BOILER ASSESSMENT AND UPGRADE STUDY
For
Tennessee Valley Authority
Allen Steam Station
Units 1, 2 and 3
Memphis, Tennessee

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RILEY
Riley Stoker Corporation
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A Member of the Deutsche Babcock Group

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ABSTRACT

The study described in this Paper is an important part of a Tennessee Valley Authority (WA) system-wide Boiler Assessment and Upgrade Program.' The purpose of this TVA program is to develop the most practical and economical solutions for problems identified through a systematic process. The TVA program is implemented by establishing Short, Intermediate, and Long Term Plans combined with a Preventive Maintenance Plan.

TVA has established six (6) specific goals for the Assessment and Upgrade Program:

- *Reduce forced outages*
- *Increase boiler efficiency*
- *Increase boiler steaming rate*
- *Evaluate future load cycling capabilities*
- *Improve operability & maintainability*
- *Evaluate compliance with the 1990 Clean Air Act Amendment*

Utilizing the stated goals as the basis, a engineering study format was developed by both TVA and Riley Stoker Corporation in the Fall and Winter of 1992/1993 for the Allen Steam Station, Units 1, 2 and 3.

The study format encompasses a structured, systematic approach to:

- *Identify mechanical and operational problem areas (Problem Identification/Subproblem List).*
- *Address possible solutions for the individual problem areas.*

The ***study*** *also evaluated state of* ***the art designs and operating philosophies including European experience based on the Riley/Deutsche Babcock alliance. The results from this study were utilized by*** *WA to develop the Short, Intermediate, and Long Term Plans, and development of the Preventive Maintenance Program.*

BACKGROUND

The Allen Station Units 1, 2 and 3 are identical Babcock and Wilcox boilers built in 1956 and are located in Memphis, Tennessee. The boilers were originally designed to operate at a continuous main steam flow and pressure of 2, 000,000 lbs/hr and 2475 psig with superheat and reheat steam temperatures of 1053/1053 °F. The units are naturally circulated and are equipped with seven (7) cyclone combustion burners designed to fire coal and natural gas. The boiler arrangement has a split parallel convection pass of primary superheat and reheat surface. The units were originally designed with gas recirculation for flue gas tempering and reheat temperature control. The cross section of the boilers is shown in **Figure 1.**

Currently the units have a relatively high forced outage rate. In an effort to improve reliability and availability the final steam temperatures as well as unit capacity have previously been derated. Due to high maintenance and fan vibration problems, the tempering flue gas recirculation system was previously removed from service. The boilers were recently converted to balanced draft operation.

STUDY APPROACH

The engineering study utilized the following structured, systematic approach:

<u>First</u> Establish the past boiler operating problems, including **both performance and** mechanical reliability problems. This step is referred to as the "Historical Review".

<u>Second</u> Establish the current unit performance and identify performance deficiencies. This step is referred to as " Performance Evaluation Testing".

<u>Third</u> Establish a Computer Heat Transfer Model of the boiler to be used to predict the unit performance when evaluating alternatives to meet the six goals of the program.

<u>Fourth</u> Evaluate options to address **the program goals.**

HISTORICAL REVIEW

A "Historical Review" of past boiler operating problems was performed which included summaries of both performance problems and mechanical reliability problems. The Historical Review was achieved by thoroughly researching available plant records, TVA central records, and interviewing plant management personnel. The findings of the Historical Review were separated into three reports: Mechanical Problems, Tube Failures, and Personnel Interviews.

<u>Mechanical Problems</u>

This report summarizes by component approximately 200 occurrences consisting mostly of mechanical problems. Included with each occurrence is the "Problem Category", e. g., pressure parts (P), cycling/performance (C), structures and seals (S), other (0). The report lists the following information.

- Subproblem Number
- Component I.D.
- Subproblem Description
- Boiler Number
- Year Of Occurrence
- Number of Occurrences
- Current Situation
- Reference Documents

An example of this report is shown in **Figure 2.**

Tube Failures

This report is a chronological summary of 580 tube failures that occurred from 1968 through 1992. This study utilized the TVA company-wide boiler tube failure report program (BTF)[1]. The summary lists the following information.

- Year Of Occurrence - Subproblem Number - Component I.D.
- Subproblem Description - Failure Cause
- Boiler Number
- Reference Document

An example of this report summary is shown **in Figure 3** and the a copy of a BTF report is shown in **Figure 4.**

Personnel Interviews

This report summarized each interview with the plant management personnel. The purpose of these interviews is to record the individual's experiences, comments, and opinions concerning problem areas. This information is in-turn added to the evaluation of problem areas. An example of this report is shown in **Figure** 5.

All documents were organized, cataloged, and stored for future reference.

PERFORMANCE TESTING

Extensive Performance Evaluation Testing was performed to collect current operating and performance data. The testing was performed on Unit 2, which was fully instrumented during a scheduled outage. Local calibrated test instrumentation was installed to ensure data accuracy and to verify the accuracy of the control room instrumentation. Test conditions were as follows:

Peak 106% Load @ normal excess **air**
Peak 106% Load @ **high** excess air
Full 100% Load @ normal excess air
Full 100% Load @ high excess air
75% Load @ normal excess air 75% Load @ high excess air
54% Load @ normal excess air
54% Load @ high excess air
47% Load @ normal excess air
45% Load @ high excess air
98% Load, #8 FW Htr. Out @ normal excess air
Load Ramp Test, 50 - 100% Load @ 1.5% per min.

The test results were compared to the original design predictions and original commissioning test data. Based on this analysis, performance deficiencies/problems were identified. This data was also used as the basis for additional engineering evaluations which included tube metal studies and analysis of auxiliary equipment. A complete test report was developed which summarized test results.

An example of the data summary sheets and the testing report findings are shown in **Figures 6 and** 7, respectively.

COMPUTER HEAT TRANSFER MODELLING

Computer modelling is a powerful tool used to predict unit performance when evaluating alternatives to meet specified objectives. Typical evaluation objectives encompass improved boiler efficiency, improving steam temperature control, firing alternative fuels, increasing steam generation, new steam conditions and performance changes with flue gas recirculation.

Background: computer heat transfer modelling is a mathematical representation of the heat transfer process in the boiler. The model evaluates the heat transfer process on **a theoretical basis and can be calibrated with actual data. The calibration includes actual surface** effectiveness factors which take into account actual surface configurations and gas flow stratification. The benefit of utilizing actual data to calibrate the model as compared to a strictly theoretical model, is the increased accuracy of the model predictions.

The TVA study utilized computer modelling, calibrated with actual testing data, to predict performance at the following operating conditions:

when operating with SH/RH steam temperatures at 1053/1053 °F.
when operating with tempering flue gas recirculation.
when firing natural gas.
when adding new high efficiency air heaters.
when increasing the boiler steaming capacity to 115% of MCR

An example of the computer modelling summaries is shown in **Figure** 8.

SUB-STUDIES

Based on the WA program goals and utilizing the Historical Review, Performance Evaluation Testing, and Computer Modelling, stand-alone reports were written on the following:

Boiler Tube Metals Evaluation
The tube metals were evaluated based on the ASME stress limitations (which determined tube wall thickness), oxidation temperature guidelines, and historical analysis of tube failures.

The majority of past forced outages were a result of tube failures. The tube metal studies were based on the **actual** field data **and/or** computer **modelling data.** The following conditions were considered: **operating** at 1053 °F **SH/RH** final steam temperatures, operating with the tempering FGR system, operating at 115% of MCR, **and** firing natural gas.

The results of the tube metal study were used as a guide to establish temperature monitoring locations, alarm setpoints, and material upgrades.

Tempering Flue Gas Recirculation Study (FGR)
Boiler performance was evaluated with the tempering FGR system in operation. The report also reviewed improved methods and arrangements for the reinstallation of the tempering FGR system to eliminate mechanical problems associated with the original system.

The tempering FGR system was removed from service in 1981 due to high maintenance and fan vibration problems. Based on the boiler performance since 1981, the deactivation of the tempering FGR system was considered by TVA to have been the cause for numerous unit operational and reliability problems which included:

- Increased fouling and slagging
- Sootbiower **overheating**
- Long **and** short term tube **overheating**

Reduced steam temperature control
Increased tube corrosion
Unbalanced flue gas flow to the SH/RH passes

The majority of these problems were attributed to the increase of the furnace exit gas temperatures (FEGT) with the tempering FGR system out of service.

The FGR study concluded that the tempering FGR system should be reactivated. This will reduce the FELT by approximately 200 to 300 °F, decrease fouling above the FGR nozzles and tube bundles, reduce high temperature corrosion of the superheater, improve reheater steam temperature control, and reduce sootblower overheating. To reduce the mechanical problems, upgrading the fan design/ arrangement and adding a dust collector upstream of the fans was recommended.

An alternate FGR system arrangement was investigated which utilized the ID fans to supply the FGR through ducts to the furnace. The advantages of this arrangement are reduced power requirements, lower *FGR* temperature, and less equipment is required (separate *FGR* and dust collectors are not required). The disadvantage is that the boiler efficiency would decrease by approximately 1.5% due to the increase in the stack temperature. Because of this, this alternate arrangement was not recommended.

Air Heater Evaluation

Alternative air heater designs were reviewed and evaluated as a means of reducing air heater leakage and **pluggage** problems while also improving the air heater's performance and reliability.

The existing boilers equipped with regenerative air heaters, have had a **history of pluggage problems, high** rates of air leakage, and low thermal performance. Options evaluated included:

1. **Rebuilding** the existing air heaters with design improvements.
2. New, upgraded Ljungstrom airheater.
3. Tubular air heaters.
4. Plate type air heaters.
5. Heat Pipe air heaters.

The results indicated that the options 1, 2, and 4 are the most feasible both economically and **physically.** TVA is further investigating these options.

Boiler Circulation Study

The existing boiler circulation system was reviewed utilizing actual operating data from downcomer subcooling and furnace heat flux profiles.

Circulation was analyzed at several load conditions including:

- 100% load (baseline).
- Top feedwater heater out of service at 100% load.
- Original peak of 106% load.
- New peak of 115% load with all feedwater heaters in service.

The study concluded that circulation is adequate at the evaluated boiler loads. These units have adequate circulation margin due the extensive use of rifled tubing in the high heat flux zones and because of the large unit height (pumping head). Areas of concern recommended for additional study are drum internal performance with possible carryunder at overload conditions and the effects of overfiring during load ramping.

Cyclone Operation Review and Refractory Inspection

The operation of the cyclones **and** possible methods to improve cyclone refractory performance were reviewed.

The existing cyclones have had **a** history of mechanical problems associated mainly with the refractory. There have also been performance problems caused by the control of air and fuel to the cyclones.

The recommendations concerning the cyclone refractory included:

- Develop improved installation, monitoring, and inspection procedures.
- Investigate the use of new types of refractory (crystolon silicon carbide).
- Develop water side curing procedures.

The recommendations concerning the cyclone operation included:

Improve the metering and measurement of coal to each cyclone.

Maintain the cyclone air **venturi and maintenance.**

Investigate the installation of 0_2 probes directly above each cyclone.

Investigate the cause of the high flyash flows, which can contribute to the fouling and tube erosion problems.

Natural Gas Firing Performance TVA is considering firing natural gas in the future. The boiler performance when firing natural gas was predicted and the tube metals were evaluated. The analysis was performed at 50%, 75%, 100% and 115% load conditions.

The results of the theoretical performance and metals study indicate that natural gas firing will not have a detrimental effect on boiler performance and the tube metals are within the ASME stress/temperature limits.

SUMMARY

Pertaining to the six TVA Goals for Boiler Condition Assessments and Upgrades Programs and based on the analysis from this study, a formal summary was established. Examples of the summary which includes Findings, Conclusions, and Recommendations, are shown the following Figures.

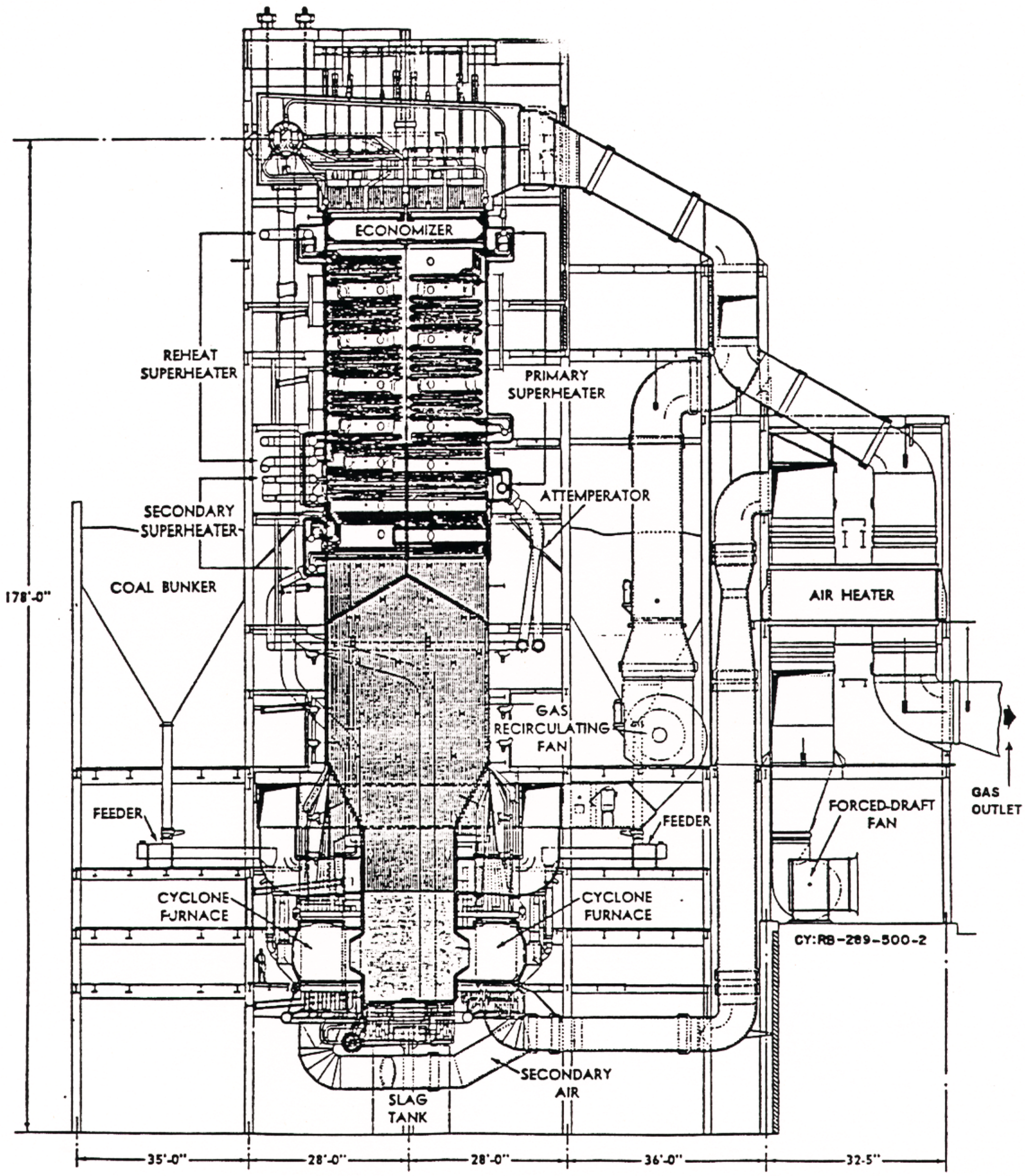
- Figure **9,** REDUCED FORCED OUTAGES
- Figure 10, INCREASE BOILER EFFICIENCY (INCLUDING UNIT HEAT RATE) -
Figure 11, INCREASE BOILER STEAMING CAPACITY
- Figure 12, EVALUATE FUTURE LOAD CYCLING CAPABILITIES -
Figure 13, IMPROVE OPERABILITY AND MAINTAINABILITY

CONCLUSION

The engineering study as reviewed in this paper demonstrates a structured, systematic approach for the identification of mechanical and operational problems and the evaluation of possible solutions. This approach, as demonstrated at TVA, can easily be applied to other units.

<u>References</u>

1. Chang, P.S., 1993, "TVA Boiler Assessments and Upgrades Program," Joint Power Conference, Kansas City, Missouri.



TENNESSEE VALLEY AUTHORITY
ALLEN STEAM STATION, UNIT 1, 2, 3
RSC CONTRACT NO. 92537

Boiler General Arrangement
Figure 1

TVA, Allen Sta.
RSC Contr.: 92537
9/22/92

SUBPROBLEM MATRIX (Part 1 of 2)

Notes:
* See part 2 for all 7640 Failure Reports.
* Boiler Startups: Fall 1958 to summer 1959.
* Plant to TVA on 1.1.65

Reference Document Key:
7640A...Failure Report
ER................Events Records, 1988 to 1992
MR................Metallurgical Reports
CA................Boiler Condition Assessment, Mar. 1992
Int...............TVA Personnel Interviews
HMP...............Marlin Penny List
PC................Notebook, P. Chang to W. Kitchen
Rep...............Inspection Reports
Corr..............TVA Correspondence
MR................Maintenance Reports

Subproblem Designation:
P = Pressure parts
C = Cycling/Performance
S = Structural/Seal
O = Other

Subproblem Number	Component I.D.	Subproblem Description	Boiler Number	Year	Number of Occurences	Current Situation	Reference Documents
O3	AH	Air Heater leakage up to 30%. Radial & sector seals worn.	1,2,3			FD fan limit reached. Load limited to 2,000,000 lbs/hr.	Int & Rep
O3(contd)	AH	Rotor shaft misalligned. Tears on T-bar. Baskets not levelled.	1,2,3			30% of T-bars need replacing. Leveled rotor on #2 Unit.	Int
O3(contd)	AH	Leakage worse on #1. Higher diff. bacause of bal. draft.				Furnace draft press.	Int & ER
O5	AH	High Air Heater pluggage. Originally designed for NG & intermittant coal	1,2,3			Wash AH's every 2 months.	Int
O5(contd)	AH	Popcorn carryover on hot side. Cold-side cake buildup.				Louver type cinder (slag) trap installed between the Econ	Int & A.H. CA
O5(contd)	AH					and A.H. in 1972. Very little popcorn now.	
C1	Slag	Slag cannot be tapped at low load.	1,2,3			Turndown limit to 1,400,000 lbs/hr. (OK below 50MW-no slag)	Int & HMP
C1(contd)	Slag	Low sulfur coal required for SO2 has high iron. T250 seems OK (<2600F).	1,2,3				Int
O4	GR	GR fan high maintenance,vibration,wheel erosion (retipped yearly).	1,2,3			GR ceased operation in 1980. Industry wide problem. Most	Int & PC
O4(contd)	GR	Overhung fan. Poor control damper design. No turning gear.	1,2,3			have removed GR, if possible.	Int
O4(contd)	ER	Duct expansion gas leaks. Duct erosion OK.	1,2,3				Int
C2	Emiss	Opacity problems. Worse on Unit #1 because of balanced draft conversion.	1,2,3			Conversion scheduled for #2 & #3 units.	ER, Int, & PC
C2(contd)	Emiss	Precipitator is marginal. Over 20% opacity if any boiler upset.	1,2,3			Perforated plates to be put at inlet to Precip.	ER & Int
C2(contd)	Emiss	Many deratings on Opacity.	1,2,3				ER

Mechanical Problems
Figure 2

TVA, Allen Sta.
RSC Contr.: 92537
9/21/92
Rev.: Dec. 1992
JAM

SUBPROBLEM MATRIX (Part 2 of 2)

Note: See separate reference for nomenclature definitions.

Year	Subproblem Number	Component I.D.	Subproblem Description	Failure Cause	Boiler Number	Reference Document
1968	P287	CYC	7	14	3	7640(PO−12−58)
1968	P288	RH1	13	11	1	7640(PO−12−58)
1968	P569	SHHDR320	11	42	1	7640(PO−12−58)
1968	P291	WW4	13	1	1	7640(PO−12−58)
1968	P286	WW4	13	1	1	7640(PO−12−58)
1968	P290	WW4	13	1	1	7640(PO−12−58)
1968	P289	WW4	13	1	1	7640(PO−12−58)
1968	P292	WW4	13	1	2	7640(PO−12−58)
1969	P293	CYC	7	42	2	7640(PO−12−58)
1969	P294	CYC	7	1	1	7640(PO−12−58)
1969	P295	CYC	7	1	1	7640(PO−12−58)
1969	P296	CYC	7	1	1	7640(PO−12−58)

Tube Failures
Figure 3

BOILER TUBE FAILURE REPORT - 7640A

REVISED

Plant ALF   Unit ☐   Report ____________   Date ☐☐-☐☐-☐☐

TOTAL LEAKS REPAIRED
- Start — Date ☐☐-☐☐, Time ☐☐-☐☐
- End — Date ☐☐-☐☐, Time ☐☐-☐☐

Quantity of Leaks Repaired ☐☐

Operating Hours on Unit ☐☐☐☐☐☐

☐ Type of Failure
1. Primary - Disabled Unit
2. Secondary

LOCATION

ELEV. ☐☐☐☐ FT. ☐☐ IN.

ELEMENT NO. ☐☐☐

ELEMENT COUNT DIRECTION ☐

TUBE NO. ☐☐☐

TUBE COUNT DIRECTION ☐

DIRECTION DEFINED:
1. LEFT TO RIGHT
2. RIGHT TO LEFT
3. FRONT TO REAR
4. REAR TO FRONT
5. TOP TO BOTTOM
6. BOTTOM TO TOP

☐ SIDE
1. FIRE
2. CASING

☐ WATERWALL
1. FURNACE FRONT
2. FURNACE REAR
3. FURNACE LEFT
4. FURNACE RIGHT
5. FURNACE FLOOR
6. DIVISION WALL
7. SCREEN FRONT
8. SCREEN REAR
9. ECONOMIZER
10. ECONHDR (Elev.)

☐ CYCLONE
1. BARREL LEFT
2. BARREL RIGHT
3. NECK TUBES
4. FRONT CLOSURE
5. REAR CLOSURE
6. RE-ENTRY THROAT
7. SLAG TAP

☐☐ O'CLOCK

☐ SUPERHEAT	Elevations
1. SEC SH 2nd STAGE	316 to 322
2. SEC SH 1st STAGE UPPER	310 to 316
3. SEC SH 1st STAGE LOWER	305 to 310
4. PRI SH 2nd STAGE UPPER	355 to 360
5. PRI SH 2nd STAGE UPPER INTERM	344 to 355
6. PRI SH 2nd STAGE LOWER INTERM	336 to 344
7. PRI SH 2nd STAGE LOWER	329 to 336
8. PRI SH 1st STAGE	322 to 329
9. SHHDR (Elev.)	

☐ REHEAT SUPERHEAT	
1. RH SH UPPER	354 to 361
2. RH SH UPPER INTERM	344 to 354
3. RH SH INTERM	336 to 344
4. RH SH LOWER INTERM	329 to 336
5. RH SH LOWER	322 to 329

HORIZONTAL TUBES:
- ☐☐ FEET FROM FRONT WALL
- ☐☐ FEET FROM REAR WALL
- ☐☐ FEET FROM LEFT WALL
- ☐☐ FEET FROM RIGHT WALL

☐☐ Description of failure
- 01 Pinhole in tube
- 02 Pinhole in tube joint weld
- 03 Leak at padweld
- 04 Leak at socket weld
- 05 Window blown out
- 06 Torch cut
- 07 Crack - thick lipped
- 08 Crack - thin lipped
- 09 Crack - at attachment
- 10 Crack - at membrane
- 11 Crack - at tangent weld
- 12 Crack - across tube face
- 13 RUPTURE

☐☐ Cause of failure - if known

Stress Rupture
- 01 Short term overheat
- 02 High temperature creep
- 03 Dissimilar weld

Erosion
- 11 Fly ash erosion
- 12 slag erosion
- 13 Sootblower erosion
- 14 Coal particle erosion

Corrosion - waterside
- 21 Caustic corrosion
- 22 Hydrogen damage
- 23 Pitting
- 24 Stress corrosion cracking
- 25 EROSION, CORROSION

Corrosion - fireside
- 31 Low temperature corrosion
- 32 Waterwall fireside corrosion
- 33 High temperature coal ash corrosion
- 34 OXIDATION
- 35 LIQUID PHASE CORROSION

Fatigue
- 41 Vibration fatigue
- 42 Thermal fatigue
- 43 Corrosion fatigue
- 61 MECHANICAL STRESS

Quality Control
- 51 Maintenance cleaning damage
- 52 Chemical excursion damage
- 53 Material defects
- 54 Weld defects (or OLD FW)
- 55 IMPINGEMENT

Failed tube OD ☐.☐☐☐ inch   Failed tube wall thick 0.☐☐☐ inch   ☐☐ Failed material

Repl tube OD ☐.☐☐☐ inch   Repl tube wall thick 0.☐☐☐ inch   ☐☐ Repl material

☐ Repairs made by
1. Grinding out/pad weld
2. Window weld
3. Replacement

1 SA 178A	5 SA 210 A1	9 SA 213 T9	13 SA 213 T22
2 SA 192 —	6 SA 210 C	10 SA 213 T11	14 SA 213 TP304H
3 SA 209 T1	7 SA 213 T2	11 SA 213 T13	15 SA 213 TP321H
4 SA 209 T1a	8 SA 213 T5	12 SA 213 T14	16 SA 213 TP347H

Comments ______________________________

Boiler Tube Failure Report (BTF)

Figure 4

TVA
PERSONNEL INTERVIEWS

I. DANNY PLUMLEE - I&C SUPERVISOR - ALLEN PLANT

1. Boiler building is extremely hot due to a poor insulation job done in the past. The cyclone furnaces were enclosed in a vestibule instead of being insulated and lagged separately. Unit #1 is better due to balanced draft. (Fran Dominioni has data showing boiler skin temperatures).

2. Casing leaks are still a problem. Unit No. 3 casing was replaced, but now still leaks. May need to measure skin temperatures again.

3. Furnace H.V.T. probe data was taken by Diamond Power approximately 5 years ago to resolve sootblower overheating problem. This data is available.

   Economizer failures are increasing. Old field welds on screen tubes, etc. are showing up.

5. New S.H. outlet headers, new PSH outlet headers, new RH outlet headers are planned.

6. Tube leaks at tube stub welds at lower ring header feeding cyclone furnace. (Phil Katz to investigate).

7. Upper & lower bifurcates eroding and cracking. They are being replaced.

8. Some waterwall failures. One above economizer. Isolated case?

9. G.R. fans taken out of service due to maintenance, vibration, gas leaks, wheel erosion. Advantages when fans were in service were: less slagging, better R.H. temperature control, less sootblower lance problems. If maintenance problems on G.R. fans could be eliminated boiler performance would improve.

10. Original steam temperatures were:

S.H. - 1050 1st derate	S.H. - 1050	Present	S.H. - 1025
R.H. - 1050	R.H. - 1025		**R.H.** -1000

   Temperature derates due to cracks in RH outlet header ligament

11. Next weak link - Economizer, lower ring header.

Example: Personnel Interviews
Figure 5

			1	3	4	6	7	9	10	12	13	14	16
	TEST NUMBER		1	3	4	6	7	9	10	12	13	14	16
	TEST STARTING DATE		8/26/92	8/26/92	8/25/92	8/25/92	8/28/92	8/29/92	8/27/92	8/28/92	8/29/92	8/30/92	8/27/92
	OBJECTIVE		-PEAK LOAD -NORM. XS. AIR	-PEAK LOAD -HIGH XS. AIR	-MCR LOAD -NORM. XS. AIR	-MCR LOAD -HIGH XS. AIR	-75% LOAD -NORM. XS. AIR	-75% LOAD -HIGH XS. AIR	-50% LOAD -NORM. XS. AIR	-50% LOAD -HIGH XS. AIR	-MIN. LOAD -NORM. XS. AIR	-MIN. LOAD -HIGH XS. AIR	-MCR -#8 FW HTR OUT -NORM. XS. AIR
	FUEL		COAL	COAL	COAL	COAL	COAL	COAL	COAL	COAL	COAL	COAL	COAL
	BOILER LOAD, % MCR		106%	106%	100%	100%	75%	75%	54%	54%	47%	45%	98%
	GROSS MW (CONTROL ROOM)		287.8	287.6	269.75	268.80	205.60	205.60	143.44	144.25	126.00	117.00	285.80
	1. WATER & STEAM FLOWS												
1.1	FW ORIFICE PRESS DIFFERENTIAL	IWC	96	97	85	85	47	47	23	23	17	15	84
1.2	FEEDWATER FLOW (CALCULATED)	KPPH	2120	2129	1995	1997	1509	1504	1077	1073	937	892	1960
1.3	FEEDWATER FLOW (CONTROL ROOM)	KPPH	2280	2286	2121	2091	1562	1564	1066	1080	910	863	2100
1.4	BLOWDOWN FLOW	KPPH	0	0	0	0	0	0	0	0	0	0	0
1.5	SH SPRAY FLOW (CONTROL ROOM)	KPPH	250.8	225.0	242.7	226.0	76.4	188.0	40.0	130.0	0	0	309.9
1.6	SH SPRAY FLOW (CALCULATED)	KPPH	234	194	220	191	73	191	0	104	0	0	317
1.7	MAIN STEAM FLOW (USING FDW FLOW)	KPPH	2120	2129	1995	1997	1509	1504	1077	1073	937	892	1960
1.8	MAIN STEAM FLOW (CONTROL ROOM)	KPPH	2183	2175	2037	2000	1500	1499	997	1025	836	770	2019
1.9	REHEAT FLOW (CALCULATED)	KPPH	1654	1656	1559	1559	1196	1195	877	880	771	737	1741
1.10	RH SPRAY FLOW (CONTROL ROOM)	KPPH	0	0	0	0	0	0	0	0	0	0	0
	2. STEAM AND WATER TEMPERATURES												
2.1	FINAL SUPERHEAT TEMPERATURE	°F	1033	1030	1030	1021	1022	1020	1030	996	991	1021	1014
2.2	SECONDARY SH INTERM. OUTLET	°F	914	926	901	932	911	899	921	920	901	936	903
2.3	AFTER SH SPRAY TEMPERATURE	°F	755	763	751	769	744	743	742	739	719	749	733
2.4	BEFORE SH SPRAY TEMPERATURE	°F	843	835	847	849	777	852	742	821	719	748	884
2.5	PRIMARY SH INTERM. HEADER	°F	759	759	753	764	703	754	686	732	671	738	774
2.6	DRUM SATURATION TEMPERATURE	°F	675	675	674	674	670	669	666	665	667	668	673
2.7	CHORDAL THERMOCOUPLE TEMPS.	°F	770	772	778	778	747	740	734	728	721	718	790
2.8	FINAL REHEAT TEMPERATURE	°F	1030	1034	1011	1033	1006	994	999	1000	992	1023	1008
2.9	COLD REHEAT TEMPERATURE	°F	675	673	663	666	619	615	587	594	559	595	675
2.10	ECONOMIZER OUTLET TEMPERATURE	°F	580	580	573	574	542	547	506	512	493	492	509
2.11	ECONOMIZER INLET TEMPERATURE	°F	560	560	553	553	523	522	485	485	470	464	477
2.13	SUPERHEAT SPRAY TEMPERATURE	°F	560	560	553	553	523	522	485	485	470	464	477

Table 1, Sheet 1 of 5

Example: Testing Summary Sheets
Figure 6

Tennessee Valley Authority
Allen Steam Station, Unit 2
RSC Contract No. 92537

3.0 Executive Summary

3.1 Objectives

The objectives of this report are the following:

- Summarize the current performance of the boiler and air heaters.
- Compare the current performance of the boiler and the air heaters with the original design performance predictions.
- Identify current, or potential, problem areas in the boiler and air heaters performances.

3.2 Findings

- Final Superheat/Reheat Steam Temperatures
  The superheater final steam temperature was being held reasonably close to its derated value of 1025°F but the reheater steam temperature was about 10 to 20°F above its derated temperature of 1000°F.
- Furnace Exit Gas Temperature (FEGT)
  An unbalance in furnace exit gas temperature exists when a fuel firing unbalance is present.
- Furnace Waterwall Tube Crown Metal Temperature
  Furnace waterwall crown tube metal temperatures slightly exceed the recommended long-term oxidation limit when operating above MCR furnace heat input rate.
- Air Heater Leakage
  Excessive combustion air leakage to the flue gas side of the air heater. The leakage varies from 25% to 40%.
- Boiler Flue Gas Leakage
  Excessive flue gas leakage from the boiler.
- Boiler Efficiency
  The boiler efficiency at rated load is 90.64%. This is reasonably close to the B&W 1960 Acceptance Test value of 90.72%.

Example: Testing Findings
Figure 7

BOILER COMPUTER MODEL PERFORMANCE

	OPERATING CONDITIONS		MCR LOAD -TEST DATA 8.25.92	MODEL MCR LOAD -PRED. w/27% GR & New A.H.	-PEAK LOAD -TEST DATA 8.26.92	MODEL -PEAK LOAD -PRED. w/27% GR & New A.H.	MODEL -PEAK LOAD -PRED. w/27% GR & New A.H.	-#8 FW HTR OUT -TEST DATA 8.27.92	MODEL -#8 FW HTR OUT -PRED. w/27% GR & New A.H.
	FUEL		COAL	COAL	COAL	COAL	COAL	COAL	COAL
	BOILER LOAD, % MCR		100%	100%	106%	106%	115%	98%	98%
	1. WATER & STEAM FLOWS								
1	MAIN STEAM FLOW	KPPH	1995	1995	2120	2120	2300	1960	1960
2	SH SPRAY FLOW	KPPH	220	293	250.8	336.0	403	309.9	342
3	REHEAT FLOW	KPPH	1559	1559	1654	1654	1790	1741	1741
4	RH SPRAY FLOW (CONTROL ROOM)	KPPH	0	0	0	0	0	0	0
	2. STEAM AND WATER TEMPERATURES								
5	FINAL SUPERHEAT TEMPERATURE	°F	1030	1053	1033	1053	1053	1014	1053
6	SECONDARY SH INTERM. OUTLET	°F	901	926	914	936	936	903	943
7	AFTER SH SPRAY TEMPERATURE	°F	751	784	755	784	783	733	774
8	BEFORE SH SPRAY TEMPERATURE	°F	847	916	843	936	968	884	955
9	PRIMARY SH INTERM. HEADER	°F	753	804	759	823	841	774	827
10	DRUM SATURATION TEMPERATURE	°F	674	674	675	675	676	673	673
11	FINAL REHEAT TEMPERATURE	°F	1011	1053	1030	1053	1053	1008	1053
12	COLD REHEAT TEMPERATURE	°F	663	678	675	689	708	675	701
13	ECONOMIZER OUTLET TEMPERATURE	°F	573	581	580	589	600	509	519
14	ECONOMIZER INLET TEMPERATURE	°F	553	553	560	560	570	477	477
15	SUPERHEAT SPRAY TEMPERATURE	°F	553	553	560	560	570	477	477

Example: Computer Model Summary
Figure 8

REDUCE FORCED OUTAGES

Findings

The majority of forced outages were a result of tube failures. Tube failures leading to forced outages since 1968 on Units 1, 2, and 3 have been:

Superheater Tubes (164).
The principal causes of SH tube failure were by liquid-phase corrosion (52 failures, occurring during the time span of 1977 to 1986), and fyash erosion (19 failures, occurring during the time span of 1975 to 1966).

Cyclone Furnace Tube Failures (158).
The principal causes of cyclone tube failure were coal particle erosion (97 failures, occurring during the time span of 1968 to 1988), and short term overheating (36 failures, occurring during the time span of 1969 to 1981).

Waterwall Tube Failures (117).
The principal causes of WW tube failures were short term overheating (25 occurring during the time span of 1969 to 1972), and floor tube slag erosion (22 occurring during the time span of 1970 to 1979).

Reheater Tube Failures (97)
The principal causes of RH tube failure were fiyash erasion (29 occurring during the time span of 1968 to 1988), and sootblower erosion (19 occurring during the time span of 1972 to 1988).
Note: Although the failure rate has reduced since 1988, metallurgical analyses of non failed tubes and of failed tubes have

indicated erosion/corrosion (RH), thermal fatigue (RH), mechanical stress, high temperature creep, and liquid ash corrosion.

Conclusions

Since 1988 the principal causes of tube failures have greatly decreased. This is attributable to: •
Change in coal source
- Increase in spacing of RH lower tube bank from 4W to 9°.
- Tube shielding.
- Upgrading of Secondary SH, 1st stage from TI I to T22 material.
- Upgrading of secondary SH, 2nd stage tubing from T22 to stainless steel.
- Reducing SH/RH final steam temperatures to 1025/1000°F.

Removing the gas recirculation system from service in 1980 caused sootblower overheating problems, may have accelerated liquid-phase corrosion attacks due to additional slag buildup, and increased furnace exit gas temperature.

Recommendations

Reinstate the FGR system:
- Lower the furnace exit gas temperature to reduce slagging, fouling, and coal ash corrosion.
- Reduces tube bundle slag and fouling build-up which, in turn, reduces flue gas laning and erosion.
- Overall gas velocities will increase, but not exceed design velocities. Increased tube erosion is not expected.
- Improved sootblower performance due to lower operating temperature. This results in less fouling of the tube surfaces.

Improve cyclone furnace performance to reduce erosive flyash carryover entering the tube bundles.
- Crush coal to smaller size
  Improve refractory in cyclone furnace barrel. Refer to Book 3, Section 9, 'Cyclone Refractory Industry.
  Conduct testing to determine the amount of fyash flow to the precipitator. This data will aid in estimating the cause of fyash erosion and be used as baseline data to evaluate improvements in the future.

Balance cyclone furnace firing rate and air/coal ratio, especially at lower loads, to reduce flue gas temperature stratifications and laning.
- Monitor superheater and reheater outlet header tube temperatures in the control room, and use as a guide to balanced leftto-right firing.
- Install 0_2 probes above each cyclone burner and use as a guide to balance air/coal.
- Change pneumatic controls to electronic controls for faster and more accurate control of burners.

Observe tube temperature limitations recommended by Riley.
- Inlet tubes to Primary Superheater Intermediate Header should be monitored in the control room, and set to alarm at 860°F.
- Before SH Spray thermowell temperatures should be monitored is the control room, and set to alarm at 990°F.
  Inlet tubes to the Secondary Superheater Intermediate Header should be monitored in the control room, and set to alarm at 975°F. All thermocouples should be repaired or replaced.
  Final superheater tube temperatures should be monitored in the control room, and set to alarm at 1105°F.
  Final reheater tube temperatures should be monitored in the control room, and set to alarm at 1135°F. If Riley's recommendation in paragraph 1.3.5 is implemented, the alarm limit can be increased to 1165°F.

Extend the stainless steel tubing in the reheater from Station #10 to Station #4. Refer to Book 2, Section 5, Figure 49.

Evaluate tubing materials which are resist to ash corrosion.

EXAMPLE OF EXECUTIVE SUMMARY
FIGURE 9

INCREASE BOILER EFFICIENCY (INCLUDING BOILER HEAT RATE)

Findings

Boiler Efficiency

- **The boiler efficiency at MCR, as tested by Riley Stoker on Unit No. 2 in August 1992, is 90.64%.**

The boiler efficiency of 90.64% Is close to the 1960 B&W boiler acceptance test efficiency of 90.62%, but is 1.3% less than the predicted efficiency by B&W design.

Boiler Heat Rate

Air Heater leakage increases FD fan power requirements.

Increased air heater draft loss increases FD fan power requirements.

Feedwater heaters are delivering water to the boiler at a temperature of approximately 17°F below design.

Excess air is higher than design.

Steam temperature control range is less than design. The design steam temperature control range is from 100% down to 60% of MCR. The actual steam temperature control range is from 100% down to approximately 80% of MCA.

The ash loss of ignition (LOI) **is 1.95% as compared to the original design of 1.05% LOI resulting in a boiler efficiency unburned carbon loss of 0.1% higher than design.**

Conclusions

Boiler efficiency was less than design because:

- **Stack temperature is approximately 50°F higher than design.**
- **Excess air is approximately 4% higher than design.**
- **Unburned carbon loss is higher than design because of cyclone furnace performance.**

Boiler heat rate items were less than design because:

- **Poor air heater performance (increased draft loss & leakage).**
- **Poor feedwater heater performance (decreased FW temperature).**
- **The removal of the FOR system (causing lower steam temperature control range).**
- **Poor cyclone furnace performance (causing increased unburned carbon loss).**

Recommendations

Repair or replace the air heaters to lower the stack temperature and reduce the draft losses.

Improve cyclone burner performance to reduce excess air operation and to improve the unburned carbon losses. Refer to recommendations In 1.3.2.

Reinstate the FOR system to improve the steam temperature control range.

Investigate the cause for the low feedwater temperature entering the boiler.

INCREASE BOILER EFFICIENCY (INCLUDING BOILER HEAT RATE)
EXAMPLE OF EXECUTIVE SUMMARY
FIGURE 10

INCREASE BOILER STEAMING CAPACITY

Findings

The current estimated capacity of the No. 2 Unit (pressurized) is limited to 107% of MCR due the FD fan capacity.

The current SH spray nozzle capacity will limit the load increase to 112% of MCR with FOR and 1063/1053 °F SH/RH final steam temperatures.

The current Primary SH, 1st stage metals will limit the load increase to 106% of MCR with FOR and 1053/1053 T· final steam temperatures. Refer to Book 2, Report 5, Figure 6,7,10 and 11.

The current reheater exceeds the oxidation temperature guidelines by 25 °F at loads above 100% with FOR and 1053/1053 °F SH/RH steam temperatures.

All other SH/RH/Econ (SRE) tube bundles are within acceptable limits for the ASME Code and oxidation temperatures up to and including 115% boiler load.

Boiler water wall Circulation is adequate up to and including 115% boiler load.

Conclusions

The FD fan capacity is limited due to excessive air heater leakage and draft loss.

The spray capacity is limited by the superheater spray nozzle orifice setting.

The primary superheater, 1st stage tube metal (SA-210A1 material in the lower half of the bundle) is not adequate per the ASME Code for boiler loads above 106% of MCR.

The August 1992 testing indicated that the reheater tube metal oxidation temperature guideline is exceeded due to a large tube-to-tube temperature unbalance caused by a steam side flow unbalance.

Recommendations

Repair or replace the airheaters.

Increase the superheater spray capacity by:
- Increasing the nozzle orifice size.
- Throttling the FW control valve.

Decrease the superheater spray flow requirements by throttling the SH control dampers. Note: this is only an option if RH spray flow is acceptable and RH gas pass erosion is no longer a problem.

Upgrade the primary SH, 1st stage SA-210A1 material in the lower half of the bundle. Refer to Book, Section 5, Figure 1.

Installing an intermediate header could be considered to improve reheater steam temperature distribution. However, before doing this, or any other alteration, further RH outlet temperature testing and evaluation would be required on Units 1 and 3 to confirm the tube temperature pattern.

Riley recommends investigating the capacity of equipment that was not reviewed in this report which include, but are not limited to, the following: safety valve capacity, cyclone burner capacity, emissions, ash removal system, coal feed system, feedwater pumping system, etc.

INCREASE BOILER STEAMING CAPACITY
EXAMPLE OF EXECUTIVE SUMMARY
FIGURE 11

Findinas

Testing was conducted in August 1902 at load cycling rates of 1.5% of MCR.

During the 1.5% cycling test, the final SH temperatures momentarily went as high as 1075 °F Note, these temperature excursions occurred several times during the test. Refer to Book 1, Section 3, Figure 51.

The cycling rate was limited by:

- Firing rate and time required to place cyclone burners in service.
- Time necessary to place the auxiliary FD fan in service.
- Control of the steam temperatures.

Recommendations

Review possible methods to reduce the time required to start the a cyclone furnace and the auxiliary FD fan during load cycling.

Review control system modifications to improve the firing rate and steam temperature control during load cycling. Review and establish the header temperature limitations.

Riley recommends that the boiler be limited to a cycling rate of 1.5% until the design cycling criteria has been defined.

EVALUATE FUTURE LOAD CYCLING CAPABILITIES
EXAMPLE OF EXECUTIVE SUMMARY
FIGURE 12

Finding and Conclusions

Operability

Steam temperature control range is less than design. The design steam temperature control range is from 100% down to 60% of MCR. The actual steam temperature control range is from 100% down to approximately 80% of MCR.

The sootblowers require more frequency of blowing, more time of blowing, and do not survive long at higher flue gas temperatures.

The air heater has pluggage problems and has increased leakage.

Unit 2 has pneumatic controls that limit the speed and accuracy of controlling and monitoring variables to maximize boiler efficiency and minimize heat rate and emissions.
At low loads, tube-to-tube steam temperature maldistribution occurred

Control room flow indications need calibration

- The accuracy for measuring the cyclone airflow is not reliable
- Control room air flow indications do not agree with calculated air flow at lower loads
- Control room steam flow indications do not agree with the calculated flows at low loads

Maintainability

Cyclone burner refractory wear.

Excessive flue gas leakage from boiler casing at cyclone furnace elevation.

Recommendations

Reinstate the FOR system to increase the steam temperature control range.

Reinstate the FOR system to reduce the flue gas temperatures at the sootblowers.

Implement an air heater option to reduce air heater pluggage and leakage. Refer to Book 3, Section 7 Convert

the pneumatic controls to electronic controls for better control and monitoring of operating variables. At low load

operation the cyclone furnace firing arrangement and coal flows should be balanced.

- Calibrate control room indicators.
  - The cyclone air flow venturis must be maintained, calibrated, and sensing lines purged on a scheduled basis.
  - Calibrate the control room air flow venturis. Refer to Book 1, Section 3, page 29.
  - Calibrate the control room steam flow indication. Refer Book 1, Section 3, page 30.

Investigate improved cyclone furnace refractory materials, installation, curing and operation. Refer to Book 3, Section 9.

Repair casing leaks at the cyclone furnace elevation.

IMPROVE OPERABILITY AND MAINTAINABILITY
EXAMPLE OF EXECUTIVE SUMMARY
FIGURE 13