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Reliability of the Solar One Plant During the Power Production Phase*

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Abstract

Solar One is the world's largest central receiver power plant. During the last 4 years the plant availability was 80%, 83%, 82%, and 96%, respectively, during hours of sunshine. This reliability is considered to be excellent considering the plant is a first-of-a-kind facility and because it has been subjected to daily cyclic service. In this paper we present the frequencies and causes of the plant outages that occurred. The ten most important causes comprised 72% of the total outage time. Qualitative insights related to the cause and mitigation of these ten are provided. The information presented in this paper will be useful to studies aimed at improving the reliability of future solar central receiver power plants. It is also useful to members of the utility industry who are considering investing in this technology or are considering cyclic operation of conventional power plants.

Introduction

Solar One, an electric generating pilot plant located near Barstow, CA, is the world's largest solar central receiver. The nominal power rating of the plant is 10 MW. This power level, or greater, is typically achieved for approximately 8 hours near the summer solstice. The project was a joint undertaking of the US Department of Energy (DOE) and of several associates. The latter consists of Southern California Edison (SCE) Company, the Los Angeles Department of Water and Power, and the California Energy Commission. The plant came on line April 12, 1982, and was placed in mothball status on September 27, 1988, after achieving all objectives of the project.

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 (Fig. 1). The heat can also be stored in the thermal storage system for later use.

The reliability of the Solar One power plant was commendable during its final four years of operation. During this period, 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%, during hours of sunshine, was established. During the first three of these 4 years the plant was close to achieving this goal and registered values of 80%, 83%, and 82%. During the final year the goal was surpassed with an availability of 96%. The average

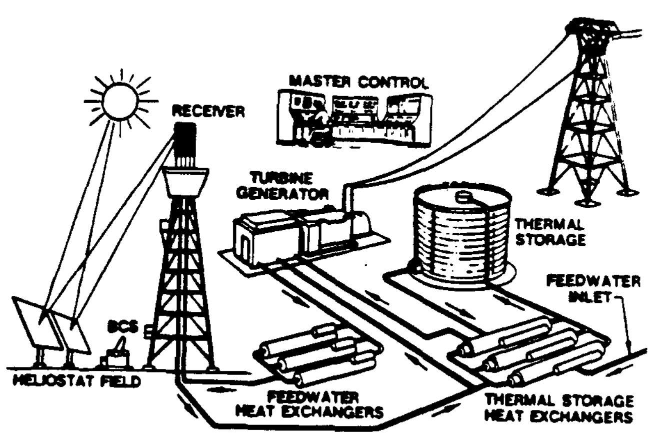

Figure 1 Solar One

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availability during the 4-year period was therefore approximately 85%. 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 excellent.

Though the average availability was 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. 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 (Ref. 1) is the best source of this information.

This paper organizes the most frequent plant outages described in the Solar One logs and displays some failure statistics. Ten of them composed 72% of the total outage time. We briefly describe these ten outage causes and recommend ways for reducing their likelihood in future central receiver plants. A more detailed discussion of these items can be found in a report we recently published (Ref. 2).

Before discussing the reliability of the plant we will first provide a brief discussion of its design.

Plant Design

Solar One consists of the following major systems:

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

Supporting these major 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 six 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 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 was operational through August 30, 1986. On that date the storage tank was damaged by fire. Since it is possible to run the plant without storage and because evaluation of the system was completed, the system was not repaired.

Plant Control System

Solar One was the first power plant in the US to employ a fully distributed process control system. It 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 controllers 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.

Availability Statistics

For purposes of availability assessment, we defined 20 subsystems at the plant. Fifteen of these systems caused the plant to be unavailable during the first three years of power production. (The statistics presented in this paper cover only the first 3 years of power production). The outage contributions from these systems are displayed in Fig. 2. It can be noted that receiver unavailability caused approximately 1/2 of the plant outages. Computer, electric power, and turbine outages were also significant. The reasons behind the outages of these systems as well as mitigation measures are discussed in the next section. Unavailability of the storage system was dominated by the fire mentioned above and will not be discussed further.

The reliability of the 1818 heliostats was excellent during the entire power production phase. Average reliability was near 98%. In the last 2 years this figure was achieved with only one maintenance man working 3/4 time. Since failures of individual heliostats do not cause a plant outage they will not be discussed further. The interested reader should refer to

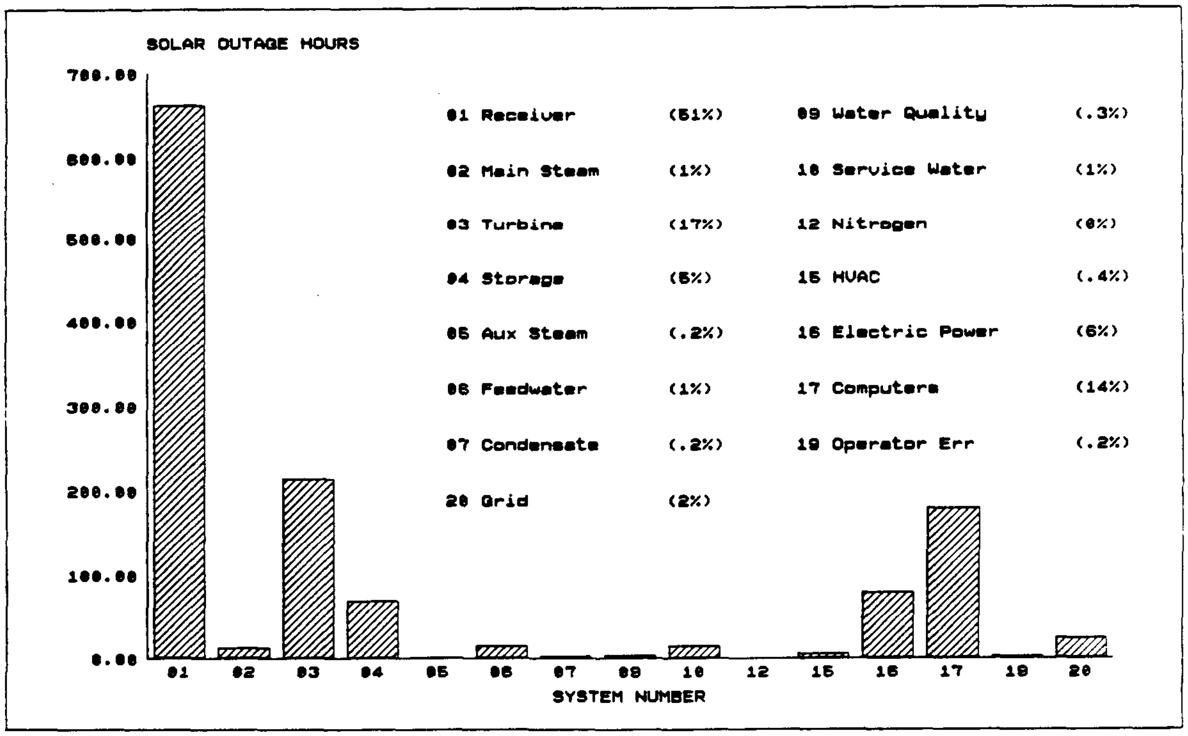

Figure 2 Plant Outages by System

Ref. 2 for a discussion of heliostat failures.

Outage Causes and Mitigation Techniques

The ten most important types of problems that caused the plant to be unavailable for power production are discussed in the following subsections. The percentages listed are the contributions to the total outage time caused by the particular outage category. Together, these ten categories comprised 72% of the total outage time.

1) Turbine-generator Inspection (15.3%)

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 major 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 and other primary rotating equipment would cause many problems.

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 have been reduced.

One method is to schedule the outage during known bad weather months or around the winter solstice when there are fewer hours of sunshine. 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. Two shifts were used because experience at other power plants suggested that productivity is low on the graveyard shift during overhaul periods. This policy may require further evaluation.

2) Receiver Tube Leaks (10.9%)

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.

The receiver has experienced four different types of tube leaks over the years. The causes of the leaks and possible solutions were studied for each type. Each of these leak types is discussed below.

Each receiver panel consists of 70 tubes. Groups of ten tubes constitute a subpanel and they 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 (i.e., hook welds). Several subpanels experienced interstice weld cracks (see Type I in Fig. 3). 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 (see Type II in Fig. 3) 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 energy absorption and thus 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

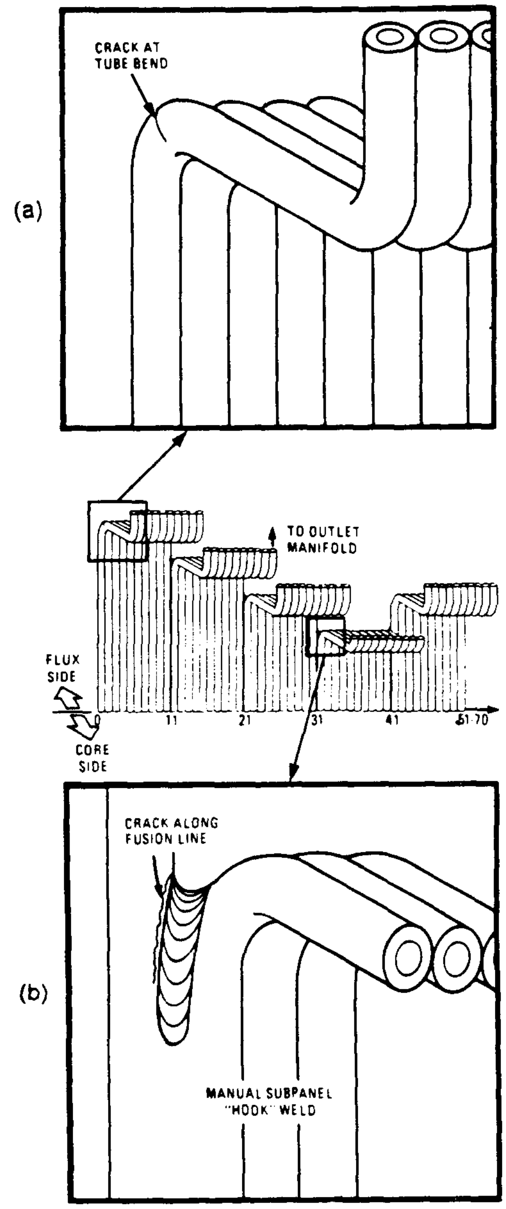

Figure 3 Locations of (a) Edge Tube Leaks (Type II) and (b) Subpanel Interstice Weld Leaks (Type I)

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 (i.e., elevation 7) 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 caused by the incident solar flux. 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 (Type III). 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. The modifications, described in the following paragraph, were 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 bumper 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 whether 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 above and below 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 symmetric location to the tube failure on panel 16.

Mitigation

Mitigation of tube leaks would require 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 generous.

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 central receiver designs should be more tolerant to axial and radial thermal expansion. The expansion system employed in a recent molten salt receiver (Ref. 3) 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 severity of the leak, 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) General repair of the receiver (9.0%)

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. 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 panels. (The receiver panels are painted black to improve absorptance of the incident solar flux). 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 the absence of 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) Damaged Receiver Panels (7.6%)

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 exercised 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 (October 10, 1984), 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. 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 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 16 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.

Panel warpage and bowing did not affect the receiver's operation and panels remained in this condition until conclusion of operations in September 1988.

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 (Ref 3.) 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 would greatly facilitate panel replacement should it be deemed necessary during the operating years. The crane would have to be protected with insulation from the solar flux and convective heat.

5) Heliostat-Array-Control (HAC) Computers (6.3%)

Description

Two HACs are used to control the heliostat field. 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 (BCS). (The BCS is used periodically to align the heliostat beams.) 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 bootstrap the hardware and software to make the computers work. These bootstrap efforts were less than successful. Often, in correcting one problem, many other problems were created. The bootstrap 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 bootstrapping. The bootstrap effort was successful in further reducing the HAC reliability and providing limited service of the BCS and OCS computers.

Recognizing that bootstrapping was not making progress, in the last operating year, the collector field was operated using only one HAC computer, and the BCS program was 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.

<u>Mitigation</u>

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.

<u>6) Failure of heliostat switchgear (5.6%)</u>

<u>Description</u>

Power from a 4160-V switchgear bus is delivered to heliostats via fourteen 4160/120-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.

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) Receiver Flow-control Valves (5.5%)

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 panels 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.

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, a receiver which circulates molten salt rather than water-steam uses only two FCVs during operation (Ref. 3).

8) Failure of receiver flow meters (4.4%)

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) Failures of the Trip System (3.4%)

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 to 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) Failure of receiver flux gauges (3.4%)

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 (Ref. 4).

Summary

Solar One achieved an average availability of approximately 85% during 4 years of power production. This was close to the 90% goal set for the plant. Considering that Solar One is a first-of-a-kind plant and that the 90% value is traditionally chosen for conventional power plants, the availability of Solar One was truly outstanding.

During the final year of power production the availability goal was surpassed and a value of 96% was achieved. The primary reasons for this improvement were the performance of more maintenance when the plant was closed (i.e., the equivalent of maintenance at night) and the reduced frequency of severe tube leaks.

Greater than 50% 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 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 were described in detail in the previous section. Also presented were recommended methods of fixing these specific problems and improving the reliability of the plant. These recommendations will be used to improve the reliability of future central receiver plants.

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