High Performance Steam Cogeneration (Proof-of-Concept Phases)

Phase II Final Report HRSG 500-Hour Test Report

Submitted to:

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SUMMARY

BACKGROUND

In the nineteen sixties, the low cost of energy and the anticipation of nuclear power for base load utility power generation eliminated incentives to solve the material and control problems associated with super critical high temperature steam plants.

With new high temperature materials and technology developed in the last thirty years, industrial cogeneration applications in the 5 to 20 megawatt range offers an ideal opportunity to increase steam temperatures and provide industry with major performance and economic gains. In many small cogeneration power plants, natural gas can be economically justified but extremely high pressures are usually not optimum. Thus, high temperature steam can be economically introduced, first on natural gas with moderate pressures, then the coal-fueled option, and finally the larger utility option at higher pressures.

Recent advances in small once-through Alloy 800 steam generators, improved materials technology, and application of small industrial gas turbine technology to steam turbine cogeneration offers the potential to make a step increase in steam temperature from around 1000°F, where industry has been for almost fifty years, to 1500°F. In small cogeneration systems, it is economically practical to introduce new technology and make a step change in temperature where it may not be possible (given the regulatory environment and economic risk) for a major change in steam temperature to be introduced in the hundreds of megawatt size of an electric utility.

Increasing the peak steam temperature in a steam turbine cycle allows more work to be extracted or electrical power to be generated from a given quantity of heat input. Figure 1 plots steam efficiency as a function of superheat steam temperature and pressure for a turbine back pressure of 166 psia. This figure clearly shows that increasing the steam conditions from the typical current practice of 900°F and 900 psia to 1500°F and 1500 psia will increase the steam cycle efficiency by 53%.

The combination of higher cycle efficiency with an advanced high efficiency steam turbine design provides a substantial increase in turbine output power for a given steam flowrate. The output of this advanced high temperature steam turbine is approximately twice that of a current industrial practice turbine for the same turbine flowrate as seen in Figure 2.

PROGRAM

Solar Turbines Incorporated and the Department of Energy (DOE) have combined to take advantage of these new technologies with a program whose goal is to approach the limits attainable with current metals and demonstrate the operation of a Once Through Steam Generator (OTSG) and steam turbine at 1500°F/1500 psia.

Solar Turbines Incorporated is conducting a four phase program for the Department of Energy to design, fabricate, and test an advanced high performance steam generator and turbine for an industrial cogeneration system operating at 1500°F/1500 psia. The

program has four phases co-funded as DOE contract DE-AC02-85CD40746 and currently the first two phases have been completed. Both the DOE and Solar Turbines Incorporated have set the following goals for this program:

1. Reduce the fuel consumption in the United States.
2. Place United States industry in a better competitive position.
3. Increase the energy efficiency of industrial cogeneration plants.
4. Improve the economics of cogeneration plants to stimulate greater use and implementation into the industrial marketplace.
5. Develop new products to serve the advanced cogeneration system market.
6. Develop the technology and systems that will allow United States industry to convert to "readily available" fuels, such as coal.

Phase I was a feasibility study to determine the optimum system and resulted in the configuration illustrated schematically in Figure 3 (Ref. 1) . The selected system has a Solar Turbines Incorporated Centaur H gas turbine engine, a supplemental-fired high temperature/high pressure Once Through Steam Generator (OTSG) producing 1500°F/1500 psia steam, and an advanced high efficiency (81%) back pressure steam turbine capable of accepting steam at these elevated conditions. Steam exits the turbine at around 166 psia (366°F saturated steam) and is used for heating in a thermal process.

The feasibility study showed that advanced steam conditions of 1500°F and 1500 psia offers a major economic impact and a step improvement in cogeneration system performance. The unique characteristic of this system is that the OTSG produces and the turbine is designed for steam at very high temperatures, 1500°F, to maximize the output power and improve the economics of industrial cogeneration. The economic improvement results not only from the greater efficiency of steam to electric energy conversion obtained with the higher system operating temperatures but also from the higher efficiency steam turbine design.

The high temperature and pressure steam generator and turbine are both new technologies that needed to be verified in the early phases of this program. Thus, a five hundred hour steam generator verification test was performed in Phase II and the results are the subject of this report. Concurrently in Phase II, the preliminary design of a high efficiency steam turbine to accept the 1500°F/1500 psia steam was performed and is the subject of a separate report (Ref. 2).

A full size steam generator and turbine are being built in Phase III of the program (currently near conclusion), and will be tested for one hundred hours at Solar Turbines Incorporated. Testing during this phase will verify performance of the final configurations of the OTSG, steam turbine, and controls.

The final phase of the program (IV) will install both the steam generator, turbine, and controls built in Phase III into a complete system for installation and long term testing at

Figure 1. Ideal steam Cycle Efficiency

Figure 2. Electrical output From Back Pressure Steam Turbo-Generators

Figure 3. Advanced Cogeneration System

an industrial field site. A detailed evaluation of the operations, durability, and performance will be made on the system and its components following one thousand hours of operation.

TESTING

The 500 hour proof of concept testing of the OTSG during the Phase III consists of a 1/6 "slice" of the full size once-through steam generator. These tests verified the design concept, performance and operating characteristics of the OTSG at the design steam conditions of 1500°F/1500 psia. Testing revealed some minor problems and design changes were recommended for incorporation into the full size unit to correct these deficiencies. A "slice" of the full size unit capable of producing 10,000 pounds per hour of steam (versus 56,000 pounds per hour for the full size unit) was selected to minimize cost yet prove the design concept. The OTSG "slice" has four of the twenty-four parallel circuits required for the full size unit and each circuit is identical and dimensionally correct with the final design. The four-circuits of the OTSG slice are seen in Figure 4 prior to installation and clearly shows the vertical serpentine once-through serpentine arrangement. Figure 5 shows the test set up and identifies the major system components.

RESULTS

The OTSG passed the 500 hour test goal by successfully completed over 527 hours of operation at $1500 \pm 20^\circ\text{F}$ and 1500 ± 15 psia with no failures or problems. Post-test examinations of the superheater tubes showed only the normal oxide layers and no deterioration that would limit long term life. Other test result were:

Figure 4. 1/6 Slice of 1500°F/1500 psia Once Through Steam Generator (OTSG)

Figure 5. 1500°F/1500 psia Once Through Steam Generator Under Test

- Thermal and mechanical performance was very close to predicted values and there were no difficulties in attaining the 1500°F/1500 psia outlet steam conditions.
- There were no noticeable differences detected between up flow or down flow boiling in the vertical tubing.
- There were no boiling flow instabilities detected and the outlet steam conditions were extremely steady.
- The preliminary control system operation requirements and procedures were defined for the final system.
- Testing successfully demonstrated an emergency cool down from steady-state operation at 1500°F/1500 psia simulating a total loss of electrical power to the system .
- Candidate furnace and casing insulations were tested and one chosen for use in the final design.
- The inlet gas flow and temperature distributions from the burner and combustion chamber into the OTSG were better than expected and very uniform over the entire OTSG inlet.

- In general, there was no distortion, creep, erosion, corrosion, or cracking on any of the OTSG tubes, including those operating at or over 1500°F. Some of the screen tubes were bent when mechanical interference occurred with the gas seal/spacer arrangement, but bending should not be a problem on the full size unit when design changes are incorporated.
- The testing revealed operating characteristics of the OTSG system and established operating procedures for specifying and designing the full size unit control system.

CONCLUSIONS

The testing showed that the OTSG can produce steam at 1500°F/1500 psia and survive with no detrimental effects. All test objectives were successfully completed with the exception of total automatic operation which was not attempted because of problems with the controller. The successful completion of the tests led to the following conclusions:

- The test verified the proof-of-concept OTSG by operating at 1500°F/1500 psia and successfully completing over 527 hours of testing.
- The testing also verified the performance calculations and provides additional confidence that the full size OTSG will perform as designed.
- Even in a manual control mode, the OTSG experienced no control problems or instabilities and no problems are anticipated with implementing fully automatic control.
- The OTSG demonstrated that it can survive the thermal effects of a complete power outage from full load operating conditions.

RECOMMENDATIONS

Building and testing the OTSG for over five hundred hours revealed some short comings that can be corrected by implementing the following recommendations:

- The insulation materials and casing designs need further test data to determine proper installation techniques and suitability for the environment. If necessary, bench testing of different types of candidate insulation materials should be performed to verify performance.
- An inlet valve at the entrance into each circuit is recommended for the initial full size OTSG. This will provide positive and variable control of the flow into each circuit and provide compensation for any edge effects or other system nonlinearities that may lead to tube or outlet header over temperatures. The valves can be replaced with fixed orifices later, if necessary.

- Closer coordination with the steam conditioning valve manufacturer is necessary to obtain a workable design with materials suitable for the environment.
- The brazing of the fins onto the thick wall superheater tube should be investigated early in the next phase. Problems encountered during Phase II suggests that major improvements in the quality of the brazing and fin/tube joint can be obtained on the full-size unit.
- Gas seals in the screen tube section of the OTSG need to be redesigned or eliminated to prevent over-lapping resulting in bent tubes.

1.0

INTRODUCTION

Industry has essentially been at a 1000°F steam plateau for almost fifty years. In the late nineteen fifties the Philadelphia Electric's Eddystone plant introduced 1200°F steam in a large coal-fueled central utility plant. This plant had exceptional efficiency but was not duplicated in subsequent plants. The large central power plant design, which has been the traditional leader in steam conditions, backed away from 1200°F steam in the nineteen sixties and reduced its operating temperature to 1130°F to increase availability. Subsequent powerplants were built in the 1000°F to 1100°F temperature range totally abandoning the higher temperatures. Utility development concentrated on coal-fueled plants at high pressures (2400 to 5000 psia) and steam temperatures where the coal by products caused fireside corrosion and erosion in the finishing superheater. With the materials and designs available at that time, a reduction in temperature was the solution to reduce fireside attack.

In the nineteen sixties the low cost of energy and the anticipation of nuclear power for base load utility power generation eliminated incentives to solve the material and control problems of super critical high temperature steam. The initial application of coal fired steam generators supplying high temperature steam to large high pressure turbines for electric utility central plants added two major difficulties that contributed to a reduction in steam conditions. The first difficulty was coal corrosion at high temperatures and the second was the size of the plant. At the hundreds of megawatt size, the technical and economic risks were too great and could not overcome the electric utility incentives of the time.

With new high temperature materials and technology developed in the last thirty years, industrial cogeneration applications in the 5 to 20 megawatt range offers an ideal opportunity to increase steam temperatures and provide industry with major performance and economic gains. In many small cogeneration power plants, natural gas can be economically justified but extremely high pressures are usually not optimum. Thus, high temperature steam can be economically introduced, first on natural gas with moderate pressures, then the coal-fueled option, and finally the larger utility option at higher pressures.

Recent advances in small once-through Alloy 800 steam generators, improved materials technology, and application of small industrial gas turbine technology to steam turbine cogeneration offers the potential to make a step increase in steam temperature to 1500°F. In small cogeneration systems, it is economically practical to introduce new technology to make a step change in temperature where it may not be possible (given the regulatory environment and economic risk) for a major change in steam temperature to be introduced in the hundreds of megawatt size of an electric utility.

Solar Turbines Incorporated and the Department of Energy (DOE) have combined to take advantage of these new technologies with a program whose goal is to approach the limits attainable with current metals and demonstrate the operation of a Once Through Steam Generator (OTSG) and steam turbine at 1500°F/1500 psia.

Solar Turbines Incorporated is conducting a four phase program to design, fabricate, and test an advanced high performance steam system for industrial cogeneration operating at 1500°F/1500 psia. The program co-funded as DOE contract DE-AC02-85CD40746 has currently completed the first two of four phases. Both DOE and Solar Turbines Incorporated have set the following goals for this program:

1. Reduce the fuel consumption in the United States.
2. Place United States industry in a better competitive position.
3. Increase the energy efficiency of industrial cogeneration plants.
4. Improve the economics of cogeneration plants to stimulate greater use and implementation into the industrial marketplace.
5. Develop new products to serve the advanced cogeneration system market.
6. Develop technology and systems that will allow United States industry to convert rapidly to available fuels, such as coal.

The first phase of the program was a feasibility study that concluded advanced steam conditions of 1500°F and 1500 psia offer a major positive impact and a step improvement in cogeneration system performance. The Phase I objectives were to:

1. Establish design criteria for industrial cogeneration plants above 4 megawatts.
2. Perform systems tradeoff studies.
3. Determine system energy and mass balance diagrams.
4. Perform component design tradeoffs.
5. Evaluate steam generator materials at 1500°F and 1500 psia in a test loop to prove the suitability of several gas turbine alloys for steam environment.
6. Select successful candidate systems and components.

The resulting system, illustrated schematically in Figure 3, has a Solar Turbines Incorporated Centaur "H" gas turbine engine, supplemental-fired high-temperature/high-pressure once through steam generator producing 1500°F/1500 psia steam, and an advanced high efficiency (81%) back pressure steam turbine capable of accepting these elevated steam conditions. Steam exits the turbine at 166 psia (366°F Saturated steam) and is used for heating in a thermal process.

The feasibility study showed that increasing the peak steam temperature in the cycle allows either more work to be extracted or electrical power to be generated for a given quantity of heat input. Figure 1 shows steam cycle efficiency as a function of superheat steam temperature and pressure for a turbine back pressure of 166 psia. Increasing the

steam conditions from the typical current practice of 900°F and 900 psia to 1500°F and 1500 psia will increase cycle efficiency by 53%.

Combining an advanced high efficiency steam turbine with the increased cycle efficiency resulting from the higher operating temperatures provides a substantial increase in turbine output for a given steam flowrate. Figure 2 shows that the output power of an advanced high temperature steam turbine is approximately twice that of a current industrial practice turbine for the same turbine flowrate. Thus the program goal is to advance the state-of-the-art and operate a complete cogeneration system at 1500°F/1500 psia.

The unique characteristic of this system is that it uses very high temperature steam (1500°F). The high temperature and pressure maximizes the output power from the steam turbine and improves the economics of industrial cogeneration. The economic improvement results from not only the greater efficiency of steam to electric energy conversion with the higher temperatures in the cycle but also from the higher efficiency steam turbine (81%) design.

The high pressure, high temperature steam generator and turbine are both new technologies that need to be verified early in the program to reduce the risk of installing a full size unit at an industrial site. Prototype testing of the OTSG was performed during Phase II and is the second phase of a four phase program. The Phase II test objective was to provide early verification of the OTSG design, performance, operation, and life by testing a smaller than full size steam generator module producing 10,000 pounds per hour of steam (versus 56,000 pounds per hour for the full size system) at 1500°F and 1500 psia for 500 hours. During testing, the OTSG was operated for 527 hours at 1500°F/1500 psia steam conditions and verified the design integrity and feasibility of the concept. The results of these tests are the subject of this report.

Phase II also included the preliminary design of a 4.0 megawatt back pressure steam turbine. This turbine will expand 56,000 pounds per hour of steam from 1500°F and 1500 psia to a back pressure of 166 psia. This design is the subject of a separate report (Ref. 2).

Phase III of the program is currently in progress and is designing, fabricating and will test a system to verify the operation of a full-size steam generator and advanced 4.0 megawatt steam turbine operating with 56,000 pounds per hour of steam at 1500°F/1500 psia. The steam generator, steam turbine, and controls will be tested for one hundred hours at Solar Turbines Incorporated test cells to prove their integrity, performance, and suitability for installation in a field test site.

The final phase of the program (Phase IV) will install both the steam generator and turbine built in Phase III into a complete system for long term testing at an industrial field site. An evaluation of the operations, durability, and performance will be made following the first one thousand hours of operation. Additional monitoring and evaluations will be made periodically during the life of the unit but are not part of this DOE contract.

1.1 TEST OBJECTIVES

The program goal is to obtain greater operating efficiencies by operating steam systems at 1500°F and 1500 psia. Since this is far above the normal operating range for current industrial and utility systems, it represents new technology and has a risk associated with its success. Phase II tested a slice of the full size OTSG to verify the concept and design of high temperature steam generation early in the overall program so that it could affect final design.

The primary test objective was to verify the mechanical and thermal operation of the vertical tube OTSG by operating at 1500°F/1500 psia for five hundred hours. More specific objectives were to:

- Determine the effects of inherent inlet gas flow or temperature mal-distributions on OTSG performance.
- Verify the radiation heat input to the OTSG.
- Verify OTSG tube matrix performance and overall heat transfer.
- Verify system performance of OTSG related components.
- Evaluate controls strategy and requirements for the full size OTSG system.
- Obtain data on transient response of the OTSG in a variety of operating conditions.
- Determine preliminary full-size OTSG start-up procedures.
- Obtain temperature profiles on tubes and structure to use in detailed stress analyses.
- Identify metallurgical problems including deterioration, distortion, and creep, on the OTSG tubing, especially in the high temperature regions.
- Determine OTSG performance at part load and off-design conditions.
- Determine if the OTSG has any boiling flow stability problems.

2.0

TEST CONFIGURATION

Testing was performed on a 1/6 slice of the full size unit (Figure 6) which produces approximately 10,000 pounds per hour of steam and provides an economical way to obtain results on prototype units with minimal construction, manufacturing, and operating costs. Solar Turbines Incorporated has tested "slices" of its production OTSG's and has obtained excellent correlation of results when compared to the full size unit's performance because the OTSG has multiple circuits that are each identical with one another from inlet to outlet headers. Thus true scaling of the size can produce very close results to the full size unit performance as each circuit performs identically to all the others.

The only area where performance adjustments are necessary, is in the relationship between the edge effects to the total heat exchanger. Past tests using the same technique show that edge effects only significantly affects the gas side pressure drop results and very good correlation in heat transfer performance can be obtained between a slice and the full size unit.

2.1 OTSG CONFIGURATION

The once-through steam generator concept is a continuous serpentine tube in which preheating, evaporating, and superheating of the working fluid takes place consecutively (Figure 7). In practice, many circuits are mounted in parallel and joined by headers to provide a common inlet for feedwater and a outlet for the steam. A pump forces feedwater through the circuits and superheated steam exits at the outlet header.

The main difference between the once-through and a recirculation type steam generator is the absence of drums. In a once through steam generator, there is no drum to separate the solids containing boiler water from the steam. As the feedwater evaporates, some of the solids, dissolved or suspended, in the feedwater will deposit in the dry-out section. The solids not deposited in the steam generator will be carried over and can be deposited in the steam turbine. Therefore, the feedwater must be of high quality and very low in suspended and dissolved solids to successfully operate an OTSG system.

An advantage to the once-through steam generator is the simplicity in the mechanical hardware and controls that should increase the overall reliability of the system. A simpler system requires less maintenance because there are fewer components which should decrease the repair outages. Because there are fewer components in the system, higher quality and more reliable components can be purchased to further increase system reliability.

In the past, Solar Turbines Incorporated has built horizontal tube OTSG's to recover waste heat from gas turbine engine exhausts. These units generally operated around 1000°F with gas turbine exhaust gasses and some supplementary fired units were operated as high as 1600°F. At these temperatures, the support structure is normally in the gas path and can withstand the hot gas environment with the proper selection of materials. Firing to 2500°F requires the use of another approach as any metal support structure in the gas stream would not survive.

Figure 6. Laboratory Steam Generator Test Unit

Figure 7. Once-Through Boiler Schematic

Unlike the horizontal tube units, the vertical tube layout eliminates most of these problems. The vertical arrangement simplifies the design by hanging the circuits from the U-bends, as seen in Figure 8, and removes the supporting structure from the hot gas stream. Another advantage of this concept is that the tubes are allowed to grow, unrestrained, towards the bottom of the case and simplifies the accommodation of large thermal expansions from ambient to over 1500°F.

To prevent overheating of the superheater tubes as the result of any edge effect problems, needle valves were installed at the entrance to each of the four circuits as a variable inlet orifice. Thermocouples mounted on the tubes just prior to entering the header measured the exit steam temperature and flow adjustments were made to equalize the exit steam temperatures and compensate for any edge effects or flow maldistributions.

A controlled flowrate to each circuit guarantees forced circulation in each and every circuit of a once-through unit and prevents dryout or burnout commonly seen with natural circulation boilers having water flow distribution problems in high temperature operation.

2.1.1 Steam Generator Design Criteria

The long operating history and many unique advantages of Solar Turbines Incorporated once through steam generator was the baseline for the high temperature/high pressure OTSG design. A few additional criteria were necessary to accommodate the higher steam temperatures. Some of the overall design criteria for the steam generator and casings were:

- The unit or modules should be truck transportable.
- The OTSG should be built in accordance with Section I of the ASME Boiler and Pressure Vessel Code.
- The OTSG should be of modular construction for scaling to other applications.
- The design should minimize flame radiation to the hot superheater tubes.
- The highest temperature superheater section should be removable for repair and/or replacement.
- The unit must accommodate thermal expansion over the range of operation.
- The OTSG should be completely shop fabricated to minimize field erection, welding, and construction costs. This criteria also maximizes the advantages of automated and assembly line operations used in the OTSG fabrication.

Figure 8. Vertical OTSG Layout

2.1.2 Steam Generator Configuration

The steam generator flow schematic, shown in Figure 9, is a vertical once-through cross counterflow configuration with a vaporizer screen similar to a Benson type boiler. Once-through here means that the water entering the steam generator flows through the unit once and exits into the outlet header as superheated steam. There is no recirculation or steam drums. In a steam generator fired behind a gas turbine engine, the maximum supplemental firing temperature limit occurs by burning all the oxygen remaining in the gas turbine exhaust. This typically results in a maximum gas temperature of around 2500°F and was the baseline for the current OTSG and burner designs.

Figure 9. OTSG Steam Flow Schematic

The OTSG tube circuit diagram is shown in Figure 10 and identifies the different steam regions at the full load design condition. Twenty-four of these circuits are assembled together to make one full size OTSG and four of these were used in the current OTSG "slice" tested in this phase. The feedwater flow generally follows a counterflow arrangement (except for the jump to the screen tubes), entering at the right, in the cool exhaust, and serpentine vertically up and down towards the hotter gases and steam outlet header on the left. Finned tubing maximizes the heat transfer throughout the steam generator except in the first 6 rows where bare tubes provide a radiation screen for the rest of the steam generator at the gas entrance.

PD91204M

Figure 10. Test Circuit Layout

The feedwater enters the OTSG preheater section at 170°F and exits at saturated liquid conditions. The saturated water then flows to the gas inlet or front of the OTSG. This section, called the first vaporizer, has bare tube rows where saturated water begins boiling. The high heat transfer coefficient accompanying the boiling provides sufficient cooling to prevent over temperature of the tube. These bare tube rows also provide a radiation screen for the remainder of the steam generator and since these tubes have boiling water inside, they can withstand the large radiation heat inputs from the flame and hot walls of the upstream ducting. Finned tubes in this area would transfer too much heat and have high fin tip temperatures requiring super alloy materials and short fins to limit the maximum temperatures.

Just two rows of bare tubes will reduce the radiation to the third row by almost 75 percent. More importantly, the bare tube vaporizer will lower the gas temperature entering the superheater tubes and should make the outlet steam temperature easier to control (because there is less temperature difference between the gas and steam temperatures).

The radiation screen provided by these tubes will also prevent thermal radiation emitted from the flame or combustion chamber walls from impinging directly on the hottest superheater outlet tubes which could cause severe circumferential thermal gradients and hot spots. The superheater outlet tubes are already operating near the maximum temperature (1600°F) and stress allowable for the alloy and any large temperature gradients should be avoided to prevent exceeding these allowable.

Since boiling cools the screen tubes to such a large extent, a material such as Alloy 800H (that has some strength at temperatures above 1600°F) can be used even in these hot gas regions. However, stress allowable can be exceeded if boiling disappears and superheat occurs in these tubes. Therefore to prevent potential damage and tube ruptures, a maximum steam quality of seventy percent leaving the bare screen tubes is the design goal to assure the nucleate boiling is occurring at all times and under all load conditions. Relatively thin wall tubing can still be used because the high boiling heat transfer coefficient forces the tube wall to the saturated steam temperature where the material stress allowable are still high.

The water/steam leaving the bare tube vaporizer or radiation screen moves back to a cooler gas region for the final heating to saturated vapor conditions (100% steam quality) in the vaporizer section. In this manner, dryout can occur in a cooler gas region to prevent any chance of tube burnout as the gas temperatures are well below the maximum allowable metal temperatures at the operating pressure. Dryout is defined as the region where the water can no longer wet the wall but is immediately turned to steam vapor. Once dryout occurs, the cooling resulting from the large nucleate boiling heat transfer coefficient disappears and the tube wall temperature rises. Since the dryout point wanders back and forth, even with steady input conditions, it is advantageous to maintain this point in a gas temperature zone where it will not cause problems.

Once the steam approaches 100% quality, superheating begins. The superheater has two separate regions. The first region uses current Solar Turbines Incorporated steam generator production materials, Alloy 800H, and raises the temperature of the steam to approximately 1200°F. The second superheater region uses a superalloy material (Alloy 617) where the steam is heated to the final outlet temperature of 1500°F.

It should be noted that in a once-through serpentine arrangement, no physical differentiation between the various sections (e.g. preheater, vaporizer, etc.) is evident but the steam generator is similar to a long continuous tube. The exact locations of the beginning and end of each section will vary with load conditions. Thus, the unit can accommodate large load changes because the superheater tube length and area is variable and not fixed as in conventional boilers.

Table 1 summarizes the tubing materials used in the OTSG. Alloy 800 is also the only austenitic material allowed by the ASME Boiler and Pressure Vessel Code for use in water wetted parts (Code Case 1325). A non-corrosion material is required for the current once-through water treatment scheme that does not control the oxygen content of the feedwater. Above 1200°F metal temperatures, Alloy 617 is the only material available that will survive the environment and allowed by the ASME Boiler and Pressure Vessel Code (Code Case 1956).

Table 1. OTSG Tube Materials

Section	Tube Materials	Tube OD x Thickness	Fin Material
Preheater	Alloy 800H	1.00 in. x 0.072 in.	SS 409
Vaporizer	Alloy 800H	1.00 in. x 0.072 in.	SS 409
1st Superheater	Alloy 800H	1.00 in. x 0.156 in.	SS 310
2nd Superheater	Alloy 617	11.00 in. x 0.156 in.	SS 310
Outlet Superheater	Alloy 617	1.25 in. x 0.375 in.	SS 310
Screen Tubes	Alloy 800H	1.00 in. x 0.72 in.	None

Figure 11 shows the tube matrix pattern for all finned tubing and does not include the six bare tube rows of the screen section that are on a special pattern to block all incoming thermal radiation. Each circuit contains 44-fourteen foot long tube rows (38 finned and 6 bare) and the slice consisted of four such circuits.

The last two rows of superheating use five circuits of thick walled (1.25 in. x 0.375 in. wall) tube. The transition from four to five superheater circuits is accomplished by using an intermediate header which not only accommodates the uneven inlet and outlet tubes, but provides a break for removing the final two rows of superheater tubes where problems are likely to occur. The last two rows superheat the steam from 1200°F to 1500°F and require greater wall thicknesses to satisfy the stress requirements of the ASME Boiler and Pressure Vessel Code. Larger diameter tubing and one extra circuit was necessary to provide enough internal flow area to keep the steam side pressure drops down to an acceptable level. One extra superheater circuit is necessary for each four normal circuits and is another reason the test "slice" consisted of four circuits.

Figure 11. Baseline OTSG Core Configuration

The last two rows, or final superheater, was 1.25 inch OD by 0.375 inch thick wall Alloy 617 tubing and is not manufactured in the heavy wall thickness required for this application. Instead, it was made from 1.25 inch diameter Alloy 617 bar and gun drilled to the final dimensions.

The boiler tubes hang vertically, as seen in Figures 12 and 13, so that the tubes can be supported out of the gas stream from the top and thermal growth occurs towards the bottom. At these temperatures, it is mandatory to accommodate the thermal growth of not only the boiler but of the structure to prevent permanent distortion and large induced stresses.

Figure 14 shows the region around the intermediate and outlet steam headers where the tube supports holding the OTSG to the upper structure can be seen. The "J" hangers installed along the length of the tube bundle are the structural components that support the entire weight of the tube bundle. Stress analyses located these hangers along the tube matrix to hold the bundle weight at temperature yet allow the tube bundle to grow and expand freely with minimum induced stresses.

The "J" hangers are simply bar stock formed in the shape of a "J". Thick wall tubing, however, was used to make the hangers in the very hot gas areas near the screen tubes so that they could be cooled by shop air to prevent over temperature of these critical structural components.

The vertical tube arrangement eliminates a number of problems such as: (1) the tubes need no mid-span or bottom end support and as such, require no structure in the hot gas stream, (2) the top support can be removed from the direct gas path thus making the design of the supporting structure an easier and more manageable task, and (3) the out-

Figure 12. OTSG Tube Assembly Prior to Installation (Gas Flows From Right to Left)

Figure 13. OTSG Installed Into Case With Furnace Section and Air Blower at Right

Figure 14. OTSG Outlet and Intermediate Headers and Hanging Arrangement

let header can be enclosed in the boiler casing to minimize leakage of hot gases to the ambient while keeping circumferential and longitudinal thermal gradients to a minimum.

2.2 SYSTEM DESCRIPTION

A schematic of the test installation (Figure 15), shows an atmospheric burner firing into a combustion chamber to supply hot gases to the OTSG. The burner, seen in Figure 16, is a single Coen Company, Inc. model CPF-19 designed for a 24 million Btu/hour heat release and is capable of heating ambient air to 2500°F. It has a 10:1 turndown for part load operations and automatic push-button starting with safeties for automatic shutdown that are independent of the microprocessor and control system. A blower supplies ambient air to the burner and has inlet louvers (actuated from the control room) to regulate the air flow. The burner discharges into an eighteen-foot-long chamber to ensure that combustion is complete prior to entering the OTSG. The combustion chamber and OTSG casing are of all welded construction to prevent any gas leaks to ambient and are internally insulated with one foot of ceramic fiber insulation.

The water/steam system (also shown in Figure 15), is an open loop system that discharges the steam generated to the atmosphere. This requires a continuous full flow make up water demineralizer to polish the feedwater. The demineralizer polishing units

Figure 15. Laboratory Steam Generator System Test Schematic

Figure 16. Overall View of Burner Controls and Air Supply Subsystems

clean city water to the required chemical and solids levels prior to entering the OTSG. Only one of two parallel full flow polishing trains was used at a time to condition the feedwater and an exhausted train could be switched with a fresh set without stopping the test. The deionizing (DI) system consisted of cation, anion, and mixed bed tanks located on trailers. A fresh set of resins lasted about twenty-four hours, then were removed to an off site location for regeneration. The removed trailer was replaced with a trailer containing fresh resins and was ready for use when the current train was exhausted.

The feedwater pump was a triplex piston pump equipped with dampers at both inlet and outlet ends to minimize the pressure and flow pulsations. The 2100 psig water discharged from the pump flowed to a distribution manifold where three control valves distributed the water to: (1) the outlet steam desuperheater, (2) a pump bypass line (to maintain a minimum flow through the pump), or (3) to the OTSG inlet distribution header.

Manually operated needle valves at the entrance to each circuit metered and controlled the flow into the OTSG. Thermocouples were placed on the tubes just prior to entering the intermediate header and after reaching steady state operating conditions, the needle valves were manually adjusted to provide equal steam temperatures from each circuit. This flow control method compensated for any mal-distributions of gas and guaranteed even temperature distributions throughout the header and final superheater tubes.

The steam exhaust line exited from the tip of the OTSG case, shown in Figure 17, and consisted of a safety relief valve, steam conditioning valve, six inch piping and a silencer. The steam conditioning valve operated at 1500 psia and 1500°F and provided control for the OTSG outlet pressure as well as desuperheating the outlet steam prior to being discharged to the atmosphere. The desuperheating water entered the valve and mixed with the steam flow to lower the steam temperature from 1500°F to about 600°F. Besides lowering the temperature, the conditioning valve dropped the steam pressure to below 200 psia so that the downstream piping could be made from lower alloy materials. The valve body was made from Hastelloy X to withstand the operating temperature and pressure and is similar to that type of valve required on the full-size system.

During start ups and shut downs, large amounts of water would exit the OTSG. A "tee" in the discharge line acted as a separator and the water flowed downward to the drain and the vapor discharged upward through the silencer. A manually operated hand valve controlled the water discharge to drains.

2.3 DUCT AND FURNACE INSULATION

Twelve inches of internal ceramic fiber insulation were installed in the ducting and furnace casings to keep the outer casing metal temperatures below 125°F. Two different types of internal "hot" insulation materials were installed for the test as listed in Table 2. The internal hot insulation is preferred to metal liners with external insulation because it (1) avoids the required cooling of a large surface area of metal at very high gas temperatures and (2) keeps the metal casing cool so that thermal expansions are not a problem on this large structure. Only a small eight square foot section of the 15-C board was tested with the majority of the insulation being the Unibloc ZR material.

Figure 17. Overall Test Installation Showing Outlet Steam Piping

Table 2. Chemical Composition of Refractory Materials in the Furnace

Description	Weld on Module Unibloc 12#ZR*	15-C Board*
Density (lb/cu. ft)	12	12
General Use Limit (°F)	2600	2600
Melting Point	3200	3300
Alumina (Al ₂ P ₃) (%)	32-36	64
Silica (SiO ₂) (%)	45-48	36
Zirconia (ZrO ₂) (%)	18-21	--
* Thermal Ceramics Company		

3.0

CONTROLS AND INSTRUMENTATION

The controls philosophy adopted for this test was for the OTSG to be manually controlled with computer assist in monitoring the alarms and shutdown criteria. The unit would always be manually started and an operator would always be in attendance to control the natural gas flow to the burner and feedwater to the OTSG. The microprocessor controller (Fisher-Porter Model 40 MC) would monitor the steady state operation of the system, adjust some non critical valve positions, and check all alarms and shutdown criteria. If the computer detected a channel in an alarm state, it automatically sequenced and shut down the burner and system. A simplified control system logic diagram is shown in Figure 18.

The operators control console, seen in Figure 19, shows the burner, feedwater pump, and blower motor controls in the panels on the far left. Above these panels are the feedwater and outlet steam pressure gauges. The microprocessor controller, seen in the center, would (1) monitor the various system measurements, (2) indicate when a data channel is over the set point limits and (3) provide automatic shutdown of the system if a critical parameter exceeded its preset limit. All data channels had audible alarm limits but only critical channels would cause the system to be automatically shutdown if exceeded. The controller would automatically position the bypass control valve and desuperheater control valve.

Figure 18. Control System Flow Diagram

Figure 19. Operator Control Console

The operator could manually operate any or all of these valves if desired but was mainly responsible for controlling the feedwater supply valve and natural gas flow to the burner. The data acquisition system (DAS, shown on the right side) is separate from the controller and consisted of four parts: (1) the computer that reads all data channels, converts to proper units and performs mathematical functions (for example calculates the pounds per hour of air flow from venturi measurements); (2) A separate DAS video screen for displaying all data channels; (3) the printer for obtaining a hard copy printout of all DAS channels; and (4) a disk drive system for storing all data channels locally. Finally, the digital readouts for the "R" type platinum-rhodium thermocouples that measure the gas inlet temperature to the OTSG and a strip chart recorder are seen above the DAS screen.

3.1 MEASUREMENTS

Table 3 is a list of the measurements required for safe operation and overall performance of the OTSG. These measurements were always displayed and continuously updated on the DAS screen during the test and contain all the required operating parameters for safe control the system.

Table 3. Measurements Required for System Operation

Gas Inlet Temperature to CTSG
Fuel Flowrate
Outlet Steam Pressure
Outlet Steam Temperature
Exhaust Steam Temperature Downstream of the Desuperheater
Feedwater Flowrate
Outlet Superheater Tube Wall Temperatures
Combustion Air Flowrate
Screen Tube Temperatures
Flue Gas Temperature in Stack
Feedwater Pressure
Feedwater Inlet Temperature
DI Outlet Specific Conductivity
Tube Temperatures into Intermediate Header

All other measurements are non-essential for immediate control of the system but may, nonetheless, be vital in determining performance or suggest performance changes in the OTSG.

The DAS monitored all 230 data channels and the non-essential data could be displayed at any time on the video monitor at the operators request or printed out.

3.2 DATA ACQUISITION SYSTEM

Complete data points (all data channels) were taken periodically and usually at one hour intervals during the test. Data acquisition monitoring and recording used a Digital Equipment Corporation (DEC) PDP 11/34 computer and an associated input cabinet. The DAS accepted all data inputs, applied standard calibration/correction factors to the required channels, and performed simple engineering calculations. The data could be stored on a disk drive or displayed in a page format at the local video display. The system monitored over 230 channels of temperatures, pressures, and flow data, throughout the OTSG, burner, air supply, feedwater, and natural gas systems as summarized below:

Type "K" Thermocouples	210 channels
Type "R" Thermocouples	3
Frequency (flow) measurements	4
Pressure Inputs	13

Figure 20 shows the instrumentation installed on one of the two interior OTSG circuits. Temperatures at many U-bend locations provided data for determining the dryout transition locations and OTSG performance as the water/steam progresses through the circuit.

Figure 20. Typical Circuit Temperature Instrumentation (All Tube Wall Measurements)

4.0

TEST RESULTS

The objective of the test was to verify a 1/6 slice of the OTSG by operating the unit at 1500°F/1500 psia for five hundred hours and obtain information regarding the mechanical design and performance. The results would provide valuable design data as well as added confidence in the design of a full size unit. Testing was performed between October 1989 and February 1991 in the combined cycle facility of Solar Turbines Incorporated's Kearny Mesa plant in San Diego, California. Testing included a total of 49 starts/stops with a total OTSG steaming time of six hundred and thirty-five hours of which five hundred and twenty-seven hours were at the design conditions of 1500°F/1500 psia.

The test objective was to obtain five hundred hours of operation at 1500°F/1500 psia on the OTSG and not duplicate, but only approximate, the full size system exhaust gas conditions. An exact simulation is extremely difficult because the exhaust gas composition of a gas turbine engine with supplemental burner cannot be easily matched with a single ambient burner firing to 2300°F.

Table 5 shows a comparison between the test and two proposed full scale engine installations. The actual test conditions closely approximates that using a Solar Turbines Incorporated Taurus gas turbine engine which is the first choice of two candidate engines proposed for the full-size system.

The OTSG operated briefly at 2500°F inlet gas temperatures during checkout but most of operation was in the 2200-2300°F range. There is some concern that the insulation materials and casing did not experience the maximum temperatures possible in the worst case design, however, these lower gas temperatures had little effect on the OTSG results, operation, or conclusions. Although the insulation did not experience the maximum temperatures that it would be exposed to in a Centaur installation, it did, however, experience temperatures that approximate the conditions expected with a Taurus engine installation.

The test had lower feedwater inlet temperatures and water vapor content in the gas than predicted for the final design and both conditions would tend to lower the OTSG test performance when compared to actual conditions. The lower feedwater inlet temperature would cause the OTSG to vaporize less steam for the same OTSG surface area as some surface would be used in heating the water from the test condition of 60°F to the anticipated system supply temperature of 170°F.

Similarly, the lower water vapor content in the gas stream during the test would lower the performance as the gas temperature would drop faster for a given heat extraction thereby lowering the temperature differences and heat transfer in the OTSG. Therefore, the test is a conservative simulation of the conditions that the OTSG will experience in an actual installation.

Table 6 summarizes the significant events that occurred during the 500 hour endurance phase of the testing. The major problem during this test was with the steam conditioning valve which soon after the initial start-up became inoperable. Inappropriate material

Table 5. Test Comparison With Scaled Engine Conditions

Description		Test	Centaur	Taurus
Gas Flow	pps	8.07	6.74	7.76
Gas Temperature	°F	2280	2500	2240
Outlet Steam Temperature	°F	1500	1500	1500
Outlet Steam Pressure	psia	1500	1500	1500
Feedwater Inlet Temperature	°F	60	170	170
Exhaust Gas Composition				
N ₂ (by vol)	%	73.45	72.60	72.11
O ₂	%	9.06	5.42	7.39
CO ₂	%	6.89	7.20	6.12
H ₂ O	%	10.60	14.78	14.38

Table 6. Summary of Endurance Testing

<u>Date</u>	<u>Description</u>
12/11/89	Started 500 Hour Endurance Test
12/15/89	Shutdown - Power supply on controller failed causing unscheduled automatic shutdown from about 1500°F with full cold air flow and no fuel flow (107 hrs accumulated).
12/18/89	Resumed Testing
12/22/89	Shutdown - Operator error - Tripped natural gas valve to automatic that shut down the gas flow and flamed out. Did not restart because of Christmas plant shut down (81 hours).
1/8/90	Resumed Testing
1/10/90	Manual Shutdown - Cage in steam control valve made of SS410 that crept and deformed closing off orifices. Steam/water flow had dropped off to a point where we could no longer maintain outlet temperatures above 1475°F without causing the screen tubes to rise above saturated conditions. Intermediate header was also 100°F above design conditions at close to 1400°F (47 hrs).
1/24/90	New valve parts installed - testing resumed
1/24/90	Unexplained burner shutdown - resumed test (44 hrs).
1/26/90	Over temperature shutdown from 1550°F/1500 psi - operator error - test resumed (14 hrs).
1/28/90	Normal shutdown for weekend. Facility power down for weekend.
1/29/90	Resumed testing
1/30/90	Shutdown; controller power supplies went dead causing fuel valve to shut. Restarted (21 hrs).
1/31/90	Pump cylinder failed causing shutdown (12 hrs).
2/1/90	Fixed pump and restarted
2/5/90	Shutdown for 2 hrs to repair pump discharge connection leak - restarted (79 hrs)
2/9/90	Normal shutdown - end of test (110 hrs).
2/14/90	Transient runs
2/16/90	Video and photo runs (12 hrs).
2/19/90	Saturated steam tests

selection caused the orifice holes in the valve plug to creep closed during high temperature operation and restrict the steam flow through the valve. There were also some minor problems with the feedwater pump and the controller power supplies that prevented total automatic operation.

4.1 DATA ANALYSIS

The following averages summarize the outlet steam temperature and pressure during the five hundred and twenty-seven hour endurance test and one hundred sixty-nine data points taken randomly during the test.

Average outlet steam temperature	=	1484°F	$\sigma = 13.9^\circ\text{F}$
Average outlet steam pressure	=	1505 psia	$\sigma = 14.5 \text{ psia}$

At the beginning of the test, the steam conditioning valve, which was also the system pressure control, froze and would not open or close. Both OTSG outlet pressure and temperature control had to be performed by adjusting feedwater flow and firing rate. Difficulties arose in hunting for the right combination of water flow and firing rate to satisfy the outlet steam pressure and temperature test criteria and lead to considerable scatter in the data. After attaining a good steady state operating point, the valve orifices would continue to slowly creep smaller and a new set of feedwater flow and firing rates would have to be found. The average outlet steam conditions, given in Table 7, show a much higher outlet steam temperature with a smaller standard deviation after the repairing the valve.

The test specification allowed the outlet steam temperature to be $1500 \pm 20^\circ\text{F}$ (1480-1520°F) and the outlet steam pressure to be $1500 \pm 15 \text{ psia}$ (1485-1515 psia or 1400-1500 psig). From Table 7, the pressure met the above criteria but the average outlet steam temperature was on the low extreme of the range prior to fixing the steam conditioning valve. After repairing the valve, the average outlet steam temperatures were well within the test tolerance band. Since the test was manually controlled, operators tended to control the system in the 1490-1500°F so that they had some upside margin if perturbations occurred in the system. This happened regularly at the start and end of shifts when the supply voltage for the plant changed causing the pump and natural gas pressure to change operating conditions. This conservative operation resulted in the average outlet steam temperature below 1500°F. Closer control tolerances could have been achieved with fully automatic steady state operation where the computer does not have anxieties inherent with a human operator.

Table 7. Test Data Comparison Before and After Steam Conditioning Valve Repair

Description	Outlet Steam			
	Average Temperature (°F)	Std Dev. Temperature	Average Pressure (psia)	Std Dev. Press.
Pre-Steam Valve Repair (234 Hours)	1480	15.8	1507	16.2
Post-Steam Valve Repair (283 Hours)	1491	7.2	1502	10.2

4.2 OTSG PERFORMANCE

Table 8 shows a comparison of the full load predictions versus the actual test results for a representative full load data point with four of twenty-four circuits. This comparison identifies several items of interest, namely:

1. The test required a higher gas flowrate to keep the burner more stable during continuous operation and prevent erroneous flame out shutdowns.
2. The inlet gas temperature was slightly higher though the steam exit conditions were the same.
3. Gas side pressure drops were about 60% of those predicted.
4. The stack temperature was lower (by 80°F) because of the different gas composition and in particular to the lower water vapor content.
5. The water/steam side pressure drop was about 8% higher than predicted.

Although the test condition was not identical with the design point, the conclusion is that the OTSG performed as well or better than predicted. The OTSG surface transferred the same amount of heat to the steam, even with the lower water content in the gas stream and no problems are expected with thermal performance with the full-size design.

**Table 8. Comparison of Design vs Test Performance
(Data Point #215)**

Description	Design (Scaled Taurus)	Test
Gas Inlet Temperature ~ °F	2240	2270
Gas Flow Rate ~ pps	7.76	8.07
Outlet Steam Temperature ~ °F	1500	1500
Outlet Steam Pressure ~ psia	1500	1500
Feedwater Inlet Temperature ~ °F	170	60
Gas Side Pressure Drop ~ °F	7.1	4.2
Stack Temperature ~ °F	395	352
Heat Transfer ~ Btu/hr/10 ⁶	16.53	16.37
Feedwater Flow ~ pph	9490	9336
Water Side Pressure Drop ~ psi	336	312

During steady state testing, the needle valves controlling the water flow into each circuit were adjusted so that the temperatures of the incoming tubes into the intermediate header were around $1300 \pm 5^\circ\text{F}$. From the start of testing, it was necessary to operate the valve on circuit #4 wide open and a larger valve was eventually installed to allow more water flow into that one circuit. The other three circuits were then adjusted to balance out the temperatures into the intermediate headers.

A large bypass flow was suspected along this side that would keep the gas temperatures higher and increase the heat transferred to this one circuit. Thus circuit #4 would require significantly more feedwater flow to prevent over temperature at the intermediate header. Analysis of the steam temperatures through the circuits concluded that a significant bypass flow exists and that it is much greater in the preheater section than towards the hotter end of the OTSG.

During the test, needle valves controlled the flow into each parallel OTSG circuit. These valves had regulating stems and a 0.250 inch maximum orifice. The flow to each circuit was calculated by measuring the pressure drop across the valve and the flow coefficient obtained from manufacturers' data as a function of the number of turns the valve was open. Table 9 shows the flow calculated for each circuit at full load OTSG operations at 1500°F/1500 psia with a total feedwater flow of around 18 gallons per minute.

Table 9. Calculated Flows to Each Circuit

Circuit	Data of 04-30-90	Data of 05-01-90	Data of 05-07-90
#1	4.86 gpm (26%)	4.64 gpm (26%)	4.54 gpm (25%)
#2	3.21 gpm (17%)	3.46 gpm (19%)	3.20 gpm (17%)
#3	3.55 gpm (19%)	3.62 gpm (20%)	4.21 gpm (23%)
#4	7.18 gpm (38%)	6.28 gpm (35%)	6.43 gpm (35%)
Total Flow	18.8 gpm	18.0 gpm	18.38 gpm

The distribution to each circuit (ideally 25%) is relatively constant from day to day. The data also confirms that circuit #4 is getting the largest flow followed by circuit #1 and confirms the existence of bypass gas flow around both sides of the tube bundle. The middle two circuits are about equal in flow but about half the flow of circuit #4. Remember that these are the balanced flows, that is, each circuit is discharging steam into the intermediate header at the same temperature ($\pm 5^{\circ}\text{F}$) and the steam temperatures into the intermediate header are all equal.

Detailed heat transfer analysis of the circuits led to the conclusion that tubes near the gas inlet or hot end experienced a uniform flow distribution. Bypass flow problems around the tube bundle only occurred near the exit end of the OTSG. This is not a serious problem but, provisions must be made to accommodate the larger required flow in the edge circuits when designing the full-size system or reduce the bypass flow significantly.

There was some concern that the greater heat transfer to the edge circuits, resulting from the greater gas flow and temperatures, may bias the test results somewhat by enhancing the overall heat transfer performance. However, extensive analysis of the heat transfer in each section revealed that the effect is local and should not effect the full size unit which should perform close to predictions.

4.2.1 Gas Side Pressure Drop

The gas side pressure drop across the OTSG tube bundle measured 4.2 inches of water compared to a predicted value of 7.1 inches of water. The existence of large bypass flows around the tube bundle resulted in a lower measured pressure drop because the flow is not passing across the tube bundle. A second effect is that the pressure drop correlation used in the calculations has been, in the past, high when compared to actual test results.

Predicting this gas side pressure drop is very important in the sizing of the OTSG because it is a target value for design and the performance of the gas turbine engine is also dependent upon this value. If the pressure drop is too high, the frontal area to the OTSG must be enlarged up to lower the pressure drop. This reduces the velocity across the tubes, lowers the gas side heat transfer coefficient and requires more surface area. The opposite is true if the pressure drop is lower than the target value and the frontal area must be decreased. Therefore, it is important to predict this value to prevent over or under sizing the heat transfer area in the OTSG.

Since there is a large bypass flow suspected in the test unit, changing the predicted calculation by the full amount would be too optimistic. A reduction of about 85% would be reasonable for the calculation of the full size unit. This would reduce the prediction from around 7.1 to about 6.0 inches of water and is consistent with test results from previous OTSG'S.

4.2.2 Stability

Boiling flow stability has been of some concern with low pressure units but diminishes as the operating pressure increases. The oscillations or instabilities are a result of thermo-hydrodynamic coupling between heat transfer, void, flow pattern and are strongly dependent on system operating pressure.

During the test, the OTSG experienced no tube to-tube or parallel channel instabilities that could be detected. The outlet temperature and pressure fluctuations were almost non-existent and what fluctuations did exist could be traced to fluctuations in the natural gas or feedwater supply systems.

4.2.3 Water Side Pressure Drop

The full load water/steam side pressure drop was 336 psi (inlet to outlet header and excluding the inlet control valve pressure drop at the entrance to each circuit) while the predicted value was around 312 psi for the same flow. This verifies the correlation used for predicting two phase flow pressure drops in the vaporizing tubes.

The edge tubes require larger flow and thus produce higher pressure drops through the circuit. It is important when sizing the feedwater pump to ensure that enough pressure head is available to supply sufficient flow to all tubes even if bypass flows exist in the full size unit.

4.2.4 Hot Shutdown

One concern with a unit operating at high temperatures and pressures, is its survivability following a complete loss of electrical power. This situation was simulated by bringing the unit to steady state conditions at 1500°F/1500 psia and then the feedwater pump, burner, and blower were turned off within seconds of each other to simulate the electrical "blackout". The fan louvers were also closed to prevent any draft that would circulate cool ambient air through the furnace, OTSG, and up the stack.

Figure 21 plots critical OTSG temperatures as a function of time. The plot shows that the hot walls and heat stored in the combustion chamber are the controlling heat sources for the transients after shutdown. Critical items of concern were the temperature profiles of the two headers which could conceivably rise above 1500°F. As seen from the figure, both headers drop off in temperature from the initial steady state value. As the remaining water in the vaporizer and economizer sections evaporates, it forms a cooling front that moves toward the outlet header.

The system pressure drops off very rapidly, lowering the saturation temperature as seen in the first screen tube row next to the combustion chamber. In this tube the temperature initially drops but then rises after the remaining water is evaporated. Circuit #4 has the most water flow but also sees the largest gas bypass flow and dries out first. The screen tube next to the furnace openings reaches 1400°F before it begins its gradual decline as the walls and internal case temperature cool. Circuit #2 takes a little longer before it dries out and begins its temperature rise. It cools to a much lower temperature before rising to about the same level as circuit #4.

The figure also shows the temperature history of the 15th row, which is in the middle of the economizer section. It has an initial 20°F rise and then continues a gradual cooling as the pressure and saturation temperature drops to atmospheric conditions. Then after about 45 minutes, it dries out and slowly rises in temperature. It never reaches the high temperatures experienced by the tubes toward the hotter gas regions of the OTSG and only approaches 900-1000°F.

Unlike the headers and superheater tubes, the cold end tubes (near the gas exhaust) experience soak back temperatures well above their operating levels. Similarly, the thermal shock on the screen tubes is severe and is probably the worst of any tube during the transient. The vaporizer tubes, normally at 620°F, will see temperatures close to 1400°F and the economizer tubes normally at 400°F will reach almost 1000°F. These temperatures occur at low pressure and the Alloy 800H tubes should survive with no difficulty as they are capable of operating at temperatures above 1600°F with very little internal pressure.

The unit operated at the 1500°F/1500 psia levels following this transient with no leaks or apparent damage. It is likely that the uneven heating and cooling experienced during this type of transient produces uneven thermal growth that can lead to deformation and bending of the tubes as discussed further in Section 4.6.2.

PD00186M

Figure 21. Full Load Transients Following Simulated Loss of Electric Power

4.2.5 Water Drain Tests

In climates where freezing is possible, steps must be taken to drain the water from the OTSG tubes during shutdowns. Because the once-through vertical serpentine tubes are not naturally drainable, new innovative methods are necessary. One method of eliminating the remaining water in the tubes after an abnormal shut down is to flow bottled nitrogen through the tubes and force the remaining water out through the outlet header. In a normal shutdown this is not a problem because the water flow is turned off immediately after a gas turbine shutdown and the residual heat in the system is sufficient to dry out all the water in the tubes.

For this test, the OTSG was filled with water and regulated nitrogen from 3000 psi bottles was admitted into the inlet water manifold. From the manifold, the gas flowed into each circuit through the needle valves. A drain tube and shut off valve was installed in the U-bend of a tube located in the middle of one of the outside circuits. After each test, the water still remaining in the two tubes connected by the U-bend was drained and measured. Several tests were performed varying the inlet header pressures to determine the nitrogen pressures required for best results. The inlet control valves remained at their normal operating settings and were the limiting orifice for the nitrogen flow.

These tests were performed with a cold OTSG, however, in a normal shutdown the casing is still hot and more water is removed as the hot tubes and casing would evaporate the remaining water. Table 10 summarizes the results of these tests. Nonetheless, test results indicated that over 95 percent of the water in the OTSG could be removed by this method.

Table 10. Results of Nitrogen Blow Down Freeze Protection Tests

Condition	Upstream Pressure (psi)	Calculated Nitrogen Flow per Circuit (scfm)	Water Remaining (ml)
Full Tube	---	---	4086 (100%)
Normal Shutdown	---	---	25 (0.6%)
Nitrogen Blow Down	100	26	350 (9.6%)
Nitrogen Blow Down	145	40	330 (8.0%)
Nitrogen Blow Down	400	105	275 (6.7%)
Nitrogen Blow Down	800	221	190 (4.7%)

4.3 CONTROLS RESULTS

The entire five hundred hour test was performed with manual control and the ease with which the OTSG could be controlled in the manual mode is a good indication that automatic control could be easily attained.

The microprocessor controller experienced problems during testing as the power supplies would randomly shut down and complete automatic control of the system was not attempted. The controller was only used to monitor the critical data channels and perform automatic shutdowns if critical alarm limits were exceeded, but did not control the feedwater and natural gas valves. The feedpump bypass and the desuperheater valves were often controlled automatically and manually controlled if the controller failed during the test. Because of this problem, all critical shutdown functions were duplicated with mechanical relays so that the controller was not necessary to continue the test.

The three active controls that the operator normally adjusted during the test were the control valves for fuel to the burner, outlet steam pressure (by adjusting the steam conditioning valve), and the feedwater flow. In an actual installation, the steam turbine inlet orifice would force the system pressure and as such would have no active outlet pressure control element. For this test, however, the steam conditioning valve position controlled the outlet steam pressure by providing the necessary outlet restriction simulating the steam turbine inlet.

During the initial testing, problems with the steam conditioning valve prevented its movement either open or close. Outlet steam pressure and temperature control during the first half of the test had to be performed by a combination of adjusting the feedwater flow and natural gas to the burner. Trying to control both outlet steam pressure and temperature with only the feedwater flow and firing rate was extremely difficult. The result was widely varying outlet steam conditions as the operator hunted for the right combination. After repairing the valve, these problems disappeared and stable outlet steam conditions could be easily maintained. A steam conditioning valve, similar to the one tested, will be installed on the full-size system bypass line but its only purpose is to bypass steam around the turbine during start ups and shut downs and is not for OTSG pressure control.

The primary OTSG control parameter during the test was the natural gas flow to the burner. Changing the feedwater flow required almost 15 minutes before the effects could be detected at the steam outlet. The effects of changing the firing temperature or fuel flow to the burner, however, were seen in seconds and excellent control of the outlet steam temperature could be easily maintained. Changes of only a few degrees in the inlet gas temperature could be attained thus allowing very close and accurate control of the outlet steam temperature.

The air flow to the burner was slightly higher than design conditions because of the burner operating characteristics. At the design flowrate, the infrared flame detector in the burner would fluctuate and eventually drop below the threshold signal causing a shutdown of the test. This was a random occurrence and by operating at a slightly higher air flow setting, this problem could be eliminated.

In summary, the adjustment of feedwater flow to the OTSG provided coarse control and would provide the anticipatory portion of the control equation. That is, given a gas flow at a given temperature and flowrate, then a feedwater flow can be calculated to provide the required outlet steam conditions. Fine tuning of the outlet steam temperature at $1500 \pm 15^\circ\text{F}$ would be done by minor adjustments to the firing or inlet gas temperature. The response time for firing adjustments is seconds and provides a much better method of control to prevent over temperature of the critical hot sections of the OTSG.

4.3.1 Start Transient

Figure 22 shows a typical start transient and is representative of most starts during the testing. The unit comes to full steam conditions in about one hour and fifty minutes, but the casing, structure, and insulation take nearly six hours to heat up and fine adjustments are continuously required as the entire thermal mass of the system asymptotically creeps up to steady state. Faster starts could be achieved in an automatic start and control mode because the manual mode requires the operator to make constant adjustments to keep the temperature and pressure from going over the preset limits. This causes considerable operator anxiety so that the design operating conditions are always approached very slowly from below the set point.

The full size system will utilize a different type of start. In this start, the controls wait for the exhaust gas from the OTSG to reach 300°F before introducing feedwater to the system. Figure 23 shows this type of "rapid start" and illustrates the fastest start up capability of the system. The inlet temperature to the OTSG simulated a non-fired gas turbine exhaust and after about 3 minutes from burner light-off the exhaust from the OTSG reaches 300°F and the feedwater pump started. After starting the feedpump, it took about 5 minutes for the OTSG outlet to go superheat and attained steady state 10 minutes later or 20 minutes from initial light-off. Upon reaching this condition, the supplemental burner is lit and ramped up to operating conditions similar to that shown in Figure 22. The ramp time is considerably less in automatic control as the computer processes the data and controls the valves at a much faster rate than a human operator. Total time for the start should be about 35 minutes to obtain the 1500°F/1500 psia conditions. However, true steady state will not occur for several hours as the insulation and structure require that long to reach true steady state conditions.

4.3.2 Shutdowns

Figure 24 shows a maximum shutdown transient that occurred when the outlet steam temperature reached 1550°F and tripped the automatic shutdown in the controller. The cool down is rapid but no water carryover or severe thermal shocking at the outlet header is evident. The OTSG survived this and two other severe shutdowns with no leaks or serious problems.

4.4 EMISSIONS

Exhaust gas emissions measurements were taken on the unit during a start and at the same operating conditions experienced during most of the testing. Figure 25 plots the NO_x data versus OTSG gas inlet temperature. At the nominal conditions for the test, NO_x levels were generally between 55 and 65 parts per million (ppm) uncorrected, with a firing temperature around 2200°F. There is some concern over the extrapolated high NO_x levels that would occur at a firing temperature of 2500°F and further discussions with the manufacturer are recommended. The full-size system will use 900°F exhaust gases from a gas turbine instead of ambient air and should act to reduce these levels. However, in a potential system where no gas turbine engine is used, the burner must be able to provide low NO_x operation in the current regulatory environment.

Figure 22. Typical Cold Start

Figure 23. Rapid Start Transients

Figure 24. Maximum Shutdown Transient From Trip at 1550°F Outlet Steam Temperature

Figure 25. Test Burner NO_x Emissions as a Function of Inlet Gas Temperature

4.5 FAILURES

The OTSG experienced no failures during the test. There were, however, two failures that occurred during testing involving the feedwater pump and the hot outlet steam conditioning valve. The steam conditioning valve problems are of particular interest since a similar valve proposed for the full size system steam bypass line.

4.5.1 Steam Conditioning Valve

The steam conditioning valve is just downstream of the outlet superheater header and performed two functions: (1) control of the outlet steam pressure and, (2) desuperheating the steam before being exhausted to atmosphere. This valve is similar to one required for the full-size system and it is important to obtain a design that can operate at these high temperatures and pressures.

Opening the valve would expose more holes in the valve plug thus lowering the operating pressure. The plug material was switched from Hastelloy "X" to SS410 without notification and at 1500°F and 1500 psia this material has no strength and would creep and close off the holes in the plug, blocking the outlet steam flow. The original circular holes that allowed steam to pass through rapidly became ellipses and eventually just narrow slits.

Problems with the valve occurred during the initial few hours of the test. After about 5 hours of operation at 1500°F/1500 psia the valve would no longer move in or out. As the

valve plug continued to creep and close the orifice holes, adjustments in both feedwater flow and firing were necessary to keep the pressure from rising above the 1500 psia set point. This was a continuous process as the holes in the valve plug slowly kept closing. Control during this period was subject to constant changes and continual hunting for the proper operating point. Then as this point stabilized, the changing hole sizes in the valve would require finding a new operating point.

During shutdowns, the valve stem could be manually pushed further open so that the next run would begin with a larger hole area than the previous run had ended. That is to say, if 16 gallons per minute maintained 1500 psia during the previous test, then 20 gallons per minute would be required after the next start for the same pressure with the larger orifice area exposed. As these holes again creep closed, the flow would have to be decreased as the pressure would rise above 1515 psia maximum operating limit.

Testing continued for two hundred and thirty-four hours until the valve was fully (100%) opened and no more improvements could be expected. As the valve holes continued to close, less and less water flow would be required to maintain the 1500 psia outlet. The water flow deteriorated to the point where the steam exiting the screen tubes became superheated, and as this significantly increases the probability of burning out a tube, it became necessary to shut down the test and repair the valve.

Figure 26 shows the valve plug with the orifice holes after 234 hours of testing. The plug distortion is also evident in this figure and the once round holes in the plug are now slits. The repair consisted of replacing the SS 410 plug with one made of Hastelloy X. The new plug had some slight design modifications to hasten delivery but were inconsequential to current operations. One such compromise was that the new plug did not provide a sealing surface for tight shut off, a feature that was not essential for this test.

The remainder of the testing went without incident and the new Hastelloy X plug performed without problems. Pressure control was again achievable with the valve that stabilized operations considerably during the remainder of the testing.

4.5.2 Feedwater Pump

The feedwater pump is a triplex piston pump and experienced two failures during the test. The first failure occurred when the teflon piston seals melted causing the pump to lose outlet pressure and flow capacity. The cause of the problem was steam flowing back to the pump through the desuperheating line after shutdowns and melting the seals. Changes in operational procedures prevented any re-occurrence of the problem and the checkout phase continued after installing new seals.

The second pump failure occurred when the middle piston case cracked and was immediately noticed when the flow to the OTSG suddenly decreased by 33%. Apparently there was a defect in the casting combined with operation at or above its design pressure rating that eventually propagated the crack until it finally failed. Testing continued without incident after replacing the failed piston casing.

Figure 26. Closeup of Steam Conditioning Valve Plug Cutout ID (Steam Exit Side)

4.6 OTSG INSPECTIONS AND EXAMINATIONS

The OTSG tubing and insulation was visually inspected following the five hundred hour test. Access to the interior of the furnace was obtained by cutting a hole in the casing and removing the insulation. The insulation was re-installed on the way out and the access cover welded onto the case. This access was used several times during the tests. The next design should plan on incorporating this or some other way of providing access into the furnace section for periodic inspections.

4.6.1 Insulation

Inspection of the casing insulation showed severe signs of distress following the test. The case is a "cold case" design meaning that the insulation is on the fireside and exposed to the hot gasses produced by the combustor. The outside casing metal temperature remains below 125°F.

Upon inspection, the hard surface coating, used as a protection for the insulation and as an erosion barrier, had fallen off large areas of the insulation and was lying on the floor. The roof was especially bad with almost no coating remaining. This failure occurred because the coating was installed too thick and could not support its own weight. The side walls were not as bad as the roof, but also had large areas where the coating had fallen to the floor. This problem is an installation problem as the coating should have been less than 1/16 inch thick but was well over 1/4 inch in some places. The loss of the coating exposed the underlying insulation to higher temperatures that contributed to the next problem.

The insulation consisted of one square foot modules attached to the metal casing with a strip of blanket insulation running horizontally above and below the modules. The problem was that significant gaps had appeared at almost every module joint as can be seen in Figure 27. These gaps provide less insulation thickness to the case as they are sometimes three inches or twenty-five percent deep into the insulation.

Figure 27. Cracks in Casing Insulation and Coating After Testing

The apparent cause of the gaps and the insulation sagging toward the bottom of the case is insufficient compression of the modules during installation. The packing was not dense enough and combined with the normal shrinkage encountered during operation, resulted in the gaps between modules.

Evidence of this problem was first noticed when hot spots discolored the casing paint. Several of these hot spots developed throughout the test as the gaps grew more toward the outer case but most were located on the transition section between the furnace and the OTSG cases. Some of these hot spots grew in size as the testing progressed others appeared to have stabilized but the longer testing continued, however, the more hot spots appeared. Long term durability of the case could be a problem as local hot spots continued to develop with some glowing red hot.

The insulation was otherwise in perfect condition with no indications of erosion, melting, material loss, or excessive shrinkage. The installation procedures must be modified to provide a tighter more compressed final installation.

Subsequent discussions with vendors revealed that other techniques are available to reduce this problem. One suggested putting the next higher temperature grade material in for the batten strips (the strip located between the one square foot modules). These strips are blanket material and would have a 3000°F rating that would shrink much less at the present firing conditions. The major change that is necessary to avoid future problems with the insulation is to modify the installation procedures, techniques, and quality assurance to ensure a more compact, denser installation.

The second type of insulation tested, the 15-C board, appeared to have survived the test in excellent shape. The only noticeable problem was one of the ceramic washers had fallen off. This type of insulation is much more expensive in both materials and installation and was not chosen for use in the full size unit.

4.6.2 Tubes

The screen tubes appeared to be in excellent shape except for some bending occurring on the screen tubes seen in Figure 28. These tubes had baffles brazed on each end to form a gas seal and prevent the incoming hot gas from bypassing the OTSG finned tube bundle. Each tube had a separate plate brazed on to allow independent growth and movement from the other tubes. The plate also acted like a fin brazed onto the tube, thus, the relatively cold fluid inside the tube would cool the plate and allow it to survive at gas temperatures up to 2500°F. At some point during the operations, possibly rapid shutdowns (such as the loss of electrical power test), the different flow rates into the circuits would cause them to cool at different rates and the cooler, shorter, tubes would move atop and overlap the adjacent plates. When the hotter tube then cooled, the over lapped tube was trapped between the plates of the other tube and had to bend to accommodate the shorter distance between the top and bottom plates.

Despite the bending, the screen tubes were still doing their intended job as a radiation screen and one could not see the superheater tubes behind the screen tubes except at the very edges.

Because of the tube bending, the baffle plates and gas sealing system are being re-designed to prevent a re-occurrence. Either a different method of gas sealing or thicker baffle plates will be incorporated to prevent the overlapping.

Figure 28. Screen Tubes After Test (Top Section)

4.6.3 Post Test Metallurgical Examination

A four foot section of one of the five hottest Alloy 617 superheater tubes (just before it entered the outlet header) was removed after the 500-hour test. A short length of the highest temperature portion of the Alloy 800H radiation screen evaporator tube was also removed to find if there were any dryout effects at high gas temperatures. Both sections of tubing were from circuit #4 which is an outside circuit.

The Alloy 617 tube was cut into longitudinal and transverse sections for evaluation. Both outer and inner diameter surfaces had a smooth, uniform appearance with a dark gray color. There was no scaling or oxide spallation and no evidence of surface cracking at magnifications up to fifty times. Some minor scaling occurred on the fins but no surface recession was detected.

Figures 29 through 31 show microstructures of the 1.25 inch OD Alloy 617 gun drilled tubing in the as-received condition, after fin brazing, and after the test, respectively. The as-received sample (Fig. 29) shows well defined twinned grains with an average grain size of ASTM 2-3. Examination at higher magnifications, showed that fine cellular carbides decorated the grain boundaries. There were also larger geometric shaped carbo-nitride precipitates within the grains or adjacent to grain boundaries. Both outer and inner diameter surfaces showed evidence of metal deformation to a depth of about 1/2 to 3/4 of a mil, from the final machining operations. The hardness of this as-received material averaged 86.1 Rockwell B.

The as-brazed sample (Fig. 30) showed fine carbide precipitates within the grains and decorating slip planes. The grain boundary carbides had become larger, less continuous and more globular compared to the as-received condition. The average grain size remained the same but the hardness measurements included a slight increase to 89.3 Rockwell B.

The general microstructure and hardness (89.7 HRB) following the test (Fig 31) was unchanged from the as-brazed condition. A thin oxide scale and intergranular oxidation had developed on both outer and inner diameter surfaces to maximum depths of 0.0012 and 0.0014 inches respectively. The development of very fine grains at the surface may be related to the formation of an alloy depleted region and surface nucleation of fine recrystallized grains. Evaluation of the outer diameter surface was also complicated by the presence of braze alloy.

Examination of a sample of Alloy 800H tubing removed from the vaporizer screen section, which normally runs at 620°F, shows only superficial surface oxidation (uniform metallic gold/brown appearance) with no detectable surface recession. A detailed examination revealed no cracks or other distress. This tube had also operated at temperatures above 625°F for 10 to 20 hours.

Results of the material evaluations are summarized below:

1. No significant oxide scaling or spallation was visually evident in the Alloy 617 superheater tubing following the test.

O.D. Surface. Note evidence of surface deformation. From centerless grind operation.

Mid-Wall Section. Carbide delineated grain boundaries.
Avg. Grain Size - ASTM 2-3;
Hardness 86.1 HRB.

I.D. Surface. Note surface deformation from gun drilling operation.

Figure 29. Microstructure of As-Received (Gun Drilled) Alloy 617 Tubing. Etch - oxalic electrolytic. Mag: 400X

O.D. Surface.

Mid-Wall Section. Heavier
carbide precipitation at grain
boundaries and general decoration
along slip planes. Avg. Grain -
ASTM 2-3; Hardness 89.3 HRB

I.D. Surface.

Figure 30. Microstructure of Alloy 617 Boiler Tubing After Fin Brazing. Etch - oxalic electrolytic. Mag: 400X

O.D. Surface. Intergranular
oxidation to a maximum depth
of 0.0012 inch.

Mid-Wall Section. No change from
as-brazed condition. Avg. Grain
Size - ASTM 2-3; Hardness 89.7
HRB.

I.D. Surface. Intergranular
oxidation to a maximum depth
of 0.0014 inch.

Figure 31. Microstructure of Alloy 617 Tubing After Testing. Superheated Exit @ 1500-1550°F. Etch - oxalic electrolytic. Mag: 400X

2. No evidence of cracking or surface distress was evident on the outer or inner diameter surfaces.
3. The high temperature, inert atmosphere fin brazing operation caused some microstructural changes and a slight increase in hardness from the as-received condition. No apparent surface oxidation or alloy depletion occurred during this operation.
4. Microstructural evaluations showed that a thin oxide scale oxidation occurred on both outer and inner surfaces of the Alloy 617 to a maximum depth of about 0.0012 inches.
5. Microstructural evaluations also showed that intergranular oxidation occurred on both outer and inner surfaces of the Alloy 617 to a maximum depth of about 0.0014 inches.
6. There was no deterioration of the Alloy 800H tubing from the initial brazed condition.

5.0

CONCLUSIONS

The high performance OTSG operated for 527 hours at 1500°F and 1500 psia with no problems proving that an OTSG can be operated and survive at these elevated temperatures and pressures. There were, however, problems encountered on ancillary equipment not associated with the OTSG. The following list summarizes the test objectives from the Test Plan (Ref. 3) and the accomplishments:

5.1 PERFORMANCE OBJECTIVES

1. *Evaluate the performance and design of the OTSG module at full, part load, and off design steady state conditions.* Testing verified OTSG performance with most of the operation at full load conditions and only briefly at part loads.
2. *Determine the flow stability versus pressure drop characteristics of the OTSG for several operation points.* The stability of the unit was exceptional with no noticeable oscillation either in the dryout zone regions or at the outlet header.
3. *Construct performance maps and make recommendations for design changes to be incorporated in the full size unit.* Although performance mapping was not extensive, recommendations for changes in both the performance prediction algorithms and the mechanical design were made.
4. *Determine the effects of any inherent inlet gas flow mal-distribution on OTSG performance.* There was initially concern with the mal-distribution from the burner and furnace adversely affecting OTSG performance. However, no flow distribution problems were evident and the gas temperature was very even from top to bottom. Instead, flow distribution problems existed at the exit end of the OTSG as a result of bypass flow around the OTSG tube bundle.
5. *Verify radiation heat input and calculations.* The radiation calculations were checked, verified and changes recommended to the calculation procedures.
6. *Verify vertical tube matrix performance and design calculations.* Analyses revealed no significant heat transfer differences between the up flow or down flow directions.
7. *Verify full size system performance.* The full size system performance was calculated using test data and incorporating the changes recommended in the calculational procedure.

5.2 CONTROLS OBJECTIVES

1. *Evaluate the performance of the control strategy and its capability for handling start-up and perturbations.* The OTSG was manually controlled throughout the test and provided greater insight into the control issues. Since the unit could be easily

controlled in the manual mode, no problems are anticipated in converting to fully automatic control. The manual control operation also intensified and established the control strategies required during start up, shutdown, emergency shutdown, and steady state.

2. *Determine the transient response and performance of the OTSG to perturbations in flow and temperature conditions.* These tests showed stable, predictable operation of the OTSG. Time constants for setting the control parameters in the full size automatic system were obtained.
3. *Perform an operational check out (steaming) of the control system.* This objective was not entirely completed because the control system used during the test experienced significant problems (it would randomly shutdown). To expedite and place the priority on completing the test, full automatic control was never demonstrated. The unit was fully controllable under manual operation and automatic control should be easily implemented. Non-critical control loops were automatically controlled but the firing rate and feed water flow control were always under manual control.
4. *Determine the optimum automatic start-up procedure.* Testing completed this objective, but it must be remembered that if the full size system has different types of equipment, then modifications to the procedure may be necessary.
5. *Determine the dynamic characteristics of the OTSG and its response to gas turbine load transients.* This objective was completed during transient testing of the OTSG and time constants calculated.
6. *Define controls requirements for the full size system.* The test defined control requirements for the full size system.

5.3 MECHANICAL DESIGN OBJECTIVES

1. *Provide a baseline record by taking photographs and measurements and by performing selected test to document "as new" conditions.* Photographs and measurements documented the baseline conditions and performance. There were no significant changes between the start and end of the test except that some screen tubes had become mechanically interlocked causing binding and bending. The problem was not serious and design changes will be made to eliminate this problem in the full-size design.
2. *Verify stress input to hot components, thermal expansion of system and ability of design to accommodate these expansions.* Testing provided temperature profiles on the tubing, structure and casing for future analyses. Detailed analysis will be performed during the next program phase.
3. *Verify draining and blowout procedures for OTSG freeze protection.* A method for removing water from the OTSG tubes showed removal rates of 90-95%. Running the unit dry during shutdown is still the best and preferred method of turning the unit off and removes over 99% of the moisture in the OTSG.

5.4 METALLURGICAL OBJECTIVES

1. *Determine the effects of 1500°F/1500 psia steady state operation for five hundred hours on the OTSG hardware.* The metallurgical examination on the tubes removed from the superheater and screen sections after the test showed no distress or significant deterioration after 527 hours of testing.
2. *Determine if distortion or creep has occurred in critical components.* No such distortion or creep has been identified in either the superheater or the screen tubes. The screen tubes experienced some minor bending as the baffle plates interlocked but was not significant,

5.5 GENERAL OBJECTIVES

1. *Verify proof-of-concept 1500°F/1500 psia system.* Testing verified the OTSG and systems concept by successfully completing the 527 hours at 1500°F/1500 psia with no problems. The experience gained during these tests will have positive influence on the design of the full size system. Some design changes will be necessary including:
 - A. More work on selecting the insulation and installation methods to be used on the casing and furnace linings.
 - B. Although the side walls where the bypass gas flow occurred were not prototypical, nonetheless, more effort must be directed to minimizing the bypass flow in the full size unit.

6.0

RECOMMENDATIONS

By successfully completing Phase II testing, it is recommended that the design and construction of the full-size OTSG start as part of Phase III of the program. The test verified both the OTSG performance and design, however, some changes are recommended. The successful completion of the test gives added confidence that the full-size system will perform as expected.

6.1 HARDWARE

- The insulation materials and casing designs need further work. If necessary, bench testing of different types of candidate insulation materials should be performed to verify their performance and installation techniques. The chosen material should survive with inlet gas temperatures of 2500°F (with a maximum continuous use temperature of 2600°F), however, the deterioration and shrinkage that occurs at around 2300°F suggests serious problems may exist if the planned 2500°F inlet temperatures are present in the full size system. Further investigation is needed even though installation procedures and techniques may be the cause of the problem.
- Better installation, inspection and quality control should be implemented for installing the furnace insulation to ensure the greatest compaction of material. Also a manhole access into the furnace section should be provided for inspections.
- An inlet valve to control the flow into each circuit is recommended for the initial full size unit. The intermediate header will be eliminated in the full size unit and control of these valves or orifices will directly control the temperature of the steam exiting each circuit. This will provide positive and direct control of the flow into each circuit and give added flexibility to compensate for any edge effects or other non-linearities. The valves can be replaced with fixed orifices later, if necessary, to prevent tampering.
- Closer coordination with the steam conditioning valve manufacturer is necessary to obtain a workable design with materials suitable for the environment.
- Close contact with the burner manufacturer should be maintained to ensure that NO_x levels are not prohibitive. The NO_x levels from firing ambient air to 2300°F are different from those obtained using gas turbine exhaust gases fired from 900 to 2300°F. However, close contact should be maintained to eliminate any surprises, especially if the field unit does not have a gas turbine engine but only a combustor operating on ambient air.

6.2 MANUFACTURING

- As part of Phase III, a subcontract has been issued to Inco Alloys International for developing a method of drawing 1.0 x 0.280 inch wall Alloy 617 tubing. This will eliminate the need for gun drilling bar stock to fabricate the thick wall superheater tubing and should reduce the material costs. The current design limits tube lengths to current gun drilling capabilities and possible utility designs may benefit from longer tubes.
- The brazing of the fins onto the thick wall superheater tube should be investigated early in the next phase. Problems encountered during Phase II suggests that major improvements in the quality of the brazing and fin/tube joint can be obtained on the full-size unit even though the maximum tube size will decrease from 1-1/4 x 0.375 inch wall to 1 x 0.280 inch tubing.

6.3 DESIGN

- Gas seals that overlapped and caused bent screen tubes should be re-designed to avoid a reoccurrence of the problem.

7.0

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