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RESOURCE RECOVERY WASTE HEAT BOILER UPGRADE

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ABSTRACT

The waste heat boilers installed in a 360 TPD waste to energy plant were identified as the bottle neck for an effort to increase plant capacity. These boilers were successfully modified to accommodate the increase of plant capacity to 408 TPD, improve steam cycle performance and reduce boiler tube failures. The project demonstrated how engineering and operation can work together to identify problems and develop solutions that satisfy engineering, operation, and financial objectives.

Major issues of interest to the industry are:

(1) Heat maldistribution through the boiler may result in boiler superheater malperformance, and accelerated slagging and corrosion of superheater tubes.

(2) Confirm the experience of other refuse to energy type plants that the upgrade of SH tubes from T22 to Incoloy 825 Material increases life expectancy. At Springfield Resource Recovery Inc. (SRRI) the original T22 tubes were in service for 5 years. It is projected that the new Incoloy 825 material will be in service 10 years or longer.

(3) The original water cooled SH support tubes located in the gas stream were removed and replaced with "hot" SH support tubes located outside of the gas stream. It is estimated that the new support system increased effective heat transfer surface by as much as 12%, and the free flue gas flow area by approximately 8%.

(4) Confirm the advantages of using rotary "air puff" type sootblowers over steam type sootblowers for relatively small power plant. The air consumption of the "air puff" sootblowers is distributed over long period of operation, and avoids the power output fluctuation that could have resulted using steam sootblowing. With the incoming flue gas temperature maintained at 1300 F, rotary "air puff" type sootblowers can be used throughout the boiler. Upgrade of the compressed air system at SRRI keeps the tubes clean and reduces the "on-line" and "off-line" water wash of these boilers to a minimum.

Plant checking and testing, design review and specification development, installation and operation results are presented.

INTRODUCTION

Plant upgrade at the Springfield Resource Recovery facility was carried out in order to increase the unit rated throughput capacity for municipal solid waste (MSW) from 120 tons/day (TPD) to 136 TPD. This unit capacity increase corresponded to an increase of waste heat boiler superheated steam production from 28,600 lb/hr to 32,200 lb/hr per boiler. In conjunction with this effort, specific design modifications were implemented in order to improve and correct operating problems associated with the plant's three waste heat boilers as originally installed. The focus of this discussion is to describe the modifications implemented and the results achieved for the steam generators and associated auxiliaries as the charging, incineration and flue gas cleaning equipment were already capable of increased capacity.

DESCRIPTION OF THE ORIGINAL WASTE HEAT BOILERS

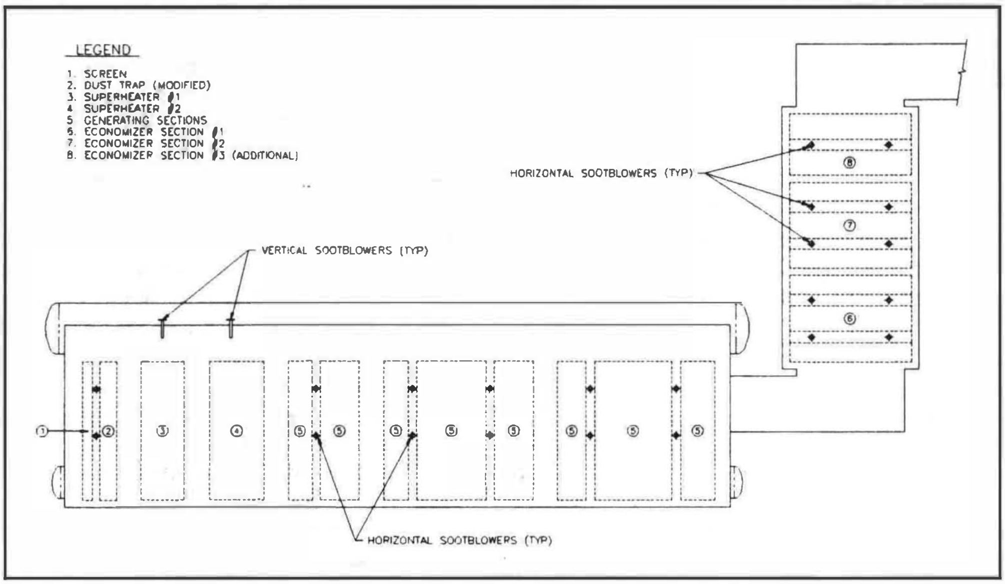
The three waste heat boilers, located downstream of the ash transfer ram hearth type incinerators, are 'A' type designs each rated for 28,600 lb/hr at 753°F and 650 psig. These units were shop fabricated and supplied by Deltak to a duty specification provided by Vicon (Vicon, at the time this project was developed, employed a waste incineration and heat recovery

Table 1. Original and Revised Tube Arrangements

Section/ Description	Tube Dia., Inches	Tube Length, FT	No. of tubes/ row	S_T, inches	No. of rows	S_L, inches
Screen	2	9.21	12	9	2	8.13
Dust Trap(1)	2	9.21	24	4.5	4/2	4.5
1st.Superheater(2)	2	8.92	16	5.25	8	5
2nd.Superheater(2)	2	8.92	16	5.25	10	5
Generating Bank	2	9.21	24	4.5	77	4
Economizer(1)	2	10	24	4	66/74	4

Notes: (1) Original/Modified
(2) Modified from Parallel to Counter Flow

Figure 1. Boiler/Economizer Layout



technology from Enercon. Vicon is no longer active in the supply of equipment for the waste to energy industry. Enercon continues to offer equipment and services for the industry). The duty specification corresponded to a unit throughput of 120 TPD of MSW at an HHV of 4,500 Btu/lb. The tube layout in each unit is as shown in Table 1. Surface orientation and sootblower location is shown in Figure 1.

The boiler was constructed with gas tight water cooled membrane finned tube walls encased in insulation and a metal skin followed by an economizer in a welded gas tight steel plate insulated enclosure. In terms of thermal duty, the boiler was designed to recover heat from an incoming flue gas leaving a mixing chamber at a flow rate of 122,000 lb/hr and a nominal temperature of 1300°F. The temperature of the flue gas entering the boiler is maintained at the 1300°F level by re-circulating a portion of the flue gas leaving the economizer at 400°F and mixing it with the flue gas leaving the incinerator secondary chamber, which is at a nominal temperature of 1800°F.

DETERMINATION OF WORK SCOPE

During the period of the engineering feasibility study the steam generator units were evaluated by plant and engineering personnel to determine the modifications required to accommodate the new service conditions. The evaluation required work in four major categories: a. Perform thermal check rating of the unit with the original model, and evaluate the results; b. Verify thermal check rating with actual plant operating data and adjust the model for predicting performance to correlate with actual data; c. Inspect and evaluate the condition of the tubing; and d. Observe and evaluate operating practices.

Thermal Check Rating

Thermal check rating was conducted using the original Deltak computer program, which modeled the thermal performance of the existing original boiler. With the unit subjected to flue gas flow rate of approximately 113% of the original rated design, it was predicted that, with the existing surface and tubing arrangement, steam generation would be approximately 108.6 % of the rated steam flow, and flue gas temperature leaving the economizer would be 438 °F. In addition, predicted superheated steam temperature at the outlet was only 740°F. To maintain the original unit thermal efficiency, and to produce the specified superheated steam temperature, it was determined that the most economical method to enlarge the steaming capacity of the boilers was to install a new economizer section with 8 rows on the top of the existing economizer (the new approach temperature is still satisfactory for safe boiler operation). Also, the existing superheater sections which could not be economically enlarged should be modified from parallel to counter flow for a net gain of heat absorption of approximately 4%. This required the original water cooled SH support tubes be removed and replaced with hot SH supports located outside of the gas flow for a net gain of effective heating surface of approximately 8% and heat transfer gain of approximately 12%.

Verify Thermal Check Rating with Actual Operating Data

Review of actual plant operating data records including data reported during the original performance testing of the plant for commercial acceptance revealed that at the rated design the superheated steam section was unable to produce the specified temperature of 753°F. Since independent thermal check rating of the section by Fluor Daniel confirmed that the heating surface and tube layout were capable of performing the specified duty, additional testing was conducted to determine the reason for the sub-par performance. Analysis of the data revealed that the actual heat absorbed, and the steam produced by the screen and the dust trap sections exceeded predicted values. As a result, total steam production was increased at the expense of a lower superheated steam temperature. Prior to the plant capacity upgrade project the maldistribution of surface was not a serious problem. A larger steam flow resulting from the reduced enthalpy of the steam produced caused the actual and design main steam line total energy to the steam turbine to remain constant. Since the inlet steam flow was still inside the steam turbine design envelope, maldistribution of surface in the boiler did not seriously impact plant production. However, with the plant operated at the new upgraded throughput capacity, larger steam flow due to reduced superheated steam temperature could no longer be accommodated.

Check rating of the unit was conducted with the model adjusted to correlate actual collected test data with the predicted values. Results produced by the modified model indicated that removal of two rows of dust trap tubes were required along with other changes to increase boiler capacity and upgrade performance to the original conditions.

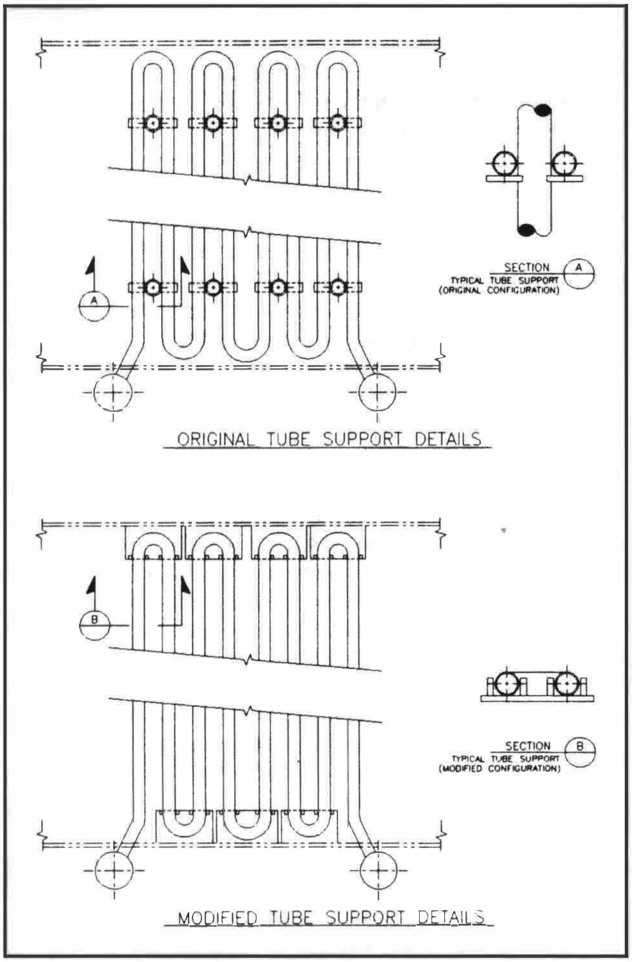
Inspect and Evaluate the Condition of Tubing

Exterior wear of the boiler SH, generating, and economizer tubing was measured for nearly 100% of the tubes. Tube wall thicknesses for each tube were taken in various locations along the tube length. Only the superheater sections had experienced significant losses due to erosion/corrosion, and in selected areas tubes were pitted. The balance of the boiler tubing was in good condition. It was concluded that the significant wear loss of superheater tubes was primarily due to external corrosion. This conclusion was based on: a. Outside surface of the tubes was not polished, which would have been the case if erosive conditions were present.; and b. Large ash deposits on the tubes and frequent "off-line", and "on-line" water washing of the boiler tended to make corrosion a more likely cause. Investigation as to the cause for the accelerated corrosion of the superheater tubes revealed problems with the existing design including high metal temperature resulting in an accelerated rate of ash build up and corrosion, the cooled tube support system located in the gas flow path promoted ash build up, and the sootblower plant air system was not large enough to keep ash deposits controlled. Even with the screen in front of the superheater tubes, the exposure of these tubes to high flue gas temperatures and ash build up caused accelerated corrosion. Experience reported elsewhere, Power Magazine, October 1992 was confirmed by this experience.

Maldistribution of surface in the boiler contributed to the corrosion of superheater tubes due to high metal temperatures. With operation of the boiler at the design inlet temperature of 1300°F, superheated steam temperature was lower than rated. To correct the short fall of steam temperature, operating personnel raised the boiler inlet flue gas temperature from the rated 1300°F to 1350°F. Although the higher flue gas temperature improved the outlet temperature of the superheated steam (still not to rated temperature), it also resulted in higher tube metal temperatures as well as accelerated the rate of ash build up due to the fusion of flyash. A study in Germany (Power 1992) shows a loss of tube life of 30,000 hours for a steam temperature increase of 325°F above 625°F. Thus a 100°F increase in temperature decreases life approximately 10,000 hours. Since metal and steam temperatures are directly related, the same effect was noted in this case. Furthermore, in a relatively short period, due to the ash build up, the performance of the superheater section would decline and water wash of the section would be required. The accelerated rate of corrosion on the outside of the superheater tubes was the result of this combination of circumstances.

The original superheater support system was designed with each of the superheater tubes resting on two support plates each located in the gas path approximately eight inches from the tube bends. The plates were welded to three inch generating tubes located in the spaces between the superheater tubes. The problem with this design was that the generating tubes and plates reduced the free area for flue gas flow and caused ash build up (excessive flue gas velocity may explain the polished appearance of the tubes in these areas). In addition, since the support tubes and plates were in the sootblower operating spray lanes, the surface behind these supports was shielded and was not being cleaned. It was estimated that ash build up in the area was responsible for reducing the effective heat transfer surface of the superheater by as much as 12%, and the free flue gas flow area by approximately 8%. An alternate design was developed with the tube bend portion of the coil resting on supportplates welded to the membrane wall. The new designreduces ash build up and allows for more complete cleaning of the superheater surface (See Figure 2).

Figure 2. Tube Supports



Observe and Evaluate Operating Practices

Each of the boilers was equipped with 24 "air puff" type sootblowers. With the original design the plant and instrument air systems were supported by two air compressors which also supplied air to the soot blowers. Each compressor rated at 250 scfm. This compressed air system was designed to support one cycle of operation for each sootblower system for each eight hour shift. The sootblowers operated at a pressure range of 125 to 150 psig. To determine air requirement for the sootblowers, testing was conducted with rented equipment. It was concluded that to maintain a clean operation of the boiler the superheater sootblower cycles had to be increased from one to three per shift, and the sootblowers located down stream of the superheaters required two cycles, one prior to the cleaning of the superheater, and one after the cleaning of the superheater. It was also concluded that for effective cleaning, sootblower operating pressure should be 160 to 200 psig (Steam sootblowing was considered. The system was rejected because the high steam consumption would result in an unacceptable power output fluctuation). In addition, plant records and observation of operations showed that the temperature elements located at the flue gas mixing chamber were frequently out of service. As a result, the temperature control system which maintained the temperature of the flue gas at the mixing chamber was disabled. During such periods the Flue Gas Recirculating Fan (FGR) and it's control dampers were set by the operator on the basis of experience, which may have resulted in higher than 1300°F flue gas temperature at the mixing chamber . It was also observed that the temperature elements at the entrance to the superheater section were more reliable, and that when the inlet temperature to the superheater is 1250°F, the temperature at the mixing temperature is 1300°F.

SUMMARY OF WORK SCOPE

As a result of the analysis of the plant operating results and the equipment as installed, changes were made to overcome the deficiencies, to eliminate the need to try to compensate by adjusting operations, and to achieve the required capacity increase. These changes directly resulted from engineering analysis, operations review, and plant tests to assure everyone that all objectives would be realized. Principal changes were:

(1) The entire superheater was replaced with a new superheater arranged in counter flow. Since counter flow increases the metal temperature of the finishing superheater section, it was decided to upgrade the tube material in this section from T22 to Incoloy 825. In addition, a conservative design approach was used and the tube material in the primary section was upgraded from the original design of T22 to Incoloy 825 as well. In addition, a new economizer section with 8 rows was installed on top of the existing one to accommodate the increase of heating duty resulting from increased throughput.

(2) Two rows of dust trap tubes were removed to both increase the superheater inlet flue gas temperature and reduce the quantity of saturated steam generated.

(3) The new superheater was supported by a "hot" support plate arrangement welded to the membrane wall. This design freed up gas flow area, and enhanced sootblower effectiveness.

(4) The program for the control of sootblower operation was reconfigured and a new sootblower air compressor rated at 800 SCFM and 250 psig was installed to satisfy the new requirements. The flue gas temperature was controlled at the entrance to the superheater instead of the flue gas temperature in the mixing chamber.

(5) The FGR fan and dampers were controlled to maintain the flue gas temperature at the entrance to the superheater at 1250°F.

RESULTS

Work scope described above was completed at the end of November 1993 and the plant was in operation a month later.

A performance test was conducted during February of 1994. Data collected during testing showed that the boiler performed the rated thermal duty as specified. Operating records, now approximately one year after the completion of the project, shows that ash build up is reduced and that the new sootblower system keeps the units clean. The "on-line" water wash of the boilers is performed only when a malfunction of a sootblower system occurs. In the past year of operation, the frequency of "on-line" water wash was reduced to once every four months (from once a month prior to the upgrade). Plant throughout can be maintained at the new design rate.

Exterior wear of the superheater tubes was measured recently (November, 1994). Tube wear was measured at 3.5 mils in the center five feet of the coils, and 1.5 mils for the two foot sections on both sides. At this rate, life expectancy of the tubes is greater than ten years, which was the rate used in the feasibility study economics. In addition, after 10 years the superheater tubes may be "rolled" so that the wear pattern of 2 o' clock and 4 o' clock is reversed since redesign of the SH coils is symmetrical, (to 8 o'clock and 10 o'clock), and the material can last for the remaining 20 years the plant has yet to operate.

REFERENCES

Collins, Steven, "Slay the WTE Plant Dragon: Boiler Tube Wastage," Power, October, 1992, pp. 42-46.