	U	1.92	0.	tubelk	RECEIVER PANEL 16	LEAKS, FILTER HOUSING GASKETS REPLACED
58	850421	COMPUTERS	U	0.67	0.67	ocscfa	RECEIVER PANEL 21	HIGH TEMPERATURE TRIP·
59	850506	RECEIVER	U	3.47	3.47	fluxfa	RECEIVER PANEL 21	TEMPERATURE CONTROL PROBLEMS
60	850511	COMPUTERS	U	5.45	5.45	haccfa	HAC ERRORS TWO TRIPS	PROB THOUGHT RESULTED FROM THE HAC CONTROLLER & ITS TIME SIGNAL
60	850512	COMPUTERS	U	0.28	0.28	haccfa	HAC TRIPPED ON LOW LOAD	PROB OCCURRED AFTER HAC WAS ASKED THE TIME
61	850515	RECEIVER	U	3.77	3.77	fluxfa	RECEIVER PANEL 9	HIGH PANEL TEMPERATURE·
62	850516	TURBINE	U	1.23	1.23	tanklk	ELECTROHYDRAULIC FLUID LEAK DISCOVERED	ON TURBINE ADMISSION STEAM CONTROL VALVE EH RETURN BYPASS LINE
63	850525	COMPUTERS	U	7.2	7.2	sdpcre	RECEIVER COMPUTER COMMUNICATION MODULE	LOSS OF COMMUNICATIONS·
63	850526	COMPUTERS	U	0.8	0.8	sdpcre	RECEIVER COMPUTER COMMUNICATION MODULE	LOSS OF COMMUNICATIONS·
64	850529	RECEIVER	U	4.28	0.	gevvfa	RECEIVER OUTLET TO THE FLASH TANK	OPERATING PISTON PROBLEM
65	850529	RECEIVER	U	4.28	0.	gevvfa	MOISTURE SEPARATOR DRAIN	WOULD NOT COME OPEN BECAUSE OF INSTRUMENT AIR LINE WAS BROKEN
66	850604	RECEIVER	U	4.17	4.17	fluxfa	UNIT TRIP	CAUSED BY HIGH TEMP ON PANEL 10, FLUX SENSOR FAILED
67	850609	COMPUTERS	U	0.45	0.45	haccfa	COMMUNICATIONS LOST DURING UNSTOWING OF FIELD	ISC LOADED UP (TIK ERROR)
68	850612	COMPUTERS	U	0.92	0.92	haccfa	ISC LOCKED UP	REBOOTED TWICE
69	850614	FEEDWATER	U	3.57	2.49	pumpfa	UNIT TRIPPED OFFLINE ON RECV HI INLET PRESSURE	CAUSED BY ERRONEOUS SPEED INDICATION ON RECEIVER FEEDPUMP
70	850616	ELEC POWER	U	0.42	0.42	4kswfa	HAC PROBLEMS CAUSED BY LOW 4kV VOLTAGE	BOTH HACS REBOOTED
71	850617	MAIN STEAM	U	1.17	1.17	fcvvfa	TEMPERATURE SWITCH 1002	HI ERRONEOUS TRIP SIGNAL PREVENTED STEAM DUMP VALVE TO BE RESET
72	850618	OPERATOR ERR	U	0.8	0.8	systfa	UNIT TRIP	OPERATOR ERROR
73	850619	RECEIVER	U	0.21	0.21	gevvfa	MOISTURE SEPARATOR DRAIN VALVE	ALSO ACTING UP
74	850619	RECEIVER	U	0.21	0.21	gevvfa	RECEIVER FLASH TANK NITROGEN INLET SOLENOID VV	EXPERIENCED PROBLEMS
75	850625	RECEIVER	U	4.	4.	floxfa	RECEIVER PANEL 21	FLOW CONTROL VALVE NOT CONTROLLING·
76	850625	COMPUTERS	U	4.	4.	haccfa	HELIOSTAT ARRAY CONTROLLER	SEVERAL LINE FAILOVERS
77	850625	COMPUTERS	U	4.	4.	haccfa	ISC CONSOLE	LOST COMMUNICATION WITH HAC
78	850702	TURBINE	U	0.73	0.73	systfa	TURBINE	PROB ENCOUNTERED WHILE TRANSITIONING TURB INTO PRESSURE CONTROL
79	850708	RECEIVER	U	5.03	5.03	fluxfa	RECEIVER TRIP	LOSS OF FLOW THROUGH PANEL 12, CHANGED "A" & "B" FLUX SENSORS
80	850709	RECEIVER	U	12.7	12.7	tubelk	RECEIVER PANEL 6,9,10	TUBE LEAK ON ROLLER ROW 6 BOTTOM WELD
81	850710	RECEIVER	U	0.7	0.7	fcvvlk	RECEIVER PANEL 5 TEMPERATURE CONTROL VALVE	PACKING LEAK
82	850710	RECEIVER	U	0.7	0.7	fcvvlk	RECEIVER PANEL 10 TEMPERATURE CONTROL VALVE	PACKING LEAK
83	850710	RECEIVER	U	0.7	0.7	fcvvlk	PANEL 18 TEMPERATURE CONTROL VALVE BONNET	LEAK OBSERVED
84	850710	RECEIVER	U	0.7	0.7	tubelk	RECEIVER PANEL 10 TUBE 70 INTERSTICE WELD	SLIGHT LEAK
85	850710	RECEIVER	U	0.7	0.7	fcvvlk	RECEIVER PANEL 4 TEMPERATURE CONTROL VALVE	PACKING LEAK
86	850712	RECEIVER	U	1.	1.	gevvfa	PREHEAT PRESSURE RELIEF VALVE	ADJUSTED THE PRESSURE SETPOINT
87	850715	RECEIVER	U	12.62	0.	tubelk	PANEL 6,9,10	TUBE LEAK REPAIR
87	850716	RECEIVER	U	12.6	3.	tubelk	PANEL 6,9,10	TUBE LEAK REPAIR CONTINUES
87	850717	RECEIVER	U	12.57	0.	tubelk	PANEL 6,9,10	TUBE LEAK REPAIR COMPLETED
88	850720	RECEIVER	U	6.04	6.04	fluxfa	RECEIVER PANEL 9	LOSS OF A & B FLUX SENSORS, C HAD ERRATIC READINGS
89	850720	RECEIVER	U	1.	1.	sdpcre	RECEIVER PANEL 6	WOULD NOT GO INTO TEMP CONTROL AUTOMATICALLY DUE TO SCRAMB TAG
90	850723	RECEIVER	U	1.29	1.29	systca	UNIT TRIP 1ST TIME	ON PANEL 12 AT HIGH TEMPERATURE
91	850723	FEEDWATER	U	1.29	1.29	pumpfa	UNIT TRIP AGAIN RELATED TO FEED PUMP	ON NO LOAD TRIP
92	850730	GRID	S	12.38	12.38	systfa	BUG 33kV TRANSMISSION LINE	RELOCATED AT GALE SUBSTATION
93	850731	RECEIVER	U	2.5	2.5	sdpcre	PANEL 4	TEMPERATURE CONTROL PROBLEM
94	850805	RECEIVER	U	3.	3.	flukfa	PANEL 21	TEMPERATURE CONTROL PROBLEM·
95	850809	MAIN STEAM	U	5.58	5.58	fcvvfa	RECEIVER RED LINE UNIT TRIP	LIMIT SWITCH (UV2905) NOT CLOSED & FULL OF WATER, SWITCH REPLACED
96	850812	RECEIVER	U	1.1	1.1	fcvvlk	BOILER PANEL 21	PACKING ADDED
97	850816	RECEIVER	U	1.77	1.77	fcvvlk	TCV ON PANEL 2,3 - VENT VALVE 8 PACKING LEAK	PACKING LEAK REPAIRED
98	850819	RECEIVER	U	0.48	0.48	gevvlk	VENT VALVE PANEL 10	PACKING ADDED
99	850820	GRID	U	7.42	7.42	systfa	LOST TRANSMISSION LINE CAUSED BY SWITCHING ERROR	AT GALE SUBSTATION - MINOR DAMAGE TO RECEIVER
100	850827	COMPUTERS	U	0.5	0.5	sdpcre	OCS ERRONEOUS FLOW INDICATED THROUGH PREHEAT PANE	LS REBUILT #1 PREHEAT PANEL (TAG #FI2230
101	850828	COMPUTERS	U	0.68	0.68	sdpctg	UNIT TRIP ON FALSE INDICATION OF LOW ENTHALPY	TRIP CAUSED BY LOSS OF DATA ON MVCU 4-2.
102	850909	RECEIVER	S	4.32	4.32	systin	RECEIVER JIB CRANE	INSPECTED AND TESTED
103	850914	RECEIVER	U	0.52	0.52	fluxfa	PANEL 11 AND 15 TEMP CONTROL PROBLEM	ADJUSTED FLUX GAINS (K1) DUE TO CHANGE OUT OF FLUX SENSOR
104	850920	RECEIVER	U	0.22	0.22	systab	PROBLEM WITH HIGH PREHEAT PANEL FLOW	RESOLVED BY REVENTING THE RECEIVER PANELS
105	850923	GRID	S	7.15	1.58	systfa	LUGO LINE OUTAGE	AT GALE SUBSTATION
106	851001	RECEIVER	U	3.75	3.75	fluxfa	RECEIVER PANEL 13-FLUX SENSOR	CAUSED A RECEIVER AND TURBINE TRIP DUE TO HIGH TEMPERATURE
107	851016	GRID	U	0.2	0.2	systfa	LUZ 33kV LINE	WORK PERFORMED ON LINE
108	851019	GRID	S	2.12	2.12	systfa	GALE SUBSTATION LUZ 33kV LINE	TRIP AND DUCTOR TESTS
109	851026	RECEIVER	U	1.	1.	systca	PANEL 21 TEMPERATURE CONTROL VALVE	CYCLING PROBLEM·
110	851030	RECEIVER	U	1.25	1.25	sdpcre	RECEIVER TRIPPED HIGH RECEIVER INLET PRESSURE	RECEIVER RESET AND REINITIATED
111	851031	COMPUTERS	U	2.23	2.23	haccfa	TRIPPED OFFLINE, TURBINE GENERATOR LOW LOAD	McDOUGAL "MASTER" CLEAR SWITCH WAS THE CAUSE
112	851101	GRID	S	1.6	1.6	systfa	GALE SUBSTATION LUZ 33kV LINE	WORK BEING PERFORMED
113	851111	ELEC POWER	U	7.67	0.	hiswfa	ENTIRE HELIOSTAT FIELD POWER LOSS	CAUSED BY LOOSE 4kV CONNECTORS
113	851112	ELEC POWER	U	7.67	6.92	hiswfa	ENTIRE HELIOSTAT FIELD POWER LOSS	CAUSED BY LOOSE 4kV CONNECTORS
113	851113	ELEC POWER	U	7.65	7.65	hiswfa	ENTIRE HELIOSTAT FIELD POWER LOSS	CAUSED BY LOOSE 4kV CONNECTORS
113	851114	ELEC POWER	U	7.63	7.63	hiswfa	ENTIRE HELIOSTAT FIELD POWER LOSS	CAUSED BY LOOSE 4kV CONNECTORS
113	851115	ELEC POWER	U	7.62	7.62	hiswfa	ENTIRE HELIOSTAT FIELD POWER LOSS	CAUSED BY LOOSE 4kV CONNECTORS
113	851116	ELEC POWER	U	7.62	7.62	hiswfa	ENTIRE HELIOSTAT FIELD POWER LOSS	CAUSED BY LOOSE 4kV CONNECTORS
113	851117	ELEC POWER	U	7.6	7.6	hiswfa	ENTIRE HELIOSTAT FIELD POWER LOSS	CAUSED BY LOOSE 4kV CONNECTORS
113	851118	ELEC POWER	U	7.58	7.58	hiswfa	ENTIRE HELIOSTAT FIELD POWER LOSS	CAUSED BY LOOSE 4kV CONNECTORS
113	851119	ELEC POWER	U	7.58	7.58	hiswfa	ENTIRE HELIOSTAT FIELD POWER LOSS	CAUSED BY LOOSE 4kV CONNECTORS
113	851120	ELEC POWER	U	5.08	5.08	hiswfa	ENTIRE HELIOSTAT FIELD POWER LOSS	CAUSED BY LOOSE 4kV CONNECTORS
114	851202	RECEIVER	S	7.02	0.	systgr	SHIELDING	RECEIVER REPAIRS

114	851203	RECEIVER	S	7.02	7.02	systgr	SHIELDING	RECEIVER REPAIRS
114	851204	RECEIVER	S	7.02	7.02	systgr	ROLLERS, LEAKS, PAINT	RECEIVER REPAIRS
114	851205	RECEIVER	S	7.02	3.02	systgr	ROLLERS, LEAKS, PAINT	RECEIVER REPAIRS
114	851206	RECEIVER	S	7.02	7.02	systgr	ROLLERS, LEAKS, PAINT	RECEIVER REPAIRS
114	851207	RECEIVER	S	7.02	5.52	systgr	ROLLERS, LEAKS, PAINT	RECEIVER REPAIRS
114	851208	RECEIVER	S	7.02	7.02	systgr	ROLLERS, LEAKS, PAINT	RECEIVER REPAIRS
114	851209	RECEIVER	S	7.02	7.02	systgr	ROLLERS, LEAKS, PAINT	RECEIVER REPAIRS
114	851210	RECEIVER	S	7.02	1.25	systgr	ROLLERS, LEAKS, PAINT	RECEIVER REPAIRS
114	851211	RECEIVER	S	7.02	0.	systgr	ROLLERS, LEAKS, PAINT	RECEIVER REPAIRS
114	851212	RECEIVER	S	7.02	7.02	systgr	ROLLERS, LEAKS, PAINT	RECEIVER REPAIRS
114	851213	RECEIVER	S	7.03	7.03	systgr	ROLLERS, LEAKS, PAINT	RECEIVER REPAIRS
114	851214	RECEIVER	S	7.03	7.03	systgr	ROLLERS, LEAKS, PAINT	RECEIVER REPAIRS
114	851215	RECEIVER	S	7.03	0.	systgr	?? REPAIRS	RECEIVER REPAIRS
114	851216	RECEIVER	S	7.05	7.05	systgr	?? REPAIRS	RECEIVER REPAIRS
114	851217	RECEIVER	S	7.05	7.05	systgr	?? REPAIRS	RECEIVER REPAIRS
115	851218	RECEIVER	U	1.07	1.07	unknfa	UNIT TRIP	PANEL 9 HIGH OUTLET TEMPERATURE.
116	851230	RECEIVER	U	3.1	0.	fcvvfa	UNIT TRIP	PANEL 9 HIGH TEMPERATURE, VALVE POSITIONER FULL OF MOISTURE
117	860105	STORAGE	U	4.65	2.67	hxerlk	OIL SIDE RUPTURE DISK	RELIEVED ON CHARGING TRAIN NO. 2
118	860117	RECEIVER	U	5.5	5.5	temxfa	PANEL 9 TEMPERATURE TRIP	PANEL 9 SCU CARD & TEMPERATURE THERMOCOUPLE CHANGED.
119	860124	RECEIVER	U	1.96	1.96	temxfa	UNIT TRIP	PANEL 9 HIGH TEMPERATURE.
120	860124	COMPUTERS	U	1.96	1.96	haccfa	HAC PROBLEMS	HAC LOCKED UP DURING TRANSITION TO ALT 2
121	860128	RECEIVER	U	0.55	0.55	temxfa	PANEL 9 THERMOCOUPLE	STARTUP DELAYED TO WORK ON PNL 9 THERMOCOUPLE WIRING
122	860201	RECEIVER	U	2.56	2.56	fcvvfa	RECEIVER PANEL 5 TEMPERATURE CONTROL VALVE	FULL OF MOISTURE
123	860201	RECEIVER	U	2.56	2.56	floxfa	PANEL 16 FLOW TRANSMITTER	REPLACED LUG TO RESTORE CONTINUITY ON PWR SIDE OF BRIDGE CIRCUIT
124	860201	COMPUTERS	U	2.56	2.56	sdpcre	RECEIVER FEEDPUMP	FLOW CONTROL PROBLEMS
125	860205	COMPUTERS	U	4.95	4.95	sdpcre	UNIT TRIP	LOSS OF SUPERHEAT, FALSE INDICATION AS NO PROBLEMS FOUND.
126	860218	COMPUTERS	U	8.2	4.	tripfa	RECEIVER RED LINE UNIT FAILED POWER SUPPLY FAIL	PART IN RLU (CHIP) FAILED AND IS ON EXPEDITE ORDER
126	860219	COMPUTERS	U	8.22	0.	tripfa	RECEIVER RED LINE UNIT POWER SUPPLY CHIP	WAITING ON RLU CHIP TO ARRIVE TO REPAIR RLU
126	860220	COMPUTERS	U	8.23	3.73	tripfa	RECEIVER RED LINE UNIT POWER SUPPLY CHIP	REPLACED CIRCUIT CHIP AND A BATTERY, REPAIRS COMPLETED ON RLU
127	860314	COMPUTERS	U	5.27	5.27	haccfa	TWO TRIPS, HAC PROBLEMS	CAUSED BY HELIOS MOVING FROM TRACK OFF RECV SUSPECT ERIN PROBLEM
128	860322	RECEIVER	U	3.75	3.75	systab	RECEIVER TRIP	FLOW CONTROL.
129	860323	RECEIVER	U	0.03	0.03	sdpcre	RED LINE UNIT TRIP	HIGH FLASH TANK LEVEL
130	860324	STORAGE	U	0.7	0.7	unknfa	RED LINE UNIT TRIP	HIGH TSS SYSTEM PRESSURE
131	860325	RECEIVER	U	3.	3.	temxfa	PANEL 9 TEMPERATURE CONTROL VALVE	VV STICKING IN OPEN POSITION, STROKED VALVE (PER ONT POSS OP ERR)
132	860404	RECEIVER	U	9.35	9.35	gevvfa	LOW SUPERHEAT TEMPERATURE PROBLEM	DRIP LINE PLUGGAGE (FOUND LARGE AMOUNT SMALL DIAM METAL PELLETS)
133	860417	TURBINE	U	1.22	1.22	systfa	TURBINE SPEED LOAD CONTROL	SPEED LOAD CONTROL KNOB LOCKED UP
134	860419	STORAGE	U	1.38	1.38	fcvvfa	CHARGING STEAM INLET VALVE	VALVE INOPERATIVE SO PRODUCED POWER INSTEAD
135	860426	FEEDWATER	U	2.83	0.2	pumpfa	UNIT TRIP	LOW NET POSITIVE SUCTION HEAD ON RECEIVER FEEDPUMP
136	860506	STORAGE	U	5.05	5.05	prsxfa	THERMAL STORAGE RED LINE UNIT TRIP	DUE TO A FALSE INDICATION OF HIGH OIL DISCHARGE PRESSURE
137	860512	COMPUTERS	S	1.	1.	haccgr	WORK ON HAC SOFTWARE	BY ART IWAKI BEFORE HE LEAVES THE SOLAR PROGRAM
137	860513	COMPUTERS	S	0.88	0.88	haccgr	WORK ON HAC SOFTWARE CONTINUES	BY ART IWAKI BEFORE HE LEAVES THE SOLAR PROGRAM
137	860514	COMPUTERS	S	0.88	0.	haccgr	WORK ON HAC SOFTWARE CONTINUES	BY ART IWAKI BEFORE HE LEAVES THE SOLAR PROGRAM
138	860519	STORAGE	U	2.35	2.35	levxfa	RECEIVED TSS RLU ON HIGH FLASH TANK LEVEL	TRANSMITTER CALIBRATED
139	860606	RECEIVER	U	11.13	11.13	tubelk	RECEIVER TUBE LEAKS PANEL 9	REPAIR TUBE LEAKS ON UPPER EXPANSION GUIDE ATTACHMENT WELDS
139	860607	RECEIVER	U	11.15	11.15	tubelk	RECEIVER TUBE LEAKS PANEL 9	REPAIR TUBE LEAKS ON UPPER EXPANSION GUIDE ATTACHMENT WELDS
139	860608	RECEIVER	U	1.13	1.13	tubelk	RECEIVER TUBE LEAKS PANEL 10	REPAIR TUBE LEAKS ON UPPER EXPANSION GUIDE ATTACHMENT WELDS
139	860609	RECEIVER	U	11.17	11.17	tubelk	RECEIVER TUBE LEAKS PANEL 10	REPAIR TUBE LEAKS ON UPPER EXPANSION GUIDE ATTACHMENT WELDS
139	860610	RECEIVER	U	11.17	11.17	tubelk	RECEIVER TUBE LEAKS PANEL 12	REPAIR TUBE LEAKS ON UPPER EXPANSION GUIDE ATTACHMENT WELDS
139	860611	RECEIVER	U	11.18	11.18	tubelk	RECEIVER TUBE LEAKS PANEL 12	REPAIR TUBE LEAKS ON UPPER EXPANSION GUIDE ATTACHMENT WELDS
139	860612	RECEIVER	U	11.18	11.18	tubelk	RECEIVER TUBE LEAKS PANEL 14	REPAIR TUBE LEAKS ON UPPER EXPANSION GUIDE ATTACHMENT WELDS
139	860613	RECEIVER	U	11.18	11.18	tubelk	RECEIVER TUBE LEAKS PANEL 14	REPAIR TUBE LEAKS ON UPPER EXPANSION GUIDE ATTACHMENT WELDS
139	860614	RECEIVER	U	11.2	11.2	tubelk	RECEIVER TUBE LEAKS PANEL 16	REPAIR TUBE LEAKS ON UPPER EXPANSION GUIDE ATTACHMENT WELDS
139	860615	RECEIVER	U	11.2	11.2	tubelk	RECEIVER TUBE LEAKS PANEL 16	REPAIR TUBE LEAKS ON UPPER EXPANSION GUIDE ATTACHMENT WELDS
139	860616	RECEIVER	U	11.2	5.97	tubelk	RECEIVER TUBE LEAKS PANEL 17	REPAIR TUBE LEAKS ON UPPER EXPANSION GUIDE ATTACHMENT WELDS
140	860624	RECEIVER	U	4.52	3.4	prsxfa	RECEIVER OUTLET PRESSURE TRANSMITTER	BAD SCU CARD.
141	860624	COMPUTERS	U	4.52	3.4	haccfa	LOSS OF POWER IN THE COLLECTOR FIELD	REPLACED POWER SUPPLY IN McDOUGAL & ORDERED PHERIPHERAL SWITCH
142	860705	RECEIVER	U	2.22	0.	fluxfa	RECEIVER TRIP	HIGH TEMPERATURE ON RECEIVER PANEL 15 FLUX SENSOR
142	860706	RECEIVER	U	1.23	1.23	fluxfa	RECEIVER TRIP	FLUX SENSOR ON PANEL 15
143	860714	RECEIVER	S	10.2	0.	tubelk	RECEIVER PANEL TUBE LEAKS	FIX TUBE LEAKS, RECV STM DUMP VV & MEASURE RECV PNL ABSORPTIVITY
143	860715	RECEIVER	S	11.43	0.	tubelk	RECEIVER	REPAIRS CONTINUE
143	860716	RECEIVER	S	11.43	11.43	tubelk	RECEIVER	REPAIRS CONTINUE
144	860717	RECEIVER	S	11.42	11.42	gevvlk	RECEIVER	REPAIRS CONTINUE
145	860727	COMPUTERS	U	11.32	11.32	tripfa	RECEIVER TRIP	ON RLU TROUBLE ALARM QI6211, RLU REPLACED
146	860728	RECEIVER	U	1.8	1.8	systca	RECEIVER PANEL 8 FLOW CONTROL	CALIBRATED PANEL 8 SCU CARD & ADJUSTED FLOW BIAS "0"
147	860729	RECEIVER	U	7.18	7.18	fluxfa	TEMPERATURE CONTROL PROBLEM, RECEIVER PANEL 21	ASJUSTED FLOW BIAS AND FLUX GAIN.
148	860802	STORAGE	U	0.6	0.6	pumpfa	CHARGING OIL PUMP P302	FAILED TO START
149	860803	RECEIVER	U	0.52	0.52	sdpcre	UI7299 TOGGLES RECEIVER TEMPERATURE CONTROL VV	CLOSED ON PLANT SHUT-DOWN.
150	860808	RECEIVER	S	3.58	0.	tubelk	RECEIVER SHUT DOWN & HYDROSTATICALLY TESTED	BECAUSE OF EXCESSIVE LEAKAGE
151	860808	RECEIVER	U	4.6	4.6	gevvlk	REPLACED "A" FLUX SENSOR ON 15 AND B ON 18 15	
152	860810	STORAGE	U	9.75	5.63	fcvvfa	TSS CHARGING TRIP	DESUPERHEATER TEMPERATURE CONTROL VALVE LEAKING THROUGH
153	860812	STORAGE	U	0.6	0.6	sdpcst	TSS FLASH TANK PRESSURE	HIGH.
154	860821	RECEIVER	U	6.93	0.	floxfa	PANEL 5 FLOWMETER PROBLEMS	REPLACED PANEL 5 FLOWMETER
155	860822	RECEIVER	U	0.55	0.55	temxfa	RECEIVER PANEL 16	BAD THERMOCOUPLES
156	860825	FEEDWATER	U	2.45	2.45	pumpfa	RECEIVER HIGH PRESSURE TRIP	AFTER ADJUSTMENT OF RECEIVER FEEDPUMP SPEED SENSOR
157	860826	RECEIVER	S	8.5	0.	tubelk	RECEIVER VALVES AND MISCELLANEOUS MAINTENANCE	DUE TO OVERLAP WEATHER MAINT SCHEDULED
158	860829	COMPUTERS	U	1.65	1.65	sdpcre	RECEIVER PANEL 19	TEMPERATURE CONTROL PROBLEM DUE TO BECKMAN TROUBLES.
159	860830	STORAGE	U	10.45	10.45	tankfi	THERMAL STORAGE TANK	FIRE
159	860831	STORAGE	U	10.43	10.43	tankfi	THERMAL STORAGE TANK	PLANT IS OPERATIONAL BUT TSU TANK IS IN COOL DOWN STAGE
159	860901	STORAGE	U	10.42	10.42	tankfi	THERMAL STORAGE TANK	PLANT IS OPERATIONAL BUT TSU TANK IS IN COOL DOWN STAGE
159	860902	STORAGE	U	4.43	4.43	tankfi	THERMAL STORAGE TANK	PLANT IS OPERATIONAL BUT TSU TANK IS IN COOL DOWN STAGE

160	860910	TURBINE	S	1.98	1.98	pumpfa	WEST LUBE OIL PUMP P927	INSTALLED AFTER PUMP WAS REBUILT
161	860911	RECEIVER	S	2.9	0.	tubelk	RECEIVER LEAK REPAIRS	SCHEDULED BECAUSE OF WEATHER OUTAGE
162	860917	RECEIVER	U	7.53	7.03	gevvtk	WEATHER CLEARED SO OUTAGE CHANGED TO UNSCHEDULED	TO CONTINUE RECEIVER REPAIRS
163	860919	RECEIVER	U	6.63	6.63	fcvvfa	RECEIVER TRIP	HIGH INLET PRESSURE PANEL 18 FLOW CONTROL POSITIONER NOT WORKING
164	860922	RECEIVER	S	3.37	0.	tubelk	RECEIVER LEAK REPAIRS	DURING WEATHER OUTAGE
165	860928	RECEIVER	U	5.07	0.	fcvvfa	PANEL 8 TEMPERATURE CONTROL	PANEL 8 TEMPERATURE CONTROL VALVE POSITIONER REPLACED
166	861016	COMPUTERS	U	0.62	0.	sdpctg	BECKMAN EPGS RGP	REPLACED 32K MEMORY BOARD.
167	861020	RECEIVER	U	8.78	8.78	tubelk	TUBE LEAKS ON PANELS 9 AND 11	REPAIRED VARIOUS LEAKS
168	861021	RECEIVER	U	1.68	1.68	systca	PANEL 21	WOULD NOT TRANSFER TO TEMPERATURE CONTROL.
169	861104	RECEIVER	U	1.17	1.17	systca	PANEL 21	TEMPERATURE CONTROL VALVE CYCLING PROBLEM.
169	861105	RECEIVER	S	1.	1.	systca	PANEL 21	TEMPERATURE CONTROL VALVE CYCLING PROBLEM INVESTIGATION
170	861112	RECEIVER	U	2.22	2.22	fluxfa	RECEIVER TRIP	RECEIVER PANEL 9 HIGH METAL TEMPERATURE
171	861121	RECEIVER	U	0.5	0.5	systab	DIFFICULTY IN ESTABLISHING RECEIVER WATER FLOW	VENTED RECEIVER.
172	861122	RECEIVER	U	2.23	2.23	systca	TRIP ON HI PANEL 9 TEMP. ADJUST FLOW BIAS.,	
173	861123	COMPUTERS	U	6.65	6.65	tripfa	UNIT TRIP, ILS FAILED CAUSING LOSS OF EPGS &	RECV CTRL, THE RECV RLU & TS RLU CONTINUED W/PROBLEMS
174	861124	STORAGE	U	7.75	7.75	fcvvfa	TRIP, ADMISSION STEAM STOP VALVE SERVO ACTUATOR	FAILED OPEN CAUSING LOW ADMISSION STEAM ENTHALPY TRIP
174	861125	STORAGE	U	6.32	6.32	fcvvfa	ADMISSION STOP VALVE HYDRAULIC FLUID SERVO VALVE	SEIZED IN OPEN POS CAUSG STOP VV TO GO OPEN CAUSG ENTHALPY TRIP
175	861127	RECEIVER	U	1.33	1.33	systca	RECEIVER PANEL 9 AND 21	CONTROL PROBLEM (ADJUSTED FLOW BIAS AND FLUX GAIN)
176	861128	RECEIVER	U	1.82	0.	sdpcre	RECEIVER TRIP (RLU)	HIGH RECEIVER PANEL 9 METAL TEMPERATURE
177	861201	COMPUTERS	U	7.77	7.77	tripfa	ILS FAILURE CPU	REPLACED THE RECEIVER LOGIC (ILS) CENTRAL PROCESSING UNIT BOARD
178	861207	COMPUTERS	U	0.75	0.	tripfa	RLU TRIP	PWR SUPPLY LEADS FAILED DUE TO OVERHEAT, REPLACED PWR RELAY
179	861208	RECEIVER	U	0.78	0.78	floxfa	RECEIVER TRIP	LOW SUPERHEAT TEMPERATURE
180	861209	MAIN STEAM	U	5.5	5.5	fcvvfa	RECEIVER UV2905 SOLENOID VALVE	WOULD NOT OPEN, REPLACED VALVE
181	861209	RECEIVER	U	0.77	0.77	sdpcre	RECEIVER PANELS 4&5	WOULD NOT TRANSITION FROM FLOW TO TEMP CONTROL
182	861209	RECEIVER	U	1.5	1.5	floxfa	PANEL 5 FLOWMETER	DEBRIS WAS RESTRICTING FLOW, TAPPED W/HAMMER &STARTED WORKING
183	861211	RECEIVER	U	7.77	7.77	tubelk	PANEL 9 LEVEL 3	TUBE FAILURE, REPAIRED LEAK
184	861217	COMPUTERS	U	2.	1.4	haccfa	LOST HAC COMMUNICATION	LINES 7 AND 8
185	861217	WATER QUAL	U	2.3	1.7	systfa	HIGH IRON IN FEEDWATER 120 PPB	
186	861217	TURBINE	U	1.5	0.9	systfa	PRESSURE TRANSMITTER	FAILURE
187	861223	COMPUTERS	U	0.5	0.5	sdpcre	RECV FEEDPUMP TOGGLED BETWEEN VALVE & FLOW CTRL	CAUSED BY THE RECV MULTIVARIABLE CONTROL UNIT (MVCU)
188	861224	WATER QUAL	U	2.05	2.05	systfa	CONDENSER HOTWELL BLOWDOWN TO DECONCENTRATE	CONDENSATE IRON PARTC
189	861226	MAIN STEAM	U	0.2	0.2	fcvvfa	V1 CONTROL VALVES	STUCK CLOSED
189	861227	MAIN STEAM	U	0.27	0.27	fcvvfa	VI SERVO MECHANISM	FAILED TO OPEN, TAPPED VALVE SERVO MECH & IT BEGAN TO RESPOND
190	861228	RECEIVER	U	1.13	1.13	unknfa	RECEIVER TRIP	PANEL 9 HIGH TEMPERATURE
191	861229	RECEIVER	U	2.14	0.	floxfa	RECEIVER PANEL 5	FLOW INDICATION
192	861229	ELEC POWER	U	2.14	0.	48swfa	CLEAR GROUND ON 480 V TURB GEN PNL	
193	861230	MAIN STEAM	U	0.4	0.4	fcvvfa	TURBINE SERVO VALVE FAILED TO OPEN	TAPPING OF VALVE SERVO MECHANISM RESTORED CONTROL OF THE VALVES
194	870102	RECEIVER	U	6.47	1.7	pdvvfa	POST MORTUM DRAIN VALVE	BECAUSE OF PANEL 9 WARPAGE (SEE ENTRY 860102)
194	870103	RECEIVER	U	7.47	0.	pdvvfa	RECEIVER DECLARED INOPERABLE	BECAUSE OF PANEL 9 WARPAGE (SEE ENTRY 860102)
194	870104	RECEIVER	U	7.48	0.	pdvvfa	RECEIVER DECLARED INOPERABLE	BECAUSE OF PANEL 9 WARPAGE (SEE ENTRY 860102)
194	870105	RECEIVER	U	7.48	7.48	pdvvfa	RECEIVER DECLARED INOPERABLE	BECAUSE OF PANEL 9 WARPAGE (SEE ENTRY 860102)
194	870106	RECEIVER	U	7.5	0.	pdvvfa	RECEIVER DECLARED INOPERABLE	BECAUSE OF PANEL 9 WARPAGE (SEE ENTRY 860102)
194	870107	RECEIVER	U	7.52	0.	pdvvfa	RECEIVER DECLARED INOPERABLE	BECAUSE OF PANEL 9 WARPAGE (SEE ENTRY 860102)
194	870108	RECEIVER	U	7.53	7.53	pdvvfa	RECEIVER DECLARED INOPERABLE	BECAUSE OF PANEL 9 WARPAGE (SEE ENTRY 860102)
194	870109	RECEIVER	U	7.53	7.53	pdvvfa	RECEIVER DECLARED INOPERABLE	BECAUSE OF PANEL 9 WARPAGE (SEE ENTRY 860102)
194	870110	RECEIVER	U	7.55	7.55	pdvvfa	RECEIVER DECLARED INOPERABLE	BECAUSE OF PANEL 9 WARPAGE (SEE ENTRY 860102)
194	870111	RECEIVER	U	7.57	7.57	pdvvfa	RECEIVER DECLARED INOPERABLE	BECAUSE OF PANEL 9 WARPAGE (SEE ENTRY 860102)
194	870112	RECEIVER	U	7.58	7.58	pdvvfa	RECEIVER DECLARED INOPERABLE	BECAUSE OF PANEL 9 WARPAGE (SEE ENTRY 860102)
194	870113	RECEIVER	U	7.6	7.6	pdvvfa	RECEIVER DECLARED INOPERABLE	BECAUSE OF PANEL 9 WARPAGE (SEE ENTRY 860102)
194	870114	RECEIVER	U	7.62	7.62	pdvvfa	RECEIVER DECLARED INOPERABLE	BECAUSE OF PANEL 9 WARPAGE (SEE ENTRY 860102)
194	870115	RECEIVER	U	7.63	0.	pdvvfa	RECEIVER DECLARED INOPERABLE	BECAUSE OF PANEL 9 WARPAGE (SEE ENTRY 860102)
194	870116	RECEIVER	U	7.65	7.65	pdvvfa	RECEIVER DECLARED INOPERABLE	BECAUSE OF PANEL 9 WARPAGE (SEE ENTRY 860102)
194	870117	RECEIVER	U	7.67	7.67	pdvvfa	RECEIVER DECLARED INOPERABLE	BECAUSE OF PANEL 9 WARPAGE (SEE ENTRY 860102)
194	870118	RECEIVER	U	7.68	7.68	pdvvfa	RECEIVER DECLARED INOPERABLE	BECAUSE OF PANEL 9 WARPAGE (SEE ENTRY 860102)
194	870119	RECEIVER	U	7.7	7.7	pdvvfa	RECEIVER DECLARED INOPERABLE	BECAUSE OF PANEL 9 WARPAGE (SEE ENTRY 860102)
195	870121	FEEDWATER	U	0.88	0.88	hxerlk	UNIT TRIP ON HIGH PANEL TEMPERATURE	#2 FEEDWATER HEATER DEVELOPED A LEAK
196	870123	RECEIVER	U	1.	1.	systin	INSPECTION OF ROLLER ASSEMBLIES AND LEAKS	ACCOMPLISHED
197	870123	COMPUTERS	U	3.8	3.8	sdpcre	UNIT TRIP PANEL 10 HIGH TEMPERATURE	TEMPERATURE CONTROL LOST DUE TO RECEIVER CCM DISK DRIVE FAILURE
198	870125	COMPUTERS	U	1.42	1.42	haccfa	PANEL 20 AND 21	PROBLEM.
199	870125	COMPUTERS	U	1.	1.	haccfa	LOST HAC'S	HAC'S FAILED
200	870130	COMPUTERS	U	7.88	5.38	haccfa	HELIOSTAT CONTROLLERS	COMMUNICATION BETWEEN THE HAC'S & THE COLLECTOR FIELD WAS LOST
201	870203	RECEIVER	U	2.45	2.45	systca	PANEL 9	DIFFICULTY IN ESTABLISHING PROPER FLOW CONTROL
202	870204	RECEIVER	S	2.37	2.37	systin	RECEIVER INSPECTION	BY SNLL, SNLA, FOSTER WHEELER & BABCOX & WILCOX REPRESENTATIVES
203	870207	RECEIVER	U	0.52	0.52	fcvvfa	PANEL 19 LOW SUPERHEAT	APPEARS THAT PANEL 19 WAS FLOODED WITH WATER
204	870212	RECEIVER	U	7.1	0.	tubelk	RECEIVER PANEL 9 AND 10 - TUBE 70	STARTUP ABORTED DUE TO LEAKS, PANEL 9 LEAK LEAK IN UPPER CLIP
205	870217	RECEIVER	U	3.43	3.43	fcvvfa	RECEIVER PANEL 6	TEMPERATURE CONTROL VALVE PANEL 6 IS STICKING
206	870217	COMPUTERS	U	1.	1.	tripfa	RLU TRIP, RECEIVER RLU POWER SUPPLY	STARTUP DELAYED DUE TO RECEIVER RLU POWER SUPPLY FAILURE
207	870221	RECEIVER	S	7.12	7.12	tubelk	PANEL 9 LEAK REPAIRS	REPAIRED 3 TUBE LEAKS & 12 TUBE CRACKS PANEL 9 LEVEL 4
208	870224	RECEIVER	U	8.3	0.	tubelk	LEAKS, EPGS AND TSS RGP POWER SUPPLY	
208	870225	RECEIVER	S	5.67	0.	tubelk	MISCELLANEOUS RECEIVER REPAIRS	DURING WEATHER OUTAGE
209	870226	AUX STEAM	S	2.47	0.	systfa	ELECTRIC BOILER HEATING ELEMENT	REPAIRED HEATER ELEMENT & CONTACTOR ON CIRCUIT #8
210	870226	MAIN STEAM	S	2.47	0.	fcvvfa	RECEIVER DOWNCOMER VALVE	EXT TRAIN #1 REMOVED FROM SERVICE TO USE ITS POSITIONER COMPONENT
211	870226	RECEIVER	S	2.47	0.	pdvvfa	RECEIVER PANEL 5	DRAIN VALVE SOLENOID VALVE WERE REPLACED
212	870226	RECEIVER	S	2.47	0.	pdvvfa	RECEIVER PANEL 9	DRAIN VALVE SOLENOID VALVE WERE REPLACED
213	870226	COMPUTERS	U	1.88	0.	tripfa	ILS SYSTEM FAILURE	CAUSE UNKNOWN, RESETTING UNIT CORRECTED PROBLEM.
214	870301	RECEIVER	U	4.8	4.8	systin	RECEIVER PANEL 9 BUCKLING	STARTUP DELYAED FOR PNL 9 WARPAGE & LOSS OF INSULATION EVALUATED
215	870302	COMPUTERS	U	2.72	2.72	unknfa	ILS TRIP	CAUSE UNKNOWN
216	870310	TURBINE	U	1.35	1.35	systfa	TURBINE PRESSURE CONTROL	V-1 ANOMALLY
217	870318	RECEIVER	S	0.38	0.38	systin	RECEIVER PANEL 9	INSPECTION AND IDENTIFICATION OF TUBE LEAKS
218	870320	TURBINE	U	2.85	2.85	systfa	TURBINE NOISE (HIGH PITCH NEAR #2 BEARING)	INSPECTION DID NOT EVIDENCE ANY UNUSUAL CONDITION

219	870322	COMPUTERS	U	2.16	1.49	haccfa	HAC FAILURE	McDOUGAL MEMORY ERROR
220	870322	RECEIVER	U	2.16	1.49	fluxfa	RECEIVER PANEL 19 "A" FLUX METER	FAILED
221	870322	RECEIVER	U	2.16	1.49	fcvvfa	PANEL 5	REPLACED TEMPERATURE CONTROL VALVE POSITIONER
222	870323	COMPUTERS	S	2.43	0.	haccfa	HAC PROBLEMS	DIAGNOSIS
223	870323	RECEIVER	S	2.43	0.	fluxfa	RECEIVER PANEL 19 "A AND B" FLUX SENS	REPLACED
224	870323	RECEIVER	S	2.43	0.	fcvvlk	RECEIVER PANEL 8	REPACKED TEMPERATURE CONTROL VALVE
222	870325	COMPUTERS	U	3.37	0.	haccfa	BACKUP HAC (McDOUGAL) - SEE 870402	FAILED OVER
222	870328	COMPUTERS	U	0.43	0.43	haccfa	HAC ANOMALIES - SEE 870402	ON TWO STARTUP ATTEMPTS
222	870329	COMPUTERS	U	6.07	6.07	haccfa	HAC ANOMALIES - SEE 870402	LOST FIELD COMMUNICATIONS
222	870330	COMPUTERS	U	3.28	3.28	haccfa	HAC FAILURE - SEE 870402	LOST COMMUNICATION WITH THE FIELD
222	870402	COMPUTERS	U	3.6	3.6	haccfa	HAC FAILURE	LOOSE WIRE ON HAC COMM LINK WAS CAUSE OF ALL RECENT HAC FAILURES
225	870404	COMPUTERS	U	1.47	1.47	haccfa	STARTUP DELYAED DUE TO ISC ON CHROMATIC	UNABLE TO COMMUNICATE WITH THE FIELD
226	870406	RECEIVER	S	3.25	1.9	tubelk	PANEL 9 TUBE LEAKS	5 LEAKS REPAIRED (3 EXTERNAL & 2 INTERNAL)
227	870406	COMPUTERS	U	1.58	0.23	haccfa	HAC FAILURES (2)	PRIME HAC FAILED TO BACKUP & ISC LOST COMMUNICATION WITH FIELD
228	870414	RECEIVER	S	7.75	7.75	systgr	MISCELLANEOUS RECEIVER REPAIRS	DUE TO INCLEMENT WEATHER
229	870415	RECEIVER	U	2.6	2.6	floxfa	RECEIVER PANEL 5 AND 12	FLOW INDICATION, LOW SUPERHEAT·
230	870419	COMPUTERS	U	4.79	4.79	haccfa	HAC	FAILURE
231	870419	RECEIVER	U	4.79	4.79	fcvvfa	RECEIVER PANEL 8	TEMPERATURE CONTROL VALVE POSITIONER
232	870421	RECEIVER	U	7.	7.	fcvvfa	VALVE 2703 AIR LEAK - WOULD'NT CLOSE TCV	BAD AIR LEAK, POSITIONER AND "O" RINGS REPLACED
233	870421	RECEIVER	S	4.07	4.07	floxfa	RECEIVER PANEL 5	FLOWMETER REPLACED WITH NEW GPM FLOWMETER
234	870423	RECEIVER	S	3.9	0.	tubelk	RECEIVER PANEL 11 TUBE LEAK ELEVATION 5 RIGHT	REPAIRED
235	870424	GRID	S	5.52	0.	systfa	LUGO SUBSTATION TEST - CANCELLED	
236	870501	RECEIVER	U	1.97	0.2	fcvvfa	RECEIVER PANEL 6	TEMPERATURE CONTROL VALVE POSITIONER REPLACED
237	870506	COMPUTERS	U	3.38	3.38	haccfa	HAC FAILURES	CHANGED OUT ERIN MEMORY LOCATION
238	870507	RECEIVER	S	3.7	0.	tubelk	MISCELLANEOUS RECEIVER REPAIRS	DUE TO INCLEMENT WEATHER
239	870509	RECEIVER	U	11.32	10.5	floxfa	RECEIVER PANEL 15 FLOWMETER FAILED	REPLACED W/24 GPM MTR, POSITION REVERSED TO INDICATE PROPER FLOW
240	870510	RECEIVER	U	6.5	6.5	fcvvfa	RECEIVER PANEL 20 POSITIONER FAILED	REPLACED PANEL 20 TEMPERATURE CONTROL VALVE POSITIONER
241	870512	ELEC POWER	U	11.35	7.	hiswfa	HELIOSTAT POWER CENTER #1 BUSHING FOUND CRACKED	BUSHING REPLACED AND OIL ADDED TO TRANSFORMER
242	870517	RECEIVER	U	3.62	0.	fcvvfa	RECEIVER PANEL 19 TEMPERATURE CONTROL VALVE	FAILED, REPLACED PANEL 19 TCV POSITIONER
243	870524	RECEIVER	U	1.18	0.	tripfa	RECEIVER TEMPERATURE CONTROL INTERLOCK	TRANSFERRED FROM MANUAL TO AUTO DUE TO TOGGLING IN/OUT FLOW CTRL
244	870528	RECEIVER	S	0.82	0.	tubelk	RECEIVER PANEL 9 REPAIRS	INSPECTION PLUG #34 REPLACED
245	870602	RECEIVER	S	4.02	4.02	tubelk	SCHEDULED RECEIVER PNL 9 AND MISC REPAIRS	TUBE LEAK REPAIRS
246	870603	RECEIVER	U	1.03	0.	tubelk	RECEIVER PANEL 8 PREFILTER FLANGE GASKET	LEAKING
247	870608	RECEIVER	U	3.22	3.22	fcvvlk	RECEIVER PANEL 21	TEMPERATURE CONTROL VALVE PACKING WAS BLOWN, REPACKED VALVE
248	870608	RECEIVER	U	3.22	3.22	fcvvfa	RECEIVER PANEL 21 I/P	REPLACED I/P AND STROKED VALVE
249	870614	COMPUTERS	U	6.47	6.47	tripfa	RECEIVER ILS 584 #1 F142 CONNECTOR	SWAPPED OUT W/RS #3 ILS-30 CONNECTOR BECAUSEoFsEVERALaNOMALIES
250	870614	RECEIVER	U	2.	2.	fcvvfa	RECEIVER PANEL 21 POSITIONER	LOW SUPERHEAT
250	870615	RECEIVER	U	1.62	1.62	fcvvfa	RECEIVER PANEL 21 TEMPERATURE CONTROL VALVE I/P	REPLACED
251	870616	RECEIVER	U	2.02	2.02	fcvvlk	RECEIVER PANEL 14 TEMPERATURE CONTROL VALVE	REPACKED
252	870616	AUX STEAM	U	2.02	2.02	systfa	AUX BOILER CONTROL POWER FUSES (2)	REPLACED
253	870622	TURBINE	S	1.11	1.11	systgr	TURBINE SEAL STEAM VAPOR EXTRACTOR	REPLACED
254	870622	RECEIVER	U	3.07	3.07	fcvvfa	RECEIVER PANEL 12 TEMPERATURE CONTROLLER FAILED	REPLACED I/P
255	870622	TURBINE	S	1.11	1.11	systgr	TURBINE LUBE OIL PRESSURE REGULATOR	ADJUSTED TO CORRECT AUTO START OF BACKUP LUBE OIL PUMP
256	870718	RECEIVER	S	11.43	11.43	systgr	MISCELLANEOUS & PANEL TUBE RECEIVER REPAIRS	SCHEDULED
256	870719	RECEIVER	S	11.42	11.42	systgr	MISCELLANEOUS & PANEL TUBE RECEIVER REPAIRS	SCHEDULED REPAIRS COMPLETED
257	870724	COMPUTERS	U	4.68	3.55	haccfa	HAC FAILURE	DIAGNOSTICS CONTINUE
258	870725	COMPUTERS	U	1.22	1.22	tripfa	RLU TRIP CAUSED BY A BAD PRINTED CIRCUIT CARD	IN REMOTE STATION 1 DISCRETE LOGIC UNIT (CPU CARD, MODICON 584)
259	870728	FEEDWATER	U	4.25	3.75	pumpfa	RECEIVER FEEDPUMP MOTOR INBOARD BEARING	REPLACED
259	870728	FEEDWATER	S	5.	4.5	pumpfa	RECEIVER FEEDPUMP MOTOR OUTBOARD BEARING	SCRAPED AND REFITTED
260	870729	RECEIVER	U	1.85	1.85	fluxfa	RLU TRIP ON PANEL 14 HIGH METAL TEMPERATURE	DUE TO A FAILURE ON PANEL FLUX SENSOR
261	870730	RECEIVER	U	1.65	1.65	fcvvlk	EXCESSIVE LEAKS ON PANEL 14 AND 15 14	REPACKED VALVE

Table 2-2 Naming Scheme for Outage Categories

Component Classes

cond - main condenser
dmin - demineralizer
ehcu - electro-hydraulic control unit
fcvv - flow control valve
flox - flow transmitter
flux - flux transmitter
gevv - general valves
hacc - heliostat array control computer
hisw - heliostat interface switchgear
hxer - heat exchanger
levx - level transmitter
ocsc - operational control system computer (supervisor control)
pdvv - receiver panel drain valve
prsx - pressure transmitter
pump - pump
rbun - remote building unit
sdpc - subsystem distributed process control
syst - system
tank - tank
temx - temperature transmitter
tgbr - turbine-generator main breaker
trip - plant trip system (interlock logic and red-line unit)
tube - tube
unkn - unknown
4ksw - 4160 volt switchgear
48sw - 480 volt switchgear

Outage Classes

ab - air binding
ca - calibration
fa - hardware failure
fi - fire
gr - general repair
in - inspection
lk - leak
re - receiver control
st - storage control
tg - turbine-generator control

Table 2-3 Failure Rates and Average Outage Times

Receiver (01) Outages

Component	Fail Mode	Out Type	Out Hours	# of Events	# ofComps	Fail rate/Comp	Avg Out Time/Event
System	General Repair	S	116.3	8	1	1.4E-03/hr	14.5 hrs
System	Inspection	S	15.4	6	1	1.0E-03/hr	2.6 hrs
Tubes	Leaks	S	24.47	12	1	2.1E-03/hr	2.0 hrs
Tubes	Leaks	U	140.61	10	1	1.7E-03/hr	14.1 hrs
General Valves	Leaks	S	11.42	1	18	9.6E-06/hr	11.4 hrs
General Valves	Leaks	U	15.04	4	18	3.8E-05/hr	3.8 hrs
General Valves	Failure	S	3.82	1	18	9.6E-06/hr	3.8 hrs
General Valves	Failure	U	10.76	6	18	5.8E-05/hr	1.8 hrs
Flow Control Valves	Leaks	S	0.0	1	18	9.6E-06/hr	0.0
Flow Control Valves	Leaks	U	14.94	10	18	9.6E-05/hr	1.5 hrs
Flow Control Valves	Failure	U	71.26	20	18	1.9E-04/hr	3.6 hrs
Panel Drain Valve	Failure	S	0.0	2	24	1.4E-05/hr	0.0
Panel Drain Valves&	Failure	U	97.94	2	24	1.4E-05/hr	49.0 hrs
Flow Transmitters	Failure	S	4.07	1	18	1.0E-05/hr	4.1 hrs
Flow Transmitters	Failure	U	56.25	16	18	1.5E-04/hr	3.5 hrs
Temp Transmitters	Failure	U	11.56	5	54	1.6E-05/hr	2.3 hrs
Flux Transmitters	Failure	U	43.72	14	18	1.3E-04/hr	3.1 hrs
Pressure Transmitters	Failure	U	3.4	1	3	5.8E-05/hr	3.4 hrs
Air Binding	During Startup	U	4.47	3	1	5.2E-04/hr	1.5 hrs
Controller Gains	Need Adjusting	U	13.95	8	18	7.7E-05/hr	1.7 hrs
Unknown	Failure	U	2.2	2	1	3.4E-04/hr	1.1 hrs

Main Steam (02) Outages

Component	Fail Mode	Out Type	Out Hours	# of Events	# of Comps	Fail rate/Comp	Avg Out Time/Event
Control Valves	Fail	S	0.0	1	6	2.9E-05/hr	0.0
Control Valves	Failure	U	13.1	5	6	1.4E-04/hr	2.6 hrs

Turbine - Generator (03) Outages

Component	Fail Mode	Out Type	Out Hours	# of Events	# of Comps	Fail rate	Avg Out Time
System	Inspect/Repair	S	197.71	3	1	5.6E-04	65.9 hrs
System	Failure	U	7.05	5	1	9.3E-04	1.8 hrs
System	Leaks	U	1.76	2	1	3.7E-04	0.9 hrs
Oil Reservoir	Leak	U	3.19	3	2	2.8E-04	1.1 hrs
EHC Unit	Leak	U	2.27	1	1	1.9E-04	2.3 hrs
Lube Oil Pump	Failure	S	1.98	1	2	9.5E-05	1.0 hrs

Storage (04) Outages

Component	Fail Mode	Out Type	Out Hours	# of Events	# of Comps	Fail rate	Avg Out Time
Tank	Fire	U	35.73	1	1	2.5E-03/hr	35.7 hrs
Pump	Failure	U	0.6	1	1*	2.5E-03/hr	0.6 hrs
Control Valves	Failure	U	21.08	3	4*	1.9E-03/hr	7.0 hrs
Heat Exchangers	Leak	U	2.67	1	3*	8.4E-04/hr	2.7 hrs
Level Transmitters	Failure	U	2.35	1	2*	1.3E-03/hr	2.4 hrs
Pressure Transmitters	Failure	U	5.05	1	5*	5.1E-04/hr	5.1 hrs
System	Failure	U	0.85	1	1	2.5E-03/hr	0.9 hrs
Unknown	Failure	U	0.70	1	1	2.5E-03/hr	

Aux Steam (05) Outages

Component	Fail Mode	Out Type	Out Hours	# of Events	# of Comps	Fail rate	Avg Out Time
System	Failure	S	0.0	1	1	1.7E-04	0.0
System	Failure	U	2.02	1	1	1.7E-04	2.0 hrs

Feedwater (06) Outages

Component	Fail Mode	Out Type	Out Hours	# of Events	# of Comps	Fail rate/Comp	Avg Out Time/Event
Receiver Feed Pump	Leaks	U	0.0	1	1	1.7E-04/hr	0.0
Receiver Feed Pump	Failure	U	10.18	5	1	8.7E-04/hr	2.0 hrs
Receiver Feed Pump	Failure	S	4.5	1	1	1.7E-04/hr	4.5 hrs
Feedwater Heater	Leak	U	0.88	1	2	8.5E-05/hr	0.9 hrs

Condensate (07) Outages

Component	Fail Mode	Out Type	Out Hours	# of Events	# of Comps	Fail rate/Comp	Avg Out Time/Event
Condenser	Leak	U	1.43	1	1	1.7E-04/hr	1.4 hrs
Demineralizer	Leak	U	1.76	1	2	8.5E-05/hr	0.9 hrs

Water Quality (09) Outages

Component	Fail Mode	Out Type	Out Hours	# of Events	# of Comps	Fail rate/Comp	Avg Out Time/Event
System	General Repair	U	3.75	2	1	3.5E-04/hr	1.9 hrs

Service Water (10) Outages

Component	Fail Mode	Out Type	Out Hours	# of Events	# of Comps	Fail rate/Comp	Avg Out Time/Event
System	Leak	U	15.72	1	1	1.7E-04/hr	15.7 hrs

Nitrogen (12) Outages

Component	Fail Mode	Out Type	Out Hours	# of Events	# of Comps	Fail rate/Comp	Avg Out Time/Event
System	Failure	U	0.0	1	1	1.7E-04/hr	0.0

Heating Ventilation and Air Conditioning (15) Outages

Component	Fail Mode	Out Type	Out Hours	# of Events	# of Comps	Fail rate/Comp	Avg Out Time/Event
System	Failure	U	5.77	1	1	1.7E-04/hr	5.8 hrs

Electric Power (16) Outages

Component	Fail Mode	Out Type	Out Hours	# of Events	# of Comps	Fail rate/Comp	Avg Out Time/Event
10 MW T/G Breaker	Failure	S	0.0	1	1	1.7E-04/hr	0.0
10 MW T/G Breaker	Failure	U	1.18	1	1	1.7E-04/hr	1.2 hrs
4 KV Switchgear	General Repair	S	5.67	3	1	5.2E-04/hr	1.9 hrs
4 KV Switchgear	Failure	U	0.42	1	1	1.7E-04/hr	0.4 hrs
480 V Switchgear	Failure	U	0.0	1	1	1.7E-04/hr	0.0
Heliostat Interface Switchgear	Failure	U	72.28	2	1	3.4E-04/hr	36.1 hrs

Computer Control System (17) Outages

Component	Fail Mode	Out Type	Out Hours	# of Events	# of Comps	Fail rate/Comp	Avg Out Time/Event
Receiver SDPC	Failure	U	39.64	16	1	2.8E-03/hr	2.5 hrs
Storage SDPC	Failure	U	0.60	1	1$	2.5E-03/hr	0.6 hrs
Turbine SDPC	Failure	U	0.68	2	1	2.0E-04/hr	0.34 hrs
Heliostat Control (HAC)	Test/Repair	S	5.48	3	1	5.2E-04/hr	1.8 hrs
Heliostat Control (HAC)	Failure	U	81.76	25	1	4.3E-03/hr	3.3 hrs
Trip System	Failure	U	44.4	11	1	1.9E-03/hr	4.0 hrs
Master Control (OCS)	Failure	U	3.3	3	1+	5.2E-03/hr	1.1 hrs

Operator Error (19) Outages

Component	Fail Mode	Out Type	Out Hours	# of Events	# of Comps	Fail rate/Comp	Avg Out Time/Event
Operators	Error	U	2.43	2	1	3.5E-04/hr	1.2 hrs

Grid (20) Outages

Component	Fail Mode	Out Type	Out Hours	# of Events	# of Comps	Fail rate/Comp	Avg Out Time/Event
Grid Substations	Switching/Tests	S	17.68	5	1	8.7E-04/hr	3.5 hrs
Grid Substations	Failure	U	7.62	2	1	3.5E-04/hr	3.8 hrs

* - Number of components in the storage charging mode of operation. Assumed 1 of 2 trains are operating.

$ - These components are only used in the storage charging mode of operation. The exposure time for these components was 396 hrs.

\+ - Assumed OCS used 1/10 of total operating time (i.e. approximately 580 hrs).

& - The "warped panel" outage that occurred in January 1987 was categorized as a failure of a panel drain valve. There were other contributing causes besides failure of this valve. See discussion in Chapter 4, item 4. An alternate approach would be to create a new outage category called "panel damage". This category would have an outage time of 92.8 hours, and a failure rate for the receiver as a whole of 1.7E-04/hr.

Table 2-4 Fault Exposure Time for the Systems at Solar One From August 1, 1984, Through July 31, 1987

System	Operating Hours
(01) Receiver	5774
(02) Main Steam	5774
(03) Turbine-Generator	5378
(04) Storage	396
(05) Auxiliary Steam	5774
(06) Feedwater	5774
(07) Condensate	5774
(09) Water Quality	5774
(10) Service Water	5774
(12) Nitrogen	5774
(15) HVAC	5774
(16) Electric Power	5774
(17) Computers	5774
(19) Operators	5774
(20) Grid	5774

Chapter 3

Qualitative Insights Regarding Plant Availability

In this chapter we provide qualitative insights regarding the more important outage categories identified in Chapter 2. For each category we describe the outage cause and present recommendations for mitigating the problem in future central receiver plants. In Section 3.1 we present the top eleven outage causes. Collectively, they composed 75% of the total outage time during the power production phase. In Section 3.2 we present qualitative insights about other reliability issues of concern to the plant.

3.1 Insights Regarding the Eleven Most Important Outage Categories

The problems that caused the plant to be unavailable the most are ranked below. The times listed are solar-outage hours. For the plant as a whole during the power production phase, the solar-outage time was 1289.5 hours.

1. Scheduled outages to inspect and repair the turbine-generator (197.7 hours).
2. Unscheduled receiver tube leaks (140.6 hours).
3. Scheduled general repair of the receiver (116.3 hours).
4. Outages due to warped receiver panels (97.9 hours).
5. Failures of the heliostat-array-control computers (81.7 hours).
6. Failures of heliostat interface switchgear (72.3 hours).
7. Failures of the flow control valves on the receiver (71.3 hours).
8. Failures of the flow transmitters on the receiver (56.3 hours).
9. Failures of the plant trip system (44.4 hours).
10. Failures of the flux transmitters on the receiver (43.7 hours).
11. Failure of the Beckman distributed-process control system for the receiver (39.6 hours).

These problems are discussed in turn below.

1. <u>Scheduled outages to inspect and repair the turbine-generator</u>

Description

It is standard utility practice at Rankine-cycle power plants to shut down the plant and inspect all plant systems at the conclusion of the first year of operation. The objectives of this initial shutdown are to a) repair failures, b) identify and/or repair incipient failures, c) plan future outage work, and d) establish maintenance frequencies. After this initial shutdown, subsequent shutdowns occur approximately every 4 years. The shutdown frequency can be longer or shorter depending on component failure frequencies and the results of previous inspections.

The outage time associated with this event is dominated by a 5-week scheduled outage that occurred in February and March of 1985. During this outage, the turbine generator and all other systems were inspected. Nothing significantly wrong was found. This was good news because early in the project, engineers were concerned that the daily thermal cycling experienced by the turbine would cause many problems. (However, engineers still believe that a 100-MW commercial-scale turbine will probably experience earlier thermal-cycling-induced failures than the 10-MW turbine at Solar One due to the larger sizes of components.) This event was classified as a "turbine-generator outage" because inspection of the turbine required the most time and was on the critical path of the outage schedule.

The 5-week outage was initially scheduled for April 1983, 1 year after startup. Due to difficulties in obtaining funds from DOE, the shutdown was delayed until 1985. This shutdown could have therefore been avoided during the early portion of the power production phase if it had occurred when originally scheduled. However, since subsequent shutdowns occur at approximately 4-year intervals, it is likely that a second shutdown would have occurred during the latter portion of the power production phase. The frequency of this event and the associated outage time are therefore considered to be representative of future central receiver plants and not unique to the Solar One experience.

Mitigation

Inspection of the turbine and other plant systems after 1 year of operation and every 4 years thereafter is a good practice, and we do not recommend altering this strategy. However, the solar outage time associated with this event could potentially be reduced.

One method is to schedule the outage during known bad weather months or around the winter solstice. For example, if the 5-week outage that occurred in February and March were scheduled around the winter solstice, solar outage time would have been reduced by at least 25%.

Another method is to implement three shifts and work on a 24 hour schedule. Two shifts were employed during the 5 week outage at Solar One. This was done because experience at other power plants suggested that productivity is low during overhaul periods on the graveyard shift. Accordingly, it is not uncommon to overhaul non-critical plants on a two-shift rather than three-work-shift basis.

2. Unscheduled receiver tube leaks

Description

The Solar One receiver routinely operates with some tube leakage. Fortunately, most leaks are not severe enough to cause a forced outage. A leak causes a forced outage when the leakage rate exceeds the capacity of the make-up water system. These are termed "severe" leaks and are the subject of this section.

Much has already been written about the receiver tube leaks at Solar One. We will therefore only provide a very brief summary. An excellent, detailed discussion can be found in Radosevich (1988).

The receiver has experienced four different types of tube leaks over the years. The time of first occurrence and the location of each type is summarized below:

Type	Time of First Occurrence (Months after Startup)	Leak Location
I	18	Interstice welds
II	19	North edge tubes at 90° bend
III	42	Clip welds on back of panel
IV	53	North edge tube below 90° bend

The causes of the leaks and possible solutions were studied for each type. Each of these leak types is discussed in turn below.

Each receiver panel consists of 70 tubes. Each group of ten tubes constitutes a subpanel and are joined by an interstice weld. At the top of the intersticial weld, the subpanels are joined by a membrane weld on the non-flux side with a membrane weld continuing to the flux side. Several subpanels experienced interstice weld cracks and/or leaks. Cracks were believed to occur due to high stresses at the weld when a large temperature difference existed between adjacent subpanels. The upper panel supports consist of seven clips welded onto each of the seven subpanels. These subpanel clips were machined to the exact outer diameter of the support tubing. Because of the absence of clearance between the clips and support tubing, the panels could not expand circumferentially with respect to the support tubing and thus placed undue stress on the subpanel interstice welds. This stress was aggravated by excessive weld mass existing at the membrane welds. These types of leaks were eliminated by grinding out a section of the interstice weld material at several locations. This action relieved the stress on the tubes caused by the thermal gradients between the subpanels.

The steam exiting a receiver panel must pass through two 90° tube bends before entering the outlet manifold. Several panels experienced tube leaks at the first 90° bend on the northernmost panel tube (called the "edge tube"). Thermal shock during shutdown operations is believed to be the cause of these types of tube cracks. Since the edge tubes operate at the highest temperature they are the most susceptible to thermal shock caused by sudden quenching by saturated water. These types of leaks were eliminated by installing radiation shields to reduce the temperature of the edge tube and by modifying the operating procedures during shutdown. The operating procedure was changed to reduce the steam outlet temperature, under controlled conditions, just prior to receiver shutdown. Then, if water at the saturation temperature accidently impinged on the tube bend, the tube would be cooler and less likely to crack from thermal shock.

Each panel is attached to the receiver structure at seven elevations. The top attachment is fixed and supports the weight of the panel. The lower six are not fixed; expansion guides allow the panel to grow axially due to thermal expansion. Clips are welded to the receiver panel at each of the lower six elevations. Fifteen of the 18 boiler panels have experienced leaks at the clip welds near the upper two elevations of expansion guides. These leaks are believed to be caused by the temperature difference between the front and back surface of the tubes and the stresses induced at the welds by the attachment system. The temperature difference causes the panel to bow outwards. However, the attachment system is designed to prevent bowing. This causes a high stress at the weld. The temperature difference between the clip and the back of the tube produces additional stress at the weld. These stresses eventually lead to cracks. The clip welds at the top expansion guides are more susceptible because the temperature differences are the greatest there. Recent modifications, described in the following paragraph, have been relatively successful in mitigating these cracks.

All of the clips on elevation 6 boiler panels were removed and all but one pair on the left and right sides of the boiler panels at elevation 5 were removed. The elevation 5 clip pairs remaining at elevation 5 were used to attach the panels to the support structure with restraining cables. The modification included installation of bubper assemblies to control potential inward panel expansion. Due to mechanical interference problems encountered in the retrofit program, only a limited number of bumper assemblies were installed. It is questionable at this time that the cable/bumper installation did anything. The apparent major benefit was reduction of localized thermal stresses that were being imposed by the welded clip assemblies.

In June 1986, the north edge tube of panel number 16 developed a leak (Type IV) on the front side of the tube about 13 ft below the top of the first 90° bend. An inspection of the tube revealed many circumferential cracks over a 4.5 ft length about the leak. Data investigations revealed that this tube experienced very high temperatures. This type of tube failure is known as "fire cracking" and occurs commonly on conventional boilers. The leak was repaired by replacing a 19 ft section of the tube. Only one other panel edge tube has experienced a Type IV failure. This occurred on panel 9 at a symetric location to the tube failure on panel 16.

Mitigation

Mitigation of tube leaks would requires the following:

1. Elimination of tube membrane welds

2. Reduction of localized stress areas

3. Increased dimensional tolerances between expansion surfaces

4. Improved panel expansion guides

Most tube leaks have been associated with welds on the panels and inadequate expansion guide sliding and rolling clearances. One need is to reduce the number of welds and be concerned with the relative size of materials welded to the tubes. In addition, expansion surface clearances should be more gererous.

Overconstraining the panel's thermal expansion can lead to tube cracks due to high thermal stresses in the tubes and the welds. The thermal environment and exposure to weather can cause corrosion of the panel's attachment system and restrict its movement. Panel attachment systems in future CR designs should be more tolerant to axial and radial thermal expansion. The expansion system employed in a recent molten salt receiver (Chavez, Smith 1988) appears to be a step in the right direction.

Stresses on the receiver tubes can be lessened through better control of temperature ramping during startup, shutdown, and cloud transients. Operating procedures and control strategies should be designed to provide better control of temperature ramping.

Forced outages can be reduced by repairing tubes before the leak rate becomes severe. Ideally, this repair work should be done at night or during inclement weather. Tube leaks at Solar One were normally scheduled for repair based on the quantity requiring repair, the leaks severity, and availability of repair personnel. Precaution must be exercised in delaying repair of tube leaks because a severe leak may starve flow from adjacent tubes and ultimately cause their failure from overheating.

Outages due to tube leak repair can be shortened by providing better accessibility. Manlifts and/or scaffolding should be readily available near the work location.

3. <u>Scheduled general repair to the receiver</u>

Description

This category includes events in which the receiver was sufficiently degraded as a whole to warrant maintenance on many components during the same outage. Maintenance activities typically performed during these scheduled outages are listed below:

a. Replacement of several flux and flow sensors
b. Leak testing
c. Repainting the receiver absorber panels
d. Receiver absorptance tests
e. Jib crane modifications
f. Shielding and insulation work
g. Maintenance of thermal expansion guides
h. Valve stem and bonnet packing

Seventy percent of the outage time associated with this event occurred during a 3-week outage in December 1985. The primary purpose of that outage was to paint the receiver absorber panels. Prior to the outage, the absorptance had dropped from the initial value of 95% to about 86%. After painting, the absorptance was restored to 96%.

Mitigation

The 3-week receiver outage that occurred in December 1985 could have been eliminated if the receiver had been painted during the 5-week turbine outage that was described previously. The receiver absorptance was known to be low in late 1984 and the receiver should have been repainted during the 5-week turbine outage. However, due to delays in obtaining DOE funds, SCE had to postpone the repainting until internal funds became available.

Receiver painting requires moderate ambient temperatures, low humidity, and wind speeds of less than 20 mph. Outage time for this event can be minimized if scheduled during times of the year when these conditions are expected. Good visual conditions are also required to apply the paint. It is questionable whether a repaint job could be done at nighttime using artificial lighting. The proper equipment should also be available to perform the work. For example, the 3-week outage could have been shortened if four rather than two manlifts had been used. There was some job interference using two manlifts because one was being used periodically for measuring receiver panel absorptance.

Outage time for this category could also be reduced by performing scheduled maintenance at night. Night maintenance was performed on an exception basis at Solar One because 1) the crew size was limited, 2) many general receiver repairs of short duration were scheduled during overcast weather conditions, and 3) the limited outage work that could not be performed on weather outage days did appear to justify a fixed night-crew shift.

4. <u>Outages due to damaged receiver panels</u>

Description

The receiver consists of 6 preheat panels and 18 boiler panels.

The flow initially passes through the 6 preheaters located in the low solar flux region of the receiver. The flow is then directed to 18 parallel boiler panels located in the higher flux zones. The boiler panels experience the more severe operating conditions and therefore are more susceptible to damage. Damage results from temperature-related phenomena. If the panel overheats or is exposed to large temperature gradients, the thermal expansion system may not be able to tolerate the radial and axial movements of the panel. If this occurs, the panel will bow and warp.

Each of the 24 receiver panels contains a drain valve. These valves are opened during startup and shutdown operations to fill and drain the water in the receiver. Panel overheating can occur due to a leaking panel drain valve; panel cooling is degraded because a portion of the flow is diverted through the leaking valve.

The first time this occurred (10/10/84), it was discovered during morning startup, and the plant was shut down prior to damaging the receiver. However, when it occurred the second time (October 1986) the operators noticed that the flow and differential pressure to panel 9 was higher than normal but they did not understand the cause. The plant continued to operate in November and December. During this time it was noticed that panel 9 was warping rapidly. Finally, on January 2, 1987 the plant was shut down due to the severe warpage of panel 9.

During the outage the receiver was inspected thoroughly, and analysis was performed to determine the cause of the warpage. Inspections showed the panel drain valve was leaking due to a badly scoured plug and seat. The leakage past the seat was determined to be the cause of the high flow and differential pressure conditions that were previously observed by the operators. Inspections also indicated binding and other problems with the thermal expansion system did not allow the panel to move properly. At the same time, analysis indicated that panels 9 and 16 were exposed to severe temperature gradients during operation.

A tentative decision was made by SCE, Sandia, and McDonnell Douglas to replace panels 9 and 16 with 2 existing spare panels. (Panel 16 had also warped over the years, though not as badly as panel 9.) However, the panels were not replaced due to lack of DOE funds. The decision was also hampered because the receiver crane was no longer in place. The crane was removed from the tower after construction because it was designed in error for ambient temperature conditions and not the receiver operating conditions.

The drain valves for panels 9 and 14 were repaired by lapping them. Additional insulation was installed to protect the panel support structure that was exposed due to the warping. Modifications were made to the thermal expansion system.

Changes were made to the operating procedures to reduce the frequency of severe temperature ramp rates and gradients. After this work was completed, the plant was returned to service on January 20th. The valves began to leak again and on February 15th the valve plug and seat rings were replaced.

Panel warpage and bowing did not affect the receiver's operation in the subsequent months. However, such deformations probably reduce receiver life and lead to additional tube leaks.

Mitigation

The thermal expansion system for the Solar One receiver is inadequate. Roller binding, as well as the inability of the system to tolerate certain panel movements, can cause the panels to deform. The expansion system employed in a recent molten salt receiver (Chavez and Smith, 1988) is a step in the right direction.

A method for quickly identifying panel drain valve leakage should be developed.

The construction crane that was used to assemble the receiver on the tower should have been designed to the receiver's operating environment and left in place. This will greatly facilitate panel replacement should it be deemed necessary during the operating years. The crane will have to be protected with insulation from the solar flux and convective heat.

5. Failures of the heliostat-array-control (HAC) computers

Description

Two HACs are used to control the heliostat field. The types of failures experienced by each of these computers are listed below:

a. The computer would freeze ("lock up") and would need to be rebooted to correct the problem.
b. Problems were experienced with the computer timing signal.
c. Communications were lost with the operator console.
d. The local power supply to a computer failed.
e. Communications between the computer and collector field were lost.

The plant was designed so that one HAC controls the field (prime) and another is in standby (backup). In theory this redundancy should have afforded reliable control of the collector field. In reality the swap-over between prime and backup never worked reliably during the entire history of the plant. The two major reasons for this are 1) incompatibility between the two HAC computers, and 2) interface problems between the HACs and the beam characterization system. These problems are discussed in the following paragraphs.

First, there was an incompatibility in the hardware and software used by the computers. The HAC used two Modcomp Classic computers. One was provided by McDonnell Douglas and the other by Martin Marietta. These computers were not equipped with current hardware and operating system software, as strongly suggested by the equipment supplier. To aggravate the condition, the hardware and operating system revision levels between the computers were not the same. The computer supplier stated frequently that the two computers would not operate reliably in the prime and backup mode, unless both computers were upgraded to common revision levels. The supplier also stated they would only support the current revision level and not some lower level. Contrary to other suppliers, Modcomp did not upgrade to a level, then freeze that configuration and continue to support it. Rather, the company insisted that it would only support its current level.

Martin Marietta and McDonnell Douglas stated that adoption of the current standard would require rewriting the HAC programs as well as the HAC interface with the balance of plant control. They indicated this would cost several million dollars and nearly a year to accomplish. This was outside the scope of the DOE budget for the plant.

It was then decided to boot strap the hardware and software to make the computers work. These boot-strap efforts were less than successful. Often, in correcting one problem, many other problems were created. The boot-strap effort continued throughout the power production phase, and as a result the plant operated frequently with only one HAC in service. Consequently, failure of the one HAC many times resulted in the plant's tripping.

The HAC's reliability decreased significantly when the BCS was placed in service. The BCS program required managing excessive data, which apparently overloaded the HAC computer communication links. It was then decided to install a dedicated Modcomp computer for the BCS and to share peripheral equipment with the Modcomp computer used by the operational control system (OCS). Using the above text, the reader is correct in assuming that the BCS and OCS computers had different hardware and operating system revision levels; these levels were also not consistent with the HAC computers! Not wanting to undergo expensive and time-consuming software revisions that would be required in upgrading the computers, it was once again decided to fix the problems by boot strapping. The boot-strap effort was successful in further reducing the HAC reliability and providing limited service of the BCS and OCS computers.

Recognizing that boot strapping was not making progress, in the last operating year (August 1987 through September 1988), the collector field was operated using only one HAC computer and the BCS program discontinued. It was recognized that failure of the single computer would result in the plant's tripping. It was felt that this was no different than controlling the plant with two unreliable computers.

Mitigation

Mitigation measures should focus on improving the automatic backup capability of the redundant computers. Based on the Solar One experience, future central receiver plants should assure that the hardware and software installed on the redundant machines are written by the same organization and are the same model and revision level. The computers should be purchased from a company that is willing to freeze revision levels and to supply appropriate labor and materials to support that level.

The BCS is a non-critical system since it is not required to operate Solar One. The HAC is a critical system since it must be available to operate the plant. From a reliability point of view, it is not good design practice to interface critical and non-critical, systems because the latter systems may cause subtle failures of the former. This type of interface is believed to have caused failures of the HAC at Solar One. If possible, future central receiver designs should avoid such an interface. If not possible, a failure-mode-and-effects analysis should be performed on the interface to gain a clear understanding of subtle interactions between the two computers.

Since personnel at Solar One were not trained to diagnose and repair HAC problems, anytime a major problem with the system occurred, an offsite repair firm was brought in. The contract with the firm provided for a 48-hour response time. Consequently, much of the outage time associated with the HAC outages was due to the 48-hour response time, as well as travel time to the site. (A trained person was not on-site because it was believed early in the project that it would not be cost effective given the expected failure frequency. Likewise, a much more expensive contract with a response time of 24 hours was not established.) Future commercial-scale plants would probably find that it is cost effective to have HAC expertise on-site since the plant would produce more power than Solar One (e.g., 100 MW vs. 10 MW), and outage time would be much more costly to the utility.

6. Failure of heliostat interface switchgear

Description

Power from a 4160-V switchgear bus is delivered to heliostats via several 4160/480-V transformers. The transformers and associated breakers are known as the heliostat interface switchgear (HIS). During the power production phase, two HIS events caused a sufficient number of heliostats to be unavailable so that there was a plant outage. The failure on 5/12/87 was a random bushing failure and resulted in a 1-day outage. The failure on 11/11/85 was more serious and caused the plant to be down for 10 days. The rest of the discussion will focus on the 11/11/85 failure.

This outage was caused by loose 4-kV connectors located in the switchgear cabinets. Continuous transformer vibrations caused many of the cables to loosen over the years, and eventually one of these cables separated from its bushing. The resulting arcing of this one cable caused excessive current flow and arcing at the other loose connections. Investigation revealed that the connectors were not properly tightened during plant construction. During the outage all connectors and bushings were either cleaned of arc-induced marks or replaced and reinstalled properly, i.e., slightly wrench tight. Some of the heliostat controllers were also damaged by the power surge. Rather than diagnose how many were affected, it was decided to take advantage of the outage time required to repair the cables and accelerate the replacement of the capacitors and retrofit of the fuse blocks located in about 400 heliostat controllers. (These heliostat repairs are described in Chapter 4.)

Since this event was caused by an installation error, it may not be representative of a mature central receiver plant operating during its useful life phase. Rather, this failure is more typical of infant mortality problems that usually occur during the break-in phase of a plant's life (See Figure 1-1).

Mitigation

Better quality-assurance practices during construction would reduce or eliminate the majority of the outage time associated with this event.

The 10-day outage time could have been reduced if more labor had been brought on site and if the repair work had been limited to the known defective connectors. The station, however, chose to inspect, clean, and retighten all 4-kV connectors to ensure that similar incidents would not reoccur.

7. Failure of receiver flow-control valves

Description

The Solar One receiver consists of 6 preheat panels and 18 individual single-pass-to-superheat boiler panels. The resultant steam flow from each of the independent boilers is controlled by its dedicated flow-control valve (FCV). Out of necessity, these air-operated valves must reposition themselves rapidly and often in proportion to available solar energy. In addition, their service is aggravated by periods of low insolation when they must operate in essentially on/off control. This is especially true of the FCVs located on the eastern panel during the morning and of the western valves in the evening. During these times insolation on the receiver is low due to severe heliostat cosine losses. Due to the excessive cycling, these FCVs wear out at a fairly rapid rate. Plant outages resulted from the following types of valve failures:

1. Valve positioners were replaced,

2. Current-to-pneumatic (I/P) elements were replaced,
3. Air solenoid valves were replaced,
4. Moisture was entrained,
5. Limit switches were replaced,
6. Calibration caused problems.

Mitigation

To operate the Solar One receiver, all 18 FCVs must be functioning properly. From a reliability point of view, it is not good design practice to require 18 valves, with relatively high failure rates, all to be functioning to run the plant. Future plants should consider installing redundant flow-control valves with upstream and downstream isolation valves to allow on-line maintenance of the defective valve. These valves should be placed in an accessible location so that one of the two parallel valves could be maintained while the receiver is operating; some of the Solar One outages caused by FCV problems could have been eliminated if the operators had been able to gain access to them during operation.

Future receiver designers should strive to reduce the number of FCVs. For example, the salt receiver that was tested at the Central Receiver Test Facility in 1987 (Chavez and Smith 1988) used two FCVs during operation.

8. <u>Failure of receiver flow meters</u>

Description

Water flowrate is measured in each of the 18 boiler panels. This information is required by the receiver control algorithm to establish adaptive gains and to provide important information to the operators in the control room so they can monitor the status of the receiver. If a flow meter fails, receiver control becomes very difficult and a plant trip often results. Target flow meters are employed. They consist of a paddle in the incoming water stream and a strain gauge mounted on the paddle's handle. The movement of the paddle caused by impact of the flowing water generates an electrical signal on the strain gauge. This electrical signal is converted to a flow signal by way of a conditioning unit. This type of flow meter was chosen because it was capable of measuring flow over the entire range expected in the boiler panels, i.e., a turndown ratio of approximately 20 to 1.

Causes of meter failure were usually due to a) lodging of foreign materials between the target and the surrounding pipe line, or b) failures of the strain gauges or transmitters. The first problem was typically corrected by tapping the flow meter with a hammer; this action dislodged debris caught between the target and the pipe line. However, when meters were previously removed (prior to tapping) evidence of contamination was never found. The second problem was corrected by replacing the strain gauge or transmitter.

Mitigation

A significant amount of maintenance was required to ensure that the paddle did not bind with the pipe line. If these types of flow meters are used in future central receiver plants, more clearance between the paddle and pipe line should be provided. However, this action may reduce the turndown of the meter.

The outage time associated with flow meter problems could have been reduced if the flow meters had been placed in a more accessible location.

Outage time could probably be reduced by providing logic to the control system to automatically switch to the flow meter on an adjacent panel on a bumpless transfer. Control is possible because adjacent panels experience approximately the same flux and flow conditions. Solar One demonstrated that flux-control signals could be used from adjacent panels. Transfer was performed manually, however. This topic is discussed further in the next section.

To operate the receiver, all 18 flow meters must be functioning properly. As described previously for the flow control valves, future receiver designers should strive to reduce the number of flow meters or should provide redundancy.

9. <u>Failures of the plant's trip system</u>

Description

The plant's trip system is designed to automatically shut down the plant when a safety limit is exceeded. An interlock logic system consisting of three Modicon 584 programmable logic units contains the plant permissives required to safely operate the plant. Two red line units, which are also Modicon 584 programmable logic units, provide safety monitoring and control of the receiver and thermal storage systems to assure shutdown of the systems when criteria for safe operation are exceeded.

Eleven outages were attributed to failures of the plant's trip system during the power production phase. These outages were primarily caused by failures of local power supplies, central processing units, circuit boards, and unknown origin. The first three failure modes were usually corrected by replacing the component. Resetting the system sometimes corrected problems of unknown origin.

Mitigation

On at least one occasion, a restart was delayed 2 days because a replacement power supply had to be reordered from an off-site source. The policy at Solar One was to maintain on-site spare parts for those items that were unique at the plant. Many items that were not unique (i.e., "off the shelf" components) had to be obtained off-site. Future commercial-scale plants should maintain a more complete inventory of spare parts at the plant. Priority should be given to components with high failure rates.

10. <u>Failure of receiver flux gauges</u>

Description

Solar flux is measured on each of the 18 boiler panels. This information is required by the receiver control algorithm to provide anticipatory control during rapidly changing flux conditions. If a flux meter fails, receiver control becomes very difficult and the plant often trips.

The harsh environment caused by the solar flux results in rapid degradation of the flux gauges. It was known at the beginning of the Solar One project that the average life of a gauge would be about 6 months. Accordingly, each panel was provided with two gauges for control purposes and one for data acquisition. In the initial operating years, both flux control gauges would fail at about the same time; i.e., both would fail before the first failure had been replaced. In subsequent years, a limited effort was made to stagger their replacement, but a structured program was never adopted. Because of their rapid deterioration and replacement expense, the station discontinued replacing the backup meter, causing forced outages due to failure of a single flux gauge. Subsequently, the station began paralleling the flux gauge on the adjacent panel to the panel having a defective gauge. This action caused a reduction in forced outages attributable to flux gauges.

Mitigation

Experience at Solar One and at the CRTF indicates that flux gauges fail about every 6 months due to the harsh environment. If flux gauges are included in future receiver designs, a strategy should be developed to minimize outage time when they fail. For a receiver like Solar One's, the best strategy would be to replace one of the two redundant flux gauges per panel on a staggered basis (i.e., every 3 months) and to provide logic to the control system to automatically switch to the backup gauge on a bumpless transfer. If the receiver design only has one flux gauge per panel, automatic transfer to the flux gauge on an adjacent panel should occur.

Flux-gauge outages could be nearly eliminated if the gauges could be removed from the harsh environment. One possible method is to use photometers that are located either a) on the ground or b) suspended near the receiver but not exposed to the solar flux. Each of these devices is composed of a photovoltaic cell, which views the flux on a particular receiver panel or control zone through a tube or telescope. The feasibility of this approach was demonstrated in an experiment conducted at the CRTF (Holmes, Boldt 1988).

11. Failure of the distributed process control for the receiver

Description

Solar One was the first application of a fully distributed process control system at a power plant. There are three subsystem distributed process control (SDPC) systems at the plant; one each for the receiver, thermal storage, and electric power generating systems. These systems were built by Beckman Corporation and programmed by McDonnell Douglas Corporation.

The receiver control algorithm is programmed within the receiver's SPDC. The system consists of several stand-alone controllers (called "multivariable control units (MVCU)") located in remote stations and a central console in the control room that allows the operators to interface with the MVCUs. For a detailed description of the system, the reader is referred to Tanner (1986) or McDonnell Douglas (1985). If a significant failure within this SPDC occurs, receiver control becomes very difficult, and a plant trip often results. Several types of receiver SPDC failures occurred during the power production phase:

1. failures of floppy disk drives,
2. garbled data bases,
3. failures caused by voltage excursions,
4. loss of communications,
5. unknown faults.

The SDPC reboots the process parameters for the plant from data archived on floppy disk drives. Soon after problems with the floppy disk drives began to occur, Beckman realized the drives were unreliable and discontinued their use in all newer systems installed at other plants. The newer Beckman systems now use hard disk drives.

Data bases categorize the various process variables that are input to the system. These variables are called tags. The outages caused by garbled data bases are not fully understood but are believed to be due to interface problems between the receiver's SDPC, the operating control (OCS) computer, and the data acquisition system (DAS) computer. Either of the latter two computers may be accessing a tag at the same time that the Beckman does. Garbled information is believed to be written to the data base when this occurs.

The receiver's SDPC is subject to voltage excursions because, unlike the SPDC's for storage and power conversion, it was not connected to the uninterruptable power supply. Consequently, when voltage excurisions occur, the receiver's MVCUs located near the top of the tower often experiences loss of control information. Correcting this problem requires rebooting the MVCUs via the receiver's distributed process controller.

Communications and other problems with the receiver SDPC were caused several times by loose control system connections; many screw-on terminal strips have been found loose, and use of ribbon cable and similar friction type connectors caused problems. The loose connections have been attributed to inadequate quality control during construction.

Mitigation

Due to the rapid evolution of computer technology, the next generation central receiver plant will undoubtedly use the state of the art control system at that time. This system will probably be substantially different from the one used at Solar One. The buyer should choose a system that has demonstrated a high degree of reliability and has been applied in other complex process control industries.

The DAS and OCS computers are non-critical systems since they are not required to be available to operate Solar One. The receiver's SDPC is a critical system since it must be available to operate the plant. From a reliability point of view, it is not good design practice to interface critical and non-critical systems, because the latter may cause subtle failures of the former. This type of interface is believed to have caused failures of the receiver's SDPC at Solar One. If possible, future central receiver designs should avoid such an interface. If not possible, a failure-mode-and-effects analysis should be performed on the interface in order to understand subtle interactions between the two computers.

The receiver's MVCUs on the tower at Solar One were not connected to the uninterruptible power supply because the additional cabling would have added to the cost of the 10-MW plant. However, this additional expenditure would be a tiny fraction of the cost a commercial-scale plant (i.e., 100 to 200 MW). It would therefore be cost-effective to attach the receiver's MVCUs to the uninterruptible power supply in future plants.

Better quality control during construction should eliminate the loose cabling problems experienced at Solar One.

3.2 Qualitative Insights Regarding Other Reliability Problems

The events described in Section 3.1 represent the most important reliability problems during the power production phase. In this section we present qualitative insights regarding other reliability problems.

1. Flange connection leaks

Solar One was provided with an extensive number of bolted flange connections to facilitate installation of equipment within the systems. Daily thermal cycling of the plant caused the flanges and their gaskets to leak routinely and they were thus a high maintenance item. It is recommended that future central receiver plants reduce the number of flanged connections to a minimum. Fossil-fuel and nuclear plants typically have components welded directly to fluid lines and employ very few flanges.

2. Heat tracing

Components that are massive and subject to frequent thermal cycles should be heat traced. For example, the steam dump valve at Solar One was exposed to a daily thermal cycle between ambient and 960 F°. After a few cycles the valve failed. The valve was then heat traced and maintained at 460 F°. The valve did not fail again after this was done.

3. Flow control valve leaks and stem erosion

Flow-control-valve outages described in the previous section were due to hardware failures of the valves. The frequent cycling of the valves also caused them to leak through the stem packing and the bonnet gasket. The cycling also caused erosion damage to the valve stems. Packing leaks and stem erosion were greatly alleviated by replacing the original valve packing with a high-temperature teflon packing.

4. Additional receiver drain valve problems

There were two additional drain valve problems beside those described in the previous section: a) frequent leakage through the bonnet gaskets due to frequent thermal cycling, and b) the feedback transducers that indicated valve position were frequently inoperative. Repair of these deficiencies did not require outages since they were corrected during other outage work.

5. Receiver panel prefilters

The receiver was provided with an inline filter having a 100 micron mesh. Down stream of the main filter, each panel was provided with its own individual 100 micron inlet filter, which was positioned immediately upstream of the flow control valve. The panel prefilters were probably not necessary and was not of good design since inspection of their internals never evidenced contamination. The filters required frequent maintenance to correct gasket leakage.

6. Orifice plugs in the receiver panels

Each of the receiver panels was provided with 70 orifice plugs at their inlet headers. (Removal of these plugs allowed access to the orifices that could be placed in each receiver tube.)

These threaded plugs were not provided with seat gaskets. Consequent to thermal cycling, the plugs were subject to frequent leakage. The original plugs were manufactured from Incoloy material which was similar to the header material.

Removal of the plugs was difficult because they were severely seized within the headers. Many times the plug removal required their physical destruction by drilling, followed by threading the hole to the next larger size. The plugs were subsequently replaced with plugs manufactured from carbon steel to facilitate their removal. The plugs, however, continued to leak and required frequent maintenance.

7. Boiler panel vent valves

The receiver was provided with two main automatic vent valves and each individual panel was also provided with a single manual vent valve. The individual vent valves, due to thermal cycling, were subject to frequent leak through and valve packing leakage.

Chapter 4

Reliability of Heliostats

In this chapter we discuss the causes of failures of individual heliostats. Failures of heliostats scattered randomly throughout the field degrade the electrical production of the plant but do not cause a plant outage. However, if a support system for the heliostat field fails (e.g., power center or HAC), tens to hundreds of heliostats in a common field location fail. This will cause a plant outage because the plant cannot operate because of the severely skewed flux distribution on the receiver. Support system failures were included in the previous two chapters. In this chapter we concentrate on failures of individual heliostats. The reliability information presented here will be valuable to designers and maintenance personnel of future central receiver plants.

A comparison of maintenance costs and plant revenues that result from an improved heliostat availability indicates that it would be cost-effective to attain an annual average availability of 99%. Figure 4-1 shows the heliostat availabilities during the power production phase. The monthly values ranged from a high of 99.7% in June 1985 to a low of 66.7% in November 1985. The low value was caused by the failure of the heliostat interface switchgear. This event is discussed in Section 3.1, item 6. The average availabilities over the first, second, and third years of power production were 96.7, 96.0, and 98.8%, respectively. Since the November 1985 event was actually a failure of a heliostat support system, discounting this event results in an individual-heliostat availability of greater than 98% during the second power production year. The 99% goal was, therefore, very nearly achieved during the entire power production phase. In the last year of operation, this high degree of availability was achieved with only one maintenance man working 3/4 time. It should be noted that availability values close to 100% are believed to be achievable, but the effort required is not deemed to be cost effective.

In the sections that follow, we describe the causes of individual heliostat failures and the corrective actions taken. The failures are grouped according to major heliostat components, depicted in Figure 4-2. Some of the failures we describe actually occurred prior to power production phase. They are included here to achieve a complete discussion of heliostat reliability at Solar One and because retrofit programs were often carried into the power production phase.

Heliostat Controller and Heliostat Field Controller Failures

The collector control system consists of a microprocessor for each of the 1818 heliostats (heliostat controller) and 64 field controllers. Each field controller communicates HAC signals to up to 32 heliostats.

During plant construction the plant experienced severe lightning strikes on August 18, 1981, and as a result several hundred heliostat controllers failed. Many of the controller printed-circuit cards contained burn marks between electronic components as well as electronic component failures. Following review of the incident it was determined that the lightning strike induced potentials and currents of 50 volts and 1 amp into the controllers, which were designed for 5 volts and 25 milliamps. It was then deemed necessary to ground the control cable shield to the heliostat pedestal which was already grounded to its supporting concrete rebar. Recognizing at that time that the collector field did not have a ground grid, some discussion regarding a retrofit was considered. However, further discussion revealed that the central receiver project in Odeillo, France also experienced similar failures and that plant was equipped with both a ground grid as well as lightning arrestors (sky wires). Accordingly, due to the expense of a ground grid retrofit and its questionable value, it was decided to limit the collector field retrofit to grounding of the control cable shield. Since that time the plant has been hit by many additional lightning strikes, and the controllers have not experienced any significant failures from them.

Shortly after initial plant operation, high controller failure rates were experienced following extreme wind conditions. The loads on the drive motors during the wind resulted in an excessively high motor current. This current progressed to the controller's electronics and damaged them. The problem was corrected by installing fuse blocks to isolate the drive motors from high current flow. The fuses were installed over a period of several years anytime a heliostat controller was serviced.

Loss of communications between the HAC, heliostat controllers, and heliostat field controllers occurred quite often during the period from 1981 through 1985 and happened anytime power to the field was momentarily lost due to grid or other problems. Initial attempts to correct the problem included cycling on and off the power to the each of the heliostat controllers. This usually reestablished communication but was very cumbersome and time-consuming. Further investigation revealed that the cause of the problem was a defective capacitor in the Sorenson power supply to the controller. Several hundred of the defective capacitors were replaced during an outage in November 1985; the remainder were replaced anytime a heliostat controller was serviced for other reasons.

The position encoder in the controller uses a filament light to help detect heliostat positions. The failure rate of these lights has been high throughout the life of the plant. The manufacturer originally placed a resistance element in series with the light in an attempt to extend the life of the light. In spite of this, the encoders were unreliable.

Limit Switches

The heliostats are provided with azimuth and elevation limit switches to limit their travel and thus prevent impact between the mirror rack assembly and the support structure and to allow identification of their position in the event their controlling microprocessor lost its orientation because of a power failure, component failure or control anomaly. The selection of a mercury wetted conjecture was excellent. However, the conjecture was supported by a mechanical suspension system that was exposed to dirt contamination during wind storms and was susceptible to oxidation. Both conditions prevented proper operation of the switch. Seizure of the limit switches due to contaminants allowed the gear drives to over-travel, causing failure of the primary gear drive or the gear drive motor. In other cases, on replacing heliostat controllers or on power losses, heliostat controllers were unable to correctly identify their proper orientation when commanded to mark, i.e., reset their position to a base reference level with respect to the limit switches. Failure to properly mark resulted in heliostats that did not properly track.

In the initial operating year, when heliostats were observed to not to be tracking properly, operators would either shake the heliostats or impact the limit switch with a 12-ft length of PVC pipe to regain operation of the limit switches. In the subsequent years maintenance personnel, when servicing heliostats for any reason, would similarly exercise the limit switches. This preventive maintenance service markedly improved the reliability of the limit switches.

Gear Drives

The heliostats are provided with azimuth and elevation gear drives contained in a common housing. The gear drives were reliable and experienced only minimal failures (30+) in the entire operating life of the plant. The gear drive failures were not directly attributable to the gear drives, but to the following:

a. Failure of a mirror assembly doubler plate, allowing a mirror assembly to hang off of a mirror rack structure, and failure of the gear drive to displace the failed assembly from the structure as the failed assembley struck the ground.

b. Limit switch failures, which allowed the gear drive to over-travel and impact the rack assembly onto the mounting plate for the gear-drive motor.

c. High winds displaced the landing mat that was abandoned in the collector field during the plant's construction. (A landing mat is a blanket placed over the soft ground under a heliostat to facilitate heliostat installation.) The mat became entrained with a mirror rack causing the gear box to fail. Presently the landing mat is progressing easterly and is expected to clear the collector field in the year 2000.

d. Other gear box failures have been observed following high wind conditions. It is suspected that the high wind may have caused some of the failures, but we believe that most failures were due to a limit switch over travel incidents described above. High wind conditions appeared to be the secondary cause. In some cases heliostats were positioned vertical and facing directly into 60+ mph winds in transitioning to a face-down position. On many occasions the plant encountered high wind speed conditions without any appreciable forewarning; i.e., wind speed can change from 10 to 60 mph in less than one-half hour.

<u>Gear Drive Motors</u>

The heliostat's gear drives are driven by two 1/6 horsepower motors. After 3 years of operation, two types of failure modes were identified:

a. The oil contained in the gear drives began to leak past defective seals between the gears and the motors. This resulted in contamination of the motor commutator. The contaminated commutator generated electrical signal noise that was fed back to the heliostat controller causing the heliostat to lose its position orientation or lose communication with the HAC. Often the noise generated by one motor's gear drive would cause loss of control of the other 31 heliostats being fed from the same heliostat field controller.

b. The drive motors were equipped with an integral gear train that interfaced with the main gear drive; i.e., the gear drive train provided the initial step down of the motor rotation to the main gear drive. The motor was equipped with a gear that was splined onto the motor shaft. The gear attachments were found to fail frequently. Slippage of the gear caused a change in the relationship between motor turns and the actual heliostat position, resulting in a heliostat's getting lost.

The above problems were resolved by overhauling the motors to replace the defective seal, cleaning the commutator and other components, and tack welding the splined gear onto the motor shaft. This effort improved heliostat reliability in the remaining operating years.

<u>Mirror Corrosion</u>

Each heliostat has twelve mirror modules consisting of a metal pan that forms five of the module's six surfaces (see Figure 4-2). The sixth surface is the glass mirror, which is supported by the aluminum honeycomb structure contained within the pan. Expansion of air contained within the pan places a high load on the epoxy adhesive that holds the mirrors together; therefore, the pan was originally equipped with a small vent. However, shortly after initial plant operation, the silver surface on the glass mirror was found to be corroding. Following this observation, it was determined that the originally installed vents did not have sufficient capacity. The test found that a high differential pressure between the atmosphere and the pan's interior existed for a sustained period as the mirror module cooled. As a consequence, any moisture accumulation along the edge seal cascaded into the module through the edge seal's imperfections. This corrosion was found to be more prevalent on those heliostats having mirror modules produced before July 1, 1981, when production changes were made to improve the edge seals. Also noted was that corrosion was generally concentrated on the mirror section furthest from the vent; i.e., mirror vents were on the inboard side and corrosion was predominantly on the outboard side.

Following test installation of oversized vents on selected heliostats and measurement of the internal pans' relative humidity, it was deemed appropriate to install large-sized vents on the heliostat pans to facilitate their venting. Over the years, the plant installed approximately 40,000 larger sized vents. The vents (up to four per mirror module) were installed on only those heliostats determined to be most susceptible to mirror surface corrosion due to defective edge seals. In addition, the normal heliostat's stow position was changed from face down to vertical to minimize contact between the silver reflective surface and entrained moisture. However, in later years the stow position was again changed to face down because preference was given to maintaining high heliostat reflectivity over minimization of mirror corrosion. To date, the equivalent glass area of less than two heliostats has been lost due to corrosion.

Doubler Pads

The mirror modules have doubler pads which are epoxied on the back of the metal pans. These doubler plates are used to mount the mirror assemblies onto the heliostat structure. In the initial operating year, the plant experienced failure of many of the doubler pads. This caused the mirror assembly to fall to the ground and break. The doubler pads' failure was attributed to contamination of the epoxy, improper mixing of adhesive and accelerator, and improper priming of the metal pans prior to applying epoxy to the doubler pads. Selected mirror assembly doubler pads were retrofitted with pop rivets. During the failure period and following the retrofit, the wind stow limit was reduced from the original 45 to 40 mph. The retrofit significantly reduced the number fallen mirror assemblies.

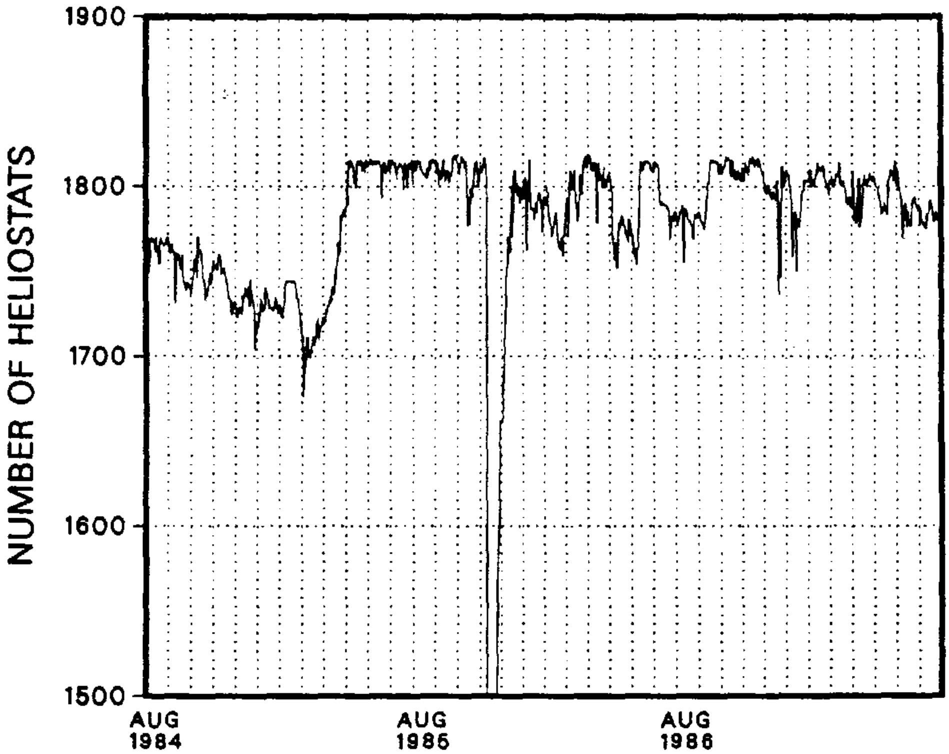
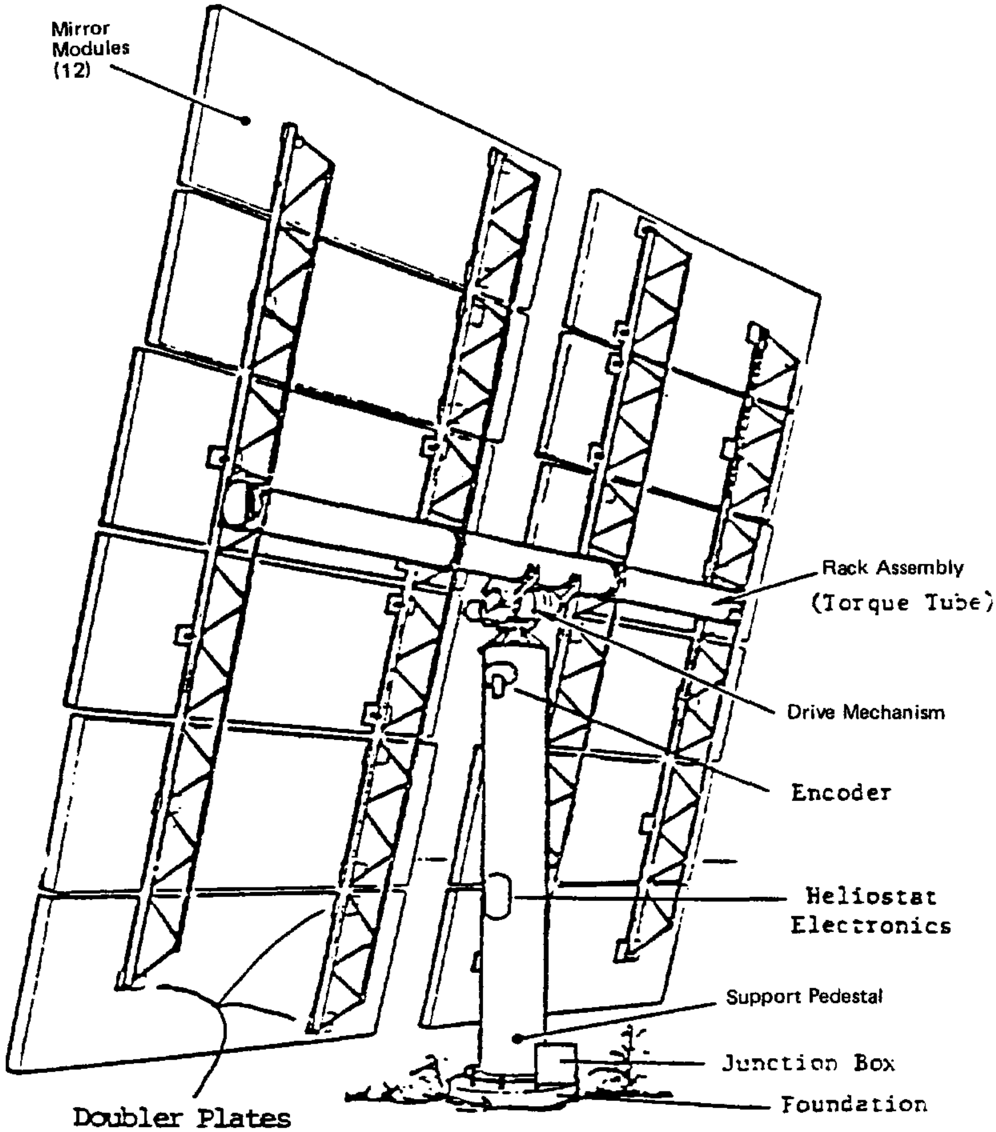
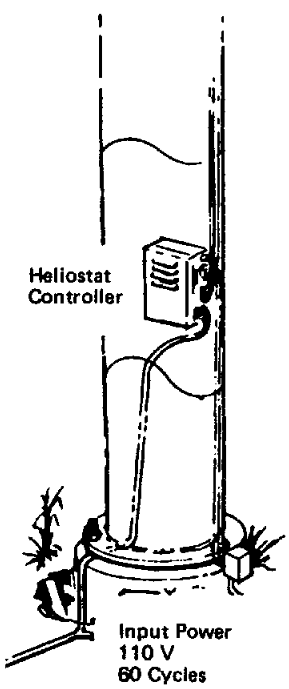


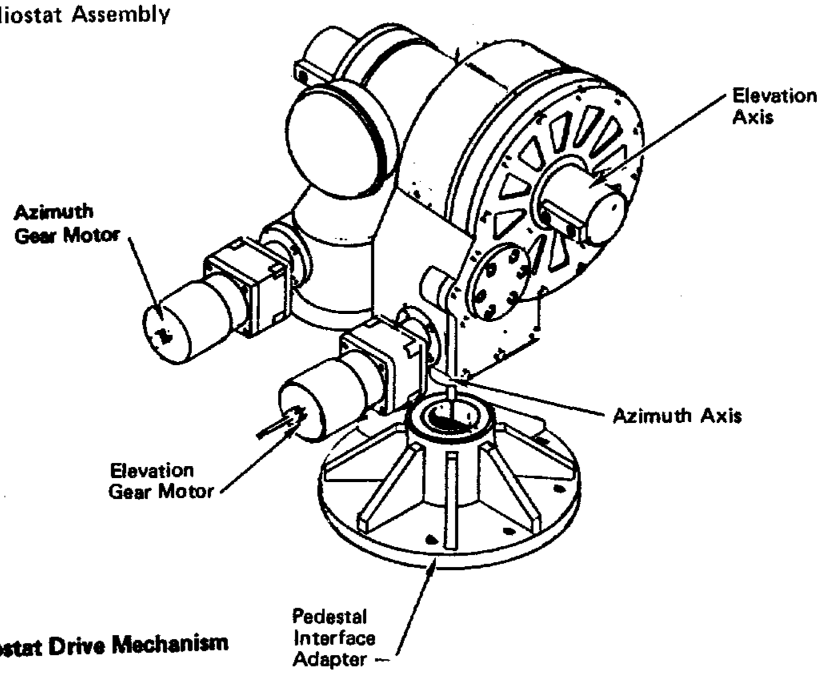
Figure 4-1 Heliostat Availability at Solar One
(1818 Total Heliostats)



Heliostat Assembly



Pedestal Showing Heliostat Controller



Heliostat Drive Mechanism

Figure 4-2 Heliostat Components

Chapter 5

Conclusions and Recommendations

Conclusions and recommendations are organized into three groups:

1) conclusions regarding the availability of Solar One during the power production phase,
2) recommended changes to the design and operation of future central receiver plants based on the Solar One reliability experience, and
3) recommended applications for the statistics and failure rates presented in this report.

Each of these groups is discussed in turn below.

5.1 Conclusions Regarding the Availability of Solar One

Solar One was close to achieving its 90% availability goal. During the three power production years, it registered values of 80, 83, and 82%. Considering that Solar One is a first-of-a-kind plant and that the 90% value is traditionally chosen for conventional power plants, the availabilities achieved at Solar One were truly outstanding.

Greater than 51% of the outage time at the plant was caused by problems with the receiver. Boiler tube leaks were the most important cause. Problems with flow control valves as well as flow and flux gauges were also important.

Approximately 17% of the down time was due to scheduled outages to inspect and repair the turbine-generator system. The maintenance performed during these outages was primarily preventive in nature, since nothing major was ever found wrong with this system.

Problems with computer systems at the plant contributed 14% to the outage time. The heliostat array control (HAC) computers were the source of most of the problems.

Each of the remaining systems at Solar One contributed less than 6% to the total outage time.

The specific problems that caused the plant to be down the most are described in detail in Chapter 3. They will not be repeated here. Also presented in that chapter were recommended methods of fixing these specific problems and improving the reliability of the plant. Most of these recommendations are also applicable to future central receiver plants. These recommendations are briefly summarized in the next section.

3.2 Recommended Changes to the Design and Operation of Future Central Receiver Plants

1. The improvement of receiver availability should be given

primary emphasis in future central receiver plants. In particular, consideration should be given to the following:

a. The number of tube welds should be minimized and membrane tube welds should be avoided.
b. The thermal expansion system should be tolerant to receiver growth in multiple directions.
c. Operating procedures should be developed to keep temperature ramp rates within acceptable limits.
d. A manlift and crane should be readily available to facilitate receiver repairs.
e. Flow control valves and other equipment with high failure rates should be made accessible to maintenance personnel when the plant is operating.
f. Receiver painting should be scheduled during other long-term outages such as turbine-generator overhauls.
g. A method for quickly identifying panel drain valve leakage should be developed.
h. Future receiver designers should try to minimize the number of active components (e.g., flux and flow sensors, flow control valves, etc.). Redundancy should be used for active components with known high failure rates.
i. Flux information should be obtained from photometers rather than flux gauges.
j. Receiver panels should employ quick-release mechanisms so that a damaged panel can be replaced rapidly. The crane that was used to construct the receiver be designed for the receiver's operating condition and left in place during the operating years to facilitate panel replacement.

2. Long-term scheduled outages, such as general turbine and receiver overhauls, should be scheduled around the winter solstice or other months with low insolation.
3. As much maintenance as possible should be scheduled at night.
4. Interfaces between control system computers need to be clearly understood and a failure-mode-and-effects analysis should be performed to understand systems interactions.
5. Interfaces should be avoided between systems required to operate the plant and those that are not. This is especially true in computer systems where system interactions can be very subtle.
6. Computer suppliers should be chosen who are willing to service older models and revision levels.
7. Hardware and software used by redundant computers should be developed by the same organization.
8. For a commercial-scale plant, it would be cost-effective to have trained individuals on site who are capable of diagnosing and repairing computer and control system problems.
9. Quality control during construction is essential to achieving a high degree of reliability. Some quality control problems take years to surface.

10. If a future central receiver project depends on government support, the government should set aside adequate contingency funds at the beginning of the project to cover any problems that may occur during the operating years.
11. All remote control stations that are vital to the operation of the plant should be attached to an uninterruptible power supply that is also attached to the station battery.
12. An adequate supply of spare parts should be on-site to facilitate rapid repair of failed components. Those components with known high failure rates should be given first priority.
13. Thermal cycling caused leakage through flanged connections, vent valves, and orifice plugs. Many of these components were not used at Solar One and should be avoided in future central receiver plants.
14. Massive components should be heat traced to avoid damage due to thermal cycling.
15. The collector field should be grounded to avoid failures due to lightning strikes.
16. Heliostat controller designs should include fuses to isolate the electronics from high current conditions.
17. The reliability of the Solar One heliostats is probably too good. They are very sturdy machines with a low failure rate and only require 3/4 of a man year to maintain greater than 98% availability. They are also expensive (>$400/m^2$). It would probably be more cost-effective for a future central receiver plant to buy less expensive heliostats that have a slightly higher failure rate.

5.3 Recommended Applications of Failure Statistics

Three years of data were used to derive failure rates and average outage times for many components and systems at the plant. Most of these components and systems can be found in designs of next-generation central receiver systems. The molten salt plant designed by the recently completed utility study is an example [Hillesland, Weber (1988)].

As part of our Annual Energy Improvement Study, Sandia plans to use the failure statistics to obtain an availability estimate for the utility study plant as well as others. We will then explore modifications to the base case plant design to see if cost-effective improvements to its reliability can be made. It is recognized that some significant differences exist between Solar One and current designs of central receiver plants. We will use caution in these areas and will seek other sources of data that may be more appropriate. Possible additional sources of data include fossil-fuel and nuclear power plants and the experimental central receiver facilities located in the United States (CRTF), Spain (Almeria), and France (Themis).

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Arizona Solar Energy Office
Dept. of Commerce
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Phoenix, AZ 85007
Attn: Dr. Frank Mancini

Bechtel National, Inc. (5)
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50/15 D8
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1512 Northgate Road
Walnut Creek, CA 94598

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Sacramento, CA 95814
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California Public Utilities Com.
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Attn: T. Thompson

Centro Investigations Energetica
Medroansental Technologie (CIEMAT)
Avda. Complutense, 22
28040 Madrid
SPAIN
Attn: F. Sanchez

DFVLR
IEA/SSPS Project
Apartado 649, E-04080
Almeria, SPAIN
Attn: M. Geyer

DFVLR EN-TT (3)
Institute for Technical
Thermodynamics
Pfaffenwaldring 38-40
7000 Stuttgart 80
Federal Republic of Germany
Attn: Dr. Manfred Becker
Dr. C. Winter
Dr. U. Nikolai

DFVLR
Linder Hoehe
5000 Cologne 90
Federal Republic of Germany
Attn: Hans Hertlein

EIR
CH-5303 Wurenlingen
Switzerland
Attn: W. Durish

El Paso Electric Company
P.O. Box 982
El Paso, TX 79946
Attn: J. E. Brown

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HGH Enterprises, Inc.
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Alternate Energy Systems
Room 661A
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Los Angeles, CA 9001[illegible]
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Attn: Mark Shank

Platform Solar de Almeria
Aptdo. 7
Tabernas (Almeria)
E-04200 Spain

Public Service Company of New Mexico
M/S 0160
Alvarado Square
Albuquerque, NM 87158
Attn: T. Ussery
A. Martinez

Pacific Gas and Electric Company (3)
3400 Crow Canyon Road
San Ramon, CA 94526
Attn: G. Braun
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System Planning
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Denver, CO 80207
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Ramada Energy Systems Ltd.
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San Diego, CA 92112
Attn: R. Figueroa

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Solar Energy Research Institute (6)
1617 Cole Boulevard
Golden, CO 80401
Attn: B. Gupta
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P.O. Box 91
Morrison, CO 80465
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302 E. Caribbean Lane
Phoenix, AZ 85022

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P.O. Box 325
Daggett, CA 92327
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Stone and Webster Engineering
Corporation
P.O. Box 1214
Boston, MA 02107
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Sulzer Bros, Ltd.
New Technologies
CH-8401 Winterthur
Switzerland
Attn: Hans Fricker, Manager

Tom Tracey
6922 South Adams Way
Littleton, CO 80122

United Solar Tech, Inc.
3434 Martin Way
Olympia, WA 98506
Attn: R. J. Kelley

University of Arizona
Engineering Experimental Station
Harvil Bldg., Room 151-D
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Solar Energy Laboratory
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