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Damodar Valley Corporation
Chandrapura Unit 2 Thermal Power Station
Residual Life Assessment
Summary Report
~~Volume 1~~
February 1995
Prepared By
Tennessee Valley Authority
Fossil and Hydro Power
Chattanooga, Tennessee

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Damodar Valley Corporation - Chandrapura Thermal Power Station, Unit 2

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Executive Summary

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Executive Summary

The BHEL / NTPC / PFC / TVA Teams assembled at the DVC's Chandrapura Thermal Power Station (CPTS) on July 19th, 1994 to execute the Unit 2 Phase II and III scope of Plant Remaining Life Assessment, and transfer the specialized technologies utilized.

The original workscope was expanded to include major plant systems that could impact the Units ability to provide sustained generation of 140 MW. Since the CPTS Units 1~3 were commissioned, they have operated at an average rating of about 90 MW. The objective of the study was revised so as to address the following:

- o Remaining Life Assessment (RLA) of critical plant system components within the boiler, turbine and their auxiliaries.
- o Evaluate critical plant systems performance, and identify:
 - System deficiency,
 - Impact on plants generation capacity and reliability, and an estimated cost to DVC,
 - Potential root cause(s) for the identified deficiency,
 - Root cause evaluation, to verify root cause,
(This effort was carried out in cases where the necessary data was available or could be established during the course of the study.)
 - Evaluation of available solutions,
 - Recommendations for upgrading systems to support plants goal of sustained full load generation.

Eight teams (Attachments 1 - 8), with representation from each organization, were established to address key aspects of the Plant Remaining Life Assessment. The plant-system assessment teams used a systematic problem-solving approach (Attachment 9) which focused on establishing the Operating Plant Parameters for each of the sub-systems. Root Causes associated with the systems deficiencies were identified. In some cases, the Potential Root Cause could not be verified until additional system performance data is established. DVC has been requested to work with BHEL and NTPC to acquire this additional data.

Based on the plant systems upgrade recommendations, BHEL, NTPC, and PFC are to jointly evaluate the feasibility of implementation and develop associated cost, schedule, and economic impact of upgrading the plant systems. TVA will review this data and issue a Techno-Economic Study for upgrading DVC's CPTS Units 1~3. Remaining Useful Life (RUL) of the key plant components, and operational guidelines to maximize system component life have been addressed by TVA.

The assessment workscope was completed by August 19 th, 1994. In some cases alternate technologies available through BHEL, NTPC and CMERI were utilized to support the assessment effort. Outlined in Table 1 is a list of these technologies and their impact on life

assessment.

The Ultrasonic Data Processing And Processing System (UDRPS) based rotor borosonic assessment was completed on two rotors by the planned departure date of August 19, 1994. Four turbine rotors were evaluated. The CTPS Unit 2 HP/RH rotor, spare LP rotor (scheduled for installation into Unit 2), and spare HP/RH rotor. The CTPS Unit 2 LP rotor had significant steam path damage and is not recommended for return to service, without restoring the L-0 and L-1 stage steam path (both ends). The spare HP/RH rotor forging was condemned following the discovery of a deep cracks at the Curtis wheel. This rotor forging has being evaluated to establish the extent of damage. Per TVA's recommendation DVC is pursuing the option of weld repairing the rotor in the US.

Summaries from each of the teams are included in the Residual Life Assessment Summary Report, and are to be reviewed / discussed with the DVC, BHEL, NTPC, and PFC management.

Highlights of the Condition Assessment are:

- o The boiler pressure parts are in excellent condition except for the damage to the primary superheater header / stub tubes, and economizer inlet header stub tubes. Typical repairs necessary on tube alignment, spacer lugs, and seals have been identified.

Based on our evaluation of the PSH system, the PSH elements in the second pass are absorbing excess energy. Preliminary evaluation of the second pass indicates excess PSH surface. This condition has been discussed with DVC, BHEL, NTPC, and PFC engineers. It is our opinion that this condition can be readily corrected by removing PSH surface. The economizer surface will have to be reduced to address the increased gas flow temperatures exiting the PSH elements.

- o **The Turbine Steam Path** is in good condition expect for the damage to the LP blading. The spare rotor steam path is in better condition and is recommended for use in Unit 2.

The Nozzle Box struts are severely cracked as a result of thermal fatigue stresses induced by the frequent flame outs. Crack propagation rates have been evaluated, and it is recommended that these cracks not be repaired.

HP/IP rotor has surface cracks at several locations along the steam seal areas. These are result of frequent flame outs, that result in thermal shocks to the rotor surface. These cracks have been evaluated to be shallow and should be machined out.

Detailed component damage assessment analysis for each of the above damaged components has been completed.

- o **The Turbine Auxiliary Systems** have been evaluated.

The Cooling Tower fouling / blockage is the root cause for the high turbine back pressure.

- o **The Fuel Processing System** has been evaluated, and is considered to be one of the primary root causes for limiting unit capacity.
- o **The Main Steam and Hot Reheat Piping Systems** were conservatively designed and have at least 30 years remaining life if operated at original design conditions. Deficiencies which should be resolved before restart of Unit 2 include restoration of insulation, replacement of six deformed hanger clamp/bolts, and adjustment of a few hanger settings.
- o **The Cold Reheat Piping System** is generally in good condition. Some areas should be re- insulated and the two rigid support clamps/bolts should be examined to determine whether they have deformation as occurred in the high temperature rigid supports.
- o **The Turbine Extraction Piping System** supports all appeared to be functioning normally within their travel range.

Table 1

Assessment / Technology	Alternate Technology / Comment	Impact on Assessment Conclusions
Boiler Tube Waterwall Wall Tube Thickness Measurement D- Meters with Data Loggers Information downloaded to the Boiler Maintenance Workstation (BMW)	D- Meters with manual data logging. Information downloaded to BMW	No Impact on life assessment. The BHEL / NTPC / DVC team has seen this process in the US.
Generator Hydrogen Coolers Eddy Current Testing	The coolers have been pressure washed and will be pressure tested. TVA's experience with the EC testing has not been good. Unless there is loss of wall thickness and or severe pitting, EC test is not effective. The coolers heat sink is raw river water.	No impact on life assessment.
Generator Retaining Rings UDRPS based in-situ evaluation	Unit 2 RR's are magnetic. To-date there have been no concerns reported in the industry regarding stress corrosion cracking of magnetic rings. These rings have been tested for their hardness. TVA has offered to conduct RR examination of another set of 18Mn-5Cr RR's provided by DVC.	Unit 2 RR's have been evaluated and are considered to be acceptable.

Turbine and Auxiliaries Assessment Team

Attachment 1

Systems	Assessment Scope	DVC	TVA	BHEL	NTPC
Steam Path (HP, IP, LP) Lube Oil System Steam Seal Front Standard	Dimensional Checks (SPA) Steam Path CDA T/G Auxiliary System Evaluation Performance Evaluation Component Degradation Refurbishment Plan	J. P. Singh(M)	H. G. Best *	A. K. Zamindar	H. K Sandhir Krishna Kumar
Plant Systems CW System F W System Condensate System Water Chemistry Cont	Plant Aux. System Evaluation Performance Evaluation Component Degradation Refurbishment Plan	R. K. Gupta(M) P. K. Mukerjee(O) G. P. Singh (M)	T. Khalid		H. K Sandhir ** Krishna Kumar

(*)-- Lead.. Turbine Steam Path Assessment

(**)-- Lead.. Plant Aux. System Evaluation

(O)-- Operation

(M)-- Maintenance

Turbine / Generator Non-Destructive Examination Team

Attachment 2

System	Assessment Scope	DVC	TVA	BHEL	NTPC
Steam Path Comp. Cylinders Casings	Steam Path Comp. Valve Components Bolting Bearing	J. P. Singh	D. E. Harvey (*) L. Hime	P. V. Sastry (**) M. S. Rawat	D.D.N. Verma
HP/IP, LP, Gen. Rotors	HP/IP, LP rotor Borosonic Gen. R. Ring				

(*) Lead... Automated NDE

(**) Lead... Flaw Characterization

Boiler NDT (UT, MT, PT, Boroscope) Assessment Team

Attachment 3

System	Assessment Scope	DVC	TVA	BHEL	PFC	NTPC
Waterwalls Superheaters Economizers Headers Drum Seals Attemperators Ash Hopper	Visual NDT (UT, MT, PT) Header ID Exam (Boroscopic)	A. K.Sarkar (M) A. Biswas (O)	L. H. Bisbee(*) H.M. Penny D.W. Fletcher	R. Easwaran P.S. Subrahmanyam	P. S. Dhingra	K.M. Chowdary K. Raman P. Deb

(*)-- Lead... Boiler NDT and Flaw Characterization

(O)-- Operation

(M)-- Maintenance

Boiler Auxiliary NDT and Assessment Team

Attachment 4

System	Assessment Scope	DVC	TVA	BHEL	PFC	NTPC
Coal Mills & Feeders Exhausters Air pre-heaters ID, FD Fans Ash Handling Burner System Ducts Plt Water Chemistry	Boiler Auxiliary Systems Evaluation (IAS) Performance Evaluation, and System Deficiencies System Component Deficiency and Assessment of Degradation Rehabilitation Scope & Plan	S. D. Rao (M) R. V. Pandey	R.L. Moates A. Puri	L. Nagarajan * Bhardwaj	Johri (*)	C. Roy

(*)Lead

Generator Assessment Team

Attachment 5

System	Assessment Scope	DVC	TVA	BHEL	PFC	NTPC
Stator Field Excitor H ₂ Coolers Bushings/Bus Sys H ₂ Cooling Sys Seal Oil Sys	Electrical Tests Visual Exam Stator Integrity Gen. Auxil. Perf.	K. Champak	Nenad Dowling* John Maybury (El Cid)	U. K. Das	Naveen Kumar	A. Sardana

(*) Lead

Plant Electrical Systems Team

Attachment 6

System	Assessment Scope	DVC	TVA	BHEL	PFC	NTPC
HT / LT Switch Gears Gen. Protection & Control Relay System H. T. Motors Switch Yard Equip.	July 94 Outage Maint. History Scope Review Reliability and Historical Review Spares Parts Review Availability, Adequacy, and Recommendations for Rehabilitation Review Plant Test Procedures Assessment of Failures Reliability of Operation (RUL)	K. Champak	Nenad Downing	U. K. Das*	N. Kumar	A. Sardana

(*)-- Lead

Component Damage Assessment Team

Attachment 7

Systems	Assessment Scope	TVA	BHEL	NTPC
All Plant Systems	Metallurgical Evaluation (Replication, Material Sampling) Component Damage Assessment (Evaluate NDT, Metallurgical data) Provide Run / Repair / Replace Recommendations Conduct RLA	A. Puri B. W. Roberts * D. Rosario	P. V. Sastri K. M. Chowdary	R. N. Mehrotra

(*)-- Lead

High Energy Piping Systems (NDT and Stress Analysis) Assessment Team

Attachment 8

HEP Systems	Assessment Scope	DVC	TVA	BHEL	NTC
Main Steam Piping and Hot Reheat Piping Systems	HEP System (Piping, Hangers) Assessment Piping System Hangers Adjustment Recommendations	J. P. Singh	D. Rosario * L. H. Bisbee B. W. Roberts Royce Gateley (@ TVA)	Kothanda Raman P.S. Subrahmanyam	Krishna Kumar

(*)-- Lead

Plant Systems Assessment Teams

Attachment 9

Objective

- o Define the system boundaries and design / acceptable operating performance parameters (OPP).
- o Identify system operating performance deficiencies (OPD), and associated impact on plant reliability, availability and cost.
(Reason For Improvement)
- o Define the problem, improvement target, and schedule for executing solution.
(Problem Statement)
- o Evaluate Potential Root Causes for system deficiencies that their impact on the systems ability to meet its OPPs.
(Root Cause Analysis using fish bone or fault tree)
- o Evaluate all Potential Root Causes and identify specific root cause that specifically address the problem statement.
(Root Cause Verification Matrix)
- o Evaluate all Available Solutions that address the Confirmed Root Causes.
(Solution Matrix : Cost, Effectiveness, Feasibility)
- o Develop **Implementation Plan**, and schedule plan

Approach

- o Evaluate Unit 2 pre-shutdown data, and operation data from Units 1~3.
- o Review above information with plant operations and maintenance staff (engineers and technicians engaged in maintaining the system components).
- o Based on evaluated data (show it graphically) define **Reason For Improvement**
- o Evaluate system performance data, deficiency and impact on system to develop the **Problem Statement**, which should state the target for improvement, and schedule for achieving target

- o Utilizing fish bone or cause and effects or fault tree analysis processes data, conduct tests and analyze problem to identify **Potential Root Causes.** Involve plant staff to insure all information surfaces, and their is a plant buy-in. **(Root Cause Analysis)**
- o Analyze All PRC's and narrow the problem to a minimum number of Primary Root Causes. **(Root Cause Verification Matrix)**
- o Evaluate All Available Solutions to address the various Confirmed Root Causes. Consult system, equipment experts / OEM's, and other users of equipment (utilities, industry) to assess the feasibility, cost, and effectiveness of the various available solutions. **(Solution Matrix : Cost, Effectiveness, Feasibility)**

Chapter 1.0

Plant Major Components Residual Life Assessment

Section 1.1

Major High Temperature Pressure Parts Constructed With 2 1/4 Chromium -1 Molybdenum Steel

Major High Temperature Pressure Parts Constructed With 2 1/4Chromium- 1 Molybdenum Steel

(Main Steam Piping, Hot Reheat Piping, Secondary Superheater Outlet Header, and Reheat Outlet Header)

The main steam piping (MSP), hot reheat piping (HRP), secondary superheater outlet header (SSOH), and reheat outlet header (RHOH) are all constructed of 2 1/4Cr-1Mo seamless steel piping. For conservatism in this analysis, it is assumed that the material conforms to the specification of 30ksi yield strength and 60ksi tensile strength which characterizes the "annealed" heat treatment. The long term limit to life is assumed to be stress rupture due to the hoop stress produced by internal pressure.

Hoop Stress Calculation

The ASME B31.1 and Section I formula for hoop stress is based on an empirical correlations which produces the best agreement between uniaxially stressed samples and a pressurized cylinder, both failing by high temperature stress rupture. The formula is as follows:

$$t_m = \frac{0.5 P D_o}{SE + Py} + A \quad (1)$$

where t_m = minimum required thickness, in
P = internal pressure, psi
 D_o = outside diameter, in
S = allowable stress, psi
E = joint efficiency factor (1 used)
 $y = 0.7$ for ferritic steels in the creep range
A = corrosion allowance (zero used)

Since the SSOH and RHOH have tube penetrations, the stress has to be enhanced to account for a ligamented body. In both cases, the axial tube spacing is the controlling factor and the ligament efficiency is simply the ratio of the tube spacing minus the hole size to the ligament spacing; ie.,

$$Lig \text{ Eff} = \frac{Spacing - Hole \text{ Diameter}}{Spacing} \quad (2)$$

The SSOH has 12 inch spacing with 1.365 inch diameter holes to give a 0.886 ligament efficiency while the RHOH has 6 inch spacing with 1.440 inch diameter holes to give a 0.760 ligament efficiency.

The following table summarizes the dimensions and pressures used to compute the hoop stress, S.

Component	D _o , in	t _m , in	Design			Typical		
			P, psi	S, ksi*		P, psi	S, ksi*	
MSP	14	2.193	2000	4.983		1850	4.610	
MSP	10.75	1.749	2000	4.746		1850	4.390	
HRP	20	0.882	464	4.936		300	3.191	
HRP	16	0.698	464	4.993		300	3.228	
SSOH	16	2.55	2000	4.875	5.502*	1850	4.510	5.090*
RHOH	20	1.45	464	2.875	3.783*	300	1.859	2.446*

* S / (Lig Eff)

The relationship between time, temperature, and stress was established by statistical regression to a database from the USA (ASTM), UK (BSCC) and Japan (NRIM) using the Larson-Miller parameter. The following relationship was utilized:

$$\log(t_r) = F_0 + \frac{F_1}{T} + \frac{F_2(\log(S) + z(SEES))}{T} + \frac{F_3(10)^{(\log(S) + z(SEES))}}{T} \quad (3)$$

Where t_r = rupture time in hours

S = stress in ksi

T = temperature in degrees Rankin (F + 460)

SEES = standard error of the estimate in log of stress

z = the deviate from the mean in the Gaussian (normal) distribution. The choice of z permits the desired statistical confidence limit to be established; ie.,

z = 1.65 for minimum properties (95% of data lies above)

z = 0 for mean properties (half above, half below)

z = -1.65 for maximum properties (5% of data lies above)

F₀ = -18.18222 (this is the Larson Miller constant, commonly taken as -20)

F₁ = 39,993

F₂ = -3911.9

F₃ = -159.19

SEES = 0.05067

Using the stresses previously calculated, the following table shows the calculated remaining life for various temperatures.

Component	OD, in	Temperature		Life at Min Prop, hrs		Life at Avg Prop, hrs	
			C	Total	Remaining	Total	Remaining
MSP	14	1005	541	2,370,000	2,190,000		
	10.75			2,900,000	2,720,000		
HRP	20			2,470,000	2,290,000		
	16			2,350,000	2,170,000		
SSOH	16	1020	549	880,000	698,000	1,950,000	1,770,000
		1040	560	419,000	237,000	922,000	740,000
		1050	566	292,000	110,000	638,000	456,000
RHOH	20	1000	538	8,670,000	8,490,000		
		1020	549	3,970,000	3,790,000		
		1040	560	1,850,000	1,670,000		
		1050	566	1,280,000	1,090,000		

The values highlighted show what is believed to be the most appropriate values for minimum strength based on a best estimate of temperature from operational data and oxide scale thickness measurements. Based on this calculation, all the components have a long remaining life. Only the SSOH has the prospect of limiting life if the plant continues to operate for several more decades. If the power output is increased to 140MW, the temperature of the SSOH header should be monitored to assure that the temperatures remain within acceptable limits.

Section 1.2

Primary Superheater Outlet Header

Primary Superheater Outlet Header and Stub Tubes

1.2.1

Executive Summary

The observed damage on the primary superheater outlet (PSO) header consisted of the following:

- Prior weld repairs on the two outboard areas of the tees in the crotch (intersection) area with re-cracking in the previously repaired right tee. Replication classified the damage mechanism as creep.
- Cracking in the tee body associated with stub tubes entering the right and left tee. Replication of one of the cracks classified the damage mechanism as creep.
- Prior weld repairs on a large number of stub tubes (32 stub tubes had either prior repairs or magnetic particle indications from the present exam).

Based on "back calculations", the design metal temperature for the header and stub tubes was inferred to be 524°C (976°F) and the design mixed steam temperature leaving the header as 505°C (941°F). However, the metal temperature inferred from oxide scale thickness was significantly higher, in excess of 538°C (1000°F) and probably about 552°C (1025°F). This high temperature causes an excessive amount of attemperation, estimated to be on the order of 100°C (180°F), to maintain the main steam outlet temperature from the secondary superheater header at a level acceptable to the turbine. The necessity for excessive attemperation both degrades the total plant efficiency and results in excessive deposits in the HP turbine. The high temperature combined with the excessive attemperation were shown by calculation to be consistent with the cracking in the tee crotch and the stub tube cracking.

The long term option for resolving the problem requires a redistribution of the heat absorption surfaces in the boiler. In particular, surface should be removed from the primary superheater. To resolve the immediate distress, several levels of action are possible, each representing both a higher cost and associated additional life. These options include the following:

- Weld repair the tee and stub tube cracks. This is the minimum work which should be performed before returning the unit to service.
- Replace the tee sections and weld repair the stub tube cracks.
- Replace the tee sections and upgrade the stub tubes to T-22 (2-1/4Cr-1Mo) alloy.
- Replace the entire header and stub tubes "in kind"; ie, no material upgrades.
- Replace the entire header and stub tubes with an upgrade to P-22 header material and T-22 stub tubes.

System: BoilerComponent: Primary SHO HeaderAssessment Method: Stress Analysis

SUB-COMPONENT	Damage / Condition Found	Damage Assessment (DA) / Recommendation (R)																																				
Outlet Tees	<p>Visual examination of the header revealed weld repairs which had been performed in previous outages, reportedly about 1982 for one tee and 1993 for the other. These repairs were in symmetric locations on the outboard crotch intersection on the exterior surface (see attached drawing). Plant personnel reported that the cracks had been previously found during visual inspections and that about 10mm (0.4in.) metal removal was required to remove the crack by PT exam. Repair was a matching P-11 electrode using preheat and PWHT by resistance heaters at 680° C (1256° F). A temperature chart of the 1993 repair was provided, documenting the PWHT. In the present exam, MT indications were found on the repair previously made on the right tee. There was an additional MT indication around the full circumference of tube 57D (RH tee) at the toe of the weld on the header side that branched circumferentially on the header to connect with tube 57C. On the LH tee, there was an MT indication on tube 19A at the toe of the weld on the header side for about 1/4 circumference which branched into the header tee body outlet for about 33mm (1.3in). Replica 3 on the right tee crotch and replica 5 (header crack at tube 19A) both indicated creep to be the damage mechanism. The two outboard U-bolts were loose and not supporting their share of the weight of the header.</p>	<p><u>(DA):</u> By "back calculation", the design temperature for the header is estimated to be about 524° C (976° F). The T-11 stub tubes are essentially sized for the same temperature. No temperatures are available for the incoming elements or the steam prior to attemperation. After attemperation, steam temperatures of 440° C (824° F) were measured on a sister unit.</p> <p>The most apparent explanations for the tee crotch cracking are excessive temperatures and piping reaction loads. Using a lower bound to the ASTM Gr-11 database, the following rupture stress-temperature pairs can be developed for 110,500 hrs (the estimated time for the 1982 failure).</p> <table><tr><th>Temp(C)</th><th>Temp(F)</th><th>MPa</th><th>ksi</th></tr><tr><td>440</td><td>824</td><td>239</td><td>34.6</td></tr><tr><td>454</td><td>850</td><td>193</td><td>27.9</td></tr><tr><td>468</td><td>875</td><td>156</td><td>22.6</td></tr><tr><td>482</td><td>900</td><td>127</td><td>18.4</td></tr><tr><td>496</td><td>925</td><td>103</td><td>14.9</td></tr><tr><td>510</td><td>950</td><td>83.6</td><td>12.1</td></tr><tr><td>538</td><td>1000</td><td>55.1</td><td>8.0</td></tr><tr><td>566</td><td>1050</td><td>36.3</td><td>5.3</td></tr></table> <p>The pressure stress in the outlet leg of the tee is 56 MPa (8.2KSI). Depending on the assumptions of boundary conditions, von Mises equivalent stresses in the range of 102-145 MPa (14.7-21.0 ksi) were estimated for a pressure of 2000 psig and differential thermal growth and 42° C (75° F) drop due to attemperation. These values are sufficiently high to explain cracking as a result of piping system stresses if the temperature is on the order of 482° C (900° F) or higher. Oxide scale thicknesses made on the T-22 portion of the tubing indicated a uniform temperature profile across the elements. However, the average temperature predicted by the correlation of scale thickness to temperature was 554° C (1030° F) or 566° C (1050° F), depending on the correlation used. These temperatures are far higher than anticipated. If they are correct, the attemperator must be dropping the temperature over 100° C (180° F), lending support to the differential expansion between the hot and cold leg piping as a major contributor to cracking in the tee.</p>	Temp(C)	Temp(F)	MPa	ksi	440	824	239	34.6	454	850	193	27.9	468	875	156	22.6	482	900	127	18.4	496	925	103	14.9	510	950	83.6	12.1	538	1000	55.1	8.0	566	1050	36.3	5.3
Temp(C)	Temp(F)	MPa	ksi																																			
440	824	239	34.6																																			
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566	1050	36.3	5.3																																			

System: Boiler

Component: Primary SHO Header

Assessment Method: Stress Analysis

SUB-COMPONENT	Damage / Condition Found	Damage Assessment (DA) / Recommendation (R)
Outlet Tees	See first page	<p><u>(DA):</u> The cracking in the tee body associated with the stub tubes is postulated to also result from the combination of system stresses from routing, lost support of the header ends, and differential temperatures coupled with temperatures that are higher than expected. Using "worst" properties, a simplified creep crack growth model of a partial circumferential-radial crack in a pressurized cylinder was performed using PC-Crack and a total relaxed stress of 63MPa (9.1KSI) with an initial crack depth of 5mm (0.2in.) at 482° C (900° F) which indicates a through wall crack would develop in about 46,900 hours (about 7 years for CTPS).</p> <p><u>(R):</u> While the creep crack growth analysis indicated that about 7 years remain before a through-wall crack would develop at a temperature of 482° C (900° F), it is not recommended that repair or replacement be deferred. As a minimum, it is recommended that the cracks in the tee crotch area and those associated with tubes 19A and 57D be weld repaired using a matching electrode (E8018-B2L recommended). Proper preheat of at least 150° C and PWHT at 680° C is advised. Apparently such a repair provided adequate service on one of the tees from 1982 before re-cracking was observed during the present (1994) outage. Care should be taken to grind a good weld contour following the repair.</p> <p>If the high temperatures inferred from the oxide scale thicknesses are correct, the PSO header is operating far outside the norms. Prior to restart, extensive instrumentation should be applied to the unit to measure steamside and gas side flows and temperatures to enable future performance to be estimated.</p> <p>The two outboard U-bolts should be readjusted so they will carry their share of the weight of the header.</p> <p>Repositioning the two attemperators to the next elbow downstream from the current position would reduce the differential expansion from the cold leg piping following attemperation and increase the life of the tee crotch area in future service.</p> <p>For longer life, the tee portion could be replaced rather than weld repaired. If this option is coupled with relocation of the attemperator, a life in excess of 25 years will likely result. However, in light of the history of cracking in the stub tube areas near the outer portions of the header, it may be preferable to replace the entire header rather than only the tee portions.</p>

PRIMARY SUPERHEATER OUTLET HEADER
 (Viewed from the rear side)
MT INDICATIONS IN REPAIR AND/OR GIRTH WELDS

PRIMARY SUPERHEATER OUTLET HEADER
 (Viewed from the rear side)
VISUAL STUB REPAIRS AND/OR MT INDICATIONS AT STUBS

INDIA1-1.DRW

Analytical Basis For Component Damage Assessment

1.2.2

Summary

To understand the distress observed on the PSO header in the tee crotch area and stub tubes, several calculations were performed. These calculations, along with the NDE and oxide scale thickness data lead to the following conclusions:

1. The implied design basis for mixed steam in the P-11 header is 505°C (941°F) or lower. The Combustion Engineering practice was to assume about 19.4°C (35°F) imbalance so the implied design metal temperature for the header is 524°C (976°F) or lower.
2. The design basis for the T-11 stub tubes is consistent with the values of temperature given above for the header.
3. There is substantial evidence that the header and stub tubes operate at temperatures substantially higher than those stated as the design basis. This is the root cause for the extensive cracking and repair history for the stub tubes.
4. Excessively high attemperation spray is required downstream from the PSO header to avoid overheating in the secondary superheater and to provide main steam to the turbine at or below 538°C (1000°F).
5. The amount of attemperation causes a high differential temperature between the hot PSO header and the cooler piping carrying attemperated steam to the SSI header to produce piping loads that cause cracking in the tee crotches in the symmetric locations observed.

The basis for the above conclusions is contained in the subsequent sections.

Header Design Basis

The header was designed in accordance with Section I of the ASME Boiler and Pressure Vessel Code. The formula for a pipe without penetrations is:

$$t_m = (0.5pD)/(SE + py) + A, \text{ where}$$

t_m = minimum wall thickness, 1.700 in measured by UT
 p = design pressure, 2000 psig
 S = allowable design stress, psi
 D = outside diameter, 12.75 in
 E = joint or quality efficiency factor, 1.0
 y = temperature factor, 0.7 for ferritic steels in creep range
 A = corrosion allowance, 0.030 in assumed

Substituting these values, S is calculated to be 43.0MPa (6.235ksi). This value has to be corrected for the header ligament efficiency to infer the header design basis. The T-11 stub tubes are specified as 2.125 in OD X 0.240 in minimum wall thickness, implying a penetration hole

diameter of 1.645 in . The "repeat pattern" on the tubes is 2@5.25in and 1@7.25 in. This gives a ligament efficiency of:

$$\text{Lig Eff} = ((5.25 + 5.25 + 7.25) - (3)(1.645)) / (5.25 + 5.25 + 7.25) = 0.722$$

$$S = 6.235 / 0.722 = 8.636\text{ksi (59.5MPa)} \text{ is the implied design stress for the header.}$$

The design temperature can be obtained by interpolating the allowable stress table as shown in the following table:

Temp, C	Temp, F	S, ksi	S, MPa
510	950	11.0	75.8
524	976	8.636	59.5
538	1000	6.5	44.8

Since CE typically used 19.4°C (35°F) temperature imbalance, the implied mixed steam design temperature leaving the PSO header is (976° - 35°) = **941°F (505°C)**.

Stub Tube Design Basis

The equation for sizing of tubing in the ASME B&PVC is:

$$t_m = (pD / (2S + p)) + 0.005D + A; \text{ using the following input:}$$

$$t_m = 0.240 \text{ in}$$

$$p = 2000 \text{ psig}$$

$$D = 2.125 \text{ in}$$

$$A = 0.00885 \text{ in corrosion allowance}$$

S is calculated as **8.636ksi (59.5MPa)**, giving the same design metal temperature of **976°F (524°C)** for the stub tubes as estimated for the header body.

Life Estimation for the Header and Tube Stubs

A linear relationship was drawn for the ASTM Grade 11 database of log(stress) versus temperature, giving the following equation for rupture life:

$$\log(S) = \text{acoef} - 0.0001445 (\text{LMP})$$

$$\text{LMP} = (T - 460)(20 + \log(\text{trup}))$$

The value of the acoef for Grade 11 material having minimum, average, and maximum is:

Min = 6.18596
 Avg = 6.27107
 Max = 6.34964

Based on plant operational data, the main steam pressure averages about 1850 psig. There is approximately 50 psi pressure drop in the finishing superheater so the stress for life estimation will be based on 1900 psig.

$$S = (1900 / 2000) (8.636) = 8.204\text{ksi} (56.6\text{MPa}).$$

Using this stress and the LMP relationship, total header life can be estimated as summarized in the following table.

Temperature C	Temperature F	Time to Rupture, Hours (S = 8.204ksi)		
		Minimum	Average	Maximum
505	941	1,100,000	2,900,000	7,080,000
524	976	255,000	656,000	1,570,000
538	1000	97,500	247,000	582,000
552	1025	37,000	92,200	214,000
554	1029	31,400	78,100	181,000
566	1050	14,500	35,600	81,600

At the time of the July - August, 1994 outage, unit 2 had accumulated 181,000 hours of operation. The highlighted values show the combination of temperature-strength properties that are consistent with no appreciable header body distress. Based on temperature predictions from steamside oxide scale thickness, it is likely that the header temperature is above 1000°F (538°C). However, a temperature above 1029°F (554°C) is unlikely since even material with maximum strength properties would be at end of life. If the future operation of the unit continues as in the past, it is probable that limited life can be expected. To enable a better estimate of future life, it is essential that a sufficient number of thermocouples be attached to the header and stub tubes to quantify the temperature distribution.

Tee Crotch Cracks and Their Growth Rate

The cool legs downstream from the attemperator and the cooler secondary superheater inlet header cause a bending moment and torque on the PSO header tees which produce tensile stresses in the area of cracking of the crotches. The magnitude of the stresses was estimated using an ANSYS piping model. The analysis assumed a 75°F (42°C) differential between the hot and cold leg piping. The results depend strongly on the relative movement (ΔX) between the centerlines of the PSO and the SSI headers. The following table summarizes the bending, maximum

principal, and effective (von Mises) stresses at the location of cracking from the piping model using an internal pressure of 2000 psig.

Fixity: Relative Expansion of Centerlines of PSO and SSI Headers	Stress, ksi (MPa)		
	Bending	Max Principal	Effective
Fixed: $\Delta X = 0$	7.03 (48.5)	23.46 (162)	20.96 (145)
Intermediate: $\Delta X = 1.0$ in (25.4 mm)	2.92 (20.1)	18.53 (128)	16.24 (112)
Free: $\Delta X = 1.84$ in (46.7 mm)	1.13 (7.8)	16.90 (117)	14.73 (102)

When creep is the damage mechanism, initiation is controlled by the effective stress and creep crack growth is controlled by the maximum principal stress. To first tee cracking reportedly occurred in 1982 when the unit had accumulated approximately 110,500 operating hours. The following table summarizes the influence of temperature on the stress to produce rupture in 110,500 hours for Grade 11 steel with minimum strength properties.

Temperature		Min Rupture Stress in 110,500 Hours	
C	F	MPa	ksi
440	824	239	34.6
454	850	193	27.9
468	875	156	22.6
482	900	127	18.4
496	925	103	14.9
510	950	83.6	12.1
538	1000	55.1	8.0
566	1050	36.3	5.3

An examination of the results indicates that temperatures of 900°F (482°C) or higher and attemperation with a ΔT of 75°F (42°C) or more are sufficient to explain the observed cracking. In reality, some relaxation of peak stresses will occur, resulting in lower sustained stresses than those predicted by the elastic piping analysis.

To explore the possibility of deferring repair or replacement of the tee crotch crack, a model of projected crack growth was made using pc-CRACK. An OD crack in the radial-circumferential plane was modeled spanning 45 degrees of arc and having an initial depth of 0.2 in (5 mm). The following conditions were assumed:

OD = 12.75 in (324 mm); Thickness = 1.70 in (43 mm)
Axial membrane stress = 3.6ksi (25MPa)

Using conservative values for the creep growth law for a temperature of 900°F (482°C), the model predicted the following remaining life for three values of bending stress.

Bending Stress, ksi (MPa)	Remaining Life, Hours
14.0 (97)	0
7.0 (48)	25,200
5.6 (39)	46,900

Since there is evidence that the header temperature is higher than that used in the analysis, even more pessimistic lives are probable. These results indicate that the cracks should either be removed and weld repaired or the tee replaced.

Section 1.3

Economizer Inlet Header

System: Boiler

Component: Economizer Inlet Header

Assessment Method: Visual, MT, StressCalculation

SUB-COMPONENT	Damage / Condition Found	Damage Assessment (DA) / Recommendation (R)
Stub Tubes and Header	Twenty stub tubes had cracks at the toe of the weld on the tube side. The existing stub tubes had evidence (fabricated from finned tubes in which the fin had been burned off) that they had all been replaced at one time in the past. This was confirmed by plant boiler personnel. Additionally, some of the structural attachments of the economizer header to the boiler steel are badly deteriorated.	<p>(DA): The economized tube bundle rests on three beams in the gas pass. The header is also in the gas pass and is firmly attached to the side wall of the back pass. With relative temperature differentials, the tubes build up a frictional load until sliding takes place. This loading produces cyclic fatigue which is most acute at the toe of the weld on the tube side (location of least section modulus plus stress concentration). With a sufficient number of temperature excursions, fatigue and cracking occur at the toe of the weld.</p> <p>(R): The rigid attachment of the header to the side wall does not permit relative movement or rotation. Redesign of the attachment is advised. Improvement in the support of the valve outside the boiler is also advised to reduce loading on the header. As a minimum, the deteriorated structural attachment must be repaired. For the stub tube cracks, the following options exist:</p> <ul style="list-style-type: none">A) Weld repair stub tubes with indications. Fatigue damage in tubes presently uncracked may lead to premature failures in future operation.B) Weld repair all the stub tubes in the area of cracking.C) Replace the stub tubes that are cracked.D) Replace all the stub tubes.

Section 1.4

Turbine Components

HP/IP Rotor OD Groove Cracking

1.4.1

Executive Summary

During the Unit 2 outage at the Chandrapura Thermal Power Station, in July/August 1994, cracking was observed at several heat groove and interstage seal groove areas at the OD of the HP/IP rotor. The maximum depth of these cracks measured using a potential drop technique was 3 mm (0.12 inch). Details regarding a prior inspection performed approximately six years ago was not available. However evidence suggests that any groove cracks were removed by machining.

Based on a review of plant operating history, the most significant contributor to the observed rotor OD cracking was assessed to be the "loss-of-fire" (or fire-out) events in the boiler which were reported to occur twice daily, on an average or approximately 500 times per year. During the fire-outs steam admission to the HP/IP turbine is stopped and the turbine metal temperature is held fairly constant (approximately 1000°F or 540°C near the inlet section). Upon restoration of fire in the boiler the turbine valves are opened and the turbine inlet section is thermally shocked with colder steam approximately 180°F (100°C) below the metal temperature. Tensile thermal stresses develop at the rotor OD intensified by the groove geometry.

Stress analyses were performed to estimate thermal and bending stresses which govern crack initiation and propagation. The peak thermal stress computed at the groove surface was 116.7 ksi including a stress concentration factor of 3.0 and the estimated number of initiation cycles at this stress level was 1100.

Fracture mechanics calculations predicted a critical crack size of 1.05 inch for a fatigue crack growth threshold of 3.0 ksi/inch, governed by once-per-revolution bending. Crack propagation calculations predicted 1200 thermal shock cycles to grow an initiated crack to the detected depth of 0.12 inch (3 mm). Crack growth from the current 0.12 inch size to the critical size of 1.05 inch was predicted after 2600 cycles or 5 years of operation assuming 500 cycles (fire-outs) per year.

Based on the stress and fracture mechanics results it was recommended that the OD cracks be machined out prior to returning the unit to service. Where possible the groove radii should be increased to minimize stress concentrating effects. It is predicted that an additional 2300 cycles or 6 years of operation would then be required to re-initiate and grow the groove cracks to a depth of 0.12 inch (3 mm) assuming future operation of the unit remains unchanged. To further extend the life of the HP/IP rotor it is strongly recommended to minimize the number of fire-out events experienced by the unit. Turbine steam/metal thermocouple data should also be obtained to better quantify the severity and frequency of thermal shocks.

During the Unit 2 outage at the Chandrapura Thermal Power Station, in July/August 1994, cracking was observed at several heat groove and interstage seal groove areas at the OD of the HP/IP rotor. A brief description of the inspection results is given below followed by a stress and fracture mechanics evaluation to assess the effect of cracking on the remaining life of the HP/IP rotor.

Review of Inspection Results

Dye penetrant testing was employed to identify locations of cracking in the heat/seal groove areas of the HP/IP rotor. These locations, shown in Figure 1, are confined to the steam inlet regions of the HP and IP sections of the rotor (Stage I and X) and between the first two stages (X, XI) of the IP rotor. Crack depth measurements, using a D.C. potential drop technique (*See Photo: Fig. 1.4.1; 1.4.2*), were performed by CMERI (Central Mechanical Engineering Research Institute). These results are summarized in Table 1 for five crack locations identified as Locations A through E in Figure 1. The circumferential extent of the cracks were 300 to 360 degrees around the OD with maximum crack depths of 2.4, 2.2, 2.9, 1.5 and 2.8 mm respectively, for Locations A through E. These crack depth measurements were repeated and found to agree within 0.2 mm of the original measurements. Based on the characteristics of the D.C. potential drop system a maximum upper bound crack depth of 4 mm was conservatively assumed to apply to these crack locations.

Examination of Potential Causes of Rotor Cracking

Based on a review of plant operating history, the most significant contributor to the observed rotor OD cracking was assessed to be the "loss-of-fire" (or fire-out) events in the boiler which were reported to occur twice daily, on an average or approximately 500 times per year. During the fire-outs steam admission to the HP/IP turbine is stopped but the turbine is not tripped; i.e., the generator remains tied to the grid functioning as a motor, driving the turbine rotor train (a condition referred to as "motoring"). During the fire-out the HP/IP turbine is bottled up and the temperature of the rotor is held fairly constant (approximately 1000°F or 540°C near the inlet section). Upon restoration of fire in the boiler (approximately 30 minutes after the fire-out), the turbine valves are opened and colder steam in the main steam and reheat piping enters the turbine, thermally shocking the hotter turbine metal. Temperature data obtained for a typical fire-out indicates that the steam entering the turbine is approximately 180°F (100°C) colder than the metal; i.e. 820°F (440°C) steam versus 1000°F (540°C) metal temperature. This thermal shock causes tensile stresses at the OD of the rotor because the OD surface is prevented from contracting due to the constraint offered by the interior of the rotor body. This thermal stress is increased at heat/seal groove locations due to the stress concentrating effect of the groove and is therefore predicted to be the prime contributor to initiation of cracking. Quantification of these thermal stresses along with bending stresses to address crack initiation and propagation is provided below.

Stress Analyses

Stress analyses of the HP/IP rotor heat/seal groove regions were performed to estimate stresses required to address crack initiation and propagation. The following load cases were considered:

Load Case 1: Thermal down-shock of 180°F due to the fire-out events

These stresses were predicted to be the prime contributor to the initiation and propagation of HP/IP rotor groove cracking.

Load Case 2: Bending stresses due to rotor weight

These stresses were required to address the possibility of crack propagation via high cycle fatigue; i.e., due to a once-per-revolution alternating bending stress.

Load case 1: Thermal down-shock of 180°F due to the fire-out events

A one-dimensional transient thermal heat transfer analysis of the HP/IP rotor inlet section was performed using SI's computer program PIPE-TS2 [1]. The geometry, material properties and thermal loading simulated in the analysis is described below followed by a summary of stress results.

Geometry: The HP/IP rotor inlet section where cracking was observed was modelled as a long cylinder with an OD of 24 inches and a bore diameter of 4 inches, based on available rotor dimensions.

Material Properties: The material specification of the HP/IP rotor was 1.25Cr-1Mo-0.5Ni steel. The following rotor material properties from the ASME code for low-chrome steels at 900°F were used in the heat transfer analysis:

Parameter	Value	Units
Thermal conductivity	19.7	Btu/hr-in-°F
Density	489	lbs/ft ³
Specific Heat	0.153	Btu/lbm-°F
Elastic Modulus	25.6×10^6	psi
Thermal Expansion Coeff.	8.5×10^{-6}	in/in/°F

Loading: Heat transfer coefficients and steam/rotor temperatures used in the analysis are summarized below:

Parameter	Value	Units
Rotor metal temperature	1000	°F
Rotor OD steam temperature	820	°F
Rotor OD heat transfer coeff.	1000	Btu/hr-ft ² -°F
Rotor ID temperature	1000	°F
Rotor ID heat transfer coeff.	0.01 (adiabatic)	Btu/hr-ft ² -°F

Stress results: The variation in axial thermal stress at the rotor OD as a function of elapsed time after the initial thermal shock is shown in Figure 2. A maximum tensile stress of 38.9 ksi was computed 150 seconds after the initial shock. The stress gradient from the rotor OD inward is shown in Figure

3. The tensile stresses decay to zero approximately 2.3 inches below the OD surface. These stresses do not account for the stress concentrating effect, K_t , of the groove. Therefore, a K_t value of 3.0 was estimated from [2] using Neuber's equations for a groove in a cylinder. The die-away in K_t with increasing depth below the surface was approximated using the following equation for a hole in a plate:

$$K_t(x) = K_t(\max) \left[\frac{1}{3} + \frac{1}{6} \left(\frac{r}{r+x} \right)^2 + \frac{1}{2} \left(\frac{r}{r+x} \right)^4 \right] \quad (1)$$

where,

$K_t(x)$ is the stress concentration at a distance x below the surface,

$K_t(\max)$ is the peak stress concentration factor (3.0), and,

r is the groove radius (approximately 0.25 inch).

Thermal stresses modified using Equation 1 to include the groove stress concentrating effect is shown in Figure 3 along with the unconcentrated stress.

Load Case 2: Bending stresses due to rotor weight

Bending stresses due to rotor weight were computed to address the possibility of crack propagation via high cycle fatigue; i.e., due to a once-per-revolution alternating bending stress. Parameters used in the bending stress calculation are summarized below:

Rotor weight, $W=36,771$ lbs (16,679 kg)

Distance between bearing centers, $l = 182$ inches.

The distribution of HP/IP rotor weight was not known. Therefore the maximum bending moment at the center of the rotor span was calculated using the equation:

$$M = \frac{W l}{4} \quad (2)$$

$$\sigma_b = \frac{M r_o}{I} \quad (3)$$

and the unconcentrated bending stress was calculated using the equation:

where,

r_o is the outside radius at the groove location, and

I is the moment of inertia given by:

$$I = \frac{\pi}{4} (r_o^4 - r_i^4) \quad (4)$$

where, r_i is the inside radius of the rotor.

Stress Results: With $r_o=11.75$ and $r_i=2$ inches, the unconcentrated bending stress computed was

1.314 ksi. Assuming a K_t of 3.0, yields a peak bending stress of 3.943 ksi. The bending stress gradient from the surface of the groove is shown in Figure 4 without and with the K_t effect using Equation 1, as described above.

Crack Initiation Calculations

The time required to initiate a crack was estimated using the design fatigue curves for carbon, low alloy and high tensile steels, from the ASME Code Section III, shown in Figure 5. For a peak surface stress of 116.68 ksi and an elastic modulus correction factor of $(30E6/25.6E6)$, an alternating stress, S_a , of 68.37 ksi was computed. From Figure 5, for an ultimate tensile strength (UTS) range of 115 to 130 ksi, approximately 1100 cycles (fire-out events) are required to initiate the HP/IP groove cracks.

Critical Crack Size

A remaining life estimate of the rotor in the as-found condition requires determination of the critical crack size. At 1000°F the fracture toughness, K_{IC} , of the rotor is predicted to be at an upper shelf value in excess of 100 ksi/inch. Thermal shock stress intensity factor (K_I) versus crack size values for an edge crack computed using SI's pc-CRACK computer code, shown in Figure 6, indicate a maximum value of 75 ksi/inch which is well below the conservatively estimated upper shelf K_{IC} value of 100 ksi/inch. Therefore a critical crack size in excess of 4 inches is predicted.

To account for possible crack propagation via high cycle fatigue bending, an alternate failure criterion was examined. Because rotation at 3000 rpm produces a large number of bending cycles, failure is predicted when the fatigue crack growth threshold, ΔK_{th} , is exceeded. Literature data including the EPRI SAFER computer code indicates a ΔK_{th} value of 5.0 ksi/inch. For conservatism, ΔK_{th} values of 4.0 and 3.0 ksi/inch were included in the calculations. K_I versus a values computed using pc-CRACK are plotted in Figure 7. Critical crack sizes of 2.08, 1.60 and 1.05 inches were estimated corresponding to ΔK_{th} values of 5.0, 4.0 and 3.0 ksi/inch.

Crack Propagation Calculations

Crack growth calculations were performed to:

- (i) estimate the number of cycles required to propagate an initiated crack to the maximum detected depth of 0.12 inch (3 mm), and,
- (ii) estimate the number of cycles required to propagate the deepest existing crack (0.12 inch) to critical size.

Crack geometry: The observed circumferential OD crack was conservatively simulated using an edge crack model in a plate.

Stresses: The primary driving force for crack growth was predicted to be the thermal shock stress computed for Load Case 1.

Crack growth law: Fatigue crack growth due to thermal shocking was predicted to be the primary crack growth mechanism. The following Paris law was assumed:

$$\frac{da}{dN} = C \Delta K^n \quad (5)$$

Fatigue crack growth data from the EPRI SAFER code [3] for rotor steels yields a coefficient, C , of

6.57E-9 and an exponent, n , of 2.35, with da/dN in inch/cycle. This data was compared with fatigue crack growth data from the ASME Code Section XI for Carbon and low-alloy steels. For an R-ratio of 0.0 and $\Delta K > 19$ ksi/inch, the ASME Code C and n values are 1.01E-7 and 1.95, respectively, yielding a crack growth rate 3 to 4 times higher than the SAFER data. For conservatism, the ASME Code data was used in the crack growth calculations.

Results: Crack growth from an assumed initiated size of 0.01 inch to the maximum detected depth of 0.12 inch was 1200 cycles. Crack growth from the present size of 0.12 inch to the minimum critical depth of 1.05 inch was predicted after 2600 cycles or 5 years of operation assuming 500 cycles (fire-outs) per year. Fatigue crack growth is plotted in Figure 8.

Conclusions

The preceding calculations predicted that approximately 2300 cycles (1100 initiation, 1200 propagation) were required to initiate and propagate cracks in the HP/IP rotor OD grooves to their present size. This estimate agrees fairly well with the rotor inspection/operating history which indicates that approximately 6 years ago no cracking was detected in the heat/seal grooves, with the rotor experiencing approximately 2000 to 3000 fire-out events since the last inspection. Having benchmarked the assumed fatigue crack growth law, approximately 2600 cycles of remaining life are predicted for the HP/IP rotor. This prediction is based on the following important assumptions:

- (i) The magnitude of the thermal shock is 180°F.
Turbine steam/metal thermocouple data for several operating scenarios (specifically including fire-out events) would be required to verify the accuracy of this assumption.
- (ii) The average number of thermal shocks per day is two.
The remaining life of the rotor could be drastically reduced if the frequency, source and magnitude of thermal shocks is greater than that assumed in the analysis.
- (iii) The maximum depth of the existing cracks measured using the potential drop technique is 3 mm.

Recommendations

In light of the above assumptions associated with the analysis it is recommended that:

- (i) Turbine steam/metal thermocouple data should be obtained to quantify the severity of thermal shocks due to the fire-outs and other significant events.
- (ii) Every effort should be made to minimize the number of fire-out events experienced by the unit.
- (iii) Prior to returning the HP/IP rotor to service the OD groove cracks should be machined out and where possible the groove radii should be increased to minimize stress concentrating effects. Crack removal will ensure an additional 2300 cycles for crack initiation or a total 6 years of service for initiation and growth to 3 mm based on past operating history.

References

1. PIPE-TS2, Structural Integrity Associates computer program to compute the transient thermal and stress response of an axisymmetric two-material cylinder, Version 1.01.
2. "Formulas for Stress and Strain," R. J. Roark and W. C. Young, McGraw-Hill Book Company, Fifth Edition, 1975.
3. F. V. Ammirato et al, "Life Assessment Methodology of Turbogenerator Rotors," EPRI report CS/EL 5593, Vol 1-4, March 1988.

Figures

- Figure 1. Schematic of the HP/IP rotor periphery indicating the locations and severity of observed circumferential cracking.
- Figure 2. Variation in axial thermal stress at the OD of a 24-inch OD, 4-inch ID cylinder subjected to a 180°F temperature down-shock, versus time after the shock.
- Figure 3. Stress gradient at the time of maximum thermal shock stress (150 sec.) without and with a K_t of 3.0.
- Figure 4. Stress gradient due to deadweight bending without and with a K_t of 3.0.
- Figure 5. Design fatigue curves for Carbon, low-alloy and high tensile steels (from the ASME Code Section III).
- Figure 6. Stress intensity factor versus crack depth for a 180°F thermal shock.
- Figure 7. Stress intensity factor versus crack depth for deadweight bending.
- Figure 8. Fatigue crack growth rate: crack size versus number of 180°F thermal shock cycles.

D.C. Potential Drop Technique

D.C. Potential Drop Crack Measurement
Fig. 1.4.1

D.C. Potential Drop Crack Measurement
Fig. 1.4.2

Crack Depth Measurement By D.C. Potential Drop

Technique

Unit #2 CTPS, DVC, India, August 1994

FIG. A	Points On The Periphery Of Rotor												
Location	0	1	2	3	4	5	6	7	8	9	10	11	12
A	1.7	2.1	1.8	2.0	1.6	1.0	1.7	2.1	2.4	1.5	1.5		
B	2.1	2.0	2.1	1.9	1.8	1.5	1.6	1.5	1.7	2.0	2.2		
C	2.3	1.5	1.9	2.5	2.6	1.9	2.6	2.9	2.2	1.9	2.5		
D	0.0	0.8	0.8	1.4	1.5	1.4	1.3	1.0	1.2	1.2	1.3		
E	1.5	1.6	1.6	1.6	2.3	2.2	2.0	2.3	2.8	2.0	2.4	2.0	2.4

(All Readings In "mm")

Figure A

For Indications at E:
Position (clock) as you
look toward the generator.

For all othr ares, clock
position is determined by
looking at the turbine end.

Figure 1

Pg117.DRW

CHANDRAPURA UNIT 2 HP/IP ROTOR OD CRKS. 180 DEG.F THERM DOWN-SHOCK

ELAPSED TIME AFTER SHOCK (SECONDS)

Figure 2

Chandrapura Unit 2 HP/IP Rotor

OD Groove: Thermal Down-shock Stresses

Distance from OD surface (in.)
 $\square$ $dt=180F, Kt=1.0$ $+$ $dt=180F, Kt=3.0$

Figure 3

Chandrapura Unit 2 HP/IP Rotor

OD Groove: Deadweight Bending Stresses

Figure 4

Design Fatigue Curves for Carbon, Low Alloy, and High Tensile Steels (from ASME Code Section III)

Figure 5

Chandrapura Unit 2 HP/IP Rotor

180 F. shock: K versus a

Crack depth (in.)

Figure 6

Chandrapura Unit 2 HP/IP Rotor

Bending stress: K versus a

Crack depth (in.)

Figure 7

Chandrapura Unit 2 HP/IP Rotor

180 F. shock: Fatigue Crack Growth

Figure 8

Rotor Forging Assessment

1.4.2

Executive Summary

An assessment of the three rotors nondestructively examined during the Unit 2 outage of the Chandrapura Thermal Power Station was performed to determine the reinspection interval. These assessments are only applicable to the near bore region and do not include blade attachment or outside surface liabilities. The basis for the assessments was:

Data taken during the outage.

Information supplied by GE from previous inspections.

Published material properties data from industry reports.

Calculations made by TVA using in-house computer programs in conjunction with

PCCrack® published by Structural Integrity Associates Inc.

Material properties data from TVA reports and other published sources.

The results are given in the attached ROTOR FORGING DAMAGE ASSESSMENTS. The following is a summary of those assessments:

HP/IP Rotor - Forging Number 5337-010 - The bore of this rotor was only visually and magnetic particle inspected. No UDRPS base ultrasonic inspection was performed. It is recommended that a UDRPS based inspection be performed at the next outage to accurately determine the size of a near bore flaw identified in the previous GE inspection report that could be of concern. Since there were no bore magnetic particle indications, there has apparently been little, if any, growth of this flaw. The main reason for concern is the location of a flaw near to the bore surface under the 19th stage. Should it grow to connect to the surface, the resulting flaw would be over 0.250" deep. The other factor of concern is the potential poor material properties. Based on the chemical analysis of the chip samples removed, a Phosphorus content of 0.018% could produce a minimum fracture toughness as low as 40 KSI/IN at room temperature. Since the remainder of the rotor appears clear, removing this flaw by overboring or bottle boring would increase the inspection cycle.

HP/IP Rotor - Forging Number 123K176VA1 - The rotor can be returned to service as is. It should be reinspected after 2000 additional start/stops or 80,000 hours of operation.

LPDF Rotor - Forging Number 55089 - The rotor can be returned to service as is. It should be reinspected after 2000 additional start/stops.

Consideration should also be given to removing ring samples from the end of the forgings at the bore. A 1" X 1" cross-section ring sample can produce sufficient material to provide samples for tensile, impact and fracture toughness. The results of the tests can be used to extend the inspection cycle and to provide an improved basis for any future assessments.

ROTOR FORGING DAMAGE ASSESSMENT

PLANT: Chandrapura

UNIT: 2

EVALUATION DATE: 10-28-94

COMPONENT: HP Rotor

ID #: 5337-010

REFERENCES:

- A) GE Inservice Ins42pection Report, Dated August 7, 1986
- B) Preliminary Condition Assessment Report, Dated August 8, 1994

PRE-EVALUATION STATUS / LIMITATION:

The last inspection report from GE indicated that the measured FATT at the time of manufacture was 200°F. GE's estimate of the variability of the FATT throughout the rotor was 250°F and an in-service embrittlement of the high temperature regions of 100°F totaled to 350°F FATT. The visual and magnetic particle inspections revealed no indications. The ultrasonic inspection revealed an indication under the 19th stage approximately 0.12" deep and 1.2" long. It was recommended that this flaw be removed by over boring or bottle boring. The reinspection interval was recommended to be 6 years.

WORKSCOPE:

- Bore preparation (honing)
- Visual bore inspection (VT)
- Magnetic particle bore inspection (MT)
- UDRPS based boresonic inspection (UT)
- Material sampling (MS)
- Forging condition assessment (FCA)

EVALUATION HIGHLIGHTS:

Honing: The bore was honed to 2.768" - 2.777".

VT: No indications were observed.

MT: No indications were observed.

UT: No inspection was performed due to equipment damage.

MS: A chemical analysis of machining chips indicates the following chemistry:

C	Mn	P	S	Si	Mi	Cr	Mo	V
0.25	0.73	0.018	0.006	0.29	0.04	1.19	1.26	0.21

Co/Nb	Ti	Cu	W	Sn	Pb	N		
0.001	0.003	0.08	<0.01	0.10	<0.002	0.007		

FCA:

Basis

Original material properties as reported in reference A:
ASTM A470 Class 8 (CrMoV)
117 - 120 KSI Tensile Strength
86 - 90 KSI Yield Strength
16.4 - 18.4 Elongation
46% - 48% Reduction in Area
250°F to 350°F FATT
10.1 - 11.6 ft.-lbs. Charpy V notch @ RT

Based on a correlation to the Phosphorus content and other comparisons to material properties data the estimated lower bound fracture toughness used for the analysis was 40 KSI√IN at RT.

Results

Based on the buried flaw 1.2" axial X 0.125" radial and 0.125" deep, the reinspection interval is estimated to be 2000 additional start/stop cycles.

RECOMMENDATION:

The rotor should be pre-warmed and operated in accordance with the GE recommended practice. The rotor should be reinspected after 2000 additional start/stop cycles or 80,000 hours of operation. The rotor bore should be ultrasonically inspected using the UDRPS system and if the results confirm the GE ultrasonic inspection, it is recommended that the area under the 19th stage be machined to remove the buried flaw.

ROTOR FORGING DAMAGE ASSESSMENT

PLANT: Chandrapura

UNIT: 2

EVALUATION DATE: 10-28-94

COMPONENT: HP Rotor (spare)

ID #: 123K176VA1

REFERENCES:

A) Preliminary Condition Assessment Report, Dated August 8, 1994

PRE-EVALUATION STATUS / LIMITATION:

No previous inspection report was available.

WORKSCOPE:

- Bore preparation (honing)
- Visual bore inspection (VT)
- Magnetic particle bore inspection (MT)
- UDRPS based boresonic inspection (UT)
- Material sampling (MS)
- Forging condition assessment (FCA)

EVALUATION HIGHLIGHTS:

Honing:

The bore was honed to 2.887" - 2.918".

VT:

No indications were observed.

MT:

Eddy current testing during the ultrasonic inspection was substituted for magnetic particle inspection. No indications were observed.

UT:

A single centroid 0.620" axial X 0.040" radial 0.070" deep 125.25 inches from the coupling end was found.

MS:

Chemical analysis of two (2) samples of machining chips indicates the following chemistries:

C	Mn	P	S	Si	Mi	Cr	Mo	V
0.31	0.83	0.015	0.007	0.25	0.11	1.26	1.13	0.22
0.29	0.82	0.013	0.007	0.26	0.11	1.26	1.10	0.22

Cb/Nb	Ti	Cu	W	Sn	Pb	N		
0.002	0.003	0.06	<0.01	0.007	<0.002	0.010		
0.001	0.001	0.05	<0.01	0.005	<0.002	0.019		

FCA:

Basis

Material properties based on the chemical analysis are estimated to be:
ASTM A470 Class 8 (CrMoV)
105 - 125 KSI Tensile Strength
85 KSI Min. Yield Strength
14% Min. Elongation
38% Min. Reduction in Area

Based on the Phosphorus content and other comparisons to material properties data the estimated lower bound fracture toughness was 40 KSI/IN at RT.

Results

The actual buried flaw found is located in the low stress area under the inlet section. The analysis results are based on an assumed surface flaw 0.125" deep and 0.25" long under the 21st stage. The fatigue life reinspection interval is estimated to be 2000 additional start/stop cycles. The creep life evaluation based on published data indicate reinspection after 80,000 hours of operation, based on 10% of the average time to rupture for stress levels under the 1st stage.

RECOMMENDATION:

The rotor should be prewarmed and operated in accordance with the GE recommended practice. It should be reinspected after 2000 additional start/stops or 80,000 hours of operation.

ROTOR FORGING DAMAGE ASSESSMENT

PLANT: Chandrapura

UNIT: 2

EVALUATION DATE: 10-28-94

COMPONENT: LP Rotor (Spare)

ID #: 55089

REFERENCES: A) Preliminary Condition Assessment Report, Dated August 8, 1994

PRE-EVALUATION STATUS / LIMITATION:

No previous inspection report was available.

WORKSCOPE:

- Bore preparation (honing)
- Visual bore inspection (VT)
- Magnetic particle bore inspection (MT)
- UDRPS based boresonic inspection (UT)
- Material sampling (MS)
- Forging condition assessment (FCA)

EVALUATION HIGHLIGHTS:

Honing: The bore was honed to 4.593" - 4.597".

VT: Pitting was observed throughout the bore. It was estimated that 0.05" of metal removal would be required to clean-up the bore.

MT: Eddy current testing during the ultrasonic scan was substituted for magnetic particle inspection. No indications were observed.

UT: UT inspection revealed no reflector centroids.

MS: A chemical analysis of machining chips indicates the following chemistry:

C	Mn	P	S	Si	Ni	Cr	Mo	V
0.29	0.34	0.008	0.014	0.01	3.23	1.75	0.41	0.065

Cb/Nb	Ti	Cu	W	Sn	Pb	N		
<0.001	0.001	0.11	<0.01	0.012	<0.002	0.010		

FCA:

Basis

Based on the above chemistry the material properties are estimated to be similar to:

ASTM A470 Class 7 (NiCrMoV)
120 to 135 KSI Tensile Strength
95 KSI Min. Yield Strength
17% Min. Elongation
50% Min. Reduction in Area

80 KSI $\sqrt{\text{IN}}$ was estimated to be the lower bound fracture toughness @ RT.

Results

Based on an assumed bore flaw 0.250" long X 0.125" deep the fatigue life reinspection interval is estimated to be 2000 additional start/stop cycles.

RECOMMENDATION:

The rotor should be prewarmed and operated in accordance with the GE recommended practice. The rotor bore should be reinspected after 2000 additional start/stops or 10 to 12 years of operation.

The method used for rotors with few or no large flaws to estimate the reinspection interval is as follows:

ESTIMATE BORE STRESS

The stress gradient profile from the bore surface to 6 inches deep is calculated using formulas from Roark and Young for stress in a thick wall cylinder under external (negative) pressure and stress in a thick wall disk under dynamic rotation. The formulas are:

$$\text{Blade load} = p \frac{b^2 (a^2 + r^2)}{r^2 (b^2 - a^2)} \quad \text{Centrif. Load} = \frac{1}{8} \frac{\delta \times \omega^2}{386.4} [(3 + \nu) (b^2 + a^2 + b^2 \frac{a^2}{r^2}) - (1 + 3\nu)r^2]$$

For example, below are the results for the 19th stage of the HP:

a = inside (bore) radius, in.	1.375					
b = outside (blade root) radius, in.	19.375					
t = wheel thickness, in.	2.75					
F = total blade force, lbs.(19th stage)	1784800	from GE report	F@OS = F*(s ² /s' ²)			
p = blade load pressure, psi	5331	(F/2πbt)				
r = radius of interest, in.	see below					
s = RPM, s' = RPM @ overspeed	3600, 3960	(ω = 2πs/60)				
ν = Poisson's ratio = .3						
δ = density = 0.283 lbs/cu.in.						
Normal Speed		Over Speed		Sum		
blade load, psi	wheel load, psi	blade load, psi	wheel load, psi	sum@NOS	sum@OS	
σ =	σ =	σ =	σ =	σ =	σ =	r =
10717	32271	12967	39048	42988	52015	1.375
7154	21463	8657	25970	28617	34626	2.375
6248	18593	7560	22498	24841	30057	3.375
5888	17318	7124	20955	23206	28079	4.375
5709	16540	6908	20013	22249	26921	5.375
5608	15945	6785	19293	21552	26078	6.375
5545	15415	6709	18652	20960	25361	7.375

FRACTURE MECHANICS ANALYSIS

The computer program PCCRACK® from Structural Integrity Associates, Inc. was used to calculate the fatigue crack growth rate to critical size of the flaws with the highest stress intensities or a default 0.125" deep X 0.250" long bore surface flaw in the highest stress region, whichever is the more critical. An important part of this process is the determination of the minimum fracture toughness. This value is the single most influential factor in the estimate of the reinspection cycle. The best solution is to have actual properties from fracture toughness tests. Methods to estimate fracture toughness, in descending order of accuracy, are: Tests from the small punch test sample, correlations to actual FATT values, correlations based on lower shelf impact values, correlations to chemistry and hardness, and correlations based only on chemistry. Other factors to be considered are vintage, melting practice, tensile and yield strengths, and operating history.

The steps taken in PCRACK are as follows:

The above stress values are used to fit a third degree polynomial equation for the NOS and the OS load cases.

The crack model chosen is "R - Elliptical surface crack in an infinite plate" for the default flaw.

The stress intensity for a range of crack sizes up to 0.75" is calculated for the NOS and the OS load cases.

The fatigue crack growth calculation is made next using the Collipriest crack growth law. The coefficients used for the rotor materials analyzed were:

	C	n	dK thres	K _{IC}
CrMoV 2.03E-08	1.56	4	40	
NiCrMoV	1.11E-07	1.34	4	80

The number of cycle blocks is usually chosen as 10,000. The number may vary depending on the number needed to produce a critical size crack. The subblocks are chosen to be nine NOS load cases and one OS load case. This frequency of overspeed tests can be reduced if needed. The initial crack size is 0.125".

Results: The number of cycle blocks required to produce crack growth from the assumed initial size (0.125 inch default) to the critical flaw size is used to establish the reinspection interval. Since each cycle block contains ten subblocks there is a safety factor of 10 included to cover unknown or unconsidered factors, such as, thermal stress, unexpectedly low material properties, and start-up procedures outside of recommended practice.

The actual output file of the PCCRACK program run for the LP rotor is included in the pages following this section.

Conclusions

Satisfactory results were obtained using the above method. Where warranted, a more rigorous method using finite element analysis and more sophisticated crack growth modeling can produce longer inspection intervals with more confidence. This may be required where a large critical flaw(s) exists and cannot be removed. Probabilistic methods of risk assessment like those in the EPRI SAFER code will also improve the calculated inspection interval. Improved inspection cycles can also be obtained by removing material samples to provide actual rotor properties.

References

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6. Viswanathan, R. and C.H. Wells, "Life Prediction of Turbine Generator Rotors" ASME, 1993

tm
pc-CRACK
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SAN JOSE, CA (408)978-8200
VERSION 2.1

Date: 9-Jan-1995
Time: 14:47:36. 8

FATIGUE CRACK GROWTH ANALYSIS

LP1

INITIAL CRACK SIZE= 0.1250
MAX CRACK SIZE FOR FCG= 3.0000

COLLIPRIEST CRACK GROWTH LAW:

$$\frac{da}{dN} = C \cdot (dK_{thres} \cdot K_{Ic})^{\frac{n}{2}} \cdot \exp\left[(-) \cdot \ln\left(\frac{K_{Ic}}{dK_{thres}}\right) \cdot \operatorname{atanh}\left(\frac{\ln(NUM)}{\ln(DEN)}\right)\right]$$

where
 $DEN = (1-R) \cdot K_{Ic} / dK_{thres}$ $NUM = (dK/dK_{thres})^2 / DEN$
 $dK = K_{max} - K_{min}$ $R = K_{min} / K_{max}$
 $dK > dK_{thres}$ $K_{max} < K_{Ic}$

CURRENT

LAWS:	LAW ID	C	n	dKthres	KIc
	NICRMOV	1.110E-07	1.340	4.000	80.000

STRESS COEFFICIENTS

CASE ID	C0	C1	C2	C3
LP1NOS	74.0381	-21.9480	5.0452	-0.3972
LP1OS	89.6071	-26.5754	6.1083	-0.4806

NUMBER OF CYCLE BLOCKS= 10000
PRINT INCREMENT OF CYCLE BLOCK= 100

SUBBLOCK	NUMBER OF CYCLES	CALCULATION INCREMENT	PRINT INCREMENT	FCG LAW ID
1	9	1	9	NICRMOV
2	1	1	1	NICRMOV

SUBBLOCK	Kmax CASE ID	SCALE FACTOR	Kmin CASE ID	SCALE FACTOR
1	LP1NOS	1.0000	LP1NOS	0.0100
2	LP1OS	1.0000	LP1OS	0.0100

crack model: ELLIPTICAL SURFACE CRACK IN AN INFINITE PLATE (A/L=0.5)

CRACK SIZE	CASE LP1NOS	CASE LP1OS
0.0600	20.701	25.054
0.1200	28.964	35.055
0.1800	35.102	42.483
0.2400	40.114	48.548
0.3000	44.392	53.726
0.3600	48.142	58.263
0.4200	51.486	62.310
0.4800	54.506	65.965
0.5400	57.261	69.298
0.6000	59.791	72.360
0.6600	62.120	75.178
0.7200	64.283	77.795
0.7800	66.301	80.237
0.8400	68.190	82.523
0.9000	69.966	84.672
0.9600	71.641	86.698
1.0200	73.224	88.614
1.0800	74.726	90.430
1.1400	76.153	92.157
1.2000	77.513	93.803
1.2600	78.758	95.309
1.3200	79.945	96.745
1.3800	81.080	98.118
1.4400	82.167	99.432
1.5000	83.210	100.694
1.5600	84.213	101.907
1.6200	85.179	103.076
1.6800	86.111	104.204
1.7400	87.013	105.294
1.8000	87.886	106.351
1.8600	88.745	107.390
1.9200	89.580	108.400
1.9800	90.393	109.384
2.0400	91.187	110.343
2.1000	91.962	111.280
2.1600	92.720	112.197
2.2200	93.462	113.096
2.2800	94.191	113.977
2.3400	94.907	114.843
2.4000	95.610	115.694
2.4600	96.502	116.773
2.5200	97.390	117.848
2.5800	98.275	118.918
2.6400	99.156	119.984
2.7000	100.036	121.049
2.7600	100.914	122.111
2.8200	101.791	123.173
2.8800	102.668	124.234
2.9400	103.544	125.294
3.0000	104.421	126.356

TOTAL	SUBBLOCK							
CYCLE	CYCLE	KMAX	KMIN	DELTAK	R	DADN	DA	A/T

TOTAL CYCLE	SUBBLOCK CYCLE	KMAX	KMIN	DELTAK	R	DADN	DA	A	A/T
BLOCK	100								
	999	9	30.63	0.31	30.32	0.01		1.1E-05	
0.0000			0.1363	0.02					
	1000	1	37.07	0.37	36.70	0.01		1.5E-05	
0.0000			0.1363	0.02					
BLOCK	200								
	1999	9	31.85	0.32	31.53	0.01		1.2E-05	
0.0000			0.1482	0.02					
	2000	1	38.55	0.39	38.16	0.01		1.6E-05	
0.0000			0.1482	0.02					
BLOCK	300								
	2999	9	33.16	0.33	32.82	0.01		1.3E-05	
0.0000			0.1610	0.03					
	3000	1	40.13	0.40	39.73	0.01		1.8E-05	
0.0000			0.1610	0.03					
BLOCK	400								
	3999	9	34.55	0.35	34.21	0.01		1.4E-05	
0.0000			0.1746	0.03					
	4000	1	41.82	0.42	41.40	0.01		1.9E-05	
0.0000			0.1747	0.03					
BLOCK	500								
	4999	9	35.88	0.36	35.52	0.01		1.4E-05	
0.0000			0.1893	0.03					
	5000	1	43.42	0.43	42.99	0.01		2.1E-05	
0.0000			0.1893	0.03					
BLOCK	600								
	5999	9	37.18	0.37	36.80	0.01		1.5E-05	
0.0000			0.2048	0.03					
	6000	1	44.99	0.45	44.54	0.01		2.2E-05	
0.0000			0.2049	0.03					
BLOCK	700								
	6999	9	38.56	0.39	38.18	0.01		1.6E-05	
0.0000			0.2215	0.04					
	7000	1	46.68	0.47	46.21	0.01		2.4E-05	
0.0000			0.2215	0.04					
BLOCK	800								
	7999	9	40.06	0.40	39.65	0.01		1.8E-05	
0.0000			0.2393	0.04					
	8000	1	48.48	0.48	47.99	0.01		2.6E-05	
0.0000			0.2393	0.04					

BLOCK	900						
	8999	9	41.43	0.41	41.01	0.01	1.9E-05
0.0000			0.2585	0.04			
	9000	1	50.14	0.50	49.64	0.01	2.9E-05
0.0000			0.2585	0.04			
BLOCK	1000						
	9999	9	42.89	0.43	42.46	0.01	2.0E-05
0.0000			0.2790	0.05			
	10000	1		51.91		0.52	51.39
3.1E-05		0.0000		0.2790		0.05	0.01
BLOCK	1100						
	10999	9		44.46		0.44	44.02
2.2E-05		0.0000		0.3011		0.05	
	11000	1		53.81		0.54	53.27
3.5E-05		0.0000		0.3012		0.05	0.01
BLOCK	1200						
	11999	9		45.96		0.46	45.50
2.3E-05		0.0000		0.3250		0.05	
	12000	1		55.62		0.56	55.06
3.8E-05		0.0000		0.3251		0.05	0.01
BLOCK	1300						
	12999	9		47.57		0.48	47.10
2.5E-05		0.0000		0.3509		0.06	
	13000	1		57.58		0.58	57.00
4.3E-05		0.0000		0.3510		0.06	0.01
BLOCK	1400						
	13999	9		49.21		0.49	48.72
2.7E-05		0.0000		0.3792		0.06	
	14000	1		59.56		0.60	58.96
4.9E-05		0.0000		0.3793		0.06	0.01
BLOCK	1500						
	14999	9		50.94		0.51	50.43
3.0E-05		0.0000		0.4102		0.07	
	15000	1		61.65		0.62	61.03
5.6E-05		0.0001		0.4102		0.07	0.01
BLOCK	1600						
	15999	9		52.71		0.53	52.19
3.3E-05		0.0000		0.4444		0.07	
	16000	1		63.80		0.64	63.16
6.5E-05		0.0001		0.4445		0.07	0.01
BLOCK	1700						
	16999	9		54.62		0.55	54.08
3.6E-05		0.0000		0.4826		0.08	
	17000	1		66.11		0.66	65.45
7.8E-05		0.0001		0.4827		0.08	0.01

BLOCK	1800						
	7999	9	56.61	0.57	56.05	0.01	4.1E-05
0.0000			0.5259	0.09			
	18000	1	68.51		0.69	67.83	0.01
9.8E-05		0.0001	0.5260		0.09		
BLOCK	1900						
	18999	9	58.79		0.59	58.20	0.01
4.6E-05		0.0000	0.5762		0.10		
	19000	1	71.15		0.71	70.44	0.01
1.3E-04		0.0001	0.5764		0.10		
BLOCK	2000						
	19999	9	61.24		0.61	60.63	0.01
5.4E-05		0.0001	0.6375		0.11		
	20000	1	74.12		0.74	73.38	0.01
2.0E-04		0.0002	0.6377		0.11		
BLOCK	2100						
	20999	9	64.43		0.64	63.79	0.01
6.8E-05		0.0001	0.7245		0.12		
	21000	1	77.98		0.78	77.20	0.01
6.2E-04		0.0006	0.7251		0.12		

Kmax EXCEEDED MATERIAL K_{1c} AT CYCLE 21260

Rotor Forging Damage Assessment

Bore Plug Removal for Bore Inspection

Fig. 1.4.2.1

HP Rotor Inlet Bowl Strut Cracking

1.4.3

Executive Summary

During the Unit 2 outage at the Chandrapura Thermal Power Station, in July/August 1994, cracking was observed at several locations on the ID surfaces of the HP rotor inlet bowl struts. The surface length of the worst crack was 5 inches, however the depth of these cracks could not be measured due to the complexity of the strut geometry. Surface length-to-depth ratios for typical fatigue cracks of the this type suggest that the crack depth would be approximately 0.5 inch. Prior inspection information for these locations was not available.

Based on a review of plant operating history, the most significant contributor to the observed HP inlet bowl strut cracking was assessed to be the "loss-of-fire" (or fire-out) events in the boiler which were reported to occur twice daily, on an average or approximately 500 times per year. During the fire-outs steam admission to the HP/IP turbine is stopped and the turbine metal temperature is held fairly constant (approximately 1000°F or 540°C near the inlet section). Upon restoration of fire in the boiler the turbine valves are opened and the turbine inlet section is thermally shocked with colder steam approximately 180°F (100°C) below the metal temperature. Tensile thermal stresses develop at the ID surfaces of the HP inlet bowl/strut region intensified by the strut-to-side-wall transition radius.

Stress analyses were performed to estimate thermal and pressurization stresses which govern crack initiation and propagation. The peak stress estimated at the crack location due to a 180°F thermal shock was 73.1 ksi including a stress concentration factor of 2.0. The estimated number of crack initiation cycles at this stress level was 6000. Hoop stresses due to pressurization of bores on both sides of the strut was conservatively estimated to be 5.4 ksi.

A ductile tearing analysis predicted a critical crack depth of 1.9 inch. Crack propagation calculations predicted 15,200 thermal shock cycles or 30 years to grow an assumed 0.5 inch deep initial crack to critical size. Creep crack growth calculations using upper bound crack growth data predicted in excess of 64,000 hours or 10 years of operation to grow a 0.5 inch deep crack to critical size.

Based on the stress and fracture mechanics results it was recommended that the HP casing be returned to service as-is, conditional upon monitoring/reinspection of the strut cracks after no more than 5 years of operation. Turbine steam/metal thermocouple data should also be obtained to better quantify the severity and frequency of thermal shocks. Prior to the next inspection, repair or replacement options should be investigated. To further extend the life of the HP/IP rotor it is strongly recommended that the number of fire-out events experienced by the unit be minimized.

Analytical Evaluation

1.4.3.1

During the Unit 2 outage at the Chandrapura Thermal Power Station, in July/August 1994, cracking was observed at several locations on the ID surfaces of the HP rotor inlet bowl struts. A brief description of the inspection results is given below followed by a stress and fracture mechanics evaluation to assess the effect of cracking on the remaining life of the HP rotor casing.

Review of Inspection Results

Dye penetrant testing was employed to identify locations of cracking in the HP rotor inlet bowl strut regions. These locations, shown in Figure 1, are confined to the ID surfaces of the struts or partitions separating the steam inlets to the HP section of the rotor arranged in two groups of four inlets at the top and four inlets at the bottom of the HP rotor. The worst cracking was observed in the first steam admission valve and the valve diametrically across from it. The total surface length of the worst crack, documented in Figure 1, was approximately 5 inches. Because of complexity of the strut geometry, crack depth measurements were not possible. However, experience suggests that thermal fatigue cracks of this type would be approximately 0.5 inch in depth, based on aspect ratios for typical fatigue cracks.

Examination of Potential Causes of Rotor Cracking

Based on a review of plant operating history, the most significant contributor to the observed rotor ID surface cracking was assessed to be the "loss-of-fire" (or fire-out) events in the boiler which were reported to occur twice daily, on an average or approximately 500 times per year. During the fire-outs steam admission to the HP/IP turbine is stopped but the turbine is not tripped; i.e., the generator remains tied to the grid functioning as a motor, driving the turbine rotor train (a condition referred to as "motoring"). During the fire-out the HP/IP turbine is bottled up and the temperature of the rotor is held fairly constant (approximately 1000°F or 540°C near the inlet section). Upon restoration of fire in the boiler (approximately 30 minutes after the fire-out), the turbine valves are opened and colder steam in the main steam and reheat piping enters the turbine, thermally shocking the hotter turbine metal. Temperature data obtained for a typical fire-out indicates that the steam entering the turbine is approximately 180°F (100°C) colder than the metal; i.e. 820°F (440°C) steam versus 1000°F (540°C) metal temperature. This thermal shock causes tensile stresses at the ID surfaces of the rotor inlet bowl/strut because the ID surface is prevented from contracting due to the constraint offered by the thicker sections of the HP inlet casing. This thermal stress is increased at strut ID surface due to the stress concentrating effect of the radius at the strut/inlet bowl interface and is therefore predicted to be the prime contributor to initiation of strut cracking. Estimates of these thermal stresses along with steady-state pressurization stresses to address crack initiation and propagation are provided below.

Stress Analyses

Stress analyses of the HP rotor inlet bowl/strut region were performed to estimate stresses required to address crack initiation and propagation. The following load cases were considered:

Load Case 1: Thermal down-shock of 180°F due to the fire-out events

These stresses were predicted to be the prime contributor to the initiation and propagation of the inlet bowl strut cracks.

Load Case 2: Steady-state stresses due to internal pressurization

Pressurization stresses were estimated to address the possibility of creep contributing to the propagation the strut cracks.

Load case 1: Thermal down-shock of 180°F due to the fire-out events

A simplified one-dimensional transient thermal heat transfer analysis of the HP rotor inlet bowl strut region was performed using SI's computer program PIPE-TS2 [1]. The geometry, material properties and thermal loading simulated in the analysis are described below followed by a summary of stress results.

Geometry: For the purposes of estimating thermal shock stresses the complexity of the HP rotor strut region was simplified to represent a thick hollow cylinder with the thermal shock applied at the ID. An ID of 8 inches corresponding to the inlet bore diameter and wall thickness of 3 inches was simulated based on measurements of the strut thickness.

Material Properties: The material specification of the HP rotor control valve chest was 1.75Cr-1Mo-V steel. The following rotor material properties from the ASME code for low-chrome steels at 900°F were used in the heat transfer analysis:

Parameter	Value	Units
Thermal conductivity	19.7	Btu/hr-in-°F
Density	489	lbs/ft ³
Specific Heat	0.153	Btu/lbm-°F
Elastic Modulus	25.6×10^6	psi
Thermal Expansion Coeff.	8.5×10^{-6}	in/in/°F

Loading: Heat transfer coefficients and steam/rotor temperatures used in the analysis are summarized below:

Parameter	Value	Units
Rotor metal temperature	1000	°F
Rotor OD temperature	1000	°F
Rotor OD heat transfer coeff.	0.01 (adiabatic)	Btu/hr-ft ² -°F
Rotor ID steam temperature	820	°F
Rotor ID heat transfer coeff.	1000	Btu/hr-ft ² -°F

Stress results: The variation in thermal stress at the rotor OD as a function of elapsed time after the initial thermal shock is shown in Figure 2. A maximum tensile stress of 36.5 ksi was computed 40 seconds after the initial shock. The stress gradient from the ID surface inward is shown in Figure 3. The tensile stresses decay to zero approximately 1.1 inch below the ID surface. These stresses do not account for the stress concentrating effect, K_t , of the strut/wall radius. Therefore, a K_t value of 2.0 was estimated from [2] using Neuber's equations. The die-away in K_t with increasing depth below the surface was approximated using the following equation for a hole in a plate:

$$K_t(x) = K_t(\max) \left[\frac{1}{3} + \frac{1}{6} \left(\frac{r}{r+x} \right)^2 + \frac{1}{2} \left(\frac{r}{r+x} \right)^4 \right] \quad (1)$$

where,

$K_t(x)$ is the stress concentration at a distance x below the surface,
 $K_t(\max)$ is the peak stress concentration factor (3.0), and,
 r is the groove radius (approximately 0.25 inch).

Thermal stresses modified using Equation 1 to include the groove stress concentrating effect are shown in Figure 3 along with the unconcentrated stress.

Load Case: Steady-state stresses due to internal pressurization

Stresses due to internal pressurization at 2000 psi were estimated to address the possibility of steady-state creep contributing to crack propagation. The average hoop stress (σ_{avg}) in the strut was estimated using the following equation:

$$\sigma_{avg} = \frac{p r_i}{t} \quad (2)$$

Stress results: With $p=2000$ psi, inside radius $r_i=4$ inches and wall thickness $t=3$ inches, an average hoop stress of 2.67 ksi was estimated for the strut region.

Crack Initiation Calculations

The time required to initiate a crack was estimated using the design fatigue curves for carbon, low alloy and high tensile steels, from the ASME Code Section III, shown in Figure 4. For a peak surface stress of 73.1 ksi ($K_t=2$) and an elastic modulus correction factor of (30E6/25.6E6), an alternating stress, S_a , of 43.8 ksi was computed. From Figure 4, for an ultimate tensile strength (UTS) range of 115 to 130 ksi, approximately 6000 cycles (fire-out events) are required to initiate the HP/IP groove cracks. For K_t values of 2.5 and 3.0, the number of initiation cycles reduce to 2500 and 1500 respectively. Prior inspection results for the HP inlet bowl/strut region were not available. Therefore, a comparison with demonstrated initiation time was not possible.

Critical Crack Size

A remaining life estimate requires determination of the critical crack size. At 1000°F, a ductile tearing analysis was performed to estimate critical crack size using SI's pc-CRACK computer code. Conservatively simulating an edge crack with a stress of 5.4 ksi (assuming pressurization of both inlet bores), a critical crack size of 1.9 inches was predicted. Material properties used in the ductile tearing analysis are summarized below:

Tensile Properties

Yield (ksi)	Flow str. (ksi)	Alpha, (Ram.- Osgood)	N (Ram.- Osgood)	Elas. Modulus ksi
19.8	25.0	2.51	4.2	30,000

Toughness Data

J-R Coeff.	J-R Exponent	J_{IC}	J_{ICmax}
1.82	0.28	0.5	2.0

Crack Propagation Calculations

Crack growth calculations were performed to estimate the number of cycles required to propagate the existing crack (estimated 0.5 inch depth) to critical size. In addition to fatigue due to thermal shocking, the possibility of creep crack growth was also examined.

Crack geometry: The observed ID surface strut crack was conservatively simulated using an edge crack model in a plate.

Stresses: Fatigue crack growth calculations were performed using Load Case 1 stresses and creep crack growth calculations were performed using Load Case 2 stresses.

Fatigue crack growth: Fatigue crack growth due to thermal shocking was predicted to be the primary crack growth mechanism. The following Paris law was assumed:

$$\frac{da}{dN} = C \Delta K^n \quad (3)$$

Fatigue crack growth data from the EPRI SAFER code [3] for rotor steels yields a coefficient, C, of 6.57E-9 and an exponent, n, of 2.35, with da/dN in inch/cycle. This data was compared with fatigue crack growth data from the ASME Code Section XI for Carbon and low-alloy steels. For an R-ratio of 0.0 and $\Delta K > 19$ ksi/inch, the ASME Code C and n values are 1.01E-7 and 1.95, respectively, yielding a crack growth rate 3 to 4 times higher than the SAFER data. For conservatism, the ASME Code data was used in the fatigue crack growth calculations.

Fatigue Crack Growth Results: Crack growth from an assumed current size of 0.5 inch to the critical size of 1.9 inches was predicted to occur in excess of 15,200 cycles or 30 years of operation assuming 500 cycles (fire-outs) per year. Fatigue crack growth is plotted in Figure 5.

Creep Crack Growth: Creep crack growth due to internal pressurization was simulated using the equation:

$$\frac{da}{dt} = H C_t^q \quad (4)$$

where, the coefficient H of 0.094 and exponent q of 0.805 for base metal represent upper bound values from [4].

Creep Crack Growth Results: Crack growth from the estimated initial size of 0.5 inch to the critical size of 1.9 inches was predicted in excess of 64,000 hours or 10 years of operation, using a steady-state stress of 5.4 ksi to account for pressurization of adjacent HP inlet bores. Creep crack growth as a function of number of operating hours is shown in Figure 6. It should be noted that an average of 1100 hours between cold starts was assumed in the creep crack growth analysis.

Conclusions

The preceding calculations predict that the number of cycles required to initiate the strut cracks are approximately 6000 cycles or 12 years of operation with an average of 500 fire-outs per year. Though the depths of the strut cracks were not measured, experience suggests that the current crack depth is approximately 0.5 inch based on aspect ratios for similar fatigue cracks. Fatigue and creep crack growth calculations predicted that the remaining life of the cracked HP inlet bowl/strut region is in excess of 10 years of operation assuming an average of 6000 operating hours per year. Assuming a safety factor 2.0 these cracks should be reinspected after no more than 5 years of operation. This assessment is based on the following important assumptions:

- (i) The magnitude of the thermal shock is 180°F.
Turbine steam/metal thermocouple data for several operating scenarios (specifically including fire-out events) would be required to verify the accuracy of this assumption.
- (ii) The average number of thermal shocks per day is two.
The remaining life of the rotor could be drastically reduced if the frequency, source and

magnitude of thermal shocks is greater than that assumed in the analysis.

- (iii) The 0.5 inch depth for the observed cracks was estimated based on experience because the complexity of the strut geometry precluded any crack depth measurements.

Recommendations

In light of the above assumptions associated with the analysis it is recommended that:

- (i) Turbine steam/metal thermocouple data should be obtained to quantify the severity of thermal shocks due to the fire-outs and other significant events.
- (ii) Every effort should be made to minimize the number of fire-out events experienced by the unit.
- (iii) The HP/IP rotor may be returned to service as-is, conditional upon monitoring/reinspection of the strut cracks after no more than 5 years of operation. Prior to the next inspection, repair or replacement options should be investigated. Caution should be taken regarding selection of weld repair options because of the possibility of introducing weld residual stresses which could further reduce the remaining life of the strut region.

References

1. PIPE-TS2, Structural Integrity Associates computer program to compute the transient thermal and stress response of an axisymmetric two-material cylinder, Version 1.01.
2. "Formulas for Stress and Strain," R. J. Roark and W. C. Young, McGraw-Hill Book Company, Fifth Edition, 1975.
3. F. V. Ammirato et al, "Life Assessment Methodology of Turbogenerator Rotors," EPRI report CS/EL 5593, Vol 1-4, March 1988.
4. PC-PIPE Version 3.0, Users Manual and Technical Description of a Computer Code for Integrity Analysis of Elevated Temperature Steam Pipes, Structural Integrity Associates, San Jose, Ca, 1989.

Figures

- Figure 1. Schematic of the HP rotor inlet bowl/strut region indicating the locations and surface extent of the worst cracks.
- Figure 2. Variation in thermal stress at the ID of a 8-inch ID, 3-inch thick cylinder subjected to a 180°F temperature down-shock, versus time after the shock.
- Figure 3. Stress gradient at the time of maximum thermal shock stress (40 sec.) without and with a K_t of 3.0.
- Figure 4. Design fatigue curves for Carbon, low-alloy and high tensile steels (from the ASME Code Section III).
- Figure 5. Fatigue crack growth: crack depth versus number of 180°F thermal shock cycles.
- Figure 6. Creep crack growth: crack depth versus number of operating hours.

Chandrapura TPS
 Unit #2
 HP Inner Cylinder
 Bowl Region - Strut Crack
 (Visual determination of extent)

Figure 1

Chandrapura Unit 2 HP Rotor Inlet Bowl

180 Deg.F Down-shock Thermal Stresses

Elapsed Time after Shock (sec.)

Figure 2

Chandrapura Unit 2 HP Rotor Casing

Turbine Inlet Strut Stresses

09 - 1

Stress (ksi)

Distance below surface (in.)

□ Kt=0 + Kt=2

Figure 3

Design Fatigue Curves for Carbon, Low Alloy, and High Tensile Steels (from ASME Code Section III)

Figure 4

Chandrapura Unit 2 HP Inlet Bowl

Fatigue Crack Growth: Thermal stresses

Figure 5

Chandrapura Unit 2 HP Inlet Bowl

Creep Crack Growth: 2000 psi pressure

(Thousands)
Number of operating hours

Figure 6

Turbine Steam Path Blade Life Assessment

1.4.4

Executive Summary

During the Unit 2 outage at the Chandrapura Thermal Power Station, in July/August 1994, the steam path blading was assessed for its remaining life based on the location and extent of erosion and foreign object impact damage. This unit is a General Electric impulse design with 9 rows in the high pressure section, 10 rows in the reheat section, and 6 rows in the double flow low pressure section. This unit has been in operation since the early 1960's. A visual inspection of the blades was made to perform this assessment.

High Pressure Section

The HP section of blades, both stationary and rotating, were found in good condition. Damage from solid particle erosion (SPE) was evident on the first 5 stages. The most damage was in the HP nozzle with approximately 5 partitions with visible erosion. The rotating buckets are eroded on the leading edge and on the tenons. The leading edge erosion is due to solid particles in the steam path impacting the bucket. The erosion on the tenons is due to solid particles impacting the tenons and being trapped between the cover and the inner cylinder. The structural integrity of the rotating and stationary blades is not in question. The partitions in the diaphragms are repairable during this outage. The amount of erosion of the tenons needs to be monitored in order to reduce the risk of cover failure. The blades in this section are good for a minimum of 10 years of service.

Reheat Section

The RH section of blades, both stationary and rotating, were found in good condition. Damage from solid particle erosion (SPE) was evident on the reheat nozzle. The last rows of the reheat section have considerable deposits. These deposits were analyzed to be made up mostly of silica. The partitions of the diaphragms are repairable during outages. The deposits are to be cleaned from steam path. The water quality for the unit needs to be improved to reduce the amount of deposits. The blades in this section are good for a minimum of 10 years of service.

Low Pressure Double Flow Section

The LPDF section of blades, both stationary and rotating, were found in good condition. The L-1 row has experienced blade failures in the past. The root cause for these failures is still under investigation. The rotor removed from this unit also had a failure in the L-0 row. This was caused from impact of the failed L-1 row. Due to deposits of silica, the steam path was found very dirty. The blades in this section are good for a minimum of 10 years of service. The results of the L-1 failure analysis will determine the recommendations for this row of blades.

Section 1.5

Main Steam and Reheat Piping

Main Steam and Hot Reheat Piping

1.5.1

Executive Summary

As part of the Unit 2 remaining life assessment for the Chandrapura Thermal Power Station Unit, the main steam and hot reheat high energy piping systems were evaluated to assess their suitability for continued service. The assessment included field inspection/testing and metallurgical evaluation in conjunction with a stress and fracture mechanics evaluation.

Magnetic particle testing revealed no reportable indications in the girth welds or hanger lugs inspected. Metallurgical replication revealed no indication of creep voiding and hardness measurements were within the material specification for A335 P22 steel. The low level of creep damage is consistent with operating temperatures 15°F to 20°F below the 1005°F design temperature. Ultrasonic examinations revealed no significant indications in the main steam piping. Only two subsurface indications were reported in the girth weld at the south-side stop valve inlet with a conservatively estimated depth of 0.2 inch (5 mm). Experience suggests that these indications are not service-induced but original fabrication imperfections. Dimensional measurements did not indicate any anomalies. Overall, the field inspection and evaluation revealed that the main steam and hot reheat piping was in good condition for continued service. The only item of concern was the condition of the piping insulation which was missing or damaged at several locations exposing the piping to the outside environment and permitting ingress of rain water and other contaminants. The subsurface indications were dispositioned with fracture mechanics calculations.

Cold and hot walkdowns of the piping systems revealed that most of the hanger supports were functioning within their travel limits. A few hangers were observed to be bottomed out in the hot condition. A comparison between observed and calculated travel for these hangers indicated that the bottomed out condition was not severe. Nevertheless, hanger adjustment recommendations were provided to alleviate the bottomed out condition. Another finding requiring repair was inelastic deformation of several hanger clamps and bolts for the main steam and hot reheat piping. Replacement of these clamps/bolts was advised using an improved clamp design (available from BHEL).

Piping stress analyses of the main steam and hot reheat piping systems were performed to calculate stresses due to system deadweight, coldpull, thermal expansion and internal pressurization. All stresses (primary and secondary) were well below the allowable limits of the ASME B31.1 Code for Power Piping and consistent with the low level of creep damage documented metallurgically. Design stress-rupture calculations indicated a remaining life in excess of 2,000,000 hours.

Fracture mechanics calculations were performed to address the possibility of reduction in remaining life due to crack propagation. Assuming the subsurface indications in the hot reheat piping to be 0.2 inch cracks, the remaining life predicted was 103,000 operating hours or 15 years.

Based on the inspection results, metallurgical replication and stress and fracture mechanics evaluations it was concluded that the main steam and hot reheat piping systems are suitable for continued service contingent upon addressing insulation deficiencies, repairing/replacing the deformed hanger clamp/bolts, and reinspection of the subsurface indications in the hot reheat piping girth weld after no more than 6 years.

The remaining life assessment for Unit 2 at the Chandrapura Thermal Power Station, in July/August 1994, included an evaluation of the main steam and hot reheat piping systems to assess their suitability for continued service. The assessment included inspections and metallurgical evaluation in conjunction with a stress and fracture mechanics evaluation to assess the remaining life of the piping systems.

Review of Inspection Results

Magnetic particle testing performed on a total of ten girth welds and three hangers did not reveal any reportable indications. Metallurgical replication revealed no indication of creep voiding consistent with low operating temperature and stress levels for both piping systems. Hardness measurements were within the material specification for A335 P22 steel. Dimensional measurements did not indicate any anomalies. Only two subsurface indications in the hot reheat line stop valve girth weld were reported by ultrasonic testing. These indications were assessed to be fabrication induced with a maximum radial extent of 0.2 inch (5 mm).

Review of hanger walkdown information

Cold and hot walkdowns of the main steam and hot reheat piping systems revealed that most of the hanger supports were functioning normally within their designed travel. The location and numbering of hanger supports for the main steam and hot reheat piping are indicated on the piping isometrics in Figures 1 and 2. The hanger supports which were observed to be topped out or bottomed out are listed in Tables 1 and 2 along with recommended adjustments. The adjustments are minor and the impact of the topped/bottomed out condition was assessed to be minor by comparing the observed travel with the calculated travel. Two items of concern which need to be addressed are: (i) repair/restoration of damaged insulation on the piping at several locations and (ii) repair of deformed hanger clamp and bolts identified in Tables 1 and 2 (short term) with a preferred replacement using an improved BHEL design (Figure 3).

Piping Stress Analyses

Stress analyses of the main steam and hot reheat piping systems were performed using the ANSYS computer program [1], to calculate stresses due to deadweight, coldpull, thermal expansion and internal pressurization. Detailed information on hanger loads and travel was not available. Therefore stresses due to deadweight were estimated by assuming perfect balance (zero displacement) for all hanger supports. This assumption is predicted to have minimal effect on the total stress state because of the low magnitude of deadweight stresses. A summary of maximum axial stresses applicable to girth welds is given below.

Summary of Maximum Axial Stresses

System	OD (in.)	Min. Wall Thk. (in.)	Axial Stress (ksi) due to:				
			Dead Weight DW	Expansion EXP	Pressure	DW+EXP (elastic)	DW+EXP (relaxed)
Main Steam	14.0	2.193	0.648	4.114	1.647	4.762	1.953
	10.75	1.749	0.021	6.893	1.541	6.914	1.960
Hot Reheat	20.0	0.882	0.139	3.364	1.440	3.503	1.969
	16.0	0.698	0.414	4.213	1.458	4.627	1.993

The maximum axial stresses listed above occurred at the stop valve inlet welds. Axial pressure stresses in the above table were computed for maximum operating pressures of 1845 psi (main steam) and 292 psi (reheat). Primary and secondary stresses computed per equations 11 and 13 of the ASME Code B31.1 code more than 50% below Code allowable values. Creep relaxation of axial stresses after 182,000 hours of operation was estimated using a constant total strain approach by Finnie [2]. These relaxed stresses were used to perform the crack growth calculations.

Design stress-rupture calculations using indicated a remaining creep rupture life in excess of 2,000,000 hours.

Crack Propagation Calculations

Crack growth calculations were performed to estimate the number of hours required to propagate surface and subsurface cracks to critical size using the PCPIPE [3] computer program.

Crack geometry: Three types of cracking were analyzed:

- (i) Surface connected ID or OD crack
- (ii) Subsurface crack located at half the pipe wall thickness
- (iii) Subsurface crack located at one-quarter the pipe wall thickness

Because of the absence of longitudinal seam welds, the above cracks were assumed to be oriented circumferentially at girth weld locations.

Stresses and Operating Conditions: Creep relaxed deadweight and expansion stresses plus the pressure stress listed in table above were used to perform the crack growth calculations. Maximum recorded operating temperatures of 1005°F and 990°F for the main steam and hot reheat piping systems and maximum operating pressures of 1845 and 290 psi, respectively, were used in the analyses. Re-initiation of primary creep was simulated only for cold startups i.e., after an average of 1144 hours.

Crack growth law: Creep crack growth due to internal pressurization was simulated in PCPIPE using the equation:

$$\frac{da}{dt} = H C_t^q \quad (1)$$

where, the following values for coefficient H and exponent q from [3] were used in the analysis:

	Coefficient, H	Exponent, q
Mean	0.075	0.805
Upper Bound	0.123	0.546

Crack Growth Results: Crack growth results for a range of initial crack sizes of 0.1 inch to 0.5 inch for the simulated surface and subsurface crack geometries are summarized in Tables 3, 4 and 5. Because critical crack sizes at elevated temperatures are typically through-wall crack growth calculations were terminated at a limiting crack growth rate of 0.001 inch/hour. These tables allow dispositioning of any detected surface and subsurface indications at girth weld locations.

For the 0.2 inch (5 mm) subsurface indications detected in the reheat stop valve inlet weld, the life predicted using mean crack growth properties was 103,000 hours (Table 5). Upper bound crack growth data was deemed to be inappropriate for these locations because there was no metallurgical evidence of advanced creep damage in any of the girth welds examined.

Conclusions

Results of the inspections, metallurgical evaluation and stress and fracture mechanics analyses indicate that the main steam and hot reheat piping have a remaining life in excess of 15 years. The absence of creep voiding in critical girth welds examined is consistent with the low operating temperature and stress levels for these piping systems. Design creep-rupture calculations predicted that less than 10% of the creep life has been consumed to date. Subsurface indications recorded for the hot reheat stop valve inlet weld are predicted to be fabrication related. Reinspection of this location after no more than 6 years will confirm this assessment. Recommendations to be followed prior to returning the unit to service are discussed below.

Recommendations

- (i) Re-installed piping at all locations where insulation is missing or damaged to prevent corrosion, loss of heat and thermal stress build up.
- (ii) Replace deformed hanger clamp/bolts for hangers MSH-2,3,7 and HRH-2,3,7 with new design as shown in Figure 3.
(Optional repair option: Replace 1-inch (25 mm) dia bolts with 1.375 inch (35 mm) dia bolts. Reinforce clamp with stiffener plates to prevent inelastic deformation.)
- (iii) Readjust hanger supports identified in Tables 1 and 2. Adjustments should be made after

repair/replacement of rigid hanger clamp/bolts. Recheck hangers in hot condition to ensure that adjustments have corrected the topped-out or bottomed-out condition.

- (iv) Reinspect hot reheat stop valve inlet girth weld after no more than 6 years of operation to verify whether subsurface indications are fabrication related or if in-service growth has resulted. Further inspection is not required if in-service growth is not observed.

References

1. ANSYS Revision 4.4 Reference Manual, Swanson Analysis Systems, Inc., December 1989.
2. Finnie, I., and Heller, A., "Creep of Engineering Materials," McGraw-Hill, London, 1969.
3. Saxena A., PC-PIPE, Version 3.0, Users Manual and Technical Description of a Computer Code for Integrity Analysis of Elevated Temperature Steam Pipes, distributed by Structural Integrity Associates, San Jose, Ca 1989.

Figures

- Figure 1. Isometric of the main steam piping indicating hanger support location and numbering.
- Figure 2. Isometric of the hot reheat piping indicating hanger support location and numbering.
- Figure 3. Schematic illustrating damaged rigid hanger clamp/bolts and suggested replacement design.

Table 1

CHANDRAPURA UNIT 2 MAIN STEAM PIPING
Pipe Supports (Inspected 7/26/94)

Sub Component	Damage Found	Damage Assessment (DA)/ Recommendation (R)
MSH-1: Constant support hanger near header outlet	Hanger almost bottomed out in the cold position (2mm between pin and stop). Cold mark=10 (L), Hot mark=6.5.	DA: Bottomed out condition is not severe (2mm gap to stop). R: Readjust cold position of hanger to 8.0. Calculated hanger movement is 1.3" upward. Record hot hanger position after readjustment to ensure that hanger is not topped out.
MSH-2: Vertical restraint near header outlet	(i) Pipe insulation missing near hanger clamp, leaving pipe exposed. (ii) Clamp/bolt deformed.	DA: Pipe exposure; possible corrosion, thermal stresses, and heat loss. R: Re-insulate with silica and mineral wool prior to startup. DA: Clamp/bolt failure could jeopardize integrity of pipe support system. R: Replace with one-piece forging design (Fig. 3).
MSH-3: Variable spring hangers below rigid restraint.	(i) Both spring cans bottomed out in the hot position. (ii) Clamp/bolt deformed.	DA: Bottomed out condition not severe. Available travel cold- to-hot = 2" approx.; calculated movement 1.53". R: Readjust both spring cans to provide at least 4" travel cold- to-hot; recheck hot position. DA: Clamp/bolt failure could jeopardize integrity of pipe support system. R: Replace with one-piece forging design (Fig. 3).

MSH-5: Variable spring hangers	Both spring cans bottomed out in the hot position.	DA: Variable springs are in tandem with constant support; therefore bottomed out condition is not severe. R: Readjust cold position to top of scale to provide maximum travel; recheck hot.
MSH-7: Vertical rigid support near turbine.	Minor deformation of clamp and bottom bolts.	DA: Clamp/bolt failure could jeopardize integrity of pipe support system. R: Replace with one-piece forging design (Fig. 3).
MSH-8: Variable spring hanger before wye inlet.	Bottomed out in the hot position.	DA: Bottomed out condition not severe. Calculated travel=0.7" down; remaining travel cold-to-hot =1 to 2". R: Readjust cold position to provide a minimum of 3" travel; recheck hot.

- Note: (1) All hanger adjustments are to be made after replacement of deformed clamps/bolts identified above.
- (2) Care must be taken to adequately support the piping system prior to any attempts to replace the deformed clamps/bolts. Only pinning the hanger above and below MSH-7 is not advised because they cannot support the high load of MSH-7 (approximately 18,000 and 25,000 lbs). It is suggested that the line be supported from below with a jack having a load capacity of at least 25,000 lbs, located near MSH-8, before the wye connection.

Table 2
CHANDRAPURA UNIT 2 HOT REHEAT PIPING
Pipe Supports (Inspected 7/26/94)

Sub Component	Damage Found	Damage Assessment (DA)/ Recommendation (R)
HRH-1: Constant support hanger near header outlet	Hanger almost bottomed out in the cold position (2mm between pin and stop). Cold mark=10 (L), Hot mark=6.5.	DA: Bottomed out condition is not severe (2mm gap to stop). R: Readjust cold position of hanger to 8.0. Calculated hanger movement is 1.7" upward. Record hot hanger position after readjustment to ensure that hanger is not topped out.
HRH-2: Vertical restraint near header outlet	(i) Pipe insulation missing near hanger clamp, leaving pipe exposed. (ii) Clamp bent and bottom bolts stretched.	DA: Pipe exposure; possible corrosion, thermal stresses, and heat loss. R: Re-insulate with silica and mineral wool prior to startup. DA: Clamp/bolt failure could jeopardize integrity of pipe support system. R: Replace with one-piece forging design (Fig. 3).
HRH-3: Variable spring hangers below rigid restraint.	(i) Both spring cans bottomed out in the hot position. (ii) Clamp/bolt deformed.	DA: Bottomed out condition not severe. Available travel cold-to-hot = 1.5" approx.; calculated movement 1.1" down. R: Readjust both spring cans to provide at least 3" travel cold-to-hot; recheck hot position. DA: Clamp/bolt failure could jeopardize integrity of pipe support system. R: Replace with one-piece forging design (Fig. 3).

HRH-5: Variable spring hanger (in tandem with constant)	Spring can bottomed out in the hot position.	DA: Variable spring is in tandem with constant support; therefore bottomed out condition is not severe. R: Readjust cold position to top of scale to provide maximum travel; recheck hot.
HRH-7: Vertical rigid support near turbine.	Clamp and bottom bolts deformed.	DA: Clamp/bolt failure could jeopardize integrity of pipe support system. R: Replace with one-piece forging design (Fig. 3).
HRH-8: Variable spring hanger.	Topped out in the hot position.	DA: Bottomed out condition not severe. Calculated travel=0.8" down; remaining travel cold- to-hot =0.4". R: Readjust cold position to provide a minimum of 2" travel; recheck hot.

- Note: (1) All hanger adjustments are to be made after replacement of deformed clamps/bolts identified above.
- (2) Care must be taken to adequately support the piping system prior to any attempts to replace the deformed clamps/bolts. Only pinning the hanger above and below HRH-7 is not advised because they cannot support the high load of HRH-7 (approximately 18,000 and 25,000 lbs). It is suggested that the horizontal section of the piping below HRH-7 be supported from below with a jack having a load capacity of at least 25,000 lbs, located near HRH-8.

Figures

- Figure 1.** Isometric of the main steam piping indicating hanger support location and numbering.
- Figure 2.** Isometric of the hot reheat piping indicating hanger support location and numbering.
- Figure 3.** Schematic illustrating damaged rigid hanger clamp/bolts and suggested replacement design.

- (1) SEE ATTACHMENT NO. 1 FOR HANGER DATA.
 (2) SEE ATTACHMENT NO. 2 FOR TRAM DATA 1-3
 (3) DIMENSIONS ARE APPROXIMATE ELEVATIONS TAKEN FROM DRAWINGS.

NDE LOCATIONS

- ⚠ HEADER OUTLET WELD.
- ⚠ THREE WELDS AT WYE BLOCK.
- ⚠ STOP VALVE INLET WELD.
- ⚠ STEAM CHEST INLET WELD.
- ⚠ HANGER LUG WELDS.

FITTINGS ASTM 369FP-22

PIPE 14" O.D. A335-P22 SEAMLESS

STOP VALVE WEIGHT - 7600

14" - 2.192 M.W.

10" - 1.697 M.W.

8" - 1.3499 M.W.

Figure 1

- (1) SEE ATTACHMENT HIL 1 FOR HANGER DATA.
 (2) SEE ATTACHMENT NO. 2 FOR TRIM DATA 1-4
 (3) DIMENSIONS ARE APPROXIMATE ELEVATIONS TAKEN FROM DRAWINGS.

WELD LOCATIONS

- ① HEADER OUTLET WELD.
- ② THREE WELDS AT WYE BLOCK.
- ③ STOP VALVE INLET WELD.
- ④ HANGER LUG WELDS.
- ⑤ HANGER LUG WELDS.

FITTINGS ASTM 369FP-22

PIPE 14" O.D. A335-P22 SEAMLESS

REHEAT VALVE WEIGHTS - 7000 EA.

INTERCEPT VALVE WEIGHTS - 15,190 EA. EA.

Figure 2

Existing Design

Replacement Design

DRW1.3.DRW

Figure 3

Section 1.6

**Cold Reheat and Extraction Piping
Executive Summary**

Cold Reheat and Extraction Piping

Executive Summary

In addition to the high temperature (main steam and hot reheat) piping system evaluations, walkdowns of the cold reheat and extraction piping were performed to assess the general condition of the hanger supports and note any other anomalies.

A summary of cold walkdown information for the cold reheat piping is provided in the attached table. All hangers appeared to be functioning normally within their travel range. At some locations, parts of the piping insulation were observed to be missing. These areas should be reinsulated to prevent corrosion, heat loss and thermal stresses. Additionally, the clamp/bolt design on the vertical pipe supports were observed to be the same as the hot reheat piping where inelastic deformation was observed. It is therefore recommended that the two rigid supports be checked for clamp/bolt deformation and repaired or replaced as necessary.

A total of 5 extraction line supports were inspected in the cold condition; four lines from the IP turbine and one from the cold reheat line. All hangers were observed to be functioning normally and no adjustments were necessary at the current time.

CHANDRAPURA UNIT 2 COLD REHEAT PIPING

Pipe Supports (Inspected 7/27/94)

Sub Component	Damage Found	Damage Assessment (DA)/ Recommendation (R)
CRH-1: Constant support hanger near header outlet	Hanger almost bottomed out in the cold position (2mm between pin and stop). Cold mark=10 (L)	DA: Bottomed out condition is not severe (2mm gap to stop). R: Readjust cold position of hanger to 8.0. Record hot hanger position after readjustment to ensure that hanger is not topped out.
CRH-2: Vertical restraint near header outlet	(i) Pipe insulation missing near hanger clamp, leaving pipe exposed. (ii) Hanger clamp/bolt design could be subject to overload deformation.	DA: Pipe exposure; possible corrosion, thermal stresses, and heat loss. R: Re-insulate with silica and mineral wool prior to startup. DA: Clamp/bolt design is poor; may result in overload deformation of the bolt. R: Long term: Replace with newer design proposed for HRH rigid hangers if excessive deformation is observed.
CRH-7: Vertical rigid support near turbine.	Hanger clamp/bolt design could be subject to overload deformation.	DA: Clamp/bolt design is poor; may result in overload deformation of the bolt. R: Long term: Replace with newer design proposed for HRH rigid hangers if excessive deformation is observed.

Note: (1) All hanger adjustments are to be made after hanger clamp/bolt modifications.

- (2) If the rigid hanger CRH-7 clamp is to be replaced care must be taken to adequately support the piping system prior to any attempts to make this modification. Only pinning the hanger above and below CRH-7 is not advised because they cannot support the high load of CRH-7 (approximately 18,000 and 25,000 lbs). It is suggested that the horizontal section of pipe below CRH-7 be supported from below with a jack having a load capacity of at least 25,000 lbs.

CHANDRAPURA UNIT 2 EXTRACTION PIPING
Pipe Supports (Inspected 8/5/94, 8/6/94)

Sub Component	Damage Found	Damage Assessment (DA)/ Recommendation (R)
Extraction lines: 3,4,5 and 6 from the IP turbine, and, 7 from the HP outlet (cold reheat)	All hangers were observed to be functioning normally within their travel range.	DA: none R: ----

Section 1.7

Boiler Tubing

Secondary Superheater

1.7.1

Oxide Scale Measurements

During the outage, the secondary superheater was measured for oxide scale. The measurements revealed that the thickest oxide scale thickness was 0.0129 inches. Based on the thickness of the scale and the operating history of this unit, the average calculated operating temperature of this component is 1010~1015 degrees F in the gas pass with a peak tube temperature of 1041 degrees F. The measured main steam temperature is 1000 degrees F or less due to the reduced power output from the unit. The results of the measured data from the LifeCode analysis are in the pages that follow. The analysis shows that the condition of this component is sufficient to operate another 20 years.

Input File Name: DVCSHP.KB1

***** Plant Information *****

Utility: DVC
Plant: Chandrapura
Location: Chandrapura, Bihar
Unit: Number 2
Test Date: 10-Aug-94
Operating Hours: 181000.0000
LAC Corrosion Temp: 3000.0000
Superheater Pressure: 2000.0000
Reheater Pressure: 464.0000
Superheater Heat Flux: 18000.0000
Reheater Heat Flux: 8000.0000
Tube Temp. Est. Technique: LABORELEC
Oxide, Insulating Value: 1.0000
User Comments: no comments at this time

***** Tube Information *****

Component: SUPERHEATER
Elevation: 200.0000
Material: T22
Orig. Tube Diameter: 2.1250
Orig. Tube Wall Thickness: 0.4700
Tube Number: 1
Pendant Number: 1

***** Tube/Oxide Characterization Parameters *****

Metal Velocity: 0.2350
Oxide Velocity: 0.2350
Filter Type: NONE
Low Cutoff Frequency: 0.0000
High Cutoff Frequency: 20.0000
Min. Detection Thresh. (%): 23.0000
Min. Detection Duration: 0.0050
Min. Detection Separation: 0.0050

put File Name: DVCSHP.KB1

***** Tube/Oxide Characterization and Remaining Life Results *****

Tube No.	Pend No.	Wvfm No.	Elev.	Man. Flag	Wall Thk.	Oxide Thk. Type	Tube Temp	Rem Life Low Avg	Layer No. Thk.
1	1	1	200.00	*	0.4618	0.0082 2	977	320000 320000	1 0.0082
1	2	2	200.00	*	0.4665	0.0112 2	1020	320000 320000	1 0.0112
1	3	3	200.00	*	0.4653	0.0100 2	1004	320000 320000	1 0.0100
1	3	4	200.00	*	0.4635	0.0106 2	1012	320000 320000	1 0.0106
1	4	5	200.00	*	0.4594	0.0094 2	996	320000 320000	1 0.0094
1	5	6	200.00	*	0.4671	0.0112 2	1020	320000 320000	1 0.0112
1	5	7	200.00	*	0.4682	0.0106 2	1012	320000 320000	1 0.0106
1	10	8	200.00	*	0.4571	0.0106 2	1012	320000 320000	1 0.0106
1	10	9	200.00	*	0.4577	0.0106 2	1012	320000 320000	1 0.0106
1	15	10	200.00	*	0.4629	0.0100 2	1004	320000 320000	1 0.0100
1	15	11	200.00	*	0.4624	0.0106 2	1012	320000 320000	1 0.0106
1	20	12	200.00	*	0.4600	0.0112 2	1020	320000 320000	1 0.0112
1	20	13	200.00	*	0.4688	0.0129 2	1041	320000 320000	1 0.0129
1	25	14	200.00	*	0.4618	0.0123 2	1034	320000 320000	1 0.0123
1	30	15	200.00	*	0.4771	0.0112 2	1020	320000 320000	1 0.0112
1	30	16	200.00	*	0.4776	0.0117 2	1027	320000 320000	1 0.0117
1	33	17	200.00	*	0.4747	0.0112 2	1020	320000 320000	1 0.0112
1	34	18	200.00	*	0.4712	0.0106 2	1012	320000 320000	1 0.0106
1	35	19	200.00	*	0.4635	0.0117 2	1027	320000 320000	1 0.0117
1	35	20	200.00	*	0.4647	0.0112 2	1020	320000 320000	1 0.0112
1	36	21	200.00	*	0.4712	0.0117 2	1027	320000 320000	1 0.0117
1	37	22	200.00	*	0.4618	0.0100 2	1004	320000 320000	1 0.0100

SSH PENDANT WALL & OXIDE THICKNESS

Plot of measured wall and oxide thicknesses for tubes in the secondary superheater pendant (File: DVCSHP).

SSH PENDANT TEMPERATURE

Plot of calculated tube temperature for the secondary superheater outlet pendant tubes (File: DVCSHP).

Reheater

1.7.2

Oxide Scale Measurements

The reheater tubes were inspected for oxide scale during the Chandrapura Unit 2 outage. Thicknesses were measured with the thickest oxide scale being 0.0094 inches. Based on the thickness of the scale and the operating history of this unit, the average calculated operating temperature of this component is approximately 980 degrees F with a peak temperature of 996 degrees F. The typical measured reheat temperature is 950 degrees F. Based on the LifeCode analysis in the pages which follow, the reheater condition is sufficient to operate another 20 years.

- T-22
- T-11
- T-1
- SA-192

TENNESSEE VALLEY AUTHORITY PLANT BOILER EQUIPMENT	
CHANDRAPURA	
REHEAT PENDANT INLET SECTION	
J ²	DATE: JUNE 7, 1994 INDIA 4

TENNESSEE VALLEY AUTHORITY PLANT BOILER EQUIPMENT		
<i>CHANDRAPURA</i>		
REHEAT PENDANT INTERMEDIATE SECTION		
J ²	N. T. S.	INDIA 5
	DATE: JUNE 7, 1994

TENNESSEE VALLEY AUTHORITY BOILER ASSESSMENT & UPGRADE		
CHANDRAPURA REHEAT PENDANT OUTLET SECTION		
J ²	NTS DATE: JUNE 1, 1994	INDIA 6

Input File Name: DVCRHP.KB1

***** Plant Information *****

Utility: DVC
Plant: Chandrapura
Location: Chandrapura, Bihar
Unit: Number 2
Test Date: 11-Aug-94
Operating Hours: 181000.0000
LAC Corrosion Temp: 3000.0000
Superheater Pressure: 2000.0000
Reheater Pressure: 464.0000
Superheater Heat Flux: 18000.0000
Reheater Heat Flux: 8000.0000
Tube Temp. Est. Technique: LABORELEC
Oxide Insulating Value: 1.0000
User Comments: no comments at this time

***** Tube Information *****

Component: REHEATER
Elevation: 200.0000
Material: T22
Orig. Tube Diameter: 2.0000
Orig. Tube Wall Thickness: 0.2800
Tube Number: 1
Pendant Number: 1

***** Tube/Oxide Characterization Parameters *****

Metal Velocity: 0.2350
Oxide Velocity: 0.2350
Filter Type: NONE
Low Cutoff Frequency: 0.0000
High Cutoff Frequency: 20.0000
Min. Detection Thresh. (%): 10.0000
Min. Detection Duration: 0.0050
Min. Detection Separation: 0.0050

t File Name: DVCRHP.KB1

***** Tube/Oxide Characterization and Remaining Life Results *****

Tube No.	Pend No.	Wvfm No.	Elev.	Man. Flag	Wall Thk.	Oxide Thk.	Type	Tube Temp	Rem Life Low	Rem Life Avg	Layer No.	Thk.
1	75	1	200.00	*	0.2420	0.0071	2	957	320000	320000	1	0.007
1	74	2	200.00	*	0.2603	0.0088	2	987	320000	320000	1	0.008
1	73	3	200.00	*	0.2738	0.0082	2	977	320000	320000	1	0.008
1	72	4	200.00	*	0.2738	0.0088	2	987	320000	320000	1	0.008
1	71	5	200.00	*	0.2691	0.0088	2	987	320000	320000	1	0.008
1	70	6	200.00	*	0.2808	0.0088	2	987	320000	320000	1	0.008
1	65	7	200.00	*	0.2761	0.0071	2	957	320000	320000	1	0.007
1	65	8	200.00	*	0.2708	0.0082	2	977	320000	320000	1	0.008
1	55	9	200.00	*	0.2544	0.0094	2	996	320000	320000	1	0.009
1	45	10	200.00	*	0.2620	0.0065	2	945	320000	320000	1	0.006
1	35	11	200.00	*	0.2608	0.0076	2	967	320000	320000	1	0.007
1	35	12	200.00	*	0.2544	0.0071	2	957	320000	320000	1	0.007
1	25	13	200.00	*	0.2785	0.0071	2	957	320000	320000	1	0.007
1	15	15	200.00	*	0.2532	0.0082	2	977	320000	320000	1	0.008
1	5	17	200.00	*	0.2908	0.0088	2	987	320000	320000	1	0.008
1	4	18	200.00	*	0.2520	0.0082	2	977	320000	320000	1	0.008
1	4	19	200.00	*	0.2538	0.0082	2	977	320000	320000	1	0.008
1	3	20	200.00	*	0.2849	0.0076	2	967	320000	320000	1	0.007
1	2	21	200.00	*	0.2844	0.0076	2	967	320000	320000	1	0.007
1	2	22	200.00	*	0.2603	0.0071	2	957	320000	320000	1	0.007
1	2	23	200.00	*	0.2785	0.0071	2	957	320000	320000	1	0.007
1	1	24	200.00	*	0.2791	0.0082	2	977	320000	320000	1	0.008
1	1	25	200.00	*	0.2802	0.0076	2	967	320000	320000	1	0.007

RH PENDANT TUBE WALL & OXIDE THICKNESS

Plot of measured wall and oxide thicknesses for the reheater outlet pendant (File: DVC RHP).

RH PENDANT TUBE TEMPERATURE

Plot of calculated tube temperature for the reheat outlet pendant (File:DVCRRHP).

ut File Name: DVCRHBT.KB1

***** Plant Information *****

Utility: DVC
Plant: Chandrapura
Location: Chandrapura, Bihar
Unit: Number 2
Test Date: 12-Aug-94
Operating Hours: 181000.0000
LAC Corrosion Temp: 3000.0000
Superheater Pressure: 2000.0000
Reheater Pressure: 464.0000
Superheater Heat Flux: 18000.0000
Reheater Heat Flux: 8000.0000
Tube Temp. Est. Technique: LABORELEC
Oxide Insulating Value: 1.0000
User Comments: no comments at this time

***** Tube Information *****

Component: REHEATER
Elevation: 200.0000
Material: T22
Orig. Tube Diameter: 2.1250
g. Tube Wall Thickness: 0.2000
Tube Number: 1
Pendant Number: 1

***** Tube/Oxide Characterization Parameters *****

Metal Velocity: 0.2350
Oxide Velocity: 0.2350
Filter Type: NONE
Low Cutoff Frequency: 0.0000
High Cutoff Frequency: 20.0000
Min. Detection Thresh. (%): 10.0000
Min. Detection Duration: 0.0050
Min. Detection Separation: 0.0050

ut File Name: DVCRHBT.KB1

***** Tube/Oxide Characterization and Remaining Life Results *****

Tube No.	Pend No.	Wvfm No.	Elev.	Man. Flag	Wall Thk.	Oxide Thk.	Type	Tube Temp	Rem Low	Life Avg	Layer No.	Thk.
1	75	2	200.00	*	0.2385	0.0082	2	977	320000	320000	1	0.0082
1	74	3	200.00	*	0.2585	0.0088	2	987	320000	320000	1	0.0088
1	73	4	200.00	*	0.2385	0.0082	2	977	320000	320000	1	0.0082
1	72	5	200.00	*	0.2426	0.0094	2	996	320000	320000	1	0.0094
1	71	6	200.00	*	0.2479	0.0082	2	977	320000	320000	1	0.0082
1	70	7	200.00	*	0.2626	0.0076	2	967	320000	320000	1	0.0076
1	65	8	200.00	*	0.2244	0.0082	2	977	320000	320000	1	0.0082
1	55	9	200.00	*	0.2356	0.0088	2	987	320000	320000	1	0.0088
1	45	10	200.00	*	0.2397	0.0082	2	977	320000	320000	1	0.0082
1	35	11	200.00	*	0.2515	0.0082	2	977	320000	320000	1	0.0082
1	25	12	200.00	*	0.2779	0.0082	2	977	320000	320000	1	0.0082
1	15	13	200.00	*	0.2227	0.0082	2	977	320000	320000	1	0.0082
1	5	15	200.00	*	0.2779	0.0082	2	977	320000	320000	1	0.0082
1	4	16	200.00	*	0.2432	0.0088	2	987	320000	320000	1	0.0088
1	3	17	200.00	*	0.2479	0.0082	2	977	320000	320000	1	0.0082
1	2	18	200.00	*	0.2326	0.0082	2	977	320000	320000	1	0.0082
1	1	19	200.00	*	0.2279	0.0076	2	967	320000	320000	1	0.0076

BOTTOM RH OUTLET TUBE TEMPERATURE

Horizontal Primary Superheater

1.7.3

Oxide Scale Measurements

During the Chandrapura Unit 2 outage, oxide scale measurements were taken of the horizontal primary superheater. Measurements of the header stubs yielded thicknesses of up to 0.0200 inches. Based on the operating history of this unit, the average calculated operating temperature of the tubes in the primary superheater is above 1000 degrees F. Additional oxide scale measurements, across the furnace on the outlet legs and across all tubes in 2 outlet elements, confirm high operating temperatures. The most critical tubing appears to be the T-11 stub tubes at the headers and the T-1 tubes midway of the horizontal primary superheater. Depending on the correlation used to convert oxide scale thickness to temperature (APTGCA or LABORLEC), the finishing passes of T-22 may also be in jeopardy based on predictions using the LABORELEC predictions. Because the primary superheater delivers steam above the desired temperature, the inlet to the secondary superheater is attemperated 100% of the time during operation. In order to operate for 20 years, the primary superheater overheating will have to be eliminated. The LifeCode analysis can be seen in the following pages.

2-1/8" O.D. X 0.240" MWT
T-11

PSH OUTLET

2-1/8" O.D. X 0.240" MWT
T-11

TENNESSEE VALLEY AUTHORITY
PLANT BOILER EQUIPMENT

CHANDRAPURA

PRIMARY SUPERHEATER

J² N.T.S. INDIA 1
DATE: JUNE 1, 1994

Input File Name: DVCPLT.KB1

***** Plant Information *****

Utility: DVC
Plant: Chandrapura
Location: Chandrapura, Bihar
Unit: Number 2
Test Date: 10-Aug-94
Operating Hours: 181000.0000
LAC Corrosion Temp: 3000.0000
Superheater Pressure: 2000.0000
Reheater Pressure: 464.0000
Superheater Heat Flux: 18000.0000
Reheater Heat Flux: 8000.0000
Tube Temp. Est. Technique: LABORELEC
Oxide Insulating Value: 1.0000
User Comments: no comments at this time

***** Tube Information *****

Component: SUPERHEATER
Elevation: 200.0000
Material: T22
Orig. Tube Diameter: 2.1250
Orig. Tube Wall Thickness: 0.4000
Tube Number: 1
Pendant Number: 3

***** Tube/Oxide Characterization Parameters *****

Metal Velocity: 0.2350
Oxide Velocity: 0.2350
Filter Type: NONE
Low Cutoff Frequency: 0.0000
High Cutoff Frequency: 20.0000
Min. Detection Thresh. (%): 10.0000
Min. Detection Duration: 0.0050
Min. Detection Separation: 0.0050

ut File Name: DVCPLT.KB1

***** Tube/Oxide Characterization and Remaining Life Results *****

Tube No.	Pend No.	Wvfm No.	Elev.	Man. Flag	Wall Thk.	Oxide Thk.	Type	Tube Temp	Rem Life Low	Avg	Layer No.	Thk.
1	3	2	200.00	*	0.3731	0.0129	2	1041	320000	320000	1	0.0129
2	3	3	200.00	*	0.3825	0.0117	2	1027	320000	320000	1	0.0117
3	3	5	200.00	*	0.3643	0.0106	2	1012	320000	320000	1	0.0106
4	3	6	200.00	*	0.3795	0.0094	2	996	320000	320000	1	0.0094
5	3	7	200.00	*	0.4165	0.0088	2	987	320000	320000	1	0.0088

Input File Name: DVCPLT.KB1

***** Plant Information *****

Utility: DVC
Plant: Chandrapura
Location: Chandrapura, Bihar
Unit: Number 2
Test Date: 10-Aug-94
Operating Hours: 181000.0000
LAC Corrosion Temp: 3000.0000
Superheater Pressure: 2000.0000
Reheater Pressure: 464.0000
Superheater Heat Flux: 18000.0000
Reheater Heat Flux: 8000.0000
Tube Temp. Est. Technique: LABORELEC
Oxide Insulating Value: 1.0000
User Comments: no comments at this time

***** Tube Information *****

Component: SUPERHEATER
Elevation: 200.0000
Material: T11
Orig. Tube Diameter: 2.1250
Orig. Tube Wall Thickness: 0.4000
Tube Number: 1
Pendant Number: 3

***** Tube/Oxide Characterization Parameters *****

Metal Velocity: 0.2350
Oxide Velocity: 0.2350
Filter Type: NONE
Low Cutoff Frequency: 0.0000
High Cutoff Frequency: 20.0000
Min. Detection Thresh. (%): 10.0000
Min. Detection Duration: 0.0050
Min. Detection Separation: 0.0050

Input File Name: DVCPLT.KB1

***** Tube/Oxide Characterization and Remaining Life Results *****

Tube No.	Pend No.	Wvfm No.	Elev.	Man. Flag	Wall Thk.	Oxide Thk. Type	Tube Temp	Rem Life Low Avg	Layer No.	Thk.
6	3	9	200.00	*	0.3249	0.0100 2	965	320000 320000	1	0.0100
7	3	10	200.00	*	0.3096	0.0082 2	939	320000 320000	1	0.0082
8	3	11	200.00	*	0.3261	0.0088 2	948	320000 320000	1	0.0088
9	3	12	200.00	*	0.2891	0.0094 2	957	263000 320000	1	0.0094
10	3	13	200.00	*	0.3384	0.0100 2	965	320000 320000	1	0.0100
11	3	14	200.00	*	0.3308	0.0094 2	957	320000 320000	1	0.0094
12	3	15	200.00	*	0.3266	0.0123 2	993	320000 320000	1	0.0123
13	3	16	200.00	*	0.3272	0.0117 2	987	320000 320000	1	0.0117
14	3	17	200.00	*	0.3284	0.0117 2	987	320000 320000	1	0.0117
15	3	18	200.00	*	0.3249	0.0112 2	980	290000 320000	1	0.0112

Input File Name: DVCPLT.KB1

***** Plant Information *****

Utility: DVC
Plant: Chandrapura
Location: Chandrapura, Bihar
Unit: Number 2
Test Date: 10-Aug-94
Operating Hours: 181000.0000
LAC Corrosion Temp: 3000.0000
Superheater Pressure: 2000.0000
Reheater Pressure: 464.0000
Superheater Heat Flux: 18000.0000
Reheater Heat Flux: 8000.0000
Tube Temp. Est. Technique: LABORELEC
Oxide Insulating Value: 1.0000
User Comments: no comments at this time

***** Tube Information *****

Component: SUPERHEATER
Elevation: 200.0000
Material: T1
Orig. Tube Diameter: 2.1250
Orig. Tube Wall Thickness: 0.4000
Tube Number: 1
Pendant Number: 3

***** Tube/Oxide Characterization Parameters *****

Metal Velocity: 0.2350
Oxide Velocity: 0.2350
Filter Type: NONE
Low Cutoff Frequency: 0.0000
High Cutoff Frequency: 20.0000
Min. Detection Thresh. (%): 10.0000
Min. Detection Duration: 0.0050
Min. Detection Separation: 0.0050

LifeCode

Page 2
08/10/94

Put File Name: DVCPLT.KB1

***** Tube/Oxide Characterization and Remaining Life Results *****

Tube No.	Pend No.	Wvfm No.	Elev.	Man. Flag	Wall Thk.	Oxide Thk. Type	Tube Temp	Rem Life Low Avg	Layer No. Thk.
16	3	19	200.00	*	0.2321	0.0100 2	965	245000 248000	1 0.0100
17	3	20	200.00	*	0.2297	0.0100 2	965	242000 242000	1 0.0100
18	3	21	200.00	*	0.2374	0.0100 2	965	257000 263000	1 0.0100
19	3	22	200.00	*	0.2374	0.0094 2	957	263000 263000	1 0.0094
20	3	23	200.00	*	0.2638	0.0094 2	957	320000 320000	1 0.0094

PSH HORIZONTAL PLATEN 3 TEMPERATURE

Plot of calculated tube temperature for PSH horizontal platen 3 (File name:DVCPLT).

Input File Name: DVCPSH.KB1

***** Plant Information *****

Utility: DVC
Plant: CHANDRAPURA
Location: CHANDRAPURA, BIHAR
Unit: Number 2
Test Date: 08-Aug-94
Operating Hours: 181000.0000
LAC Corrosion Temp: 3000.0000
Superheater Pressure: 2000.0000
Reheater Pressure: 464.0000
Superheater Heat Flux: 18000.0000
Reheater Heat Flux: 8000.0000
Tube Temp. Est. Technique: LABORELEC
Oxide Insulating Value: 1.0000
User Comments: no comments at this time

***** Tube Information *****

Component: SUPERHEATER
Elevation: 200.0000
Material: T22
Orig. Tube Diameter: 2.1250
Orig. Tube Wall Thickness: 0.4000
Tube Number: 1
Pendant Number: 62

***** Tube/Oxide Characterization Parameters *****

Metal Velocity: 0.2350
Oxide Velocity: 0.2350
Filter Type: NONE
Low Cutoff Frequency: 10.0000
High Cutoff Frequency: 50.0000
Min. Detection Thresh. (%): 10.0000
Min. Detection Duration: 0.0050
Min. Detection Separation: 0.0050

put File Name: DVCPSH.KB1

***** Tube/Oxide Characterization and Remaining Life Results *****

Tube No.	Pend No.	Wvfm No.	Elev.	Man. Flag	Wall Thk.	Oxide Thk.	Type	Tube Temp	Rem Life Low	Rem Life Avg	Layer No.	Thk.
5	62	19	200.00	*	0.4107	0.0112	2	1020	320000	320000	1	0.0112
4	62	20	200.00	*	0.3825	0.0112	2	1020	320000	320000	1	0.0112
3	62	21	200.00	*	0.3919	0.0123	2	1034	320000	320000	1	0.0123
2	62	22	200.00	*	0.4171	0.0129	2	1041	320000	320000	1	0.0129
1	62	23	200.00	*	0.3989	0.0147	2	1060	320000	320000	1	0.0147

Input File Name: DVCPSH.KB1

***** Plant Information *****

Utility: DVC
Plant: CHANDRAPURA
Location: CHANDRAPURA, BIHAR
Unit: Number 2
Test Date: 08-Aug-94
Operating Hours: 181000.0000
LAC Corrosion Temp: 3000.0000
Superheater Pressure: 2000.0000
Reheater Pressure: 464.0000
Superheater Heat Flux: 18000.0000
Reheater Heat Flux: 8000.0000
Tube Temp. Est. Technique: LABORELEC
Oxide Insulating Value: 1.0000
User Comments: no comments at this time

***** Tube Information *****

Component: SUPERHEATER
Elevation: 200.0000
Material: T11
Orig. Tube Diameter: 2.1250
Orig. Tube Wall Thickness: 0.4000
Tube Number: 1
Pendant Number: 62

***** Tube/Oxide Characterization Parameters *****

Metal Velocity: 0.2350
Oxide Velocity: 0.2350
Filter Type: NONE
Low Cutoff Frequency: 10.0000
High Cutoff Frequency: 50.0000
Min. Detection Thresh. (%): 10.0000
Min. Detection Duration: 0.0050
Min. Detection Separation: 0.0050

out File Name: DVCPSH.KB1

***** Tube/Oxide Characterization and Remaining Life Results *****

Tube No.	Pend No.	Wvfm No.	Elev.	Man. Flag	Wall Thk.	Oxide Thk.	Type	Tube Temp	Rem Life Low	Avg	Layer No.	Thk.
15	62	1	200.00	*	0.3449	0.0100	2	965	320000	320000	1	0.0100
14	62	9	200.00	*	0.3378	0.0112	2	980	320000	320000	1	0.0112
13	62	11	200.00	*	0.3378	0.0123	2	993	320000	320000	1	0.0123
12	62	12	200.00	*	0.3455	0.0123	2	993	320000	320000	1	0.0123
11	62	13	200.00	*	0.3402	0.0117	2	987	320000	320000	1	0.0117
10	62	14	200.00	*	0.3443	0.0117	2	987	320000	320000	1	0.0117
9	62	15	200.00	*	0.3266	0.0123	2	993	290000	320000	1	0.0123
8	62	16	200.00	*	0.3490	0.0088	2	948	320000	320000	1	0.0088
7	62	17	200.00	*	0.3425	0.0094	2	957	320000	320000	1	0.0094
6	62	18	200.00	*	0.3284	0.0129	2	1000	278000	320000	1	0.0129

Input File Name: DVCPSH.KB1

***** Plant Information *****

Utility: DVC
Plant: CHANDRAPURA
Location: CHANDRAPURA, BIHAR
Unit: Number 2
Test Date: 08-Aug-94
Operating Hours: 181000.0000
LAC Corrosion Temp: 3000.0000
Superheater Pressure: 2000.0000
Reheater Pressure: 464.0000
Superheater Heat Flux: 18000.0000
Reheater Heat Flux: 8000.0000
Tube Temp. Est. Technique: LABORELEC
Oxide Insulating Value: 1.0000
User Comments: no comments at this time

***** Tube Information *****

Component: SUPERHEATER
Elevation: 200.0000
Material: T1
Orig. Tube Diameter: 2.1250
Orig. Tube Wall Thickness: 0.4000
Tube Number: 1
Pendant Number: 62

***** Tube/Oxide Characterization Parameters *****

Metal Velocity: 0.2350
Oxide Velocity: 0.2350
Filter Type: NONE
Low Cutoff Frequency: 10.0000
High Cutoff Frequency: 50.0000
Min. Detection Thresh. (%): 10.0000
Min. Detection Duration: 0.0050
Min. Detection Separation: 0.0050

put File Name: DVCPSH.KB1

***** Tube/Oxide Characterization and Remaining Life Results *****

Tube No.	Pend No.	Wvfm No.	Elev.	Man. Flag	Wall Thk.	Oxide Thk.	Type	Tube Temp	Rem Life Low	Avg	Layer No.	Thk.
16	62	3	200.00	*	0.2374	0.0129	2	1000	92000	137000	1	0.012
17	62	4	200.00	*	0.2467	0.0100	2	965	155000	200000	1	0.010
18	62	5	200.00	*	0.2526	0.0106	2	972	155000	200000	1	0.010
19	62	6	200.00	*	0.2444	0.0112	2	980	131000	173000	1	0.011
20	62	8	200.00	*	0.2767	0.0094	2	957	230000	281000	1	0.009

PSH HORIZONTAL PLATEN 62 TEMPERATURE

Plot of calculated tube temperature for PSH horizontal platen 62 (File:PSHPLT).

Input File Name: PSHVER.KB1

***** Plant Information *****

Utility: DVC
Plant: Chandrapura
Location: Chandrapura, Bihar
Unit: Number 2
Test Date: 10-Aug-94
Operating Hours: 181000.0000
LAC Corrosion Temp: 3000.0000
Superheater Pressure: 2000.0000
Reheater Pressure: 464.0000
Superheater Heat Flux: 18000.0000
Reheater Heat Flux: 8000.0000
Tube Temp. Est. Technique: LABORELEC
Oxide Insulating Value: 1.0000
User Comments: no comments at this time

***** Tube Information *****

Component: SUPERHEATER
Elevation: 200.0000
Material: T22
Orig. Tube Diameter: 2.1250
Orig. Tube Wall Thickness: 0.4000
Tube Number: B
Pendant Number: 1

***** Tube/Oxide Characterization Parameters *****

Metal Velocity: 0.2350
Oxide Velocity: 0.2350
Filter Type: NONE
Low Cutoff Frequency: 0.0000
High Cutoff Frequency: 20.0000
Min. Detection Thresh. (%): 10.0000
Min. Detection Duration: 0.0050
Min. Detection Separation: 0.0050

LifeCode

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out File Name: PSHVER.KB1

***** Tube/Oxide Characterization and Remaining Life Results *****

Tube No.	Pend No.	Wvfm No.	Elev.	Man. Flag	Wall Thk.	Oxide Thk.	Type	Tube Temp	Rem Life Low	Rem Life Avg	Layer No.	Thk.
B	75	2	200.00	*	0.3795	0.0129	2	1041	320000	320000	1	0.012
B	71	3	200.00	*	0.3783	0.0123	2	1034	320000	320000	1	0.012
B	69	4	200.00	*	0.3860	0.0147	2	1060	287000	320000	1	0.014
B	67	5	200.00	*	0.3830	0.0135	2	1048	320000	320000	1	0.012
B	65	6	200.00	*	0.3989	0.0123	2	1034	320000	320000	1	0.012
B	57	9	200.00	*	0.3907	0.0129	2	1041	320000	320000	1	0.012
B	55	10	200.00	*	0.3930	0.0141	2	1054	320000	320000	1	0.014
B	53	11	200.00	*	0.3825	0.0153	2	1066	245000	320000	1	0.015
B	51	12	200.00	*	0.3936	0.0129	2	1041	320000	320000	1	0.012
B	47	13	200.00	*	0.3895	0.0117	2	1027	320000	320000	1	0.011
B	43	15	200.00	*	0.3866	0.0129	2	1041	320000	320000	1	0.012
B	41	16	200.00	*	0.3736	0.0123	2	1034	320000	320000	1	0.012
B	39	17	200.00	*	0.3801	0.0129	2	1041	320000	320000	1	0.012
B	37	18	200.00	*	0.3813	0.0112	2	1020	320000	320000	1	0.011
B	35	21	200.00	*	0.3877	0.0141	2	1054	320000	320000	1	0.014
B	33	22	200.00	*	0.4018	0.0117	2	1027	320000	320000	1	0.011
B	29	23	200.00	*	0.3860	0.0129	2	1041	320000	320000	1	0.012
B	25	24	200.00	*	0.3954	0.0106	2	1012	320000	320000	1	0.010
B	23	25	200.00	*	0.3807	0.0117	2	1027	320000	320000	1	0.011
B	21	26	200.00	*	0.3819	0.0117	2	1027	320000	320000	1	0.011
B	19	27	200.00	*	0.3613	0.0094	2	996	320000	320000	1	0.009
B	15	28	200.00	*	0.3883	0.0141	2	1054	320000	320000	1	0.014
B	11	29	200.00	*	0.3789	0.0106	2	1012	320000	320000	1	0.010
B	9	30	200.00	*	0.3819	0.0129	2	1041	320000	320000	1	0.012
B	7	31	200.00	*	0.3731	0.0123	2	1034	320000	320000	1	0.012
B	5	32	200.00	*	0.3872	0.0141	2	1054	320000	320000	1	0.014
B	1	33	200.00	*	0.3883	0.0129	2	1041	320000	320000	1	0.012

TUBE B - PSH

Plot of wall and oxide thickness for PSH vertical tubes below roof tubes (File: PSHVER).

TUBE B - PSH TEMPERATURE

Plot of calculated tube temperature for PSH vertical tubes below roof tubes (File: PSHVER)

Input File Name: CHANDPSH.KB1

***** Plant Information *****

Utility: DVC
Plant: CHANDRAPURA
Location: CHANDRAPURA
Unit: Number 2
Test Date: 04-Aug-94
Operating Hours: 181000.0000
LAC Corrosion Temp: 3000.0000
Superheater Pressure: 2000.0000
Reheater Pressure: 464.0000
Superheater Heat Flux: 18000.0000
Reheater Heat Flux: 8000.0000
Tube Temp. Est. Technique: APTECH
Oxide Insulating Value: 1.0000
User Comments: no comments at this time

***** Tube Information *****

Component: SUPERHEATER
Elevation: 200.0000
Material: T22
Orig. Tube Diameter: 2.2250
Orig. Tube Wall Thickness: 0.3502
Tube Number: D
Pendant Number: 75

***** Tube/Oxide Characterization Parameters *****

Metal Velocity: 0.2350
Oxide Velocity: 0.2350
Filter Type: NONE
Low Cutoff Frequency: 0.0000
High Cutoff Frequency: 20.0000
Min. Detection Thresh. (%): 17.0000
Min. Detection Duration: 0.0050
Min. Detection Separation: 0.0050

LifeCode

APTECH OXIDE CORRELATION

08/04/94

t File Name: CHANDPSH.KB1

***** Tube/Oxide Characterization and Remaining Life Results *****

Tube No.	Pend No.	Wvfm No.	Elev.	Man. Flag	Wall Thk.	Oxide Thk.	Type	Tube Temp	Rem Low	Life Avg	Layer No.	Thk.
D	75	1	200.00	*	0.4171	0.0141	2	1034	320000	320000	1	0.0141
D	74	2	200.00	*	0.4160	0.0129	2	1027	320000	320000	1	0.0129
D	73	3	200.00	*	0.3954	0.0159	2	1043	320000	320000	1	0.0159
D	72	4	200.00	*	0.4042	0.0112	2	1015	320000	320000	1	0.0112
D	71	5	200.00	*	0.3966	0.0117	2	1019	320000	320000	1	0.0117
D	70	6	200.00	*	0.4201	0.0159	2	1043	320000	320000	1	0.0159
D	69	7	200.00	*	0.4112	0.0159	2	1043	320000	320000	1	0.0159
D	68	8	200.00	*	0.3848	0.0123	2	1023	320000	320000	1	0.0123
D	67	9	200.00	*	0.4171	0.0147	2	1037	320000	320000	1	0.0147
D	66	10	200.00	*	0.3936	0.0141	2	1034	320000	320000	1	0.0141
D	65	11	200.00	*	0.4048	0.0129	2	1027	320000	320000	1	0.0129
D	65	12	200.00	*	0.3948	0.0135	2	1030	320000	320000	1	0.0135
D	64	13	200.00	*	0.4565	0.0088	2	996	320000	320000	1	0.0088
D	64	14	200.00	*	0.4676	0.0147	2	1037	320000	320000	1	0.0147
D	64	15	200.00	*	0.4665	0.0153	2	1040	320000	320000	1	0.0153
D	64	16	200.00	*	0.4671	0.0153	2	1040	320000	320000	1	0.0153
D	63	17	200.00	*	0.4671	0.0153	2	1040	320000	320000	1	0.0153
D	63	18	200.00	*	0.4201	0.0182	2	1055	320000	320000	1	0.0182
D	62	19	200.00	*	0.4177	0.0176	2	1052	320000	320000	1	0.0176
D	61	20	200.00	*	0.4207	0.0112	2	1015	320000	320000	1	0.0112
D	60	21	200.00	*	0.4065	0.0123	2	1023	320000	320000	1	0.0123
D	59	22	200.00	*	0.4183	0.0088	2	996	320000	320000	1	0.0088
D	58	23	200.00	*	0.4124	0.0094	2	1001	320000	320000	1	0.0094
D	58	24	200.00	*	0.4136	0.0182	2	1055	320000	320000	1	0.0182
D	57	25	200.00	*	0.3178	0.0006	2	776	320000	320000	1	0.0006
D	57	26	200.00	*	0.4101	0.0123	2	1023	320000	320000	1	0.0123
D	56	27	200.00	*	0.4042	0.0141	2	1034	320000	320000	1	0.0141
D	55	28	200.00	*	0.3913	0.0129	2	1027	320000	320000	1	0.0129
D	54	29	200.00	*	0.4283	0.0100	2	1006	320000	320000	1	0.0100
D	53	30	200.00	*	0.4071	0.0100	2	1006	320000	320000	1	0.0100
D	52	31	200.00	*	0.4019	0.0094	2	1001	320000	320000	1	0.0094
D	51	32	200.00	*	0.4142	0.0153	2	1040	320000	320000	1	0.0153
D	50	33	200.00	*	0.4453	0.0176	2	1052	320000	320000	1	0.0176
D	49	34	200.00	*	0.4089	0.0117	2	1019	320000	320000	1	0.0117
D	48	35	200.00	*	0.4136	0.0117	2	1019	320000	320000	1	0.0117
D	47	36	200.00	*	0.4160	0.0112	2	1015	320000	320000	1	0.0112
D	46	37	200.00	*	0.3848	0.0135	2	1030	320000	320000	1	0.0135
D	45	38	200.00	*	0.4753	0.0100	2	1006	320000	320000	1	0.0100
D	45	39	200.00	*	0.4641	0.0123	2	1023	320000	320000	1	0.0123
D	45	40	200.00	*	0.4718	0.0088	2	996	320000	320000	1	0.0088
D	44	41	200.00	*	0.4154	0.0159	2	1043	320000	320000	1	0.0159
D	43	42	200.00	*	0.4347	0.0141	2	1034	320000	320000	1	0.0141
D	42	43	200.00	*	0.4406	0.0129	2	1027	320000	320000	1	0.0129
D	41	44	200.00	*	0.4389	0.0147	2	1037	320000	320000	1	0.0147
D	40	45	200.00	*	0.4136	0.0164	2	1046	320000	320000	1	0.0164
D	39	46	200.00	*	0.4242	0.0141	2	1034	320000	320000	1	0.0141
D	38	47	200.00	*	0.4148	0.0135	2	1030	320000	320000	1	0.0135

APTECH CORRELATION

08/04/94

t File Name: CHANDPSH.KB1

***** Tube/Oxide Characterization and Remaining Life Results *****

Tube No.	Pend No.	Wvfm No.	Elev.	Man. Flag	Wall Thk.	Oxide Thk.	Type	Tube Temp	Rem Life Low	Rem Life Avg	Layer No.	Layer Thk.
D	38	48	200.00	*	0.4112	0.0153	2	1040	320000	320000	1	0.0153
D	37	49	200.00	*	0.4083	0.0100	2	1006	320000	320000	1	0.0100
D	36	50	200.00	*	0.4071	0.0123	2	1023	320000	320000	1	0.0123
D	35	51	200.00	*	0.4019	0.0170	2	1049	320000	320000	1	0.0170
D	34	52	200.00	*	0.4001	0.0141	2	1034	320000	320000	1	0.0141
D	33	53	200.00	*	0.4071	0.0153	2	1040	320000	320000	1	0.0153
D	32	54	200.00	*	0.4130	0.0147	2	1037	320000	320000	1	0.0147
D	31	55	200.00	*	0.4101	0.0170	2	1049	320000	320000	1	0.0170
D	30	56	200.00	*	0.4160	0.0159	2	1043	320000	320000	1	0.0159
D	29	57	200.00	*	0.4207	0.0164	2	1046	320000	320000	1	0.0164
D	28	58	200.00	*	0.4518	0.0164	2	1046	320000	320000	1	0.0164
D	27	59	200.00	*	0.4042	0.0159	2	1043	320000	320000	1	0.0159
D	26	60	200.00	*	0.4060	0.0147	2	1037	320000	320000	1	0.0147
D	25	61	200.00	*	0.4224	0.0117	2	1019	320000	320000	1	0.0117
D	24	62	200.00	*	0.4042	0.0112	2	1015	320000	320000	1	0.0112
D	24	63	200.00	*	0.4001	0.0135	2	1030	320000	320000	1	0.0135
D	23	64	200.00	*	0.4030	0.0106	2	1011	320000	320000	1	0.0106
D	22	65	200.00	*	0.3954	0.0141	2	1034	320000	320000	1	0.0141
D	21	66	200.00	*	0.4295	0.0147	2	1037	320000	320000	1	0.0147
D	20	67	200.00	*	0.4201	0.0153	2	1040	320000	320000	1	0.0153
D	20	68	200.00	*	0.4201	0.0141	2	1034	320000	320000	1	0.0141
D	19	69	200.00	*	0.4013	0.0117	2	1019	320000	320000	1	0.0117
D	19	70	200.00	*	0.4048	0.0141	2	1034	320000	320000	1	0.0141
D	18	71	200.00	*	0.4089	0.0088	2	996	320000	320000	1	0.0088
D	18	72	200.00	*	0.4089	0.0170	2	1049	320000	320000	1	0.0170
D	17	73	200.00	*	0.4489	0.0117	2	1019	320000	320000	1	0.0117
D	16	74	200.00	*	0.3913	0.0141	2	1034	320000	320000	1	0.0141
D	15	75	200.00	*	0.4318	0.0147	2	1037	320000	320000	1	0.0147
D	14	76	200.00	*	0.4136	0.0141	2	1034	320000	320000	1	0.0141
D	13	77	200.00	*	0.4042	0.0141	2	1034	320000	320000	1	0.0141
D	12	78	200.00	*	0.4071	0.0147	2	1037	320000	320000	1	0.0147
D	12	79	200.00	*	0.4054	0.0071	2	978	320000	320000	1	0.0071
D	11	80	200.00	*	0.3895	0.0176	2	1052	308000	320000	1	0.0176
D	10	81	200.00	*	0.4530	0.0153	2	1040	320000	320000	1	0.0153
D	9	82	200.00	*	0.4001	0.0135	2	1030	320000	320000	1	0.0135
D	8	83	200.00	*	0.4065	0.0200	2	1062	272000	320000	1	0.0200
D	7	84	200.00	*	0.4048	0.0094	2	1001	320000	320000	1	0.0094
D	7	85	200.00	*	0.4160	0.0100	2	1006	320000	320000	1	0.0100
D	6	86	200.00	*	0.4036	0.0141	2	1034	320000	320000	1	0.0141
D	5	87	200.00	*	0.4136	0.0129	2	1027	320000	320000	1	0.0129
D	4	88	200.00	*	0.3948	0.0117	2	1019	320000	320000	1	0.0117
D	3	89	200.00	*	0.4048	0.0147	2	1037	320000	320000	1	0.0147
D	2	90	200.00	*	0.4065	0.0088	2	996	320000	320000	1	0.0088
D	1	91	200.00	*	0.3925	0.0123	2	1023	320000	320000	1	0.0123

TUBE D - PSH HEADER STUB TEMPERATURE

Plot of calculated tube metal temperature for PSH outlet header stub tubes (APTECH: File: CHANDPSH).

Input File Name: CHANDPSH.KB1

***** Plant Information *****

Utility: DVC
Plant: CHANDRAPURA
Location: CHANDRAPURA
Unit: Number 2
Test Date: 04-Aug-94
Operating Hours: 181000.0000
LAC Corrosion Temp: 3000.0000
Superheater Pressure: 2000.0000
Reheater Pressure: 464.0000
Superheater Heat Flux: 18000.0000
Reheater Heat Flux: 8000.0000
Tube Temp. Est. Technique: LABORELEC
Oxide Insulating Value: 1.0000
User Comments: no comments at this time

***** Tube Information *****

Component: SUPERHEATER
Elevation: 200.0000
Material: T22
Orig. Tube Diameter: 2.2250
Orig. Tube Wall Thickness: 0.3502
Tube Number: D
Pendant Number: 75

***** Tube/Oxide Characterization Parameters *****

Metal Velocity: 0.2350
Oxide Velocity: 0.2350
Filter Type: NONE
Low Cutoff Frequency: 0.0000
High Cutoff Frequency: 20.0000
Min. Detection Thresh. (%): 17.0000
Min. Detection Duration: 0.0050
Min. Detection Separation: 0.0050

LifeCode

LABORELEC OXIDE CORRELATION

08/04/94

t File Name: CHANDPSH.KB1

***** Tube/Oxide Characterization and Remaining Life Results *****

Tube No.	Pend No.	Wvfm No.	Elev.	Man. Flag	Wall Thk.	Oxide Thk.	Type	Tube Temp	Rem Low	Life Avg	Layer No.	Thk.
D	75	1	200.00	*	0.4171	0.0141	2	1054	320000	320000	1	0.0141
D	74	2	200.00	*	0.4160	0.0129	2	1041	320000	320000	1	0.0129
D	73	3	200.00	*	0.3954	0.0159	2	1072	164000	320000	1	0.0159
D	72	4	200.00	*	0.4042	0.0112	2	1020	320000	320000	1	0.0112
D	71	5	200.00	*	0.3966	0.0117	2	1027	320000	320000	1	0.0117
D	70	6	200.00	*	0.4201	0.0159	2	1072	227000	320000	1	0.0159
D	69	7	200.00	*	0.4112	0.0159	2	1072	203000	320000	1	0.0159
D	68	8	200.00	*	0.3848	0.0123	2	1034	320000	320000	1	0.0123
D	67	9	200.00	*	0.4171	0.0147	2	1060	320000	320000	1	0.0147
D	66	10	200.00	*	0.3936	0.0141	2	1054	320000	320000	1	0.0141
D	65	11	200.00	*	0.4048	0.0129	2	1041	320000	320000	1	0.0129
D	65	12	200.00	*	0.3948	0.0135	2	1048	320000	320000	1	0.0135
D	64	13	200.00	*	0.4565	0.0088	2	987	320000	320000	1	0.0088
D	64	14	200.00	*	0.4676	0.0147	2	1060	320000	320000	1	0.0147
D	64	15	200.00	*	0.4665	0.0153	2	1066	320000	320000	1	0.0153
D	64	16	200.00	*	0.4671	0.0153	2	1066	320000	320000	1	0.0153
D	63	17	200.00	*	0.4671	0.0153	2	1066	320000	320000	1	0.0153
D	63	18	200.00	*	0.4201	0.0182	2	1100	0	293000	1	0.0182
D	62	19	200.00	*	0.4177	0.0176	2	1099	0	296000	1	0.0176
D	61	20	200.00	*	0.4207	0.0112	2	1020	320000	320000	1	0.0112
D	60	21	200.00	*	0.4065	0.0123	2	1034	320000	320000	1	0.0123
D	59	22	200.00	*	0.4183	0.0088	2	987	320000	320000	1	0.0088
D	58	23	200.00	*	0.4124	0.0094	2	996	320000	320000	1	0.0094
D	58	24	200.00	*	0.4136	0.0182	2	1100	0	278000	1	0.0182
D	57	25	200.00	*	0.3178	0.0006	2	692	320000	320000	1	0.0006
D	57	26	200.00	*	0.4101	0.0123	2	1034	320000	320000	1	0.0123
D	56	27	200.00	*	0.4042	0.0141	2	1054	320000	320000	1	0.0141
D	55	28	200.00	*	0.3913	0.0129	2	1041	320000	320000	1	0.0129
D	54	29	200.00	*	0.4283	0.0100	2	1004	320000	320000	1	0.0100
D	53	30	200.00	*	0.4071	0.0100	2	1004	320000	320000	1	0.0100
D	52	31	200.00	*	0.4019	0.0094	2	996	320000	320000	1	0.0094
D	51	32	200.00	*	0.4142	0.0153	2	1066	269000	320000	1	0.0153
D	50	33	200.00	*	0.4453	0.0176	2	1099	0	320000	1	0.0176
D	49	34	200.00	*	0.4089	0.0117	2	1027	320000	320000	1	0.0117
D	48	35	200.00	*	0.4136	0.0117	2	1027	320000	320000	1	0.0117
D	47	36	200.00	*	0.4160	0.0112	2	1020	320000	320000	1	0.0112
D	46	37	200.00	*	0.3848	0.0135	2	1048	320000	320000	1	0.0135
D	45	38	200.00	*	0.4753	0.0100	2	1004	320000	320000	1	0.0100
D	45	39	200.00	*	0.4641	0.0123	2	1034	320000	320000	1	0.0123
D	45	40	200.00	*	0.4718	0.0088	2	987	320000	320000	1	0.0088
D	44	41	200.00	*	0.4154	0.0159	2	1072	215000	320000	1	0.0159
D	43	42	200.00	*	0.4347	0.0141	2	1054	320000	320000	1	0.0141
D	42	43	200.00	*	0.4406	0.0129	2	1041	320000	320000	1	0.0129
D	41	44	200.00	*	0.4389	0.0147	2	1060	320000	320000	1	0.0147
D	40	45	200.00	*	0.4136	0.0164	2	1077	155000	320000	1	0.0164
D	39	46	200.00	*	0.4242	0.0141	2	1054	320000	320000	1	0.0141
D	38	47	200.00	*	0.4148	0.0135	2	1048	320000	320000	1	0.0135

LABORELEC OXIDE CORRELATION

08/04/94

7 File Name: CHANDPSH.KB1

***** Tube/Oxide Characterization and Remaining Life Results *****

Tube No.	Pend No.	Wvfm No.	Elev.	Man. Flag	Wall Thk.	Oxide Thk.	Type	Tube Temp	Rem Life Low	Rem Life Avg	Layer No.	Thk.
D	38	48	200.00	*	0.4112	0.0153	2	1066	260000	320000	1	0.0153
D	37	49	200.00	*	0.4083	0.0100	2	1004	320000	320000	1	0.0100
D	36	50	200.00	*	0.4071	0.0123	2	1034	320000	320000	1	0.0123
D	35	51	200.00	*	0.4019	0.0170	2	1083	83000	320000	1	0.0170
D	34	52	200.00	*	0.4001	0.0141	2	1054	320000	320000	1	0.0141
D	33	53	200.00	*	0.4071	0.0153	2	1066	248000	320000	1	0.0153
D	32	54	200.00	*	0.4130	0.0147	2	1060	320000	320000	1	0.0147
D	31	55	200.00	*	0.4101	0.0170	2	1083	98000	320000	1	0.0170
D	30	56	200.00	*	0.4160	0.0159	2	1072	215000	320000	1	0.0159
D	29	57	200.00	*	0.4207	0.0164	2	1077	170000	320000	1	0.0164
D	28	58	200.00	*	0.4518	0.0164	2	1077	245000	320000	1	0.0164
D	27	59	200.00	*	0.4042	0.0159	2	1072	185000	320000	1	0.0159
D	26	60	200.00	*	0.4060	0.0147	2	1060	302000	320000	1	0.0147
D	25	61	200.00	*	0.4224	0.0117	2	1027	320000	320000	1	0.0117
D	24	62	200.00	*	0.4042	0.0112	2	1020	320000	320000	1	0.0112
D	24	63	200.00	*	0.4001	0.0135	2	1048	320000	320000	1	0.0135
D	23	64	200.00	*	0.4030	0.0106	2	1012	320000	320000	1	0.0106
D	22	65	200.00	*	0.3954	0.0141	2	1054	320000	320000	1	0.0141
D	21	66	200.00	*	0.4295	0.0147	2	1060	320000	320000	1	0.0147
D	20	67	200.00	*	0.4201	0.0153	2	1066	284000	320000	1	0.0153
D	20	68	200.00	*	0.4201	0.0141	2	1054	320000	320000	1	0.0141
D	19	69	200.00	*	0.4013	0.0117	2	1027	320000	320000	1	0.0117
D	19	70	200.00	*	0.4048	0.0141	2	1054	320000	320000	1	0.0141
D	18	71	200.00	*	0.4089	0.0088	2	987	320000	320000	1	0.0088
D	18	72	200.00	*	0.4089	0.0170	2	1083	95000	320000	1	0.0170
D	17	73	200.00	*	0.4489	0.0117	2	1027	320000	320000	1	0.0117
D	16	74	200.00	*	0.3913	0.0141	2	1054	314000	320000	1	0.0141
D	15	75	200.00	*	0.4318	0.0147	2	1060	320000	320000	1	0.0147
D	14	76	200.00	*	0.4136	0.0141	2	1054	320000	320000	1	0.0141
D	13	77	200.00	*	0.4042	0.0141	2	1054	320000	320000	1	0.0141
D	12	78	200.00	*	0.4071	0.0147	2	1060	305000	320000	1	0.0147
D	12	79	200.00	*	0.4054	0.0071	2	957	320000	320000	1	0.0071
D	11	80	200.00	*	0.3895	0.0176	2	1099	0	227000	1	0.0176
D	10	81	200.00	*	0.4530	0.0153	2	1066	320000	320000	1	0.0153
D	9	82	200.00	*	0.4001	0.0135	2	1048	320000	320000	1	0.0135
D	8	83	200.00	*	0.4065	0.0200	2	1102	0	242000	1	0.0200
D	7	84	200.00	*	0.4048	0.0094	2	996	320000	320000	1	0.0094
D	7	85	200.00	*	0.4160	0.0100	2	1004	320000	320000	1	0.0100
D	6	86	200.00	*	0.4036	0.0141	2	1054	320000	320000	1	0.0141
D	5	87	200.00	*	0.4136	0.0129	2	1041	320000	320000	1	0.0129
D	4	88	200.00	*	0.3948	0.0117	2	1027	320000	320000	1	0.0117
D	3	89	200.00	*	0.4048	0.0147	2	1060	299000	320000	1	0.0147
D	2	90	200.00	*	0.4065	0.0088	2	987	320000	320000	1	0.0088
D	1	91	200.00	*	0.3925	0.0123	2	1034	320000	320000	1	0.0123

TUBE D - PSH STUB TUBE TEMPERATURE

Plot of calculated tube temperature for PSH stub tube D (Laborelec, File: DVCPSHLB).

During the Chandrapura Unit 2 outage, a remaining life assessment was conducted on the waterwalls. It was found that the waterwall platen elements have a history of localized overheating in the horizontal tubes and tube bends. Two of these tubes were cut, on element one, for ID examination and metallurgical analysis. The analysis revealed that the tubes contained heavy ID deposits. It is recommended that tube samples be removed for deposit analysis and post outage chemical cleaning probably be required. If ID deposits are prevented, the waterwalls should be capable of 20 more years of life.

TERREXIA VALLEY AUTOMATIC
PLANT GROWING EQUIPMENT

CHANDRAPURA
WATER WALLS

INDIA 10

Chapter 2.0

Plant Systems Evaluation

Section 2.1

Fuel Handling / Processing System

System Boundaries

The processing system evaluation encompassed the coal yard, bunkers, feeders, coal mills, exhausters, and fuel pipes.

System Description

Fuel is delivered to CTPS from open pit coal mines, via rail cars and trucks. Rail cars unload at two tippler stations, which feed their coal to the two coal crushers. Trucks are mainly unloaded in the coal yard. Coal is stocked in the yard and fed through a grate to the coal crushers. Crushed coal is fed via belts to the coal hoppers, from which point it is transferred to the coal bunkers. The bunkers feed the rotary stoker feeders that deliver coal to the five bowl type mills. Rotary fan type exhausters deliver coal to the tangentially fired tilting burners.

System Design Objective

The fuel processing system was designed to deliver 218,000 LB/HR of 55 grind, 70% through coal, using four out of five mills (C-E Raymond 733 Bowl Mills).

System Deficiency

In order to assess the unit capacity limitations a performance test carried out on February '94 at CTPS Unit 2, by BHEL, NTPC, and DVC engineers. This test identified the following limitations:

- o Maximum generation achieved = 110 MW
with five mills in service
- o Plant heat rate = 2,525.72 kcal/HR
- o Coal Consumption = 70.34 tons/HR
- o Coal HHV = 3,950 kcal/HR
- o Average Mill Output (5 mills) = 14.7 tons/HR
- o Mill motor current = 87 amps
- o Limited mill output
- o Full load current 90 amps

CTPS Unit 1~3 plant records indicate that the units have essentially operated at a maximum capacity of 90 MW. During the monsoon period (May~August) the generation capacity drops further to 70~80 MW/unit. This showed that the mill grinding capacity was limiting unit capacity. The objective of this system assessment is to evaluate the root causes for Unit capacity limitation, and provide recommendations for upgrading capacity.

Reason For Improvement

The CTPS Units 1~3 are averaging 90 MW/Unit with a loss generation = 50 MW/Unit.
The cost of lost generation to DVC has been evaluated per the following assumptions:

- o Units will generate power at 70% PLF
- o There is demand for full generation
- o Power Sale Price = Rs 1.30 kcal/kwh
- o Plant Heat Rate = 2,525 kcal/kwh
- o Coal Milling Parts consumption associated with 50 MW of generation is estimated to be Rs 3 Cr / Yr / Units 1~3

Revenue Loss (approximate) = Rs 120 Cr / Year / Units 1~3

Fuel Cost = Rs 7.8 Cr / Year / Units 1~3

Cost of generation loss = Rs (120 - 7.8 - 3.0) Cr /Year / Units 1~3
= Rs 109 Cr / Year / Units 1~3

Problem Statement

Low heat output from the mills is limiting boiler capacity.
Unit milling capacity is at about 67% of design.

Goal

Increase milling output to 100%.

- Unit Mills Output is about 67% of Design

- Increase Mills Output to 100% of Design by 1996.

- Unit Mills Output is about 67% of Design
- Increase Mills Output to 100% of Design by 1996.

Root Cause Verification Matrix

System: Fuel Processing

Problem Statement: Low Mill Output

PRC	Verif. Process	Analysis / Results	Conclusions	Comments
A1-1 Low Flow Velocity	- Visual Air Flow Test	- Performance Test not conducted. - Maintenance staff indicated frequent blockage of rifflers. This could be resulting from carry over of heavy wet particles and excess moisture.	No indication of low velocity, but there are signs of riffler blockage.	Conduct test in vertical pipe before the burners.
A1-2 High Coal Moist	- Coal Test - Visual Observation	- Coal samples from the feeder have water dripping, and the coal readily cakes. Coal conditions indicative of moisture in excess of 13~15%. - Plant coal sample test is misleading.	This is a Root Cause "RC" causing: - Low mill air outlet temp. - Riffler blockage.	An independent coal test is being conducted by BHEL labs.
A1-3 Poor Exhauster Spider Rebuilt Practices	- Observe Process - Check Rebuilt vs. Design	- Plant staff rebuilds spider on the pulverizer floor. - Spider blades are replaced, but spider run-out is not addressed by DVC maintenance. - Clearance on spider are excessive (1"~2") vs. 0.5" design. - Average rebuilt cycle time is 30~45 days. Worn spider removed from service had holes in blades. These were operated well beyond service life.	This is a "RC" effecting exhauster efficiency, hence reducing drying capacity.	Plant does not have standards for spider rebuild. Very short rebuild cycle would mandate a large inventory of spares. (see B2-4 and Mill selection)
A1-4 Low APH Outlet Temperature Design: 488F at 120MW Actual: 381F at 110MW	- Measur. - Performance Test	Gas inlet to APH @ 120MW Design Temp. = 548F Per the Perf. test conducted in Feb. 94 at 110MW = 442F, which is 106F below design. (Per design data, the APH outlet temp. does not change significantly from 110 to 120MW)	Low Gas inlet temperature to the APH is a "RC" for low APH outlet temperature, leading to low mill drying capacity.	Evaluate the boiler performance (second pass) for primary root cause.

PRC	Verif. Process	Analysis / Results	Conclusions	Comments
A1-5 Blockage of APH	<ul style="list-style-type: none"> - Inspction - Maint. practice - Pr. drop test 	<ul style="list-style-type: none"> - APH baskets are clogged, ash has sintered. This is indicative of water ingress. - APH not washed frequently in-situ. - It is extremely difficult to remove the APH baskets, and was not cleaned following economizer tube leaks. - The APH soot blowing system (bottom) has not been used for a long time. Except for the motor, the system appears to be intact. - Desing APH $\Delta P = 35\sim 50\text{mm H}_2\text{O}$ per Perf. test conducted in Feb. 94 (110MW) APH inlet pressure = 160 mm H₂O APH outlet press. = 35 mm H₂O = 125 mm H₂O 	<p>APH baskets are clogged as evidenced by the high press. drop & visual observation.</p> <p>This is a "RC" caused by infrequent cleaning of the APH baskets.</p> <p>The Soot Blowing system should be restored. In addition to the bottom soot blowing, install a top Soot Blowing system.</p> <p>APH Should be blown at least weekly, while mill is operating.</p>	<p>Develop in-situ APH steam or high pressure air blowing procedure whn ΔP increases.</p> <p>If baskets are heavily fowled and soot blowing is ineffective, resort to in-situ wash with use of high pressure high volume washing technique, with use of the APH blower mechanism & fly ash sluice water. Alternately washing from top and bottom then air blowing usaully results in clean APH in 36~48 hours.</p>
A1-6 Oil / Water Ingress into APH	<ul style="list-style-type: none"> - Review design arrangement - Econ. tube leaks - Oil carry over - Test for oil/water - Operational practices 	<ul style="list-style-type: none"> - APH design has no provision for removing the hot baskets weighing almost 1000Kg. - There have been 10 economizer tube leaks since the APH hot baskets were replaced. - APH baskets are not cleaned following and economizer tube leak. - With frequent fireouts, repeated oil gn firing, and oil gun condition, there is bound to be oil carry over that mixes with ash and bakes. - The APH's are turned off during boiler cleaning leading to few baskets being loaded with ash. 	<p>Water / Oil ingress into APH is a contributory "RC" for APH fowling.</p> <p>Lack of in-situ cleaning and the extreme difficulty of the removal of baskets are the "RC's". (see A1-4)</p>	<p>Install a oil / water probe in the gas backpass for making maintenance aware of oil / water ingress into APH.</p> <p>See A1-4 for APH cleaning Recommendations.</p> <p>Keep APH's operational during boiler cleanup.</p> <p>Investigate APH basket changes (dual hot basket) to facilitate removal.</p>

PRC	Verif. Process	Analysis / Results	Conclusions	Comments
A2-1 Low Design Selection Temp. For Coal Conditions	<ul style="list-style-type: none"> - Design curves for RB733-S - Mill temp. measurement 	<ul style="list-style-type: none"> - Mill capacity curve data At the mill design temp. (DT) of 477F, the mill can handle a maximum of 8% moisture. For 13% moisture, need 525F; For 8% moisture, need 477F DT; For 7% moisture, need 356F DT. - Actual measured temperature = 356F 	<p>This is a "RC" for low mill outlet temp. when the moisture exceeds:</p> <ul style="list-style-type: none"> - 8% for 477F DT - 7% for 356F DT 	Coal moisture can be lowered by switching to a Stacker Reclaimer System. (see A3-2)
A2-2 Low Flue Gas Inlet Temp. to the APH	<ul style="list-style-type: none"> - Measur. - Compare to design 	<ul style="list-style-type: none"> - Per Performance Test in Feb. 1994 at 110MW = 442F - Per design curves need 548F at 120MW <p><i>Note: Does not change much for 110MW</i></p>	Primary "RC" for low mill inlet temperature.	<p>The PSH bundle tube outlet temp. is at 1000~1050F. Gas outlet temperature is 106F.</p> <p><u>Indication of too much heat absorption in the backpass.</u></p>
A3-1 High % of Fines	<ul style="list-style-type: none"> - Test Coal - Compare with design 	<ul style="list-style-type: none"> - Per the 3/8/89 coal sample test: 30% of coal through 4.76mm screen. - Design: Should be less than 10%. (see data sheet) <p><u>Higher % fines increases:</u></p> <ul style="list-style-type: none"> - The net coal surface area and the % moisture carryover. - increases feeder jams, since the coal tends to cake into hard compact mass. (see photo figures_____) 	This is the "RC" for reducing Mill Grinding Output.	See section B3-2 for impact of moisture on feeder jams.

PRC	Verif. Process	Analysis / Results	Conclusions	Comments
A3-2 Coal Pile Management	<ul style="list-style-type: none"> - Review CTPS Coal Management System - Evaluate Alternatives 	<p>CTPC's main bottom grade loader system fed by trucks is prone to moisture pickup, since the bottom wet coal is pushed into the coal stream. The main coal storage, where the trucks unload, is a source of water pickup. The coal is dumped from the trucks, pushed into heaps, and later pushed into the grate. Driving over wet coal with high % fines results in coal caking.</p> <p>Investigated a truck tippler system that would accelerate coal tipping and eliminate driving over the coal. This would reduce moisture pickup and minimize coal caking.</p> <p>The two wagon tippler system is effective and minimizes moisture pickup. Consider covering the coal pile over the hoppers feeding the plant. This will significantly reduce moisture added to coal during residence time over the hopper.</p>	<p>This is the "RC" that contributes to high moisture in coal.</p> <p>See section on coal management recommendations.</p>	Have a coal management specialist evaluate the CTPC layout and develop execution plans.
B1-5 Exhauster Design (Limiting mill motor overload)	Verify design and compare to actual.	<p>The exhauster is powered by the same motor as the mill.</p> <p>This exhauster was designed for 900 rpm. It is identical to other US installations.</p> <p>At 100 rpm it draws more current thus limiting the mill, since the motor current reaches its capacity of 89 amps.</p> <p>Colder mill outlet temp. contributes to higher mill load by virtue of increased density.</p>	<p>This is a Contributory Root Cause ("CRC"), limiting mill loading through motor overload.</p> <p>If motor is replaced, the increased HP requirement should be addressed.</p>	<p>Prior to changing the motor, all mill related "RCs" should be addressed.</p> <p>The mill is undersized and will need to be upgraded / changed.</p> <p>See Mill Selection section indicating wrong selection of mill.</p>
B1-1 Coal Pile Managing	(see A3-2)			

PRC	Verif. Process	Analysis / Results	Conclusions	Comments
B1-2 High % of Fines in Coal	(see A3-1)	(see A3-1)	This is a "RC" for reducing Mill Grinding output.	
B1-3 Roll to Bowl Clearances	<ul style="list-style-type: none"> - Interview - Visual Obs. and Measur. 	<p>High bowl to roll clearances > 1.0" vs. 0.25".</p> <p>This results in deeper coal bed in bowl, thus increasing drag due to rolls "plowing". This increases the power requirements.</p>	This is a "CRC" that contributes to the high motor current.	
B1-4 High Roll Spring Pressure	<ul style="list-style-type: none"> - Interview - Visual Obs. 	<p>Roll spring setting procedure is dimensional only. This does not compensate for the changes in spring rates of springs.</p> <p>Examination of broken parts is indicative of high spring pressure.</p> <p>Coal Analysis indicates high HGI (65~68). This indicates that the spring pressures can be reduced.</p>	<p>This is a "CRC" that results in increased mill loading, causing higher motor current.</p> <p>Grinding capacity is not improved.</p>	Have a mill properly set-up and observe performance.
B1-5 Exhauster Design Selection	<ul style="list-style-type: none"> - Maint. Data - Rebuild Data - Performance Data 	<p>CTPC Units 1~3 exhausters are exposed to very severe coal abrasion conditions.</p> <p>Exhauster rebuild cycle is 45 days, in which time the blades are severely worn. One exhauster from Units 1~3 is rebuilt every 14~15 days.</p> <p>Changing to ceramic blades will provide increased life by a factor of three. This is not a long term solution since one exhauster would have to be rebuilt every 45 days. Ceramic blades require the spider frame to be squared with minimal blade support distortion. <i>New spiders will be required if ceramic blades are used.</i></p> <p>No flow data, but the mill suction / discharge pressure is expected to be normal with the rebuilt spiders.</p>	<p>An exhauster type mill is not compatible with this type of abrasive coal.</p> <p>(see Mill Selection section)</p>	

PRC	Verif. Process	Analysis / Results	Conclusions	Comments
B2-1 Incorrect Restriction Angle	<ul style="list-style-type: none"> - Visual Obs. - Interviews 	<p>Per the observations made by the BHEL mill specialist and confirmed by TVA during the phase II~III on site implementation, the air restriction angles appear incorrectly set.</p> <p>Plant staff do not have a procedure for setting the angle.</p>	<p>Update Mill Maintenance Procedures.</p> <p>This is only a contributory factor impacting mill drying capacity</p>	
B2-2 Roll to Bowl Clearances	<ul style="list-style-type: none"> - Visual Obs. - Interviews 	<p>Roll assemblies wearing out at a rapid rate, even the mill is set-up with new rolls, per OEM spec.</p> <p>The roll to bowl clearances are high because of the bowl liner section top ends have curled up. The rolls are set at an angle, which results in th scalloping of the rolls.</p> <p>Average new roll life is 3000 hours. This means that a mill is refurbished every 120 days. There rolls wear so fast that there is no time to re-set them.</p> <p>The plant has been fighting these mills since there installation. The high wear rate, due to coal characteristics, makes the adequate mill maintenance almost impossible.</p> <p>These bowl mills are not ideal for these coal conditions. The Race-Ball mills, operating in Units 4~6 are more suitable for this application.</p>	<p>Mill capacity could be improved with improved maintenance. However, with these high wear rates is would be difficult to maintain.</p> <p>This is a "CRC" that impacts mill capacity.</p>	
B2-3 Spring Pressure Setting	<ul style="list-style-type: none"> - Visual Obs. - Interviews 	<p>The roll assemblies springs are set too tight. There is virtually no movement, in-lieu of a smooth rocking action.</p> <p>Mill resetting procedures need to be reviewed withthe plant staff.</p>	<p>Some performance improvement could be achieved with proper mill settings.</p> <p>This is a "CRC" that contributes to the reduced mill capacity.</p>	As stated in B2-2 and the Mill Selection section, this mill is unsuitable for these coal conditions.

Coal Handling System

2.1.2

System Description

The coal handling system consists of 2 rail car dumpers, each rated at 600 t/h. Each of these feed separate crusher buildings via single belts. An open grate reclaim hopper feeds onto one of the rail car belts for truck reclaim. From 1 crusher building 2 belts proceed toward outlets over a main hopper where the belts discharge through telescoping chutes. Single belt from the second crusher building discharges through a telescoping chute on the ground for storage. Coal from this storage pile is pushed by dozer to the main hopper when needed.

The main hopper has 4 outlets and 4 feeders that feed 2 inclined belts, with a capacity of 500 tons per hour, leading to the powerhouse each provides fuel to either of the six (6) units. The main hopper area provides ground storage area as well.

The truck unloading area and storage area is located between the two car dumpers. The trucks have side doors that open and allow coal to feed out onto the ground and be shoveled out of the truck, often requiring the truck to be moved while several laborers shovel out the coal. Occasionally, emptying trucks takes hours. The coal is pushed up for storage and then pushed to the truck reclaim hopper.

Coal Handling Evaluation

The fuel processing system evaluations pointed out coal moisture as a contributor to a number of problems encountered. During rainy season the coal handling operation was found to add to the moisture ingress into the coal. This occurs primarily in the truck unloading and the raw coal storage area.

The main hopper being at ground level and being exposed to the elements results in additional water during rain periods.

The truck unloading and storage area is not graded to enhance drainage of water. As a result, the coal and ground on the working side (hopper and truck arrival side) get saturated with water. The truck and equipment movement over the wet coal together causes the inert content of the coal to mix and form a very sticky mass. This sticky mass gets pushed into the reclaim hopper, causing sticking/bridging problems throughout the conveying and fuel processing system.

Capacity Evaluation

The two inclined belts from the main hopper to the powerhouse are rated at 500 t/hr each. . It is likely that these belts would be the limiting factor due to the system layout.

The plant (6 Units) fuel requirements at full load is about 600 t/hr. This will increase as the coal heating value drops (typical phenomenon as they mines are worked. The conveyor belt feed capacity from the two inclined conveyor belts is 1000 t/hr. These conveyor belts would have to operate at their full capacity for 16~18 hours per day to meet the plants full load requirements.

Electrical / Mechanical Systems Reliability

At this point, electrical and mechanical reliability must be considered. Electrically the coal handling area is already experiencing numerous trips and grounds. With the additional requirements of handling a maximum burn rate of coal these problems will likely become more prevalent and even more apparent. The electrical problems observed and discussed with this coal handling operation are similar to problems with facilities of like age. The control and power cable insulation and circuit breakers have deteriorated and result electrical faults, especially during rainy season. These are at their end of life.

Some of the conveyors belts have frayed and will require to be replaced in the near future. The conveyor drives and reduction should be checked for potential problems.

Recommendations

A) Coal Yard

The coal yard area should be cleared of coal and regraded (contoured) to enhance run off away from the working areas and coal stack.

A simple hydraulic truck dumping (tippler) device should be installed. This would eliminate the truck and bulldozer traffic movement the coal and speed truck coal unloading.

Coal should moved with front loaders with tires, instead of bulldozers.

Install a silo or pile cover over the main hopper area. This would provide some measure of protection from the rain.

B) Capacity

The system capacity overall is adequately designed for supplying fuel to the six (6) units under maximum burn rate conditions. However, owing to system age and overall condition, the system (electrical cables) does not have adequate spare capacity to handle breakdowns or reduced load operation.

Conclusions

As discussed above, the coal management (handling) in the yard is a significant contributor to the moisture pickup and coal caking. The system capacity is marginal. Operating at part load of the system capacity for long periods of time may have hidden or shadowed some other emergent problems.

The complete coal handling system needs to be thoroughly evaluated by a coal yard specialist, who should evaluate the recommended upgrades, and develop implementation plans.

Fuel Burner System

2.1.3

System Boundaries

Burner windbox, fuel /oil / air nozzles, and burner tilting mechanism.

System Description

The burner windboxes are of a fabricated design. mounted on each of the four corners of the furnace. The fuel and air streams from the burners are directed to a firing circle in the center of the furnace. The fuel and air nozzles are vertically adjustable through pneumatically operated tilting mechanism.

In each of the burner boxes there are five (5) levels of fuel nozzles and one oil gun between the bottom fuel nozzles. Additionally, in each burner box there are six (6) eclectically ignited pilot oil torches for light off. Oil guns are of the mechanically atomized type. The tilting mechanism is actuated by a pneumatic cylinder and drives all burners and nozzles in unison.

System Evaluation

The burner tilt mechanism has been disabled for some time. Majority of the tilting mechanism appears to be intact. The burners have been fixed in the horizontal position. This fixed burner position leaves the operator without the ability to control the reheat temperature. The reheat temperature has been about 20~30°C lower than design. This condition could be as a result of reheat tube fouling.

The coal burner nozzles have been welded and clad overlaid for improved wear resistance. Some of the nozzles have holes and patches. In general the nozzles are in acceptable condition.

The major problem with the firing system is that the boiler loses fire about 2~3 times a day.

Reason For Improvement

Frequent fire out cost DVC not only the loss of generation, but also results significant damage to the turbine. Following a flame out (lasting on the average about 30 minutes) the main steam and reheat temperatures drop by about 50°C. The steam path components do not cool during this event, and may actually rise in temperature due to windage losses. When fire is restored the cooler main and reheat steam shocks the steam path component. These frequent thermal shocks have resulted in HP/RH rotor and nozzle box strut cracking.

The Loss of Generation Revenue is estimated to be the following:

Loss of revenue	=	Rs 10.3 Cr / Year / Units 1~3
Increased cost of oil	=	Rs 2.4 Cr / Year / Units 1~3
Coal Savings (approx.)	=	Rs 0.7 Cr / Year / Units 1~3

Net Loss Of Revenue From Fire Outs Is $\approx$ Rs 12 Cr / Year / Units 1~3

The above revenue loss is based on the following assumptions.

- o There are on the average three flame outs per unit per day
- o Fire is out for about 30 minutes per flame out, during which time oil is used to restore the fire.
- o Plant PLF is about 70%, and generation is required
- o Plant average generation during fire outs is 70 MW
- o Power sell price is Rs 1.30 / kwhr
- o Coal cost is about Rs 400 / ton
- o Oil cost is about Rs 6,000 / ton
- o Oil consumption is about 3.6 tons / hr

Problem Definition

**Frequent Flame Outs at CTPS Units 1~3
Are Costing DVC Rs 12 Cr/Year /Units 1~3**

Goal

**Eliminate Flame Outs
Execute Upgrades By 12/95**

System: Burner**Symptom: Burner Set-Up; Controls & Instrumentation; Secondary Air Distribution**

PRC	Verif. Process	Analysis / Results	Conclusions	Comments
Initial Burner Set-up	<ul style="list-style-type: none"> - On-site alignment check. - Compare fireouts to fuel nozzle position 	<p>Tests conducted by BHEL on Unit # 2 during the Level II / III assessment (August 94) shows severe misalignment. BHEL is evaluating the data to establish the impact on fire ball / vortex stability.</p> <p>Fireouts occur immediately following loss of the mill / feeder supplying the lower burners.</p> <p>TVA and NTPC experience with burner alignment is that the flame stability is not an aspect ration of the boiler.</p>	This is a Potential RC, that needs to be evaluated.	<p>Per DVC's request BHEL is developing a workscope for addressing the burner alignment, if necessary.</p> <p>This scope should be part of the burner tilt rehab package being developed by BHEL. Requested at the July 15, 94 steering committee meeting.</p>
Mill Airflow Control	<ul style="list-style-type: none"> - Check Original Design. - Check similar systems in operation 	<p>This not part of the original design.</p> <p>Mill air flow controls are essential to low volatile coals. Other thermal plants in India burning this have installed these controls.</p>	This is a contributory RC.	Damper control systems are available for retrofit
Lack of Automatic Secondary Air Damper Control (SADC)	<ul style="list-style-type: none"> - Check design 	<p>Automatic SADC was not part of the original scope of supply.</p> <p>The manual dampers are not being used by the plant. Simulated test conducted in Feb. 94, showed that when the SAD was manually closed following loss of mill, flameout did not occur.</p> <p>With the current low volatility fuel and coal conditions (high % moisture and fines) that can cause feeder jams, a SADC will avoid flameouts.</p>	This is contributory RC that should be addressed.	

Solution Matrix

System: Burner

RC	Potential Solution	Effectiveness	Cost	Feasibility	Total	Comments
Burner Alignment	A) Re-design the Burner Windbox, based on alignment data. Install new Burner System with automatic tilting mechanism & controls (BHEL offers a tangential firing system that readily adapts to this unit).	6	3	7	42	BHEL Automatic Tilting Tangential Firing System upgrade used for cost basis.
	B) Readjust existing Burners. This would require the burner tilts and remote control system restored.	6	1	9	54	
Mill Airflow Control	A) Engineer and install new mill airflw controls.	8	2	9	72	
Lack of SADC System	A) Engineer and install SADC system. Note: This is only a cure for minimizing flame outs following loss of feeder. This does not address the root cause for the poor flame instability, which is the primary root cause of frequent flame outs.	9	1	10	90	This could be implemented as part of the burner alignment and control upgrade.

Ash Handling System

2.1.4

System Description

The bottom ash is removed from each unit wet bottom ash hopper through a clinker grinder by a jet pump system. The jet pump system conveys the ash to a common ash pit. The common ash pit is an above ground concrete structure that provides the mixing point for the ash system. The flyash from the precipitators is conveyed pneumatically from the hoppers to the common ash pit through a hydroveyor system.

The flyash and bottom ash mixture is pumped from the common ash pit to the impoundment area. The ash water mixture is discharged through 2 parallel and redundant pump/piping arrangements. A single pump for each discharge outlet is located near the ash pit wall; 2 or 3 other pumps are located about 100 feet down stream of the first pump. The plant has noted that 3 pumps are required to pump the mixture to the ash pond. The pumps, either 3 or 4, are driven by 75 HP motors each through multiple "V" belt drives. The motors and pumps operate at 1000 RPM.

The piping is standard abrasion resistant 6 in cast piping with dresser type coupling.

Conclusions

The ash removal system from the individual bottom ash hoppers to the common ash pit and the removal and transport system from the precipitators to the common ash pit appears to be capable of coping with the additional loading necessary to get back to full load conditions.

The removal and discharge system from the common ash pit is an operating and maintenance liability before all the new precipitators are tied in. The discharge line size is too small requiring additional pumps and horse power to provide sufficient flow and head requirements. This system will be pushed beyond expectations with the addition of more precipitators or future ash pond modifications such as raising the dikes.

The remaining life of the existing ash pond is short.

Recommendations

Redesign the common ash pit discharge pump and piping system. Larger diameter pumps should be considered that operate at much lower speed and sized to allow single pump per outlet connection. The slower speed pumps will require less maintenance and will provide some flexibility for future increased head or flow requirements if motors are properly sized with this in mind. The ash line size should be increased to at least 10 in., but sizing should result in optimum flow velocities for the product being pumped.

A long range and short range plan for ash storage should be developed and any existing or proposed environmental regulations should be evaluated as a part of the plan. (With full burn conditions on all units, this plant will generate approximately 2,000,000 cu yds of ash per year.)

Boiler Capacity Review Phase I

2.1.5

As Found Conditions

This section was prepared by ABB-CE Services, Inc. based on information obtained during two site visits to Chandrapura Thermal Power Station (November-December 1993 and July 1994). The reproduction quality of some material in this section is poor, but is made from the best available original copies.

Damador Valley Corporation
Chandrapura Thermal Power Station

Boiler Capacity Review
Phase I

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For
Tennessee Valley
October 18, 1994

ABB C-E SERVICES, Inc.

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TO		CONTRACT DATA SHEET			FROM GENERAL SALES - DATA June 10, 1964		
L. J. Andresen Raymond Division Chicago		CONTRACT NO. 15759 & 15063			File alphabetically DAM Destroy sheet dated 12/18/63		
		DISTRICT OFFICE EXPORT CREDITED WITH SALE			CONTRACT March 30, 1961 DATE Dec. 5, 1963		
PURCHASER		DAMODAR VALLEY CORPORATION, ALIPORE, CALCUTTA, INDIA					
USER		DAMODAR VALLEY CORPORATION, ALIPORE, CALCUTTA, INDIA					
PLANT CHANDRAPURA THERMAL		CONS. GIBBS & HILL, INC. (1 & 2)			INDUSTRY P. U.		
NAME PWR. STA. - UNITS 1, 2 & 3		ENGR. BURNS & ROE, INC. (3)					
BOILER	NO. 2	SQ. FT. H.S. 18,330			P R E S S	DESIGN 2150	
	1	PER UNIT				OPER. 1955	
	DESIGNATION 38"-4-3/4" 151-3 RR 70 28"-0-15/32" 94-3			TURBINE			
				THROTTLE			
FURNACE		VOLUME CU. FT. TOTAL 94,900	TYPE OF BOTTOM Basket	WIDTH 38"-4-3/4"			
Plain Tube Furnace - Skin Cased				FRONT TO REAR 28"-0-15/32"			
SUPERHEATER		TYPE Multistage with Platens		REHEATER		TYPE Interstage	
ECONOMIZER		NO. 2	TYPE CF-S 72W x 10 ^H x 38"-4"Lg.				
AIR HEATER		NO. 4	TYPE 23 VI 54				
		NO. 2	MAKE Ljungstrom				
FUEL BURNING EQUIPMENT		15 No. 733X Bowl Mills and Tilting Tangential Burners					
FUEL		INDIAN BITUMINOUS			ASH FUSION TEMP. F	GRIND-ABILITY	HHV
F.C. 34.9	VOL. 13.8	MOIST. 6.0	CO ₂ 5.3	ASH 40.0	2192	55	7,380
OPERATING CONDITIONS							
FUEL		COAL					
		CONTROL POINT	M.C.				
LB STEAM PER HOUR ACTUAL	PRIMARY	574,000	960,000				
	REHEAT	503,000	847,800				
STEAM TEMP. F LEAVING	SUPERHEATER	1005	1005				
	REHEATER	1005	1005				
REHEAT DATA	ENTERING TEMP.		680				
	ENTERING PRESS.		491				
FEEDWATER TEMP. F		418	467				
TEMP. AIR TO AIR HEATER							
TEMP. GAS FROM AIR HEATER		256	277				
OVERALL EFFICIENCY % *Guaranteed		87.3	87.0				
SUPPLEMENTARY DATA		C-E to furnish all pressure parts including finned tubes, settings, casing, insulation, structural steel including 15 tons of steel for supporting elevator.				GENERATOR KW	
						MFR. RATING	
						2 - 125,000 1 - 140,000	
		PLANT ELEV. 620'					

FORM NO. 1-2-62

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TO L. J. Andresen Raymond Division Chicago		<h1 style="margin:0;">CONTRACT DATA SHEET</h1>		FROM SALES DATA DIVISION December 11, 1961 File alphabetically DAM Destroy sheet dated	
CONTRACT NUMBER 15759		DISTRICT OFFICE EXPORT		CONTRACT DATE March 30, 1961	
TAB 15		CREDITED WITH SALE			
PURCHASER		DAMODAR VALLEY CORPORATION, ALIPORE, CALCUTTA, INDIA			
USER		DAMODAR VALLEY CORPORATION, ALIPORE, CALCUTTA, INDIA			
PLANT NAME CHANDRAPURA THERMAL PWR. STA.-UNITS 1 & 2		CONS. ENGR. GIBBS & HILL, INC. NEW YORK, N. Y.		INDUSTRY P. U.	
PROPOSED FUEL		INDIAN BITUMINOUS		ASH FUS. TEMP. F 2192	BTU PER LB AS FIRED 7380
F.C. 34.9	VOL. 13.8	MOIST. 6.0	CO₂ 5.3	ASH 40.0	SUL. 0.6
FUEL BURNING EQUIPMENT		CONT. SECT. YRB	10 - No. 733X Raymond Bowl Mills		
and Tilting Tangential Burners					
FURNACE		CONT. SECT. YPFS	SQ.FT.H.S. PER FURN. 18,330	TYPE OF BOTTOM Basket	
Plain Tube Furnace - Skin cased					
FRONT TO REAR 28'-0-15/32"		WIDTH 38'-4-3/4"		VOLUME 94,900 CU.FT. GROSS	
BOILER		CONT. SECT. YBR	NO. 2	SQ.FT. H.S.EA. -	P R E S S U R E
DESIGNATION 38'-4-3/4" 151-3 28'-0-15/32" 94-3 RR 70		MFR. C-E		DESIGN 2150 OPERATING 1955 at S.O.	
STEAM WASHER				BOILER NUMBER 1 & 2	
SUPERHEATER		CONT. SECT. YSH	TYPE Multistage with Platens		DESUPERHEATER
CONTROL RANGE 574,000 to 960,000 with burner tilt & desuperheaters		SQ.FT. H.S. 92,170		FOR SUPHT'R. Spray	
REHEATER		TYPE Interstage		FOR REHEATER Spray	
ECONOMIZER		CONT. SECT. YCONS	NO. 2		MAKE C-E
TYPE CF-S 72 W x 10 H x 38'-4" lg.		SQ.FT. H.S.EA. 63,750			
AIR HEATER		CONT. SECT. YCAHL	NO. 4		MAKE Ljungstrom
TYPE 23 VI 54		SQ.FT. H.S.EA. 76,300			
MISCELLANEOUS DATA		C-E to furnish all pressure parts including finned tubes, settings, casing, insulation, structural steel including 15 tons of steel for supporting elevator. All other equipment including tubing for furnace, superheater and reheater by others.			
E X P E C T E D P E R F O R M A N C E					
FUEL		C O A L			GENERATOR KW
LB STEAM PER HR-ACTUAL PRIMARY REHEAT		* 960,000 847,800	574,000 503,000	2-125,000 Outdoor Unit	
FEEDWATER TEMP. TO BOILER		467 539	418 501	REHEAT DATA	
STEAM TEMP. at S.O. & R.O.		1005	1005	847,800 LB Steam/HR.	
HEAT RELEASE BTU/CU.FT./HR.		13,950	8,900	Enter. Temp. 680 F	
TEMP. GAS FROM AIR HEATER		277	256	" Press. 491 Psi	
TEMP. AIR FROM AIR HEATER		465	488	Leav. Temp. 1005 F	
OVERALL EFFICIENCY %		87.0	87.3	" Press. 464 Psi	

* Guarantee

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and is not to be divulged to anyone outside of the organization.

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WESTERN DAMASK VALLEY SEPARATION

CONT. NO. 13759 15062 — units 1, 2, 3

PULVERIZER AND EXHAUSTER SPECIFICATIONS

12.5 MW

II. FUEL

1. TYPE: - (E. BLT., MID.W. BLT., PET COKE, ETC.)
2. SOURCE - (MINE, STATE, COUNTY)
3. SIZE TO MILL
4. HARDGROVE GRINDABILITY (**-ASSUMED: ***CONTRACT):
5. ANALYSIS - HEATING VALUE TO MILL BTU/LB.
 - VOL. MATTER " " %
 - TOT. MOISTURE " " %
 - MAX./MIN. TOT. MOISTURE TO MILL %

A	B
<u>EXD/A</u>	<u> </u>
<u>174 x 0</u>	<u> </u>
<u>55%</u>	<u> </u>
<u>7390</u>	<u> </u>
<u>13.5</u>	<u> </u>
<u>6.0</u>	<u> </u>
<u>8.0 / 4.0</u>	<u> </u>

III. PERFORMANCE

1. FUEL
2. NUMBER MILLS OPERATING
3. LB. RAW COAL/HR. PER MILL
4. FINENESS, % THRU 200 MESH
5. TOT. MOIST. IN COAL TO MILL %
6. AIR FLOW THRU EXH. LB./HR.
7. TEMP. OF MIX. LVG. EXH. °F.
8. AIR AND/OR GAS TEMP. REQD.
 - o MILL INLET °F.
9. STATIC PRESSURE o EXHAUSTER OUTLET "WG
10. NEGATIVE PRESSURE o MILL INLET "WG
11. TOT. POWER INPUT TO MILL, EXH.
 - KWH/TON

MAX. BLR. CAP.

MAX. MILL CAP.

A	SA	A	B
<u>5</u>	<u>4</u>	<u> </u>	<u> </u>
<u>35,800</u>	<u>44,750</u>	<u>46,000</u>	<u> </u>
<u>80</u>	<u>80</u>	<u>80</u>	<u> </u>
<u>6</u>	<u>6</u>	<u>8 = 6</u>	<u> </u>
<u>78,600</u>	<u>80,400</u>	<u>80,400</u>	<u> </u>
<u>180</u>	<u>180</u>	<u>180</u>	<u> </u>
<u>340</u>	<u>385</u>	<u>418 - 385</u>	<u> </u>
<u>12.55</u>	<u>13.90</u>	<u>13.90</u>	<u> </u>
<u>1.0</u>	<u>1.0</u>	<u>1.0</u>	<u> </u>
<u>17.0</u>	<u>17.0</u>	<u>17.0</u>	<u> </u>

MAXIMUM FEEDER CAPACITY

45000 to 49000 LB/HR.

C.E. INC. PROPOSAL NO. 18059 DATED AND PURCH. SPEC. NO. DATED
ARE A PART HEREOF

GENERAL DATA CHECKED BY: P. H. [Signature] CONTRACT ENGINEER.

DATED 3-20

FUEL AND PERFORMANCE CHECK BY: W. C. King JR CALC. DIV.
ENGRS. DEPT.

DATED 3/13/64

REVISED: 1.) ADDED CONT. NO. 15062 2-17-64 N.C.

CONDITIONS

170°C

Moist - 6.0

Ash - 40.0

? CO₂ 5.3?

HHV 7380

H₂ 55

FC 34.9
VM 13.8
S = 0.6

} for
Co
do
8h

STATION ENGINE
MADISON AVE.
PULVERIZER AND EXHAUST

Post-It™ brand fax transmittal memo 7571 # of pages = 3

To: RILL MOVIN	From: BOB FEINDEL
Co: AEB	Co: AEB
Dept:	Phone #: 3410
Fax: 9918	Fax #: 2895

ACQUISITION NO. _____ DATED 5/31/81 CONTRACT NO. _____

CUSTOMER AMADOR VALLEY COOP. PLANT CHANDRAPURA LOCATION INDIA
CONSULTING ENGINEER 2

I. GENERAL DATA:

1. NO. OF MILLS PER UNIT 5 TOTAL ON CONT. 10 SIZE 73.3 X BOWL TYPE
2. EXHAUSTER: (INTEGRAL) (~~SEPARATE~~) SIZE 3576Y TYPE WHEEL: (WHIZZER) (~~OTHER~~) REQ'D. DIA. 70
3. FEEDER: - (~~SEPARATE~~) (SEPARATE - (CENTER FURNISH SPOUT, FEEDER TO MILLS))
FEEDER SIZE

8"	()
16"	()
30"	()
50"	()
67"	()
4. FURNISH FEEDER HOPPER (YES) (~~NO~~)
5. MILL DRIVE: MOTOR, HP 500 RPM 1000 FURN. BY (C.E., INC.) (~~OTHER~~)
GEARING 15.3 TO 1 RATIO. MOTOR SHAFT EXTENSION (~~OTHER~~) (DOUBLE)
6. EXHAUSTER DRIVE: MOTOR, HP REM FURN. BY (C.E., INC.) (~~OTHER~~)
7. FEEDER DRIVE: VARI-STROKE FURN. BY (C.E., INC.) (~~OTHER~~)
SEE NOTE * VARI-STROKE OR OTHER
FEEDER DRIVE MOTOR: (SPECIAL) - HP 1 RPM 1500 VOLTAGE 400 V FREQ. 50 CPS
(WITH) (~~OTHER~~) SLIDE BASE FURN. BY (C.E., INC.) (~~OTHER~~)
9. FEEDER INTERRUPTING RELAY: STANDARD FURN. BY (C.E., INC.) (~~OTHER~~)
(STD. STYLE #1961721) OR OTHER
10. INTERRUPTING RELAY ADJUSTABLE RESISTOR: STANDARD
(STANDARD 1 OHM, TYPE 100-A) OR OTHER
FURN. BY (C.E., INC.) (~~OTHER~~)
11. COAL FLOW ALARM REQ'D.? (~~YES~~) (NO)
12. CENTER HOT AIR REQ'D.? (~~YES~~) (NO) DIA. _____
13. FLEX. CPLGS. FAST
FAST OR OTHER
14. COUPLING GUARDS REQ'D.? (YES) (~~NO~~)
15. JOURNAL BUFFER SPRINGS REQ'D.? (~~YES~~) (NO)

MILLS TO BE CONSTRUCTED IN ACCORDANCE WITH LATEST REGULATIONS OF NATIONAL BOARD OF FIRE UNDERWRITERS.

REVISIONS: 2-CHRS ON CONTRACT.

⚠ EXHAUSTER WAS 80Y. NO. OF MILLS PER CONT. WAS 5. 5-9-81 RPT
Added Ex. wheel dia, added 110. on items

I. INTRODUCTION

The Damodar Valley Corporation, Chandrapura Station Units #1 and #2 are the focus of this report. The Units have been operating at reduced capacity for over 20 years. This report is a mechanical evaluation of some of the equipment which is negatively effecting the steam generating capacity.

SCOPE:

The work in this report reflects Phase I of the a two phased approach to resolve the capacity problems at the C-E Units at the Damodar Valley Corp. Chandrapura power Station. The Phase I scope consists of performing a mechanical evaluation on the present condition of the fuel delivery system including the feeders, pulverizers, exhausters and riffles. The condition and possible upgrades to the windbox tilting system, the air preheater and the windbox secondary air damper system will also be inspected and recommendations made.

The proposed Phase II portion of this approach would evaluate the boiler performance and make recommendations to evaluate how the full rated Unit capacity could be regained.

The author and Mr. Peter Chang of the Tennessee Valley Authority traveled to the Chandrapura Station. Units #1 and #2 were the focus of the inspections. At the time of arrival, Unit #1 was not in operation due to mill exhauster blade replacements. Unit #2 was in operation but at reduced load due to the loss of a boiler water feed pump and limitations of fuel delivery due to high mill motor amps.

The 2C mill on Unit #2 was stopped and an internal inspection was performed to evaluate the mill components including the feeders and exhausters. The inspection was also to make an inventory of any mill deficiencies before any mill operating data was recorded. Several adjustments and calibration were made to the mill before a series of two mill tests were run. Results of the inspection and the performance data can be seen in the inspection section and Pulverizer Engineering Milling System Review section included in this report.

During the middle of the site visit, Unit #2 was shut down for a major outage and Unit #1 was brought back into operation. At this time it was decided to do a performance test on mill (1B) because all the exhauster blades had been replaced during the outage the week before. An internal inspection was also done on this mill and associated equipment. Adjustments and calibration of some of the equipment was also done. The results of the inspection and the performance data can be seen in the inspection section and Pulverizer Engineering Milling System Review section included in this report.

DAMODAR VALLEY CORP., CHANDRAPURA STATION

While Unit #2 was down, the doors to the windbox duct and the APH were opened so that an internal inspection could be performed. Results of these inspections are included in the inspection section of this report.

II. SUMMARY:

MILLING SYSTEM

The Chandrapura boilers are presently unable to achieve their rated design steam flow. This is partly due to the milling system attaining the maximum mill motor rating but delivering less than the original design coal throughput when grinding the current coal. The limiting factors on the milling system are wear, present exhauster fan wheel diameter, coal properties, and the feeder capacity.

ABB C-E estimates the mill capacity shortfall to be approximately 30 percent with 10 to 15 percent being attributable to wear on milling components, 5 to 10 percent due to the exhauster fan delivering less than design mill air flow, and 5 to 10 percent being due to coal properties. In addition, when the coal has a combination of high ash content and low higher heating value, there will be further boiler load limitation because the feeders are unable to deliver the coal demand of the boiler. The situation is made worse by the amount and size of rocks in the incoming coal.

To recover the milling system shortfall, ABB C-E recommends a program of exhauster fan rebuilding, clean air testing, mill rebuilding, and mill testing to re-establish the present milling system maximum capacity. It is estimated that it could recover about 15 percent of the mill capacity.

To increase the milling system capacity beyond this, ABB C-E recommends installing a High Efficiency Exhauster Fan Wheel, replacing the mill motors with new 600 H.P. motors, and replacing the existing feeders with belt type feeders of greater capacity. This could regain most of the mill capacity.

If upgrades to the 733 mills do not work, there are several major items that could be done. To regain the unit milling through put capacity, the existing 733 mills could be rehabilitated and a new sixth (6th) 733 RB mill installed. This would require a more detailed study on the physical possibility of the location of the new mill, bunker configuration, additional feeder, additional windbox elevations, etc.

The last alternative recommended by ABB C-E is to add one additional 733 mill on each unit or convert the existing 733 RB mills to 753 RB mills to regain any additional capacity required. See the Pulverizer Engineering Milling System review for more details for a conversion.

WINDBOX and DAMPERS:

From the inspection, the windbox and dampers appear to be functional. It is recommended that D.V.C. clean the ash from all the secondary air ductwork and windboxes. D.V.C. should consider installing remote actuating damper drives

onto the existing dampers. At this time, these damper drives could be open/close type so that unit trips could be avoided during flame-outs. The drives could be pneumatic or electric driven.

It also appears that an additional oil elevation could be added between the coal elevations C and D. This would be a benefit because the upper coal elevations could be put in service with oil support when the firing is unstable. At this time, during low and/or unstable firing the lower elevations are fired because the only oil support is at the AB oil elevation. Firing at the upper elevations could help the RH temperature.

AIR PREHEATER:

The data from the previous tests conducted last year, indicted that the APH was plugged and possibly causing the ID fan motor overloading, low APH temperature pickups, and large pressure drops across the APH. At the time of this visual inspection, no major problems were found with the APH seals or the baskets.

Several things can be investigated to see if these problems noted are due to other causes:

- It should be investigated whether the original design set-up of the APH baskets was changed. This could be adding to the problems with the APH pluggage. The original design only has Hot and Cold end baskets. The plant reports that they have Intermediate baskets. See the APH inspection section for more detail.
- The condition and frequency of the economizer ash pulling should be investigated to determine if this maybe overloading the APH baskets with ash. See the APH inspection section for more detail.
- The Feedwater heaters should be repaired/replaced so that the APH gas inlet and air outlet temperatures can be raised. Putting the Feedwater heaters in service would help reduce the chance of the gas and ash reaching the dew point and sticking to the elements.
- The possibility of replacing the Ljungstrom APH with a Tubular APH could also be investigated. At this time, the B&W units at the station have tubular air preheaters. The plant reports that they do not have any major problems with pluggage. See the APH inspection section for more detail.
- Replace the existing Ljungstrom hot end baskets with new loose pack APH basket elements which could reduce the pluggage in the APH. See the APH inspection section for more detail.

III. RECOMMENDATIONS:

MILLING SYSTEM:

The recommendations to upgrade the milling system to restore the milling system capacity are summarized in the following. The intention is to carry out the upgrades one step after another on one mill, until the present shortfall is eliminated. Once the mill capacity has been recovered, the remaining steps, if any, do not have to be implemented. Whatever level of upgrades has been determined as necessary for one mill would then be installed on the remaining mills.

1. Restore the mills and exhaustor fans to original design clean air capability.
2. Perform clean air tests.
3. Rebuild one mill to "like new" condition.
4. Perform maximum mill capacity and fineness tests on this mill.
5. Install and test a high efficiency exhaustor fan wheel on the rebuilt mill.
6. Install a 600 HP mill motor in combination with the high efficiency exhaustor fan wheel on the rebuilt mill.
7. Replace feeders with belt type feeders of higher capacity.
8. Review mill maintenance.
9. Retrofit an additional mill or convert the 733 RB mills to 753 RB mills.

WINDBOX and DAMPERS:

Install electric or pneumatic damper drive actuators for either variable positioning (to control windbox to furnace DP or fuel damper ramps) or just "Open / Close" positioning.

TILT LINKAGES:

Perform a detailed inspection of the tilt linkages in place and determine what is causing binding. Replace hardware that is not functioning correctly.

AIR PREHEATERS:

1. Re-commission Air preheater soot blower system.

2. Investigate if ash problems are being caused by economizer ash overload.
3. Investigate why Intermediate Baskets were added if not original design. After investigate if the new baskets are detrimental to the operation of the APH.
4. Put Feedwater heaters in service and perform a performance test on the APH's to investigate in more detail any performance problems in the air preheaters.
5. Investigate the possibility of installation of Tubular APH's if ash plugging in the Ljungstrom APH's can not be controlled.
6. Contact ABB CE APH for the feasibility of installing new "DL" loose pac baskets in the existing Ljungstrom air preheater.

IV. INSPECTIONS

2C FUEL DELIVERY SYSTEM

2C Fuel Delivery system was inspected prior to taking any operational data or testing, to assess the condition of the mills. The delivery system included the Feeder and Bunker 2C, Pulverizer 2C, and Exhauster 2C. See figure 2 for the orientation of the fuel delivery system and the typical operating pressures and temperatures.

The fuel delivery system was found to be in poor condition due to excessive wear on all the components. The following is the inspection report for this system:

=====

2C Feeder:

The feeder 2C was found in very poor condition. See photo 1 for a picture of the feeder.

The C-E volumetric feeder works on the principal that each of the eight buckets (pockets) on the feeder roll will deliver the same volume of coal. As the coal enters the top of the feeder from the bunker, the leading edge of the bucket is leveled off by a hinged gate mechanism. The hinged gate is spring loaded so that if a reasonable size object enters the feeder, it should be able to pass with out jamming. Since the volume of the buckets is kept constant, the volume quantity of coal per revolution should remain constant. The feeder speed is then varied to control the amount of coal being fed into the pulverizer.

The feeders at Chandrapura are jamming due a large amount of oversized stones. The stones are larger than the hinged gate mechanism can allow to pass and can get caught at the hinge gate or at the feeder outlet as the emptying bucket rotates after emptying.

Feeder Body:

The feeder had several holes in the corners of the body as shown in figure 3. The largest and most noticeable was at the square to round transition at the feeder outlet. The feeder rear poke hole door also had signs of wear do to erosion. These holes should be repaired and the high wear areas should be hard faced to reduce the reoccurrence of holes in the body. It appears the condition of the 2C feeder was typical of all the other feeders on Unit #1,2 and 3. These holes allow cold atmospheric air to infiltrate into the feeder and reduce the mill temperature.

FIGURE 2

INTEGRAL FEEDER

INDEPENDENT FEEDER

VARISTROKE
EXTERNAL VIEW OF FEEDERS

FIGURE 3

Feeder Spider and Rolls Blades:

The spiders are heavily worn and repaired regularly. The roll blades have heavy erosion wear and are un-even in relation to one another for the same feeder. See figure 4 for an illustration of the location of these components. With worn blades, the delivery of coal to the mill for the same feeder speed will be different over a period of time due to shorter blades.

The Spider can be upgraded with the new stainless steel feed roll spider and blade assembly to reduce the wear and the amount of coal sticking to the blades. The blades should be replaced or upgraded so that they will retain their original blade dimensions longer.

At the time of the inspection all of the blades were covered with a thick layer of moist coal fines sticking to the inner portion of the blade. It was the Monsoon season at the time of the inspection, so that this increased the amount of moisture in the raw coal. This layer of sticking coal takes up some of the volume of each bucket so that the feeder will not deliver the same volume of coal per revolution. The moist coal can also increase the potential for feeder outlet and/or coal feed pipe pluggage.

Feeder Hinge Gate Mechanism and Blade:

The hinge gate mechanisms was in very poor shape at the time of the inspection. Figure 5 illustrates the set of the hinge gate. Because of the severe rock jams of the feeders, the spring rod bushings are damaged and are loose on the shaft. Also, to avoid further rock jamming, the jam nuts on the spring rod have been loosened so that the spring is not compressed. Because of these two items the hinge blade can not act as a leveling device as intended. Instead the blade rides over the top of the coal piled in the buckets.

During period that the author was on site, the coal crushers had been rehabilitated so that the size of the rocks coming into the feeder was reduced. This resulted in less frequent feeder jams. Unfortunately this was also the Monsoon season so that the feeder inlet and outlet were jamming due to the high moisture in the caking up coal. If the amount of rock and/or the sizing of the rock is not reduced, then the volumetric function of the feeders can not be maintained due to wear on the rock.

Feeder Hot Drying Air:

The hot air system to the feeders appeared to be working. The hot air inlet piping was touched and checked for warmth. This was to verify a flow path to the feeder. See figure 4 for the orientation of the feeder hot air inlet. The hot air is critical to assure that the feeder buckets are dry so no coal will stick to the blades. At the time of the

TYPICAL VOLUMETRIC FEEDER ARRANGEMENT

FIGURE 4

2 - 43

FEEDER HINGED GATE MECHANISM

FIGURE 5

mill operation, the feeder blades had coal stuck on the blades. The air inlet to the feeder roll should be further inspected to assure that all the necessary hot air is reaching the blades to allow drying.

Another problem in keeping the feeders hot is that this feeder and all the other feeders are normally run with the feeder door open as shown in the photo 1. This is done to avoid feeder jams due to the large amount of rock in the raw coal. (The rocks fall out the door rather than trying to pass between the blades and the feeder roll liners (see figure 4) and jamming at the feeder outlet. Unfortunately when the door is constantly opened the feeder drying temperature can not be maintained by the feeder hot air connection and the moist coal can cake up on the blades. A bigger problem is that with the doors left open, the cold "tramp" is entering the mill and reducing the pulverizer drying air temperature.

Feeder Drive and Control Mechanism:

The feeder drive and controls are in very poor condition. The drives are the outdated Hilliard Clutch Vari -Stroke design which requires frequent maintenance. The drive should be rebuilt or upgraded as should most of the feeder drives in the plant.

The pneumatic control of the drives are also in poor condition. It appears this is due to lack of spare parts to maintain the equipment. The feeder controls are driven off a 3 to 27 psig signal from the controller in the control room (3 psig = 0 RPM, 27 psig = 5 RPM). During the performance testing of the mill, it was found that there was a large difference between the feeder speed and the indicated signal in the control room.

The feeder controls were also set up different from original design. The design specifications calls for this model feeder to be controlled from 0 to 12 RPM with the optimum range of the feeders between 6 and 12 RPM. The plant controls personnel informed the author that at this time they are set up for 0 - 5 RPM operation. The D.V.C. change in control range could be a resulted from the volumetric feeders being designed to deliver 67 lbs of coal per revolution (30.5 kg) while tests on site showed it was delivering 55 kg per revolution. The difference is most likely due to the fact that the volume in each bucket is no longer controlled. This is due to the poor condition of the feeders and the moisture in the raw coal due to the monsoon rains. While on site the feeders could never be run more than 5 RPM without the mills running back due to high amps. The average feeder speed on both the Units was 1 to 2.5 RPM.

Variable A.C. Motor Volumetric Feeder Drive Conversion:

Many of the old Vari-Stroke feeders in the US have been upgraded to Variable Frequency A.C. Motor Conversions with Programmable Controllers and EDDY Current Clutch Drive. This type of motor has [proved to be much more reliable and easier to

maintain than the old Vari-Stroke design. The cost for a conversion would be approximately \$20,500 USD per feeder if the parts were purchased from ABB CE-Services in the US. The pricing of these parts is in section VI. PRICING 2.0 733 MILL UPGRADES.

BELT FEEDER:

One of the possibilities for reducing the feeder jams would be to change out the old Vari-Stroke feeders with new belt type feeders. Attached in the APPENDIX section A.1 is a write-up from STOCK for Volumetric and Gravimetric feeders specifically designed to replace the ABB CE type Vari-Stroke feeders. These short belt feeders are generally a minimum of 2'-2" offset from the bunker/feeder inlet to the feeder/mill outlet. One of the main limiting factors in installing a short feeder is the clearance needed at the feeder inlet and outlet to allow for the larger hoppers needed. It appears from the site visit that there should be enough room to install a short belt feeder. This should be verified on site and with STOCK before pursuing this course.

From STOCKS experience in India, they recommended the use of a large 36" diameter bunker outlet valve with a 36" to 24" diameter feeder inlet. Their experience has shown that this can decrease the possibility of coal pluggage due to the wet coal especially during the rainy seasons. See figures STOCK A.1 and A.2 for a typical set up of this type of system.

STOCK does make these small belt feeders with Volumetric and Gravimetric models. STOCK recommends that the Gravimetric feeder be used since the price between it and the volumetric are comparatively little. The Gravimetric feeder would also give D.V.C. much better control of the pulverized firing process.

STOCK estimates that a typical belt Gravimetric feeder model which they would recommend for Chandrapura would cost \$90,000 USD each. This price would include a bunker shut off valve, down spout, flow alarm, expansion couplings, feeder, feeder outlet hopper and the down spout connected to the pulverizer. This price could vary if any unusual requirements are required.

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and is not to be divulged to anyone outside of the organization.

DAMADOR VALLEY GRP.
CHANDRA PURA STATION
UNITS 1, 2, 3 - 5 MILLS / UNIT.

STOCK A.2 2 - 47 ABB C-E SERVICES

Mill 2C

The mill is a 733 RB style mill originally supplied in 1961. Refer to figures 6 and 7 for the location of all the components referred to in the section below.

Journals:

The condition of the journals is very poor. The plant reports that coal is migrating from the journal head skirt and getting to the journal shaft and bearings. This is causing premature failure of these components. The plant estimates that they must replace the bearings every 12 months. These mills are made to run on a negative pressure in the bowl area which should prevent coal from getting to these components. Unfortunately, the mill pressure sometimes goes positive due to the frequency of Unit and mill trips which cause excursions in the mills. The only way to prevent the coal migration and the premature failure would be to install a seal air system which would have a higher pressure so that clean air is always flowing from the journals to the bowl. Due to the conditions around the mills the seal air system would have to have a filter so that dirt and dust in the atmosphere would not be blown into the bearings.

The rubber journal air seal assemblies is cracked and allowing a large amount of cold atmospheric "tramp" air into the mill. These seal the journal and the separator body (see figure 8). These seals must be replaced and maintained so that the temperature in the mill can be maintained at the proper setting for drying the coal.

Journal Saddles:

The journal saddles are in fair condition but are hard to move for adjustment. The plant maintenance department reported that they need spare saddles for other mills but none are available.

Journal Springs:

At the time of the inspection, the journal springs were compressed down so that there was no movement when the mill was loaded. This indicates that the roll's grinding pressure was high, which results in higher mill power consumption.

Before the mill was tested, the journal spring pressure was re-adjusted. After relaxing the springs it was found that all three sets of journal springs on 2C mill had been compressed to 1-1/2" to 1-1/4". All the springs were readjusted to 1" compression. During operation there was movement of the springs which indicated that were not over compressed.

BOWL MILL
 GENERAL ARRANGEMENT
 (TYPICAL)

FIGURE 7

CENTER FEED CLASSIFIER

ROLLER JOURNAL ASSEMBLY
FIGURE 7

FIGURE 8

One problem that was found was that the springs were not deflecting equal amounts. See the following table for the deflections:

2C Pulverizer Journal Spring Deflection		
LOCATION	Initial Compression	Operational Deflection
JOURNAL 1	1"	0"
JOURNAL 2	1"	1/8 - 1/4"
JOURNAL 3	1"	1/4 - 1/2"

This could indicate that the springs do not have the same "K" factor. These are the original springs and most likely should be checked to see if they meet the design "K" rate (amount of force needed to compress a spring a specified amount of distance). The only reliable way to do this is to make up a hydraulic compression rig so that the springs can be compressed 1 to 1-1/2" and record the amount of force need from the hydraulic ram. A comparison can be made from spring to spring to check if they are equal in "K" rate. If the springs are not equal, this can cause unequal loading from journal to journal in the pulverizer which can cause uneven loads on the mill shaft and lead to premature failure. See figure 9 for an illustration of the loading that can occur due to uneven spring loading.

It is recommended that D.V.C. purchase a hydraulic ram assembly and then fabricate a spring compression device so that all springs on all the mills can be checked.

Journal Trunnion Shafts:

The journal trunnion shafts are also in poor condition. The rubber bushings on which the trunnion shafts move is worn out and frayed. Since the trunnion shafts really only flex approximately 1 cm, the shafts should not be greased at this location. This is so that the flex motion is taken up by the rubber bushing not slipping on the grease. The maintenance department says that they do replace these bushings as they get worn.

The brass thrust plates were worn thin on the thrust side of the journal. These should be replaced or switched with the free side brass thrust plate which is thicker. If these thrust plates are allowed to get too thin, they will allow the whole journal assembly to move in a horizontal direction.

FIGURE 9

Several of the journal oil fill pipe nipples are uncovered or are have a rag stuffed into the end (see figure 8 for the location). These nipples should be covered with a pipe cap so that no contamination can get into the journal bearing oil from the coal and dust in the atmosphere.

Journal Roller Bearings:

The journal roller bearings were not disassembled and/or inspected. The plant reported that the bearings and shafts have a high incident of failure due to coal migration. The maintenance reported that the journal shafts and bearings for all the mills have to be replaced every year due to the oil contamination problem. Adding journal seal air should help eliminate the amount of oil contamination and prolong the life of these components.

Journal Rolls:

All three rolls were visually inspected and all found to be in poor condition. From the condition of the three journals it was assumed that the plant does not change out all three rolls at a time. Later this was confirmed with the plant maintenance. They just replace the most worn out rolls as they are found. This can be a problem since this can cause uneven grinding from roll to roll since the surfaces of the rolls will be in varying degrees of wear.

The journals #1 and #3 were worn approximately 1" to 1-1/2" in relation to a straight edge held across the face of the roll. The #2 roll had more wear with 1/2" to 3/4" at the roll heel and 1-1/2" at the toe. The #2 journal had large sections of material missing on the roll surface. See photo 2. The largest section missing was approximately 1/2"L x 1/2"W x 1/4" deep. The rolls are all refurbished locally with a Ni-hard face. These voids in the roll face indicate that they are not spun cast so that voids may develop in the Ni-hard casting during manufacturing. See photo 3 which shows the worn rolls ready to be shipped for re-surfacing with Ni-Hard.

The ring to roll gaps were all reset on all three rolls. The rolls were tilted in so that there was a 1/4" - 3/8" gap at the top of the roll (heel) and 3/8" - 5/8" gap at the bottom (toe) as is recommended by C-E. It appears that the plant maintenance is familiar with tilting the journal rolls in but was not used to moving the whole journal assembly to get the correct gaps on both the top and bottom.

Pulverizer Bowl:

The bowl segments were inspected and found to be worn. See photo 4 for an indication of the amount of wear. The bull ring segments had 1/4" to 1/2" dishing of the segments with 90% of the bowl ribs eroded away. Figure 10 shows the amount of

INSTRUCTIONS FOR THE INSTALLATION OF RIBBED OR UNRIBBED SEGMENTED BULL RINGS

1. REMOVE BOWL EXTENSION RING AND OLD BULL RING.
2. REPLACE BOWL WEAR PLATE IF NECESSARY.
3. CLEAN INTERIOR SURFACES OF BOWL.
4. INSTALL NEW BULL RING SEGMENTS IN A CLOCKWISE MANNER BY THE NUMBERS ON THE SEGMENTS. THERE MAY BE SOME CLEARANCE ON EITHER SIDE OF LAST SEGMENT INSTALLED. THIS IS NORMAL, SHIMMING IS NOT NECESSARY. SEGMENTS WILL TIGHTEN IN OPERATION.
5. REPLACE BOWL EXTENSION RING. THIS RING SHOULD NOT CLAMP THE BULL RING SEGMENTS TIGHT.

INSTALLATION OF SEGMENTED BULL RINGS

FIGURE 10

wear in relation to the design dimensions. The maintenance department reported that the these bull ring segments on 2C were changed out on January 10, 1994. The wear in the photos is approximately 6 months worth. The material of the bull rings segments is assumed to be Ni-Hard.

Heavy wear on the bull ring segments will cause larger gaps between the roll and the segment. This will result in less effective attrition grinding between the roll and the segment and cause a drop in mill grinding capacity for a set fineness.

The bowl extension rings appeared to be in fair condition and are level with the restriction angle as designed. The problem is that the restriction rings must be extended to maintain the proper gap. See the section on mill liners and deflectors.

Separator Body:

The separator body is very worn but has no patches. Some of the sections have become very eroded and should be hard faced to regain thickness and strength.

Mill Liners and Deflectors:

As is most everything in these mills, the mill liners and deflectors are very worn. See figure 11 for an orientation of the liners and deflectors.

The upper mill side, lower mills side and bottom liners have holes in them due to erosion. The fit up of the liners is also poor, creating gaps between liners where coal can accumulate behind the liners. See photo 5 for a typical poor liner fit up. This type of coal accumulation is a potential for coal fires in the mills if the mill outlet temperature was ever increased to the design value. If the liners can not be replaced, then the gap between them should be filled with a high temperature epoxy resin with ceramic beads to resist the high erosion of this area.

The fit up of the restriction angle to the bowl extension ring is poor. The air inlet vanes are also in bad shape. Figures 12 and 13 show the proper setting of these components.

The gap between the restriction ring and the bowl extension ring should be 1/8". The gap in 2C mill is between 1/8" and 3/4". Such a large gap can lead to the primary air bypassing the three air inlets next to the journals and can increase spillage. This gap should be reset to design values.

The Air Inlet Vanes were attached in the field by D.V.C. on the recommendation of C-E to help decrease the mill spillage. The majority of the vanes in 2C mill are OK but worn. On one vane, the angle is not set at 45° but at 5° to 10°. Photo 5 shows

FIGURE 11

FIGURE 12

FIGURE 13

the vane at a shallow angle. This low angle will create a restriction in the air inlet which will require a higher negative under bowl pressure to pull enough air through the smaller opening this will result in higher power consumption for the mill and exhauster. These air inlet vanes should be replaced and new ones mounted in the correct orientation.

Mill Scrapers:

The mill scrapers are located on the underside of the mill bowl and are attached to the mill lower skirt. The mills have two scraper assemblies which rotate with the bowl and sweep away any rejects from the mill under side to the discharge chute. An inspection revealed that one scraper was missing. The mill has been operating with just one scraper for a long time. The other scraper was in very bad condition. The scraper assembly shaft was worn very thin and allowed the whole assembly to flop around as it rotated. Half of the scraper wear plate was broken off and sitting 4" above the floor. See photo 6 for the condition of the mill scraper. The scraper wear blade should sit approximately 1/4" off the mill floor as shown in figure 14. If the gap is greater it will allow a layer of rejects to pile up on the mill floor and create a fire hazard. These scrapers should be replaced and a new set installed so that there are two per mill.

Mill Floor:

The mill floor appeared to be in good condition with a small amount of grooves eroded in by rejects dragged around by the scraper. It is unknown what the condition of the insulation is underneath. Most likely this insulation is asbestos and should be left alone unless hot spots develop on the mill floor.

Classifiers:

The classifiers were found in the 1.3 (0-6) position on the indicators at the separator top. It appears that they are not changed due to the fact that there approximately 4 - 5" of coal fines covering the deflector regulator assemblies. See figure 15 for an illustration of these assemblies.

The classifiers were found to be in fair condition with some of the bars protecting the blade shafts broken free. Most of the classifiers were found to be tracking correctly in relation to one another. All the classifiers blades on mills 2C and 1 B were re-calibrated to have a gap of 6.5" from the top of the blade to the classifier opening with the vane in the "Zero" position. These blades shafts were then tac welded to avoid slippage. After the calibration was done all the deflectors were set to the previous position of 1.3 for operation.

FIGURE 14

TO SET DEFLECTOR MECHANISM:

1. SLACK NUTS (6)
2. WITH A WRENCH TURN THE VANE SHAFT (8) COUNTERCLOCKWISE UNTIL YOU HEAR AND/OR FEEL THE CLASSIFIER IN ITS CLOSED POSITION.
3. HOLD THE VANE CLOSED AND MOVE DEFLECTOR LEVER (4) COUNTERCLOCKWISE UNTIL TIP (4) IS 1-5/8" TO 1-3/4" FROM EDGE OF SEGMENT (5)
4. TIGHTEN NUTS
5. SET DEFLECTOR LEVER TO NUMBER 3 ON SEGMENT AS SHOWN.
6. REPEAT ABOVE PROCEDURE ON ALL VANES.

ITEM NO.	DESCRIPTION	Q'TY
1	PLUNGER KNOB	1
2	PLUNGER	1
3	SPRING	1
4	DEFLECTOR LEVER	1
5	SEGMENT	1
6	CAP SCREW, HEX NUT & LOCKWASHER	2
7	CAP SCREW	3
8	VANE SHAFT	1

DEFLECTOR REGULATOR ASSEMBLY

FIGURE 15

Inner Cones:

The inner cone on 2C mills was found to have many patch repairs. The cone had holes at the time of the inspection. The inner side of the cone was heavily grooved from the re-circulating coal traveling down the cone as shown in photo 7. The inner cone is of the old design with the spiral wrapping around the lower portion of the cone. This design is no longer used and does not have to be put back if the cone is ever replaced.

The inner cone spout extensions were also found to have holes and patch repairs. It appears that the feed pipe from the feeder is not centered over the spout I.D. Because of this the feeding coal is falling directly on the side of the spout extension creating accelerated wear. Photo 8 is a view looking up the feed pipe showing where this is happening. Photo 9 shows the holes and patches in the extension as a result of this offset.

Inverted Cone:

The inverted cones on both mills were approximately 4.5" to 5" from the inner cone. This gap is larger than expected but if the plant is not getting bypassing of the classifiers resulting in oversized coal particles in the fineness than it can remain.

Deflector Ring:

The deflector ring was found to be in good condition and extended approximately 11" down from the separator top. At this time there are no problems with this ring.

Coal Feed Pipe:

The feed pipes appeared to be in fair condition except for the centering inside the inverted cone. The coal feed pipe 2C was 11" from the inner cone to the bottom of the feed pipe. It should be pointed out that in photo 8 there was the start of coal deposits in the coal pipe. This was most likely due to the mill being stopped and the wet coal fines from the bunker and feeder, leaking down on the feed pipe and caking the sides. This could lead to bridging of the deposits and feed pipe pluggage. The separator bodies are becoming very worn. These wear areas may have to be weld overlaid to regain some thickness. Once again, if the mills ever regain temperature and/or coal upgrading this will create fire hazards.

Gearbox and Gearbox Oil:

An internal inspection of the gearbox shaft and worm gear was not performed due to time constraints. The maintenance department is complaining that they have a lot of coal contamination of the oil. See figures 16 and 17 for the orientation of the gearbox components and the flow of gear oil. The contamination is leading to the upper shaft bearings having to be replaced every 2-3 years. The lower bearings are replaced every 5 years. They feel this is due to an oil circulation problem due to coal plugging the oil passages in the shaft. A pump and filter system may need to be installed to insure proper flow to the bearings. The oil is changed every six months or whenever there is indications of contamination. The oil is only checked by visual inspection of the oil flow port. D.V.C. uses a local Indian oil called USW Servo Mesh SP-257 (10C).

Mill Main Vertical Shaft:

The main vertical shaft was not inspected due to access problems and time constraints. The plant maintenance department reported that the main vertical shafts, bearings and worm gear are not original and that many of the mills have these local India replacements. They reported that they had experienced problems with these new shafts until they were able to make a better fit up of the shaft to the bowl and to keep a tight clearance on the key way. At this time they feel that they are over these problems with the new installation practices..

The upper and lower main vertical shaft bearings have been replaced "in kind" with the original manufactures brand. The maintenance said that they tried local bearings before, but found that they failed too frequently. The "in kind" bearings now last approximately five years before they have to be replaced. D.V.C. purchases a new set from C-E once a year.

The Upper bearings are reported to last 2 - 3 years and the lower bearings last 5 years. D.V.C. attributes the difference in life spans to coal particles contaminating the lube oil and plugging up the path from the bushing impeller to the upper bearing. Since the upper bearing is above the gearbox oil level, this would starve the upper bearing resulting in the failures. A new seal air system maybe require to keep the coal out of the oil.

Mill Motor:

The original mill motor is a General Electric rated at 87.7 amps with a 1.15 service factor. See the section on maintenance records for the complete motor data. All of the mill motors have been rewound by a local Indian company. The quality of the rewinding and the present rating of the refurbished motors can not be verified at this time.

GEAR HOUSING
GENERAL ARRANGEMENT

FIGURE 16

MILL CROSS SECTION
LUBRICATION
FIGURE 17

The plant has a feeder runback at 87 amps to avoid burning up the motor (which has happened before). Presently the limiting factor of the milling system is the mill motor amps. The operators run the mills according to mill motor amps.

No electrical tests were done on the motors to establish their capacity.

2C Exhauster:

The mill exhauster was inspected internally and externally. Heavy wear was found on all components which could effect mill performance. See figures 18, 19 and 20 for the orientation of the components inspected.

Exhauster Casing and Periphery Liners:

The liners had heavy wear throughout. Inspections showed that these areas have been repaired, replaced and weld overlaid several times. Photo 10 shows the high amount of wear on the periphery liners. The liners have erosion up to 5 mm deep. the plant maintenance tries to keep up with the amount of wear on the liners as shown in photo 10. Any change to the geometry of the fan housing can effect the performance of the exhauster. To aid in the life span of the liners, they could be changed out to Silica Carbide style with better wear life. This would allow longer life and better clearances. (only if they are replaced when the erosion becomes excessive.

Exhauster Inlet Vane:

The exhauster inlet vane was intact but had been repaired at one time. This was probably due to erosion of the vane due to the coal. At this time this blade appeared to be in good condition. See photo 11.

Exhauster Fan Blades:

The exhauster blades are fabricated by the plant out of plain carbon steel checkered plate. The maintenance department reports that these blades must be replaced every 30 to 50 days. At the time of the July 9, 1994 inspection, all the blades in Unit #2 exhausters were 40 days old. As shown in Photo 12 and 13 the fans blades had a high amount of wear at the fan blade tips. Because the plant fabricates the blades by torch cutting them from plate steel, the blades usually vary in size and shape from blade to blade. The plant attempts to statically balance the fan assembly. This is done by hand rotating the assembly and adding weight to the ends of the blades so that any heavier blades don't always end up rotating to the bottom.

NOTE
REFER TO DWGS AND B/M
FOR DETAIL AND
PART NUMBERS

RPS VIEW A-A

RB/RS VIEW A-A

TYPICAL EXHAUSTER ASSEMBLY

FIGURE 19

FIGURE 20

The gap between the blades and the inboard and outboard side plates was found to be excessive. The gap should be 3/8" to 3/4" (0.38 to 0.75") on either side. The following is a table of the findings:

2C EXHAUSTER BLADE GAPS BETWEEN BLADES AND SIDE WALLS			
Blade	Top of Blade gap in inches	Bottom of Blade gap in inches	Whizzer Wheel gap in inches
1	2.2	2.25	0.75
2	2.12	2.75	1
3	2.2	2.5	0.9
4	2	2.6	1.5
5	2.12	2.2	1.5
6	2.06	1.9	1.25
7	2.12	1.9	1.5
8	2.2	1.8	1.12

The gaps on this exhauster are excessive and will reduce the capacity of the exhauster due to bypassing around the blade. The side plate liners and/or the exhauster blades need to be increased in width.

At the time of the inspection the fan blades were 24 to 25" long by 21 to 22" wide. The milling system reviewed in section 6.0, estimates from the blade sizes found that the exhauster blades are probably shorter than design. The blades should be installed so that the overall exhauster wheel dimension is 70". By design these blades should be able to be extended so that the overall exhauster wheel diameter can be 76". Unfortunately, as the blade size increases, the motor load also increases. The

increase in motor load may be offset by the possibility of backing off the journal spring pressure. The springs were set to reduce the amount of spillage but with the increased airflow and velocities, the coal may be held on the bowl with lower spring compression.

It should be noted that it is unusual that the fan blades had wear on the bearing side of the blade. Usually the incoming coal is picked up first by the exhauster inlet side of the fan blade and carried to the exhauster outlet. This usually causes wear on the exhauster inlet side of the fan blades.

The plant has tried using hard faced blades to reduce wear but reported that the

exhausters experienced high vibration when operated with the heavier blades. Therefore, before any new blades are tried, the fan must be statically and dynamically balanced and the exhauster bearings and pedestal must be inspected.

Exhauster Spider and Whizzer Disc:

The spider and Whizzer wheels were found to have heavy wear. The spider has been previously repaired but appeared to be structurally sound.

The Whizzer wheel has been hard faced but has signs of wear.

In the exhauster inlet pipe, the 90° bend causes a large part of the coal stream to channel to the outside elbow of the pipe. Then as the coal stream heads for the exhauster inlet a large majority tends to go to the bottom of the exhauster inlet rather than the center of the exhauster fan blade assembly. To compensate for this the Whizzer wheel picks up this heavy coal stream and accelerates it so that it will not fall out to the bottom of the exhauster and channel to the sides of the exhauster. The increased gap between the Whizzer wheel and the side wall will effect the ability of the wheel to throw the coal into the stream of the exhauster. This gap should be reduced to increase the exhauster efficiency.

Exhauster Outlet Riffles:

The exhauster outlet riffles were inspected and found to be heavily eroded. The riffle partitions are thinned and some have bent and block part of the air stream. See photo 14 to view the condition of the riffles. The riffles are used to attempt to balance the coal/air stream leaving the exhauster. with the riffles in this condition it can cause imbalances in the coal piping downstream and lead to unbalanced tangential firing.

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1B FUEL DELIVERY SYSTEM:

The 1B Fuel Delivery system was inspected prior to taking any operational data or testing to assess the condition of the mills. The delivery system included the Feeder 1B, Pulverizer 1B, and Exhauster 1B

As with the 2C fuel delivery system, the 1B system was found to be in poor condition due to excessive wear on all the components. In relative terms, the 1B system was in somewhat better condition because Unit #1 had just come back from an outage and some parts had been replaced or repaired. The following is the inspection report for this system:

1B Feeder:

The feeder 1B was found in poor condition. See the following for the component descriptions.

Feeder Body:

The feeder body was relatively in the same shape as the 2C feeder. See the 2C section Feeder Body for details.

Feeder Spider and Rolls Blades:

The feeder spider and roll blades were relatively in the same shape as the 2C feeder. See the 2C section Feeder Spider and Roll Blades for details. The blades on the feeder were measured from the roll cylinder to the outboard edge of the blade and found to be 17" long x 3-3/8" high x 3-1/2" wide. The blade heights appear to be short due to the wear on the blades. The blades should be reinstalled with the original size blades.

Feeder Hinge Gate Mechanism and Blade:

The feeder hinge gate and blade were in the same shape as the 2C feeder. See the 2C section Feeder Hinge Gate Mechanism and Blade for details.

Feeder Hot Drying Air:

The feeder hot drying air was in the same shape as the 2C feeder. See the 2C section Feeder Hot Drying Air for details. At feeder 1B, the hot air system had steam coming through the bunker outlet gate drain. This was causing moisture to come into the feeder. The steam is due to the drain system being tied to other drain systems and during start-ups there is a back flow through the drain system.

Feeder Drive and Control Mechanism:

The feeder drive and control mechanism were relatively in the same shape as the 2C feeder. See the 2C section Feeder Drive and Control Mechanism for details. A coal capacity calibration test was not done on feeder 1B because the feeder had been sitting for over ten days and the coal had dried in the silo. This would not have given representative data.

On July 6, the B mill had a control room indication of 24 psig (88%) and the feeder was clocked at 2 to 2.5 RPM. Later on July 9, the control room indicator for this same feeder was 16.5 psig (56%) but the clocked feeder speed was actually 5 RPM. On this same day the 1C feeder indicated 24 psig (88%) but was at 2.75 RPM and 1D

feeder indicated 21 psig (75%) but was at 2.35 RPM. This indicates that the feeder controls need to be repaired and re-calibrated.

Mill 1B

The mill is a 733 RB style mill originally supplied in 1961. Refer to figures 6 and 7 for the location of all the components referred to in the section below.

Journals:

The general condition of these journals compared to the 2C journals was better. The rolls were newer but still worn. At the time of the inspection the journal roll #3 was hard turning. The journal was replaced with another used journal which turned easier..

The rubber journal air seal assemblies on this mill were also leaking. An attempt was made to patch the leaks with goop but the air was still being sucked into the mill.

Journal Springs:

Before the mill performance test, the journal spring pressure was re-adjusted. After relaxing the springs it was found that journal #1 was compressed to 3/4" and journals #2 and #3 were compressed to 1". All the springs were readjusted to 1" compression. During operation there was movement of the springs which indicated that the springs weren't over compressed. It appeared that during operation the journal springs were relatively deflecting the same amount.

Journal Trunnion Shafts:

The journal trunnion shafts are in the same condition as those of Unit #2, 2C mills. Refer to the 2C Journal Trunnion Shaft section of the report for details.

Journal Roller Bearings:

The journal roller bearings were not disassembled and/or inspected. The journal roller bearings are in relatively the same condition as those of Unit #2, 2C mills. Refer to the 2C Journal Roller Bearings section of the report for details.

Journal Rolls:

The journal rolls were found to be in better condition than those of mill 2C. The #1 and #2 journals had approximately 1" of wear relative to a straight edge placed across the journal face. The #3 journal roll was slightly better with only 3/4" wear in this same area. See photos 15, 16, and 17 to see the relative condition of the rolls. None of these rolls had any material missing like on the 2C rolls.

The ring to roll gap was set the same as those in 2C mill. See the 2C Journal roll section for details.

Pulverizer Bowl:

The 1B bowl was found in generally the same condition as the 2C mill. All the ribs had been worn off the bowl segments except the very top edge of the bowl. See photo 8 for the general condition of the bowl segments.

Each segment was worn approximately 1/2" to 3/4" at the bottom and 3/8" at the top relative to a straight edge held against the segment face.

Separator Body:

The 1B separator is worn but still in good condition. Any areas of high wear could be hard faced to regain thickness and strength.

During the inspection it was found that there was a 1-3 mm gap between the mill bottom and the separator body. While in the mill, light could be seen coming in from the gap. This gap should be filled to reduce "cold tramp air" from entering the mill and reducing the mill coal drying capability. A high temperature grease or gasket compound could be pumped in tot gap and the separator body hold down bolts tightened to stop the leakage.

Mill Liners and Deflectors:

The condition of the mill liners and deflectors is in worse condition than those of mill 2C. See the 2C section for the general condition of these components. The highlights of this section on mill 1B is:

- One air inlet vane is at too shallow an angle (5°) and is almost completely worn.
- The mill side liners have poor fit ups with large gaps behind liner plates.
- The lower mill side liner has large holes eroded in the wall.
- The bowl extension ring/restriction ring gap is approximately 3/4"
- The upper mill side liners were heavily worn

Photos 19, 20, and 21 show the condition of these components described above.

Mill Scrapers:

The 1B mill also only has one scraper like mill 2C. Unlike 2C, 1B has a home made fixed scraper that is welded to the lower skirt and hang approximately 3 - 4" off the mill floor as shown in photo 23. The other scraper and scraper bracket in the lower skirt were missing. The fixed scraper will work but will eventually fail and could bust up the mill bottom.

Mill Floor:

The mill floor was heavily grooved from rock and tramp iron being dragged across it by the scrapers. This floor should be replaced to provide a uniform level so that coal can not hide out in the floor.

Mill Lower Skirt:

The mill lower skirt has been modified by the plant so that the flanged bottom section no longer exists. See photo 24 and compare it to the mills side photo of 2C mill in photo 6. Without this lower section the gap between the lower skirt and the floor has increased and will allow easier access for coal to migrate into the mill bowl shaft and bearings. The lower skirt should be replaced or additions made to the lower skirt to maintain the gap of 3/16" to 3/8".

Classifiers:

The 1B classifiers were found in relatively the same condition as those of mill 2C. The classifier blades were re calibrated and set to 1.3 exactly like those of mill 2C. See section 2C Classifiers for details.

Inner Cones:

The inner cone was much more eroded than on mill 2C. The cone had many holes and patches with the largest at the interface of the inner cone and the inner cone drum. This hole was approximately 1" x 1" as shown in photo 25 Photo 26 shows the heavy wear pattern on the inside of the inner cone. The cone should be replaced and ceramic liners installed on the inside to reduce the wear on the mill.

The inner cone spout extension is also heavily patched. Most of the patches are not seal welded and are allowing bypassing. This should be repaired

Inverted Cone:

The inverted cones on both 2C and 1B mills were approximately 4.5" to 5" from the inner cone. This gap is larger than expected but if there is no bypassing of the classifiers resulting in oversized coal particles in the fineness than it can remain.

Deflector Ring:

The deflector ring was found to be in good condition and extended approximately 11" down from the separator top. At this time there are no problems with this ring.

Coal Feed Pipe:

The feed pipe appeared to be in fair condition.

Gearbox and Gearbox Oil:

An internal inspection of the gearbox shaft and worm gear was not performed due to time constraints. See the section on 2C Gearbox and Gearbox Oil for more detail.

Mill Motor:

The original mill motor is a GE rated at 87.7 amps with a 1.15 service factor like mill 2C. See the mill 2C section on Mill Motor and the Maintenance Record Section for more details.

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1B Exhauster:

The mill exhauster was inspected internally and externally. Heavy wear was found on all components which could effect mill performance. See figures 18, 19, and 20 for the orientation of the components inspected.

Exhauster Casing and Periphery Liners:

The 1B exhauster periphery liners were repaired during the outage the week before as shown in photo 27. Patch plates were welded over the existing plates and some spots were hard-faced.

The wear on the periphery liners is similar to that on exhauster 2C. See the section on 2C Exhauster Liners for more details.

Exhauster Inlet Vane:

The exhauster inlet vane is in the same general condition as the one on exhauster 2C. See the 2C section on Exhauster Inlet Vane for more details.

Exhauster Fan Blades:

All of the exhauster blades were replaced with home made carbon steel blades which is the normal maintenance practice. All were in good condition for the mill testing. Photo 28 shows the condition of the new blades before operation. This should be compared to photo 13 which shows the 2C blades after less than 40 days of operation.

The gap between the blades and the inboard and outboard side plates was found to be excessive. The gap should be 3/8" to 3/4" (0.38 to 0.75") on either side. The following is a table of the findings:

1B EXHAUSTER BLADE GAPS BETWEEN BLADES AND SIDE WALLS			
Blade	Top of Blade gap in inches	Bottom of Blade gap in inches	Whizzer Wheel gap in inches
1	1.5	1.2	0.75
2	1.5	1.06	0.75
3	1.06	0.75	1.6
4	1.3	0.25	1.56
5	1	0.6	1.25
6	1.12	1	1.12
7	1.25	1.06	1
8	1.25	1.25	1.12

The gaps on this exhauster are excessive and will reduce the capacity of the exhauster due to bypassing around the blade. The side plate liners and/or the exhauster blades need to be increased in width.

At the time of the inspection the fan blades were 24 to 25" long by 21 to 22" wide as were the 2C blades.

Exhauster Spider and Whizzer Disc:

The spider and Whizzer wheels wear found to have some wear. The spider appeared to be structurally sound.

The Whizzer wheel has been hard faced and was replaced during the outage. Photo 29 shows the extent of wear on one of the Whizzer wheels replaced during the Unit #1 outage.

Exhauster Outlet Riffles:

The riffles on exhauster 1B are in the same condition as those on exhauster 2C. See that section for more details.

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Plant Mill System Maintenance Records :

UNIT 2 MILL MAINTENANCE RECORDS			
Mill #	Exhauster Blades Changed	Bull Ring Changed	Journal Roll Changed
2A	June 6, 1994	January 10, 1994	N/A
2B	June 6, 1994	February 17, 1994	N/A
2C	June 6, 1994	January 10, 1994	N/A
2D	June 18, 1994	January 22, 1994	N/A
2E	January 10, 1994	February 22, 1994	N/A

The journal shaft & bearings and the mill main shaft and bearings have a high incident of failure. This is due to the coal contamination the oil. The following is the expected life of these components.

MILL MOTOR DATA:

All motors have been re-wound several times by a local India company. There is no record if the mill RPM's are the same after the mill motors were rewound.

MOTOR TYPES:

GE Motor: Mills 1B - 1E, 2A, 2C, 2D, 3A- 3E

Limited auto trip 90 amps / H.P. 500, F/L RPM 980 / f/l amps 87.7 / Volts 3000 / 3 ϕ - 50 ~Hz / Rise 60°C / Time Rating - Cont. / Service factor 1.15 / Code F / Type -KG / Frame 63372 / Bearing : Mill Side No. 591C873 - J / Fan Side 6997361BHI.

BHEL Motor: Mills 1A, 2B and 2E

Limited auto trip 90 amps / Frame RKSP16884 / K.W. - 450 / RPM 990
Starter amps 103 amps / Volts 3000 / 3 ϕ - 50 Hz / rating - Continuous /
Insulation Class B / Connection λ .

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WINDBOX & DAMPERS:

Unit #2 was shut down and the windbox and dampers were inspected. The mechanical side of the windbox and dampers was found to be in good condition. All dampers were stroked open (except some coal fuel dampers) and found to move easily. The only problem found in the windbox was the amount of ash accumulated in the compartments. Photo 30 and 31 shows the typical 1 to 1.5 ft of ash found in all four windboxes.

The coal compartments were found to be plugged with ash and several of the lower auxiliary air compartments were almost 100% plugged. This amount of ash can create a reduction in the compartment area so that the velocity of the air out of the windbox will increase. This could cause the coal ignition points to be pushed further away from the nozzles and could lead to part of the flame out conditions since the flame propagation speed will be increased. The ash could also cause incorrect distribution of the secondary air in the windbox causing improper combustion.

The plant personnel reported that the lower coal fuel dampers are always run in the closed position. The associated auxiliary air dampers are opened to a predetermined setting if that coal or oil elevation is in service. These settings were reported to have been set up during the first commissioning and have changed little since then. The following is a table with the damper settings found on Unit #1:

UNIT #1 WINDBOX SECONDARY AIR DAMPER SETTINGS		
Damper	Type	Position Locked
EF	Aux. Air	100% Open if 'E' mill running
E	Coal	Closed all the time
DE	Aux. Air	100% Open if 'D' mill running
D	Coal	Closed all the time
CD	Aux. Air	60-80% Open if 'C' mill is running
C	Coal	Closed if 'C' mill is running
BC	Aux. Air	30 - 40% Open if 'B' mill is running
B	Coal	Closed if 'B' mill is running
AB Oil	Oil	30% Open
A	Coal	Closed if 'A' mill is running
AA	Aux. Air	20 - 30% Open if 'A' mill is running

These settings are a consequence of having a low volatile coal which requires special attention to maintaining flame propagation. The windbox coal fuel secondary air dampers on the lower elevations are closed during firing because the fuel is so hard to keep alight that if the dampers were opened, they could blow out the flame for that elevation.

After any upgrading of the fuel and/or the fuel firing equipment the windbox secondary air dampers settings should be tuned and re-adjusted to provide the best burner and furnace conditions.

Remote damper actuators can be installed on these dampers so that they can be manipulated from the control room to help reduce Unit trips due to flame-outs. "OPEN - CLOSE" functioning actuators can be implemented so that if a mill or feeder trips, the associated secondary air dampers can be automatically closed. This will allow the windbox to furnace delta pressure to be maintained and the other elevations of fuel to be sustained. It appears that there is enough room for electric or pneumatic drive actuators to be mounted on the outside of the windbox, on the damper shafts.

For better stability of the boiler, it appears that another elevation of oil could be added to the windbox between coal elevations 'C' and 'D' at the 'CD' auxiliary air compartment. C-E drawing # E-142-214 shows that the compartment areas for all the secondary air are equal. Therefore an oil gun the same size as the one in elevation 'AB' could be installed. This may require a change in the way that the dampers are set to allow sufficient air around the fire when running (CD' oil), ('CD' oil and 'C' and/or 'D' coal), or just ('C' and/or 'D' coal).

By adding another elevation of oil at elevation 'CD', the operators would have more confidence in firing the upper elevations with oil support. Firing the upper elevations could help gain more Reheater temperature.

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TILT LINKAGES:

The tilt linkages were inspected from inside the windbox through the windbox dampers. It appears that all the components are intact from the original tilt installation. The only exception was the horizontal links in elevation DE auxiliary air compartment in corners 1 and 2 (this will have to be replaced). All the linkages and lever arms are intact on the outside of the boiler also. Tests should be conducted during the outage to stroke each part of the linkage and determine if this system, can be rehabilitated. Attached in APPENDIX section A.2 is a procedure for checking the windbox tilts and several areas and fixes for common tilting problems. Attention should be paid to the zero gap check so that the existing coal pipes do not put a load on the coal nozzles and hinder the tilting operation when the unit is in operation.

=====

AIR PREHEATERS:

The air preheaters are Contract LAP 1989 Ljungstrom regenerative vertical air preheaters. A visual inspection was done on the hot gas side and the hot and cold air side. The Air Preheaters were targeted for inspection because previous test data indicated a high level of APH bypass. The low temperatures along with high amps on the I.D. fans made the APH sealing suspect.

APH SEAL GAPS:

After an inspection it appears that the gaps between the radial seals and the seal plates are not excessive. The gaps on the hot end were typically 1/4 to 3/8" and wear marks were seen on the full length of the radial seals. This indicates that the seals are making contact and sealing at the highest unit loads. The seals on the cold end were even better with approximately only 1/4" gap all around. The circumferential seals also appeared to be good. There was no evidence of heavy oil fouling on the hot or cold end baskets. This was unexpected due to the amount of heavy and light oil fired continuously during coal firing.

Since the unit runs at reduced loads and the air preheater gas inlet temperatures are below design, the air preheater will not seal as well as design. After any modifications are made to raise the gas inlet temperatures going into the air preheater, then the radial seals must be re-adjusted.

ASH ACCUMULATION:

There was also a large amount of ash accumulation on the air outlet side of the APH. It was assumed that the gas inlet side would have the higher concentration of ash. See photos 32 and 33. The large accumulation of ash in the secondary air duct work was evidence that ash is getting caught in the APH and traveling from the gas side to the air side as the air preheater rotates and is laying out in the ductwork. This is called entrained ash. Up to 3 feet deep ash piles were found in the secondary air ducts at the APH outlet. The lower amount of ash on the gas side may have resulted when the Unit was shut down the ash in the gas side was carried away to the outlet duct work.

APH BASKETS:

The hot end baskets had some ash pluggage and were heavily eroded particularly at the outside radius. The plant reported that these baskets have not been replaced since 1992. The cold end baskets were in good condition. They were replaced 3-4 months ago. The plant also reported that they usually get pluggage in the intermediate baskets. During the inspection these baskets could not be checked due to access. It would make sense that the pluggage would occur in this section as the gas temperature became cooler in this basket section and the flyash began to plate out on the elements.

An interesting fact about the plugging of the air preheaters is that the original Air Preheater Contract Specification obtained from ABB Air Preheater shows that the original design for the air preheaters specified 42 inch high Hot end Baskets and 12 inch high Cold end baskets. The original specifications did not include any intermediate baskets. See the attached Original Contract Review General Specification sheet and the General Specification sheet in APPENDIX section A.3.a for this information.

Adding another section to the APH could actually reduce the heat transfer surface due to the amount of additional supports needed for the new baskets. These supports must be added between the layers so that the amount of heat transfer surface available is reduced. Added supports could effectively double the amount of non-heat transfer surface in the APH. Typically a one (1) inch reduction in heat transfer area could mean 3 to 5°F loss in heat pick-up.

An extra layer could cause increased pluggage because the gas must now travel a more torturous path. This change in gas flow path can allow ash to plate out on the elements causing more pluggage. Sootblower cleaning effectiveness could also be effected since the blowing medium would have a harder time reaching the inner basket.

It should be investigated if the original APH did come with only a HOT and a COLD end baskets and why a change was made to include Intermediate baskets. It may be beneficial to use the original basket configuration to reduce pluggage.

OPERATIONAL EFFECTS ON APH PERFORMANCE:

At the time of the inspection the APH Sootblowing system had not been operational for several years. This, in combination with the continued use of co-firing heavy oil and coal, has created a large potential for APH fouling. From observations of the Unit in operation, the combustion of the heavy oil is far from optimized so that the potential is even greater.

Another operational problem is that the High Pressure Feedwater Heaters not operational. This is contributing to the low gas inlet temperature and can lead to the gases reaching the dew point and coating the elements. The heater should be replaced or restored to service.

At this time no reports or records could be found that would indicate that other plants with the same ash characteristics and with such a high ash volume were able to keep their Ljungstrom type air heaters from plugging. It maybe beneficial for D.V.C.. to inquire with BHEL and ask for there experience with other plants around India.

TUBULAR AIR PREHEATERS:

Because these air preheaters are a Ljungstrom Regenerative type they have the potential to plug up with out proper cleaning. If the amount of ash is excessive, the closely packed heater elements may trap ash between the elements and cause pluggage. For this reason, Sootblowing is always recommended to clean the baskets during operation.

A properly designed tubular Air heater may be better suited for coal with this large amount of ash. Since ABB C-E services does not manufacturer tubular air preheaters we can not comment on the performance of them at this time. The D.V.C. Chandrapura units 4 and 5 do have tubular air heaters and the plant reports that they do not have any major plugging with them. D.V.C. may want to contact local tubular air preheater manufacturer's to evaluate the benefits and/or penalties of installing a tubular air preheater on these units.

For an example, the tubular air preheaters may not plug as easily but they also have several problems associated with them. The first is the cost.

- Tubular air preheaters are generally more expensive than the Ljungstrom type.
- The tubular air heaters are much heavier than Ljungstrom air heaters and would require reinforcing the duct work and the hangers to take this load.

ECONOMIZER ASH HOPPER OVERLOADING:

The amount of pluggage in the air preheater could also be due to the overloading of the economizer hoppers. It was learned that during the start-up phase of the Units, heavy air preheater pluggage was experienced. After an investigation it was found that the economizer outlet hopper ash removal system was not working properly. The ash was piling up in the hoppers and when the ash pile reached a critical height, it fell onto the air preheater and plugged it.

The economizer ash hopper and/or the ash hopper removal system was not inspected during our trip. This system should be investigated to determine if the ash is being pulled at regular intervals to avoid ash spill over into the air preheater.

LJUNGSTROM LOOSE PACK BASKETS:

ABB C-E Air Preheater does make loose packed baskets which can reduce the amount of pluggage in the basket elements. The new 'DL' baskets must be used in combination with a strict sootblowing regime. The looser packed elements in the baskets "rattle" when sootblowing so that plugged ash can be shaken as well as blown off the elements.

Attached in the APPENDIX section **A.3.b** is a write-up from ABB C-E Air Preheater describing the development and the implementation of the loose pack system. The determination of the class of coal ash pluggage requires the sulfur content of the coal and oil, the ratio amount of coal and oil fired, the cold end dew point of the APH gas outlet, and the coal and ash analysis. This information can determine the classification and the probability of the ash pluggage. The information should be obtained so that a better evaluation of the APH pluggage can be made. Even without this information, the APH would most likely plug less with the new loose 'DL' baskets. The classification of coal pluggage is generally used to assess the amount of additional cleaning devices needed.

The write up in the APPENDIX section **A.3.b** lists customers that have switched to the DL elements and shows the general physical difference between the old and new style baskets. The budget price for a new set of hot end DL loose pack baskets for

one APH is \$36,000. The cold end baskets would be an additional \$22,000 USD. ABB APH reported that the design of the cold end baskets did not change from the original when using the DL configuration therefore only new Hot end baskets would only have to be purchased.

Photo #1
2C Feeder w/ Door Open

Photo 2
2C Journal Roll #2 w/ Spalling Material

Photo 3
Worn rolls to be Refurbished

Photo 4
Mill 2C
Bowl Segment
Wear

Photo 5
2C Mill Side Liners and Air Inlet Vane

Photo 6
2C Mill Broken Scraper

Photo 7
2C Inner Cone
w/ Heavy Wear

Photo 8
2C Feed Pipe Offset
from Ext. Spout
Causing Erosion

Photo 9
2C Ext. Spout Wear
from Offset Feed Pipe

Photo 10
2C Exhauster
Periphery
Liner Wear

Photo 11
2C Exhauster
Inlet Damper w/
Repaired Blade

Photo 12
2C Exhauster
Blades w/
40 days of
Wear

2C Exhauster Riffls w/
Heavy Wear and Thinning

Photo 14

2C Exhauster Blades w/
40 Days of Operation

Photo 13

Photo 15
1B Journal 1 & 2 Wear
on Roll Face

Photo 16
1B Typical Roll
Wear

Photo 17
1B Mill Bowl and Journals 1 & 2

Photo 18
1B Typical Bowl Segment Wear

Photo 19
1B Mill Side Liner and Air Inlet Vane

Photo 20
1B Lower Mill Side Liner Worn

Photo 21
1B Extension Bowl Ring/ Restriction Ring Gap

Photo 22
1B Upper Mill Side Liner Heavily Worn

Photo 24
1B Lower Skirt
Bottom Edge Modified
Increasing Gap of
Mill Floor to Skirt

Photo 23
1B Mill Scraper

Photo 26
1B Inner Cone
Wear w/ Patches
and Holes

Photo 25
1B Inner Cone 1" x 1"
Hole at Drum to Cone
Interface

Photo 27
1B Mill Periphery
Liner Repair
During Outage

Photo 28
1B Exhauster
Blades Installed
During Outage

Photo 29
1B Exhauster Fan Wheel
Notice Heavy Wear on Whizzer Wheel
Worn Blade Edges Were Cut Off

Photo 30
Unit 2 Windbox
w/ 18" of Ash

Photo 31
Unit 2 Windbox
w/ 18" of Ash

Unit 2 APH Air Side w/ a
Large Amount of Ash on Air Outlet Side

Photo 34

Unit 2 APH Air Side w/ a
Large Amount of Ash on Air Outlet Side

Photo 33

V. PERFORMANCE DATA:

Several performance type tests were performed on the 2C mill and the 1B mill to provide data for an evaluation of the existing mill capacity. The test port set-up for the performance tests can be seen in figure 22. From this data C-E Pulverizer Engineering has evaluated the data and predicted what upgrades or rehabilitations can be done to the mills to bring the capacity up. See the section MILLING SYSTEM REVIEW for details of the capacity evaluation.

The following is the list of performance related type testing performed on these mills:

	MILL	TEST	DATE PERFORMED
-	Mill 2C	Clean Airflow Test	July 7, 1994
-	Mill 2C	Performance Test	July 8, 1994
-	Mill 1B	Performance Test	July 11, 1994

Attached are the data sheets from these tests. An evaluation of the data can be found in the Pulverizer Engineering MILLING SYSTEM REVIEW.

All testing was not done under ideal conditions. Due to problems with the Units, the mills could not held stable during the test period. Because of this, further evaluation may require more testing with more strict conditions for the mills. During all the testing, all the milling equipment was in manual operation. Therefore, any changes that were made in the operation of the boiler could have effected the mill performance data.

These tests were also performed on mills with a large amount of wear. The 2C mill system had wear on the mill bowls and rolls and the exhaustor blades. Due to this, the testing program was moved from Unit #2 to Unit #1. This was done because all the exhaustor blades on Unit #1 were replaced during the outage the week before. A cursory inspection was made on all the Unit #1 mills and it was found that 1B mill had the least amount of wear on the rolls and bowl.

It should also be noted that the load on Unit #2 was limited due to the failure of one of the Boiler Water feed Pumps. The Unit was limited to 80 MW.

Both 2C and 1B mills were inspected and adjusted prior to conducting a mill performance test. See the Inspection section for the results of the inspection and the adjustments made to each of the mills.

Feeder Capacity Test:

A test was conducted to try to establish the feed rate of coal entering the mills during the test. The test involved actually weighing the amount of material coming out of a feeder for one revolution. At the time the only possible feeder available was 2C.

The 2C mill had been shut down for several days previously and the feeder door was open. A plastic sac was held under the feeder outlet and the feeder roll was slowly rotated 1 revolution using the hand wheel. The test was conducted three times and the amount of coal weighed after all three tests were completed. The first test weighed 46 kg, second weighed 50, and the third weighed 54 kg. It was assumed that 5 kg of sample had been lost on each sample because it took 4 to 5 sample catches per revolution sample. The average of the test was approximately 55 kg (12 lbs) per revolution which is almost double the design value per revolution.

Mill Coal Fineness Testing:

No mill coal fineness tests were done on either 1B or 2C mills due to questionable methods and equipment used by the plant for taking coal fineness samples. Photo 34 and figure 21 shows the plant supplied equipment verse the C-E standard sampling device. The plant tried to take one sample but the following problems with the system were found:

- No Aspirating fittings or air on the exhaust coal sampling ports.
- Leaking sampling bottle on cyclone.
- Improper home made sample lance on cyclone.
- Improper opening on lance. The hole was not at the end of the lance and it was elliptical not square with a kicker block.
- No proper sampling analysis shaker device.

Due to all these problems it was decided that any data taken with this equipment would result in false data.

Mill Raw Coal Analysis:

At the end of the mill test on 2C and 1B mill, a 5 pound coal sample was taken from the feeder door. At the time zip lock plastic bags were not available. Local Indian light weight plastic bags had to be use instead. The bags were triple wrapped and the ends melted to try to seal the bag.

The coal samples were sent to ABB India who then sent the samples to the Shriram Institute for Industrial Research for coal analysis. A Proximate analysis and an Ultimate analysis were done on both samples. Unfortunately because of

a mistake in communication, a total moisture analysis was not done on the coal. The results of the coal analysis are attached to this section.

It was surprising to find such large differences in the Hard Grove Grindability and the amount of ash from the samples. The coal in the 2C and the 1B bunkers was supposed to be the same at the time of the test. The laboratory assured ABB India that a representative amount of rock and coal were test together as a sample so that actual mill grinding parameters could be found. With these results this is questionable.

Due to the poor quality of the sample a mill heat balance was very limited.

**POWDERED COAL
SAMPLING DEVICE
AND FITTINGS**

FIGURE 21

CHANDRAPURA
MILL PRESSURE
TAP LOCATIONS

MILL OUTLET
(INVERTER
HEAD
PRESSURE.

* ALL U-TUBE
(CLEAR
(PLASTIC) MANOMETERS ARE 1/4"

TO MILL SHOULD BE TIGHT AND LEAK
TESTED.

EXHAUSTER

BOWL MILL
GENERAL ARRANGEMENT
(TYPE 1)
FIGURE 1

CLASSIFIED OUT
PRESSURE

UNDER BOWL
PRESSURE

UNDER
BOWL
ABOVE
BOWL ΔP

ABOVE
BOWL
P

EXHAUSTER
INLET P

EXHAUSTER OUT
(2 SIDES)

FIGURE 22

Photo 34
D.V.C Coal Fineness Sampler
Bottle Leaks & Lance is Wrong

CUSTOMER	D.V.C.	MILL TYPE	RB	MILL No.	1B
PLAN	Chandrapura	MILL SIZE	733	DATE	7/11/94
CONTRACT No.					
MILL NUMBER			1B		1B
START			19:00		20:00
Coal Feed Rate 1 rev = 55kg			16698		12705
Feeder Speed RPM			2.3		1.75
Primary Air Pressure A/B		in w.g.			
Primary Air Fan Amps		Amps			
Primary Air Temp A/B board*		Deg F	352 / 356		354 / 356
Outlet Temp board		Deg F	158		122
H.A.D. Position board		% Open 3 - 27 psig	14		14
H.A.D. Position Local		% Open	65		70
Underbowl Suction		in w.g.			
Furnace Pressure		in w.g.	<-0.35>		0.6
Motor Amps (runback 87 amps)		Amps	80 - 82		80 - 82
Number Mills Operating		A - E	A - D		A - D
Unit Load		MW	72		75
Air Inlet Temp-Wet		Deg F	N/A		N/A
Air Inlet Temp-Dry		Deg F	N/A		N/A
Airflow Traverse		lbs/min	747		
Barometric Damper Position		% Open	2 - 5		2 - 5
Exhauster Inlet Damper Position		% Open	100		100
Exhauster Inlet Temperature		Deg F	N/A		129
Inlet Temp-Wet		Deg F	N/A		N/A
Outlet Temp-Wet		Deg F	N/A		N/A
DP Manometers					
Underbowl Pressure		in w.g.	< - 0.75 >		< - 0.5 >
Abovebowl Pressure		in w.g.	< - 8.38 >		< - 9.62 >
Converter Head Pressure		in w.g.	< - 9.75 >		< - 10.5 >
Exhauster Inlet Pressure		in w.g.	< - 9.5 >		< - 11 >
Exhauster Outlet Pressure		in w.g.	10		9.25
Journal Spring Pre-load Prior		inches	1.75		
Journal Spring Preload @ Test		inches	1		1
Ambient Temperature					
Classifier Settings		1 - 6	1.3		1.3
Fineness					
50		% on			
100		% thru			
200		% thru			
Spillage		lb/hr			
Coal Temp.		Deg F			

CUSTOMER	D.V.C	MILL TYPE	RB	MILL No.	2C
PLANT	Chandrap	MILL SIZE	733	DATE	7/8/94
CONTRACT No.					
MILL NUMBER			2C		
START			16:47		
Coal Feed Rate 1 rev = 55kg			151.2		
Feeder Speed RPM			2.75		
Primary Air Pressure A/B		in w.g.			
Primary Air Fan Amps		Amps			
Primary Air Temp A/B		Deg F	203 / N/A		
Outlet Temp Board		Deg F			
H.A.D. Position Board		% Open 3 - 27 psig	27		
H.A.D. Position Local		% Open	100		
Underbowl Suction		in w.g.			
Furnace Pressure		in w.g.			
Motor Amps		Amps	77.5		
Number Mills Operating		A - E	3		
Unit Load		MW	50		
Air Inlet Temp-Wet		Deg F	89		
Air Inlet Temp-Dry		Deg F	98		
Airflow Traverse		lbs/hr			
Barometric Damper Position		% Open	0		
Exhauster Inlet Damper Positon		% Open	100		
Exhauster Inlet Temperature		Deg F	118		
Inlet Temp-Wet		Deg F	102		
Outlet Temp-Wet		Deg F	118		
DP Manometers					
Underbowl Pressure		in w.g.	< -1.5 >		
Abovebowl Pressure		in w.g.	< -6.9 >		
Converter Head Pressure		in w.g.	< -8.25 >		
Exhauster Inlet Pressure		in w.g.	< -8.25 >		
Exhauster Outlet Pressure		in w.g.	12.25		
Journal Spring Pre-load Prior		inches	1-1/2"		
Journal Spring Preload @ Test		inches	1		
Ambient Temperature			92		
Classifier Settings		1 - 6	1.3		
Fineness					
50		% on	N/A		
100		% thru	N/A		
200		% thru	N/A		
Spillage		lb/hr	ALL ROCK		
Coal Temp.		Deg F	89		

PULVERIZER HOT AIR FLOW TEST DATA									
UNIT		1				LOAD		75	
PULVERIZER No.		B				DATE		7/11/94	
BAROMETRIC PRESSURE		In Hg			29				
BAROMETRIC TEMPERATURE		Deg C							
TIME					START			FINISH	
FEEDER RATE 1 REV = 65 kg					16698			12705	
FEEDER SPEED		%			2.30			1.75	
PULV LOAD		%							
PULV EXIT TEMP		Deg F			158			122	
PA TEMP A/B		Deg F			352/358			354/358	
HAD POSITION		% OPEN			65			70	
BAROM DAMP POSITION		% OPEN			0			0	
EXH. INLET DAMPER POS.		% OPEN			100			100	
U.B. press		In w.g.			-0.75			-0.50	
A.B. press.		In w.g.			-8.38			-9.62	
EXH IN press.		In w.g.			-9.50			-11.00	
EXH OUT press.		In w.g.			10.00			9.25	
MOTOR AMPS		amps			80 - 82			80 - 82	
PITOT TUBE CORR FACTOR		dP Cp			0.84		VEL Cv	1.00	
TRAVERSE POINT LOCATION		TAP A	TAP B	TAP C	TAP D	TAP E	TAP F	TAP G	TAP H
Pos.	In W.G.								
8	Deg. C								
Pos.	In W.G.								
7	Deg. C								
Pos.	In W.G.								
6	Deg. C								
Pos.	In W.G.	0.09	0.22	0.20	0.11	0.31			
5	Deg. C	348	345	345	344	348			
Pos.	In W.G.	0.12	0.23	0.28	0.32	0.32			
4	Deg. C	348	349	351	357	351			
Pos.	In W.G.	0.13	0.18	0.25	0.31	0.34			
3	Deg. C	348	348	349	352	350			
Pos.	In W.G.	0.07	0.12	0.20	0.29	0.35			
2	Deg. C	348	349	349	350	349			
Pos.	In W.G.	0.09	0.11	0.22	0.30	0.30			
1	Deg. C	347	348	350	351	333			
					READING 1	READING 2	READING 3	READING 4	AVERAGE
DUCT STATIC PRESSURE in W.G.					0.89	0.89	0.89	0.89	0.89

2 - 112

PULVERIZER HOT AIR FLOW TEST DATA									
UNIT		1					LOAD	75	
PULVERIZER No.		B					DATE	7/11/94	
TOTAL DUCT AREA		sq. ft			7.500				
TRAVERSE POINT AREA		sq. ft			0.300				
AVERAGE TRAVERSE TEMP		Deg. F			348				
MINIMUM TRAVERSE TEMP		Deg. F			333		DEVIATION %		4
MAXIMUM TRAVERSE TEMP		Deg. F			357		DEVIATION %		3
TRAVERSE POINT LOCATION		TAP A	TAP B	TAP C	TAP D	TAP E	TAP F	TAP G	TAP H
Pos.	lbs / hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Btu / hr	0	0	0	0	0	0	0	0
Pos.	lbs / hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Btu / hr	0	0	0	0	0	0	0	0
Pos.	lbs / hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	Btu / hr	0	0	0	0	0	0	0	0
Pos.	lbs / hr	1179.8	1848.0	1762.0	1307.5	2189.6	0.0	0.0	0.0
5	Btu / hr	100226	165589	148348	109755	186012	0	0	0
Pos.	lbs / hr	1364.0	1884.8	2077.1	2212.3	2220.5	0.0	0.0	0.0
4	Btu / hr	116184	160801	178033	192891	180326	0	0	0
Pos.	lbs / hr	1417.9	1668.4	1865.1	2184.2	2290.2	0.0	0.0	0.0
3	Btu / hr	120467	141741	167438	187766	195724	0	0	0
Pos.	lbs / hr	1040.6	1361.4	1757.6	2115.1	2325.1	0.0	0.0	0.0
2	Btu / hr	88391	116004	149761	180760	198115	0	0	0
Pos.	lbs / hr	1180.5	1304.3	1842.3	2150.0	2174.2	0.0	0.0	0.0
1	Btu / hr	99989	110804	157440	184282	176463	0	0	0
TOTAL MASS FLOW		lbs / hr			44 822		lbs / min		747
TOTAL HEAT FLOW		Btu / hr			3812199		Ncu.m/s		4.37
AVERAGED TEMPERATURE		Deg. F			348				
VENTURI DP (MEASURED)		in W.G.			#REF!				
DUCT K FACTOR		x 10 E+01			#REF!				
VENTURI DP (INSTRUMENT)		in W.G.	A / B	#REF!	#REF!				
VENTURI TEMP (INSTRUMENT)		Deg. F	A / B	#REF!	#REF!				
INSTRUMENT K FACTOR		x 10 E+01	A / B	#REF!	#REF!				

PULVERIZER HOT AIR FLOW TEST DATA									
UNIT		1			LOAD	75			
PULVERIZER No.	B				DATE	7/11/84			
BAROMETRIC PRESSURE		in Hg		28.62					
BAROMETRIC TEMPERATURE		Deg F		85					
				START				FINISH	
TIME									
FEEDER RATE		Tonne/Hr							
FEEDER SPEED		%							
PULV LOAD		%							
PULV EXIT TEMP		Deg F							
PA TEMP A/B		Deg F							
HAD POSITION		% OPEN							
BAROM DAMP POSITION		% OPEN							
EXH. INLET DAMPER POS.		% OPEN							
U.B. press		in w.g.							
A.B. press.		in w.g.							
EXH IN press.		in w.g.							
EXH OUT press.		in w.g.							
MOTOR AMPS		amps							
PITOT TUBE CORR FACTOR		dP Cp	0.84		VEL Cv	1.00			
TRAVERSE POINT LOCATION		TAP A	TAP B	TAP C	TAP D	TAP E	TAP F	TAP G	TAP H
Pos.	in W.G.								
8	Deg. C								
Pos.	in W.G.								
7	Deg. C								
Pos.	in W.G.								
6	Deg. C								
Pos.	in W.G.	0.10	0.14	0.22	0.08	0.03			
5	Deg. C	367							
Pos.	in W.G.	0.11	0.16	0.39	0.40	0.41			
4	Deg. C	389							
Pos.	in W.G.	0.13	0.16	0.38	0.41	0.48			
3	Deg. C	370							
Pos.	in W.G.	0.16	0.12	0.37	0.40	0.48			
2	Deg. C	370							
Pos.	in W.G.	0.16	0.11	0.37	0.40	0.48			
1	Deg. C	372							
					READING 1	READING 2	READING 3	READING 4	AVERAGE
DUCT STATIC PRESSURE in W.G.					0.74	0.74	0.74	0.74	0.74

[illegible]

PULVERIZER HOT AIR FLOW TEST DATA									
UNIT		1					LOAD	75	
PULVERIZER No.		B					DATE	7/11/94	
TOTAL DUCT AREA		sq. ft			7.500				
TRAVERSE POINT AREA		sq. ft			0.300				
AVERAGE TRAVERSE TEMP		Deg. F			74				
MINIMUM TRAVERSE TEMP		Deg. F			367		DEVIATION %		-398
MAXIMUM TRAVERSE TEMP		Deg. F			372		DEVIATION %		403
TRAVERSE POINT LOCATION		TAP A	TAP B	TAP C	TAP D	TAP E	TAP F	TAP G	TAP H
Pos.	lbs / hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Btu / hr	0	0	0	0	0	0	0	0
Pos.	lbs / hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Btu / hr	0	0	0	0	0	0	0	0
Pos.	lbs / hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	Btu / hr	0	0	0	0	0	0	0	0
Pos.	lbs / hr	1228.1	1948.4	2442.5	1472.9	801.9	0.0	0.0	0.0
5	Btu / hr	110255	0	0	0	0	0	0	0
Pos.	lbs / hr	1285.5	2082.9	3252.0	3293.4	3334.3	0.0	0.0	0.0
4	Btu / hr	116151	0	0	0	0	0	0	0
Pos.	lbs / hr	1397.7	2016.8	3210.0	3334.3	3531.8	0.0	0.0	0.0
3	Btu / hr	126549	0	0	0	0	0	0	0
Pos.	lbs / hr	1550.7	1803.9	3167.5	3293.4	3531.8	0.0	0.0	0.0
2	Btu / hr	140393	0	0	0	0	0	0	0
Pos.	lbs / hr	1648.8	1727.1	3167.5	3293.4	3607.7	0.0	0.0	0.0
1	Btu / hr	141013	0	0	0	0	0	0	0
TOTAL MASS FLOW		lbs / hr			61425		lbs / min		1024
TOTAL HEAT FLOW		Btu / hr			634361		Ncu.m/s		5.99
AVERAGED TEMPERATURE		Deg. F			44				
VENTURI DP (MEASURED)		in W.G.			#REF!				
DUCT K FACTOR		x 10 E+01			#REF!				
VENTURI DP (INSTRUMENT)		in W.G.	A / B	#REF!	#REF!				
VENTURI TEMP (INSTRUMENT)		Deg. F	A / B	#REF!	#REF!				
INSTRUMENT K FACTOR		x 10 E+01	A / B	#REF!	#REF!				

[illegible]

PULVERIZER HOT AIR FLOW TEST DATA									
UNIT		1					LOAD	75	
PULVERIZER No.		B					DATE	7/11/94	
TOTAL DUCT AREA			sq. ft		7.500				
TRAVERSE POINT AREA			sq. ft		0.300				
AVERAGE TRAVERSE TEMP			Deg. F		74				
MINIMUM TRAVERSE TEMP			Deg. F		367		DEVIATION %		-396
MAXIMUM TRAVERSE TEMP			Deg. F		372		DEVIATION %		403
TRAVERSE POINT LOCATION		TAP A	TAP B	TAP C	TAP D	TAP E	TAP F	TAP G	TAP H
Pos.	lbs / hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Btu / hr	0	0	0	0	0	0	0	0
Pos.	lbs / hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Btu / hr	0	0	0	0	0	0	0	0
Pos.	lbs / hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	Btu / hr	0	0	0	0	0	0	0	0
Pos.	lbs / hr	1228.1	1948.4	2442.5	1472.9	901.9	0.0	0.0	0.0
5	Btu / hr	110255	0	0	0	0	0	0	0
Pos.	lbs / hr	1286.5	2082.9	3252.0	3293.4	3334.3	0.0	0.0	0.0
4	Btu / hr	110151	0	0	0	0	0	0	0
Pos.	lbs / hr	1397.7	2016.8	3210.0	3334.3	3531.8	0.0	0.0	0.0
3	Btu / hr	126549	0	0	0	0	0	0	0
Pos.	lbs / hr	1550.7	1803.9	3167.5	3293.4	3531.8	0.0	0.0	0.0
2	Btu / hr	140393	0	0	0	0	0	0	0
Pos.	lbs / hr	1648.8	1727.1	3167.5	3293.4	3607.7	0.0	0.0	0.0
1	Btu / hr	141013	0	0	0	0	0	0	0
TOTAL MASS FLOW			lbs / hr		61425		lbs / min		1024
TOTAL HEAT FLOW			Btu / hr		634361		Ncu.m/s		5.99
AVERAGED TEMPERATURE			Deg. F		44				
VENTURI DP (MEASURED)			in W.G.		#REF!				
DUCT K FACTOR			x 10 E+01		#REF!				
VENTURI DP (INSTRUMENT)			in W.G.	A / B	#REF!	#REF!			
VENTURI TEMP (INSTRUMENT)			Deg. F	A / B	#REF!	#REF!			
INSTRUMENT K FACTOR			x 10 E+01	A / B	#REF!	#REF!			

SHIRAM INSTITUTE FOR INDUSTRIAL RESEARCH

(A UNIT OF SHIRAM SCIENTIFIC & INDUSTRIAL RESEARCH FOUNDATION, DELHI)
79, UNIVERSITY ROAD, DELHI-110002

Telephone : 3135400/401

Telex : 7257287

Tel : 87-78051

Fax : 81-11-727676

E-Mail: shiram@delhi.sir@vsnl.net

Issued to :

TEST CERTIFICATE

No. 151740 40B-024-0282

Date: 27.08.94

sk

M/s Area Brown Boveri Ltd. (ABB),
Chandiwala Estate, Maa Anand Mal,
Kalkaji, Ashram Marg,
New Delhi - 19

Your Ref. No.:

Date: 08.08.94

Sample Particulars:

One sample of coal, marked I-B, was received.

TEST RESULTS

(1) Proximate Analysis, % by mass

(on dry basis)

(a) Ash content 39.63

(b) Volatile matter 15.78

(c) Fixed carbon (by diff) 44.59

(2) Ultimate Analysis, % by mass

(on dry basis)

(a) Ash 39.63

(b) Carbon 48.00

(c) Hydrogen 4.04

(d) Sulphur 0.31

(e) Nitrogen 0.93

(f) Oxygen Remainder

(3) Hard Groove Grindability Index 74.4

(H.B.I.)

SHIRAM

AUTHORISED SIGNATURE

- NOTE
1. The report refers only to the tested samples and applicable parameters. Endorsement of products is neither accepted nor repudiated.
 2. Total liability of our institute is limited to the invoice amount.
 3. Samples will be destroyed after one month from the date of issue of test certificate unless otherwise specified.
 4. This report is not to be reproduced wholly or in part and cannot be used as an evidence in the Court of Law and should not be used in any advertising media without our special permission in writing.

SHIRIAM INSTITUTE FOR INDUSTRIAL RESEARCH

(A UNIT OF SHIRIAM SCIENTIFIC & INDUSTRIAL RESEARCH FOUNDATION, DELHI)
19, UNIVERSITY ROAD, DELHI-110007.

Telephone: 725787

Telex: 031-78081

Fax: 011-7257878

E-Mail: shiriam@vsnl.com
Issued to:

TEST CERTIFICATE

M/s Area Brown Boveri Ltd. (ABB),
Chandiwala Estate, Maa Anand Mal,
Kalkaji, Ashram Marg,
New Delhi - 19

No. 151741 408-024-0285

Date: 27.08.94

Your Ref. No.:

08.08.94

Sample Particulars:

One sample of coal, marked 2-C, was received.

TEST RESULTS

(1) Proximate Analysis, % by mass

(on dry basis)

(a) Ash content : 51.91

(b) Volatile matter : 13.74

(c) Fixed carbon (by diff) : 34.33

(2) Ultimate Analysis, % by mass

(on dry basis)

(a) Ash : 51.91

(b) Carbon : 52.47

(c) Hydrogen : 3.14

(d) Sulphur : 0.28

(e) Nitrogen : 0.72

(f) Oxygen : Remainder

(3) Hard-Groove-Grindability Index : 84.3

(H.B.I.)

SHIRIAM

AUTHORISED SIGNATURE

- NOTE:-
1. The result listed refers only to the tested samples and applicable parameters. Extent of work is further indicated in the report.
 2. Test facility of our Institute is limited to the indicated amount.
 3. Samples will be destroyed after one month from the date of issue of test certificate unless otherwise specified.
 4. This report is not to be reproduced wholly or in part and cannot be used as an evidence in the Court of Law and should not be used in any advertising media without our special permission in writing.

VI. MILLING SYSTEM REVIEW

MILLING PLANT

On each of the three boilers, raw coal is pulverized and transported to four (4) corners of tilting tangential burners by five (5) ABB C-E 733 RB bowl mills equipped with 3576Y exhaustor fans originally supplied with 70" diameter whizzer fan wheel assemblies. Each pulverizer had a theoretical maximum capacity of 46000 pounds per hour at a coal product fineness of 80% through 200 mesh U.S. sieve size when grinding Indian high volatile B bituminous coal with a HGI of 55 and an as fired moisture content of 6 % and operating with a mill outlet temperature of 180 degrees F. Raw coal is fed to each pulverizer by an ABB C-E 67# volumetric feeder of the overshot roll type which was designed for a maximum feeder capacity of 49000 pounds per hour of raw coal with a density of 50 pounds per cubic foot.

SCOPE

The Chandrapura boilers are presently unable to achieve their rated design steam flow. This is partly due to the milling system attaining the maximum mill motor rating but delivering less than the original design coal throughput when grinding the current coal. ABB C-E was requested by Tennessee Valley Authority (TVA) to review the milling system - coal feeders, pulverizers, and exhausters - and make recommendations to increase the throughput of the milling system.

THEORETICAL MILL CAPACITY

Each 733 RB pulverizer had a maximum theoretical capacity of 46000 pounds per hour at a coal product fineness of 80% through 200 mesh U.S. sieve size when grinding Indian high volatile B bituminous coal with a HGI of 55 and an as fired moisture content of 6 % and operating with a mill outlet temperature of 180 degrees F. The design coal analysis is provided in Table 1 along with the two coal analyses for the coal samples obtained from 1B and 2C mill feeders during the visit by ABB C-E Services to the Chandrapura plant in July 1994.

The current coals are somewhat different from the original design coal. Both the current coal samples had higher Hardgrove Index (HGI) values than the original design coal which indicates the current coals are easier to grind and the pulverizer capacity is increased. On the other hand, there is a fairly large variability in the ash content of the current coal samples with the 2C sample

Table 1

Chandrapura Coals			
Coal	Chandrapura Design	Present 1B	Present 2C
F.C., %	34.9	41.9	32.3
S, %	0.6	0.29	0.26
H ₂ O, %	6.0	6.0*	6.0*
Ash, %	40.0	37.3	48.8
HHV, Btu/lb.	7380	8391**	6499**
Rank	Hi.Vol. B Bit.	Low Vol. B Bit.	Low Vol. B Bit.
HGI	55	74.4	84.3
V.M., dry, %	13.8	14.8	12.9

*Assumed value

**Calculated value from Dulong formula

having significantly more ash than the original design coal. The variability in ash content is also seen in the higher heating value which varies from as high as 8400 Btu per pound for sample 1B to as low as 6499 Btu per pound for sample 2C. These changing ash content and HHV do not affect the pulverizer capacity directly. The pulverizers will continue to grind the rated throughput of coal. However, when the increased ash content, decreased HHV coal is fed to the boiler, the coal demand will be increased to obtain the same steam output. This will require that more coal is fed to the mills causing either the mills to be overloaded or the boiler load to be limited due to feeder or mill limitations. Large swings in coal properties also make it difficult for the mills to provide a constant output.

The mill capacity for the original design and current coals compared to the required coal flow per mill at MCR boiler coal flow is presented in Table 2.

733 RB Mill Capacity versus Boiler Demand			
Coal	Chandrapura Design	Present 1B	Present 2C
H ₂ O, %	6.0	6.0*	6.0*
Rank	Hi. Vol. B Bit.	Low Vol. B Bit.	Low Vol. B Bit.
HGI	55	74.4	84.3
V.M., dry, %	13.8	14.8	12.9
Fineness, % - 200	80	80	80
733 RB Capacity, pounds per hour	46000	54000	66000
Feeder Capacity, pounds per hour	49000	49000	49000
Coal Flow per Mill, 4/5 mills @ BMCR, pounds per hour	44750	39358**	50816**
Coal Flow per Mill, 5/5 mills @ BMCR, pounds per hour	35800	31487**	40653**

*Assumed value

** Approximate value based on ratio of Design HHV/Current coal HHV

Table 2

The data in Table 2 shows that the mill capacity should be adequate for 4 or 5 mill operation for mills in new condition, except for one instance for the 2C current coal. For this coal with a HHV of only 6499 Btu per pound, the boiler demand is greater than the maximum feeder capacity when firing 4 of 5 mills. In other words, the feeder capacity is limiting boiler load for the high ash, low Btu per pound coals.

Another thing that must be considered is that there is a loss in mill capacity as the grinding parts wear: up to 10 to 15 percent. The mill reaches its capacity limit when either the mill motor attains its maximum power limit, when the mill begins to spill coal excessively, or when the mill pressure drop becomes too high. If the mill capacity in Table 2 is reduced by 10 percent and then compared to the coal flow per mill required by the boiler, it is evident that for 4 of 5 mill operation at BMCR with the design coal with a HGI of 55, the mill has insufficient capacity.

In other words, the boiler will be limited in load if the mills are worn and a low HGI coal is being fired. In fact, boiler MCR cannot be achieved with 4 of 5 mill operation when firing coal with a HGI less than 60 if the mills are worn.

If it should occur that coal with both HGI less than 60, and high ash content, low HHV be fired with the mills in a worn condition and 4 of 5 mill operation is required, then the shortfall in boiler capacity from MCR could be considerable. For this situation with coal of 55 HGI, 49 percent ash and 6500 Btu per pound HHV, the boiler requires 50816 pounds per hour per mill. However, each mill can only deliver 41400 pounds per hour. Therefore, the shortfall from BMCR would be almost 20 percent.

What is important to note from the preceding is that this 20 percent shortfall for 4 of 5 mill operation is due to mill wear and coal properties only. About 10 percent can be recovered by keeping mills in new condition all the time, but as anyone who operates a power plant knows, this is not a practical solution. The other 10 percent is due to coal properties which are out of the control of the mill supplier and mill operator-owner. These shortfalls are not recoverable simply with rehabilitation of the mills and improved maintenance practices.

INSPECTION OF FEEDERS, PULVERIZERS, and EXHAUSTERS

The coal feeders, pulverizers, and exhausters were inspected by ABB C-E Services personnel during a visit to the site in July 1994. The internals of 1B and 2C mill and exhauster were inspected at that time.

Of the items noted, the following are those which have a detrimental effect on the performance of the milling system:

Feeders:

The **feeder gate hinge** is operated with an excessively large clearance by the plant to avoid rock hang-ups in the feeder. This practice usually leads to uncontrolled feeding with large variability in feed rate which in turn cause boiler load swings.

Another contributing factor to variability of coal feed rate was the inconsistency in **feeder roll blade heights** which will affect the amount of coal delivered per revolution of the feeder.

There were several sources of **air ingress** through the feeder - holes in the feeder outlet hopper transition and feeder doors left open for ease of observing and removing feeder hang-ups caused by rock in the raw coal - which will cause more cold air than is wanted to enter the mill. This practice will prevent adequate drying of the coal by the hot mill inlet air and reduce mill capacity and mill outlet temperature.

2C feeder was calibrated on site and it was determined that the **coal feed rate** was 55 kilograms or 121 pounds per revolution. At the maximum speed setting at site of 6 RPM it is equivalent to 43600 pounds per hour. This is 10 percent less than the original equipment capacity of 49000 pounds per hour.

Pulverizers:

As stated in the preceding, 1B and 2C mills were internally inspected prior to air flow testing and data collection so that the state of the tested mills would be known.

The **inner cones** on both mills were found to have holes. Holes in the inner cone allow the pulverized coal to bypass the deflector openings in the drum section of the inner cone classifier and proper classification of the pulverized coal does not occur. The result is that more than the normal percentage of coal particles greater than 50 mesh U.S. sieve size exit the pulverizer leading to combustion problems like higher unburned carbon, poorer flame stability, and increased furnace wall slagging.

The **center feed pipes** were found to be off center. In addition to increased wear on the lower portion of the inner cone, this can sometimes cause rough operation of the mill which in turn can prevent the mill from attaining peak performance.

The **inverted cone to inner cone clearance** on both mills was 4.5 to 5 inches; the **feed pipe to inner cone clearance** on both mills was 6.3 inches. Both dimensions are measured perpendicular to the inner cone slope. These dimensions are greater than what is normally expected. The nominal dimensions are 3 to 3.5 inches minimum for the inverted cone to inner cone clearance and 4.5 inches for the feed pipe to inner cone clearance. However, these dimensions can and are set up differently in the field to optimize mill fineness. These settings may be satisfactory provided the mill fineness is acceptable. If the mill fineness is not acceptable (the most likely problem being too high a +50 mesh U.S. sieve size value) then these inner cone clearances may be contributing to the problem.

On 2C mill, the **journal springs** were compressed to different heights; the journal springs on 2C and 1B as well were reset equally to 1 inch initial compression. After putting the 2 mills back in service, it was noted that the journal springs deflected different amounts. The differing deflections could be due to differences in the spring rates of the springs. Operation in this manner, in addition to increasing the magnitude of cyclic stresses on the main vertical shaft of the gearbox, which results in premature shaft failures, often prevents the mill from attaining peak performance depending on the amount of variance. Typically this can cause lower fineness values, higher power consumption, higher mill pressure drop, or rough operation.

The **journal air seals** were noted as being worn and air was observed to be infiltrating the mill through large gaps near the journal head skirt. Also, there was a gap between the **separator body flanges**. These gaps will allow more cold air than

is wanted to enter the mill. This practice will prevent adequate drying of the coal by the hot mill inlet air and reduce mill capacity and mill outlet temperature.

On 2C mill, **roll wear** depth was measured to be 1 to 1.5 inches on rolls #1 and #3 and 1.5 inches on #2 roll. For the testing, the roll to ring gap was set at 1/4 to 3/8 inches at the top of the ring and 3/8 to 5/8 inches at the bottom of the ring.

On 1B mill, roll wear depth was measured to be 1 inch on #1 and #2 rolls. The #3 roll was a new journal assembly but was replaced because the journal assembly had a bearing problem. The replacement roll was not new but had lesser wear depth than the other two rolls. The roll to ring gap was set at 1/4 to 3/8 inches at the top of the ring and 3/8 to 5/8 inches at the bottom of the ring for the testing.

Operating mills with rolls of differing wear depths is not good practice. In addition to increasing the magnitude of cyclic stresses on the main vertical shaft of the gearbox, which results in premature shaft failures, this practice prevents the mill from attaining peak performance depending on the amount of variance. Typically this can cause lower fineness values, higher power consumption, higher mill pressure drop, or rough operation.

The **bull ring segments** of both mills were measured to have a wear depth at the maximum wear point of 1/4 to 1/2 inches.

There were some **air vanes** in the air openings around the bowl periphery installed at a 5 degree from horizontal angle. In addition the **deflector kicker liners** were worn through. The bowl to bowl extension angle gap was measured to be 1/4 to 1/2 inches. These air entry areas are critical to having the correct air velocity entering the mill from the underbowl to the mill for proper grinding

and classification of the coal and minimal coal spillage with optimum rejection of pyrites and tramp iron. The condition observed would prevent this from happening. The 5 degree air vanes would restrict air flow causing excessive mill pressure drop and promoting coal spillage. The worn out deflector kicker liners would allow air to enter the above bowl area more or less vertically instead of being directed in towards the bowl which could overload that area of the bowl periphery and promote coal spillage.

Exhausters:

The exhausters for 1B and 2C mills were inspected and it was found that the **fan blades** were 24 to 25 inches long by 21 to 22 inches wide with a casing to blade side clearance of 3/4 to 1-3/4 inches. It was also noted that the edges of the blades were left rough cut. The fan blades originally supplied were 26 inches long by 22-1/2 inches wide. This means that the current fan blades result in an exhauster fan wheel diameter that is 66 to 68 inches diameter instead of the required 70 inch

diameter and in excessive side casing to fan wheel clearances. This will result in reduced mill air flow which in turn will result in higher mill power consumption and /or mill spillage and reduced mill capacity.

MILL CLEAN AIR TESTS

Clean air tests were conducted on 1B and 2C mill. The results of the tests are shown in Table 3.

Mill Clean Air Tests				
Mill	Avg. Velocity (feet per sec.)	Total Measured Air Flow (pounds per minute)	Corrected Air Flow (lbs./min. @ 180 F)	% of Standard
1B	114	1899	1655	124
2C	102	1595	1481	110

Table 3

The criteria for acceptable exhauster clean air flow is that the air flow corrected to the design mill outlet temperature, (in this case 180 degrees F), be between 135 percent and 160 percent of the standard mill air flow which. For this mill size the standard airflow is 1340 pounds per minute. The 35 to 60 percent margin above design air flow is to allow for the reduction in air flow that occurs

when the pulverized coal and water vapor displaces some of the air volume entering the exhauster fan under operating conditions.

As Table 3 shows, the exhauster air flows for both mills tested was below the acceptable minimum air flow. This is most likely due to the diameter of the exhauster fan wheels being too small, as was indicated by the inspection of the exhausters. As stated previously, the smaller blades can result in higher mill power consumption and /or mill spillage and reduced mill capacity.

MILL HOT AIR TRAVERSE TESTS

A pitot tube traverse of the hot air duct to 1B mill was conducted with the mill under load. From the test data the actual air flow to the mill during the test was calculated.

The measured air flow entering the mill was 41400 pounds per hour for the mill at approximately 50 percent load. This compares to 73400 pounds per hour based on a mill heat balance calculation at the same load and design conditions. The mill inlet air flow is 44 percent lower than design and is due to the many factors previously

identified - air ingress in the feeder and the mill, 5 degree air vanes around the bowl, and undersize exhaust fan blades.

ACTUAL MILL CAPACITY

There were maximum boiler load tests conducted in December 1993 on unit 1 with the normal run of mine raw coal containing quantities of rock. During these tests, 4 of 5 mills carried 71 percent turbine load and 5 of 5 mills carried 90 percent turbine load.

4 of 5 mills averaged 81 of a possible 87.7 mill motor amps and it was estimated that the average per mill coal flow was 30750 pounds per hour. 5 of 5 mills averaged 85 of a possible 87.7 mill motor amps and it was estimated that the average per mill coal flow was 30800 pounds per hour. No determination of the HGI of the raw coal feed or of the fineness of the pulverized coal was done.

In January 1994, unit 2 was tested for maximum capacity with a clean coal, i.e., the rocks were picked from the coal especially for this test. For this test, there were data taken as shown in Table 4 for the mills.

Table 4 shows that the approximate mill load is about 60 percent yet the mill motors are almost fully loaded.

Mill readings were taken on 1B mill during the hot air flow traverse in July 1994. No fineness samples were taken, but for 16700 pounds per hour throughput, compared to a worn mill capacity of 48600 pounds per hour assuming an optimistic 80 percent - 200 pulverized coal fineness, or 34 percent mill load, the mill motor was at 92 percent load.

January 1994 Clean Coal Test		
Turbine MW	95	110
% Turbine Load	76	88
Coal HHV (Btu/lb.)	7112	7112
Coal HGI	82	82
Max. Mill Cap., Worn @ 80%-200 (lb./hr.)	57240	57240
# Mills in service	4	5
Estimated Coal Flow/Mill (pounds per hour)	35300	32700
% Mill Load	62	57
Mill Motor Amps	85	86
% Mill Motor Load	97	98

Table 4

The preceding estimations of coal feed rate, mill motor load, and mill load must all be viewed somewhat suspiciously because many measurements have been taken without calibrated equipment and assumptions have been made to fill in missing data. The values presented are not to be taken at face value as accurate.

However, the approximations presented do demonstrate that the mills fall short of their rated capacity and that the mill motor power is higher than it should be. The data presently collected cannot identify all the reasons for this.

REBUILDS and UPGRADES

Reviewing the preceding, it can be seen that there are many problems with the feeders, mills, and exhausters that are preventing the milling system from attaining maximum capacity. The data is not complete enough to identify what percentage capacity reduction is due to each problem. There can be a capacity limitation caused when low HGI, high ash low HHV coal is burned. The mill capacity shortfall is somewhere around 30 to 40 percent.

To restore this milling system shortfall, a step-wise approach of equipment rehabilitation, testing and data collection, and equipment upgrades is best to further identify and solve problems while restoring mill capacity in an economic manner.

When rehabilitating equipment, there will be a choice between replacing or repairing milling system components. In some instances it will be better to replace the component in question to ensure dimensional clearances and dimensions, critical to maximum performance, are maintained than to repair the component.

Step 1 - Restore mill air flow to design:

Eliminate all points of air in leakage by repairing the holes in the feeder outlet hopper transitions, closing feeder doors, closing up the separator flange gap, and restoring the journal air seals to like new condition. Most of the air ingress points can be sealed by patching and welding provided no holes exist afterwards. The journal air seals should be replaced with new assemblies to ensure a tight sealing interface with the journal.

Patch all holes in the inner cones or replace the inner cones with a new ones. Repairing the cones will be acceptable provided no holes exist afterwards.

Reposition the 5 degree air vanes at the bowl periphery to 45 degrees.

Rebuild the exhausters to new condition replacing all liners with new ones and installing rebuilt fan wheels with fan blades for 70" fan wheel diameter. Grind smooth rough cut fan blade edges, and pay particular attention to the condition of the fan bearings and make sure all fan wheels are balanced.

It is recommended that all exhauster fan fabricated parts and liners be replaced with new factory quality components so that all fan internal dimensions are re-established. It is critical for maximum fan performance that the fan diameter and width, fan blade to casing clearances, periphery inlet ring clearance, and whizzer blades be correct dimensionally.

Then perform a clean air test on each mill to check whether the design clean air flow and balanced pipe to pipe flow is being achieved. If additional air flow is required, the fan blades can be lengthened: this fan model can have up to 76" fan wheel diameter.

Step 2 - Restore mills to maximum capability:

Rebuild at least one mill to like new condition and test the mill for its maximum capacity at rated fineness and maximum fineness at rated capacity. For these tests raw coal samples must be taken for HGI analysis, Proximate analysis including total moisture, Ultimate analysis, and HHV. Also fineness samples must be taken at the same time as the data is taken using ABB C-E fineness sampling equipment and procedure. (Note: the equipment at site now is not acceptable due to the altered sampling nozzle and lack of aspirators in the coal pipes.)

The mill should be operated at a mill outlet temperature of 180 degrees F during these tests. The rated fineness is 80% -200 mesh U.S. sieve size.

There is a benefit to operation at 180 degrees F which maybe achievable if the air ingress has been eliminated per step 1. Mill capacity could be increased about 2 percent by raising the mill outlet temperature from 160 to 180 degrees F.; more moisture is removed from the bed of coal on the bowl making the coal easier to grind.

There are advantages to operating the mills with the fineness at 80 percent through 200 mesh U.S. sieve size: Finer particles going through the exhauster will reduce exhauster wear, as wear is a function of particle size, and higher fineness coal particles will provide better flame stability to minimize flameouts during the feeder rock jams.

The feeder must be calibrated and provide a regulated flow. If the feeder must be rebuilt to new condition to do this, then it should be done.

Rebuilding one mill for this testing means:

- re-centering the center feed pipe in the cone.

- restoring the inverted cone to inner cone clearance and feed pipe to inner cone clearance to nominal dimensions if fineness cannot be achieved. This can be done by repair without component replacement provided the proper dimensions are maintained around 360 degrees of the pipe periphery.
- replacing the journal springs so that the spring rates are the same or setting the springs with the hydraulic spring fixture so that the springs can be set to the same initial setting. Spring replacement is not required if the hydraulic setting procedure is used to set the initial spring setting.
- installing new grinding rolls and bull ring segments and setting roll to ring gaps in accordance with ABB C-E instructions. The rolls and rings should be replaced with new components to ensure the roll - ring profiles are correct. This will provide the maximum mill capacity with the lowest possible power consumption. The price of these parts is approximately \$19,400 USD per mill if the parts were purchased from ABB CE- Services in the US. The pricing of these parts is in section VI. PRICING 1.0 MILL REBUILD.
- replacing all separator body liners, restoring the air vanes, and replacing the bowl restriction angle making sure to minimize the gap around the bowl. This air entry area around the bowl is critical to having the proper air entry velocity which is required for proper drying, classification, and no coal spillage. The replacement of separator body liners with new parts in this zone will ensure the deflector kicker liner nose is not worn away and "kicks" the coal into the bowl. The air vanes can be repaired, not replaced, provided the vanes are the correct length and orientation and are not curled over due to thinning. The air restriction angle and bowl extension ring should be replaced to minimize the gap between these components so that mill capacity is not reduced due to excessive coal spillage due to low air velocity. See figure 23 for location of these replacement parts. The price for the parts in this section would be approximately \$17,200 USD per mill if the parts were purchased from ABB CE- Services in the US. The pricing of these parts is in section VI. PRICING 1.0 MILL REBUILD.
- restoring the mill scrapers to the proper clearance from the mill bottom. The scraper assemblies should be replaced with new assemblies to re-establish proper scraper blade to mill bottom clearances for prompt removal of reject material from the underbowl. The price of these parts is approximately \$2,892 USD per mill if the parts were purchased from ABB CE- Services in the US. The pricing of these parts is in section VI. PRICING 1.0 MILL REBUILD.

Step 3 - Install and test a high efficiency exhaustor fan wheel:

After determining the maximum capability of the rebuilt mill, a decision can be made whether to proceed with additional modifications.

The high efficiency exhauster fan wheel can be sized for increased air flow - increased fan power which may reduce grinding power, or same air flow - reduced fan power which makes more mill motor power available for grinding. A mill capacity increase of 10 percent is typical if mill capacity is being limited by air flow. The price of a High Efficiency Exhauster is approximately \$38,740 USD per exhauster if the parts were purchased from ABB CE- Services in the US. The pricing of these parts is in section VI. PRICING 2.0 733 RB MILL UPGRADES.

Repeat the mill tests to determine the maximum mill capacity.

Step 4 - Install a 600 HP mill motor in combination with the high efficiency exhauster fan wheel:

Some additional mill capacity may be gained by installing larger mill motors, if at this point, the mill is capacity limited by motor power. The mill gearbox will have to be analyzed to check if the gearbox can carry the additional power transmission.

Repeat the mill tests to determine the maximum mill capacity.

Step 5 - Replace feeder with belt type feeder of higher capacity:

This will prevent the boiler load being limited by the feeders for low HHV coal and allow the mills to attain a higher rating. The belt type feeders will be less susceptible to rock jams so the feeder doors can remain closed and air leakage will be reduced.

This retrofit will require a redesign and replacement of the coal bunker bottom to offset the coal feeder inlet from the outlet enough to fit in a belt type feeder, which typically has a longer minimum length than the overshot roll feeder. The shortest conventional belt feeder available is 2 feet 6 inches long. However, there is a 2 belt feeder design with one belt over a return belt which allows for the inlet to be located over the discharge. This could be used to avoid having to carry out bunker modifications. Another possibility is to install the belt feeder with the feeder inlet below the existing bunker downspout and arrange the feeder to discharge into the adjacent mill in a staggered arrangement. This option would work best with the addition of a mill so that there is an even number of mills to stagger the feeders in pairs. See the INSPECTION section 2C feeder and APPENDIX section A.1 for more details. STOCK company estimates that each feeder set up would cost approximately \$90,000 USD.

With belt feeders, there will exist the possibility that the belts may be damaged by the incoming rocks in the feed. Since there are belt type feeders on other units at the Chandrapura Station, similar experience can be expected.

To keep the existing overshot roll feeders in service until belt feeders are retrofitted will require that the feeder RPM be increased to about 7 RPM in order to obtain the design feeder capacity for the present feeder hinge gate setup. To eliminate plugging due to rock jams, the maximum rock size fed to the feeders must be reduced to 3 inches, the maximum diameter that will pass through the feeder. This can be accomplished by installing grizzlies upstream of the bunker to remove rocks over 3 inches. The bunker downspout and feeder discharge hopper and downspout to mill can be increased in diameter to reduce coal plugging. If this interim fix provides acceptable feed rates without plugging and rock jams, then the belt feeder retrofit is not necessary.

Step 6 - Review mill maintenance:

Staggered mill maintenance

This approach to mill maintenance is to overhaul each mill one after the other on one unit, with the time interval between mills being such that, when all the mills on one unit are overhauled, the first mill that was overhauled is now worn out, and the cycle starts again. This practice results in one mill new, one mill worn all the time and every other mill somewhere in between, for an average worn capacity loss of half the maximum all the time. If it is assumed that one mill loses 10 percent capacity due to wear, then staggered mill maintenance results in an average mill capacity loss of 5 percent.

Mill maintenance where all mills are allowed to become fully worn and then all the mills are overhauled at once, results in 10 percent loss in mill capacity at the time immediately preceding the mill overhaul.

The plant can review their mill maintenance practice to see which approach provides the higher mill loading against their annual boiler demand.

Shorter maintenance interval

The other thing that can be done is to rebuild mills to new condition at shorter intervals than presently, i.e., before the mills become fully worn, or upgrade mill components to provide longer time between overhauls.

Step 7.a - Retrofit an additional mill:

If the preceding steps do not produce sufficient mill capacity, then continuous 5 of 5 mill operation or the retrofit of a sixth mill should be considered. The retrofit scenario provides 20 percent additional capacity.

Step 7.b - Conversion of 733 RB mill to 753 RB mill:

Another possibility is to convert the existing 733 RB mills to 753 RB mills for approximately 8 percent capacity increase. This has been done before as described in the APPENDIX section A.4 733 RB / 753 RB MILL CONVERSION.

The write up is a 1966 proposal to a customer (Metropolitan Edison Company) for the conversion of their 733 RB mills to 753 RB mills to gain capacity. The exact parts that would be needed for a conversion for D.V.C. would not be the same as those in this proposal. The basic idea is to replace / increase the size of the coal piping, exhaustor outlet, riffle distributors, mill bowl, and mill side liners while leaving the body of the mill and exhaustor intact.

Figures 24 and 25 show the standard CE curves for these two mills. The 753 RB mill has a base capacity (at 55 grind through 70%) of 59,100 lb/hr. The 733 RB mills that are at Chandrapura have a mill capacity of 54,500 lbs/hr with the same conditions.

These means an approximate 2 metric tons per hour theoretical difference. This would be about an 8% increase in capacity. The 733 RB mills now are approximately 30% below theoretical capacity from the estimates in the section above. It should be noted that much of the lost capacity in the 733 mills is due to worn parts, low air temperature and exhaustor wear. If the mills were converted many of these problems would be taken care of in the conversion.

As a note, the customer did not make the conversion due to the economics of the conversion.

PULVERIZERS

PERFORMANCE DESIGN STANDARD SHEET NO. 80-034

RB

FIGURE 24

PULVERIZERS

PERFORMANCE DESIGN STANDARD SHEET NO. 80-033

RB

MAX. MILL CAPACITY WITH PREHEATED AIR - THOUSAND LBS. PER HOUR

FIGURE 25

Section 2.2

Turbine Auxiliary Lube Oil System

Lube Oil System

Problem Statement

Inadequacies of lube oil system leading to the possibility of low purity level of oil at the inlet to bearings and controls.

System Description

Unit No. 2 of CTPS is provided with unitized lube oil system. The system consists of a main oil pump which is turbine shaft driven, an AC motor driven auxiliary oil pump, a DC motor driven emergency bearing oil pump, and an AC motor driven turning gear oil pump. The main oil tank (mot) is mounted at the O.M. Level. The purification system provided is a bowser system. The mot is provided with 2 x 100% oil coolers. A unit drain oil tank is provided so that the mot can be emptied into the unit drain oil tanks. Oil transfer pumps are provided. The block diagram of the lube oil system is shown in attachment I.

Analysis

An examination of the Unit 2 mot, after draining, indicated poor oil condition. Considerable sludge had accumulated at the bottom of the tank. The original oil vapor exhausters is removed and a contingency vapor exhauster has been installed.

Efficient operation of the lube oil system is vital to the operation of the turbine/generator set. Apart from maintaining the adequate flow and pressure of lube oil, the purity of the oil is recommended by the OEM. The lube oil system design data is in attachment II. The efficiency of the lube oil system has been analyzed by means of the "fish bone" technique of root cause analysis (attachment III). According to the pre-shut down data recorded, the system is supplying adequate pressure to all bearings and the oil temperature is within limits. The root cause of the problem of low purity oil was investigated. The major findings of the study are as follows:

- Oil sludge in the mot of Unit 2 has solid particles of ash and coal that have entered the system through the location of the removed vapor extractors.
- The oil drain line, in the condenser, has a hole in it.
- Bearing oil seals at the main turbine bearings have excessive clearance.

Damage assessment:

Openings in the mot (location of the original vapor extractors) is the main source of contamination.

- Bearing oil seal clearances are high and allow contamination of the lube oil.
- The oil drain line in the condenser allows oil to be drawn into the feed-water system.

Recommendations:

- Drain the oil from the bowser unit. Clean the lube oil tank and the bowser units completely.
- Relocate the oil drain piping on the turbine end of the double flow low pressure turbine. Field route the new piping away from the exhaust of the turbine.
- Modify the piping arrangement for the new vapor extractor as shown on attachment IV. Close all openings on the lube oil tank (i.e., locations of the old vapor extractors). Install vacuum measurement instrumentation on the tank and on the bearings and adjust the tank vacuum to the required values to maintain the bearings at 1" to 1.5" water vacuum.
- The lube oil needs periodic sampling to monitor the oil supply system.
- The bearing oil seals need to be returned to design clearances.

BLOCK DIAGRAM OF LUBE OIL SYSTEM

ATTACHMENT 1

Design Data of Lube Oil System

Attachment II

Main Oil Pump

Number:	1
Type	Centrifugal
Drive	Main turbine shaft
Capacity	2050 LPM
Discharge pressure	14.1 kg/square cm

Auxiliary Oil Pump

Number:	1
Type	Centrifugal (vertical)
Drive	AC motor - 125 Hp, 400 V
Capacity	1514 LPM
Discharge pressure	12.7 kg/square cm

Bearing Emergency Oil Pump

Number:	1
Type	Centrifugal (vertical)
Drive	DC motor - 10 Hp, 250 V
Capacity	852 LPM
Discharge pressure	2.8 kg/square cm

Turning Gear Oil Pump

Number:	1
Type	Centrifugal (vertical)
Drive	AC motor - 20 Hp, 400 V
Capacity	1287 LPM
Discharge pressure	2.8 kg/square cm

Main Oil Tank

Number:	1
Capacity	14,380 liters

Turbine Oil Coolers

Number	2
Type	Vertical, not mounted, shell and tube type
Tube material	Arsenical admiralty
Tube od	5/8"
Cooling water	31.5 liters/second at 35°C
Temp of water (inlet)	35°C
Temp of water (out)	37.8°C
Temp of oil (inlet)	57.2°C
Temp of oil (out)	46.1°C

Drain Oil Tank

Number	2 common for 2 units
Capacity	16 cubic meters each

Oil Transfer Pumps

Number	2 common for 2 units
Capacity	68 LPM each
Tdh	1.57 kg/square cm

Lube Oil Purifier

Number	1
Type	Bowser
Pump Capacity	68 LPM @4.57 kg/square cm

Operating Parameters

Pressure at mop discharge	14 kg/square cm
Pressure at bearings	2.1 kg/square cm
Oil temp at inlet of coolers	56°C
Oil temp at outlet of coolers	44°C

FISH BONE ANALYSIS FOR LUBE OIL SYSTEM

LUBE OIL VAPOR EXTRACTOR MODIFICATION
ATTACHMENT IV

Section 2.3

Turbine Steam Path Assessment

Turbine Steam Path Assessment

HP/RH

The HP was found in fair condition. There is considerable erosion of the nozzle in the area of the first quadrant. The struts in the HP bowl have cracks. The whole HP turbine was very dirty. Minor tenon erosion was found on the first five rows of the HP. The HP rotor has indications in the mid-span. These are evaluated by the CDA team. The RH section of the rotor was in good condition. Heavy deposits (96% silica) were found on the last two rotating stages. The RH nozzle was in fair condition with minor bounce back damage found. The steam path audit was performed and the recommendations are attached (HP down 3.88%, RH down 3.08%). The HP/RH rotor is to be returned to service in this unit.

LP

The LPDF rotor was found with L-0 GE bucket failure and shroud over three blades was missing. Two L-1 GE buckets were removed due to bucket failure. The shroud, on several groups, has been lowered on the blades to allow reinstallation. L-2 shroud had a crack area. The disk, at the L-0 on the generator end, was damaged by water from the water glands entering the turbine. The balance weights showed considerable erosion. The tenons have minor erosion damage. The stellite erosion shields, on the generator end, have considerable damage. The LP L-0 diaphragm on the Gen End has several partitions damaged due to the L-1 failure. The L-0 diaphragms on both the GE and TE have "ballooned". The cross-over expansion joint was found to have three small holes. The LP section was very dirty (96% silica). The buckets on L-2 and L-3 both ends have deposits up to 0.040" thick. The steam path audit was performed and the recommendations are attached (LPDF down 4.00%). The spare LPDF rotor is to be installed in this unit.

Valves

The inspection of the screens on the MSV's showed 10% plugged. Left MSV plug has a single crack in the stellite. The valves are in good condition. The reheat stop and intercept valves do not seat according to the erosion pattern in the stellite.

Controls

A detailed walk-down of the turbine controls system was performed to assess its condition. Discussions were also held with the operation and maintenance personnel in this area. The assessment and discussion revealed no major control system problems. There have been no turbine trips due to control system problems. The control system is operating with no "governor bobble". This is a good indication of the healthy control system. The oil trip test is performed during some start-ups, but actual mechanical over-speed testing has not been performed for quite some time. It is recommended that actual mechanical over-speed test be performed at a reduced speed of 105%, especially after any work is performed in the front standard components.

No major oil leaks were found on the valve hydraulic actuators. Air supply to the valves was acceptable.

The turbine extraction line non-return valves (NRV's) were also inspected. These NRV's do not have counter weights attached or limit switches mechanically or electricity connected. The online test mechanism on there valves is also not functional. It is recommended that these valves should be made functional and tested, as they play a very important role in the turbine over speed control protection.

Complete maintenance on all the key control components is performed every major outage, which is good maintenance practice.

ASSESSMENT SCOPE

This outage included inspection of the following systems:

- Complete valve inspection.
- Complete inspection of control and safety systems.
- Inspection of HP/RH, and LPDF.
- Inspection of generator.

STEAM PATH AUDIT

The losses due to steam path degradation revealed several areas of repair needed. The losses are as shown below:

<u>Component</u>	<u>KW Losses</u>
A. Interstage Packing	
<i>HP</i>	<i>522.35</i>
<i>RH</i>	<i>216.59</i>
B. End Packing	
<i>N-2</i>	<i>307.28</i>
C. Radial Spill Strips	
<i>HP</i>	<i>236.54</i>
<i>RH</i>	<i>637.93</i>
<i>LP-T</i>	<i>396.61</i>
<i>LP-G</i>	<i>93.63</i>
D. Miscellaneous Leakages	
<i>Holes in Crossover</i>	<i>57.31</i>
<i>Expansion Joint</i>	
E. Flow Path Damage	
<i>Total Losses</i>	<i>5,845.47</i>
F. Surface Roughness	
<i>HP</i>	<i>563.51</i>
<i>RH</i>	<i>351.83</i>
<i>LP-T</i>	<i>137.68</i>
<i>LP-G</i>	<i>137.68</i>
G. Cover Deposits	
<i>HP</i>	<i>None</i>
<i>RH</i>	<i>None</i>
<i>LP-T</i>	<i>8.20</i>
<i>LP-G</i>	<i>9.42</i>

<u>Component</u>	<u>KW Losses</u>
H. Trailing Edge Thickness	<i>None</i>
I. Other	<i>None</i>

Total *9,522.05 KW **

* This is at 140 MW. Estimate losses at 100 MW is 6,800 KW.

Steam Path Audit Recommendations:

Perform the Following Replacements, Modifications, and Cleaning:

Interstage Packing:

HP	Replace stages: 2, 3, 4, 5, 6, 9
RH	Replace stages: None
LP-T	Replace stages: None
LP-G	Replace stages: None

End Packing:

N-2	Replace all rings
-----	-------------------

Radial Spill Strips:

HP	Replace stages: 1, 6, 9
RH	Replace stages: 10, 11, 14, 15, 16, 18, 21
LP-T	Replace stages: 22, 23, 24
LP-G	Replace stages: 24

Miscellaneous Leakages:

Repair holes (3) in crossover expansion joint

Flow Path Damages:

1. Clean turbine to remove deposits on rotating and stationary steam flow path.
2. Repair partitions on HP nozzle.
3. L-0 diaphragms need ballooning repaired.
4. L-1-G buckets need to be refurbished.

Surface Roughness:

Most of the surface roughness is due to the deposits in the rotating and stationary steam flow path components. Therefore, cleaning to remove the deposits will eliminate these losses.

Repair Procedures for Turbine Steam Path

HP/RH Inlet Flanges

- The correct gaskets should be installed in the flanges. Refer to the general electric parts manual.

Repair of Damaged L-0 Diaphragms on the Generator End

- Blend all raised portions of partitions to original contours.
- Remove damaged areas that can not be blended.
- Perform inconel weld repair of removed portions of partitions.
 - * Pre-heat to 400 degrees F and maintain during welding
 - * Use inconel 82 wire
 - * Use copper chill block to establish profile.
 - * After weld completed raise temperature to 600 degrees F for 1/2 hour followed by cooling to room temperature.
- Blend weld repaired portions of partitions to original contours.

Lube Oil Piping in Condenser

- Remove existing piping from the two oil drain lines.
- Weld prep the nipples on each drain line.
- Field route new schedule 40 carbon steel pipe between the drain lines and away from the exhaust of the turbine end of the low pressure turbine.

Eroded Balance Weights

- Record and remove all balance weights from the low pressure rotor.
- After rotor blades have been rebuilt and installed the low pressure rotor should be high speed balanced.

Bucket Refurbishment

- The L-0 and L-1 buckets on the turbine and generator end should be removed without damage to the buckets. The L-2 buckets in the group affected by the damaged shroud should be removed.
- The buckets should be refurbished. L-0 should have stellite nose installed. The tenons on L-0, L-1, and L-2 should be rebuilt.

Crossover Expansion Joint Repair

- Grind out hole to get to good metal.
- Weld fill the holes.

L-0 Diaphragms Ballooning Partitions

- Construct a fixture that will fit across the diaphragm.
- Use hydraulic jack to slowly force the ballooned areas back to original profile.
- See attached sketch.
- Drill 1/4" holes at partition tips on downstream side.

L-O DIAPHRAGM BALLOONING REPAIR

Turbine Audit Summary

Entire Turbine

Audit Section	Change In Power Loss (KW)	Change In Heat Rate (BTU/KWH)	Heat Rate Loss (%)
Interstage Packings	738.94	29.51	0.37
End Packings	307.28	8.55	0.11
Radial Spill Strips	1364.71	73.06	0.91
Miscellaneous Leakages	57.31	3.29	0.04
Flowpath Damages	5845.47	35.03	0.44
Surface Roughness	1190.71	54.70	0.68
Cover Deposits	17.63	1.01	0.01
Trailing Edge Thickness	0.00	0.00	0.00
Other (Hand Calculations)	0.00	0.00	0.00
Total	9522.05	217.41	2.71

Entire Turbine

Casing	Change In Power Loss (KW)	Change In Heat Rate (BTU/KWH)	Heat Rate Loss (%)	Change In Efficiency
HP Casing	1995.48	64.20	0.80	-3.88
IP Casing	1297.66	75.09	0.94	-3.10
LP Governor	713.60	41.12	0.51	-4.34
LP Generator	438.44	25.21	0.31	-2.47
Flow Change Impact	5076.88	-	-	-
Total	9522.05	217.41	2.71	-

System: Turbine/Generator**Component: HP/RH****Assessment Method: VISUAL**

Sub Component	Damage/Condition Found	Damage Assessment/Recommendation
HP Inlet Flanges	The gasket area on both the main steam and hot reheat inlets are in poor condition. (See Photo: Fig. 2.3.2; 2.3.3; 2.3.4)	<p>DA The gaskets used, were of the wrong material. Damage from steam washing.</p> <p>R <u>This outage:</u> Install correct gasket material.</p> <p><u>Next outage:</u> Be prepared to re-machine the face of the flanges to obtain a good fit.</p>
Steam Path Audit	See "SPA" section of this report. (See Photo: Fig. 2.3.5; 2.3.6; 2.3.7)	<p>DA Normal wear in unit</p> <p>R See "SPA" recommendations</p>
HP Nozzle Partition Damage	Approximately 5 partitions eroded. (See Photo: Fig. 2.3.8)	<p>DA To be performed by "CDA" team</p> <p>R To be performed by "CDA" team - Weld Repair.</p>
RH Nozzle (10th Stage Diaphragm)	Damage on trailing edge. (See Photo: Fig. 2.3.10)	<p>DA Bounce back of FOD</p> <p>R Monitor damage</p>
HP Inner Cylinder	Crack in struts. (See Photo: Fig. 2.3.11)	<p>DA To be performed by "CDA" team</p> <p>R To be performed by "CDA" team - Leave as is.</p>
HP/RH Rotor (To Be Returned To Service)	<p>- Cracks in N-2 packing area. (See Photo: Fig. 2.3.13; 2.3.14)</p> <p>- Minor tenon erosion on rows 1-5</p>	<p>DA To be performed by "CDA" team</p> <p>R To be performed by "CDA" team - machine cracks out.</p> <p>DA Caused by "SPE" and "FOD"</p> <p>R Monitor rate of erosion.</p>

System: Turbine/Generator**Component: LPDF****Assessment Method: VISUAL**

Sub Component	Damage/Condition Found	Damage Assessment/Recommendation	
L-0 Diaphragm - Generator End	- Damage to partition leading edge. (See Photo: Fig. 2.3.15)	DA	Damage due to the failure of the L-1 bucket.
		R	Weld repair and recontour the damage partitions.
Lube Oil Piping In Condenser	- Erosion of piping.	DA	Water erosion of piping
		R	Re-route away from exhaust, install new piping monitor erosion of struts.
Steam Path Audit	- See "SPA" section of this report. (See Photo: Fig. 2.3.5; 2.3.6; 2.3.7)	DA	Normal wear in unit.
		R	See "SPA" recommendations.
L-0-G Wheels (Rotor to be Removed)	- Erosion in balance weight area. (See Photo: Fig. 2.3.16; 2.3.17)	DA	Water from the water glands due to leakage.
		R	The change from water glands to steam seals will eliminate this problem. The eroded balance weights need to be removed and new weights installed.

<p>L-0-G (Rotor to be Removed) 9 Buckets Per Group With 2 Tenons Per Bucket</p>	<ul style="list-style-type: none"> - 2" of blade tip broken off - Shroud missing from 3 buckets - "FOD" and water erosion has caused stellite strips to peel off. Additional strips are lifted and will come off in service. - Shroud has lifted and leading tenon is broken. - Tenons have been damaged by washing. Additional shroud lifting is probable. <p>(See Photo: Fig. 2.3.19)</p>	<p>DA Shroud failure attributed to tenon damage from erosion or "FOD" following L-1 blade failure.</p> <p>Stellite strip failures form "FOD" and water erosion.</p> <p>Failed tenon as a result of "FOD". Tenon failed in tensile overload and not fatigue.</p> <p>L-0 stage is well detuned, airfoil failure is not at a high stress point.</p> <p>R Replace L-0 stage, remove the buckets carefully without damaging the finger roots and airfoil. Refurbish the L-0 stage buckets for an additional 25 years of life.</p>
<p>L-1-G (Rotor To Be Removed) 5 Groups of 7 Buckets 3 Groups of 6 Buckets One Tenon Per Bucket</p>	<ul style="list-style-type: none"> - Several bucket groups have the radial height reduced to reinstall shroud. The height has been reduced by approximately 0.25". - 2 buckets have been removed from the row due to a blade failure. <p>(See Photo: Fig. 2.3.21)</p>	<p>DA The bucket height was reduced to re-establish tenon height. This repair increased the group frequency, however these blades have operated for 6 years, therefore the groups are still well detuned.</p> <p>R Replace the L-1 stage buckets. Remove the buckets carefully for refurbishment, for an additional 25 years of life.</p>
<p>L-2-G (Rotor To Be Removed) Under/Over Shroud 9 Buckets Per Group 3 Buckets Overlap Continuous Coupled</p>	<ul style="list-style-type: none"> - Shroud has cracked and buckled. 0.25" lift. Pulled in affected buckets 1/16". <p>(See Photo: Fig. 2.3.23)</p>	<p>DA This was caused by "FOD".</p> <p>R Remove shroud and weld repair tenons. Re-install shroud.</p>

L-0-T (Rotor To Be Removed)	"FOD" has caused stellite strips to peel off. Additional strips are lifted and will come off in service.	<p>DA Stellite strip failures from "FOD" and erosion.</p> <p>R Replace L-0 stage. Remove the buckets carefully without damaging the finger roots and airfoil. Refurbish the L-0 stage buckets for an additional 25 years of life.</p>
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System: Turbine/Generator

Component: Valves

Assessment Method: NDE

Sub Component	Damage/Condition Found	Damage Assessment/Recommendation
Main Stop Valves	<ul style="list-style-type: none"> - Left valve crack in stellite - Stem erosion on right valve in the area of the by-pass. - Right valve has threads damaged on 2 studs. <p>(See Photo: Fig. 2.3.25; 2.3.26)</p>	<p>DA Cracked due to normal wear. Erosion due to "SPE" or water. Mechanical damage to threads.</p> <p>R Note and monitor.</p> <p>Replace stem. In future, install new valve with skirt to protect valve stem and replace "MSV" plug.</p>
Reheat Stop Valves	<ul style="list-style-type: none"> - There was not an obvious seat line on the stellite of the valve plug. <p>(See Photo: Fig. 2.3.27)</p>	<p>DA Improper mating of surfaces</p> <p>R Lap the valve stem and replace "MSV" plug</p>
Intercept Valves	<ul style="list-style-type: none"> - There was not an obvious seat line on the stellite of the valve plug. - Right valve has threads damaged on 5 studs. <p>(See Photo: Fig. 2.3.28)</p>	<p>DA Improper mating of surfaces. Mechanical damage to threads.</p> <p>R Lap the valve into the seat. Note and monitor threads damage.</p>

System: Turbine/Generator

Component: Controls

Assessment Method: Visual

Sub Component	Damage/Condition Found	Damage Assessment/Recommendation	
Load Limit Motor Coupling	Coupling Not Aligned. <i>(See Photo: Fig. 2.3.31)</i>	DA	Load limit not in service.
		R	Place load limit in service.
Control Tubing	Poor condition.	DA	System repairs.
		R	Replace tubing next outage and install protection.

System: Turbine/Generator

Component: Spare Rotors

Assessment Method: Bore Sonic

Sub Component	Damage/Condition Found	Damage Assessment/Recommendation
Spare HP/RH Rotor (This Rotor Is to Become a Serviceable Spare Hp/Rh Rotor)	<ul style="list-style-type: none">- 4"-5" deep crack.- Creep damage of curtis and 10th stage wheel.	<p>DA The 4"-5" cracks are thermal fatigue. The creep damage is due to stress and temperature.</p> <p>R Bore exam rotor. Perform additional replications to determine how deep the creep damage is.</p> <p>Perform weld repair if rotor is in good condition.</p>
Spare LPDF Rotor (This Rotor Is to Be Installed In "CTPS" Unit 2)	<ul style="list-style-type: none">- Bore exam has not been performed.- (8) L-3-T buckets have been cut-off at root.- L-3-T shroud is lowered due to failure of the buckets.- Rotor steam path is in better condition than the removed rotor.	<p>DA (8) buckets missing from L-3-T. Reason unknown.</p> <p>Steam path of rotor in good condition, other than loss of buckets and lowered shroud.</p> <p>R Perform a bore inspection of the rotor.</p> <p>Perform dimensional check between in-service rotor and spare rotor.</p> <p>If there are no liabilities, install rotor in "CTPS" Unit 2.</p>

System: Turbine/Generator**Component: Controls****Assessment Method: Visual**

Sub Component	Damage/Condition Found	Damage Assessment/Recommendation
Front Standard: -Speed Governor -Pre-Emergency Governor -Speed Relay -Auxiliary Pilot Valves -Load Limit Trip Piston -Initial Pressure Regulator	- Load limit motor coupling not aligned/connected. - No looseness in linkages/levers. - Backlash on gears good. - No visual damage found.	DA R Align and connect load limit motor coupling. Disassemble, clean, inspect, check critical clearances. Replace the component if necessary. Re-assemble with new gaskets/o-rings.
Control Valves: -Control Valve Servo-Motor -Speed Relay Linkage -Air Tubing/Supply -Solenoid Valve	- Overall condition good. - No oil leaks observed.	DA R Disassemble, clean, inspect, check critical clearances. Replace the component if necessary. Re-assemble with new gaskets/o-rings.
Main Stop Valve: -Bypass Valve Mechanism -Relay Dump Valve -Actuator Oil Leak -Air Tubing/Supply -Solenoid Valve	- Overall condition good. - No oil leaks observed.	DA R Disassemble, clean, inspect, check critical clearances. Replace the component if necessary. Re-assemble with new gaskets/o-rings.

Re-heat Stop Valve: -Relay Dump Valve -Actuator Oil Leak -Air Tubing/Supply -Solenoid Valve	- Overall condition good. - No oil leaks observed.	DA R Disassemble, clean, inspect, check critical clearances. Replace the component if necessary. Re-assemble with new gaskets/o-rings.
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System: Turbine/Generator

Component: Controls

Assessment Method: Visual

Sub Component	Damage/Condition Found	Damage Assessment/Recommendation
Intercept Valve: -Relay Dump Valve -Actuator Oil Leaks -Pre-emergency Gov. Linkage -Air Tubing/Supply -Solenoid Valve	- Overall condition good. - No oil leaks observed.	DA R Disassemble, clean, inspect check critical clearances. Replace the component if necessary. Re-assemble with new gaskets/O-rings
Turbine Trip Mechanisms: -Vacuum -Main Shaft Pump -Emergency Trip Valve -Master Solenoid Valve -Relay Dump Valve	- Overall condition good. - No oil leaks observed.	DA R Disassemble, clean, inspect check critical clearances. Replace the component if necessary. Re-assemble with new gaskets/O-rings

Emergency Blowdown Valve: -Air Relay -Linkage	<ul style="list-style-type: none"> - Overall condition good. - No oil leaks observed. 	DA R Disassemble, clean, inspect check critical clearances. Replace the component if necessary. Re-assemble with new gaskets/O-rings
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System: Turbine/Generator

Component: Controls

Assessment Method: Visual

Sub Component	Damage/Condition Found	Damage Assessment/Recommendation
"NRV" To LP Heater No. 3 -Counter Weight -Limit/Position Switch -Air Tubing/Supply -Test Mechanism	<ul style="list-style-type: none"> - Counter weight not installed. - Limit switch not mech. aligned/elec. conn. - Test mechanism not functional. - Air tubing in poor condition. 	DA R Install counter weights, align and connect limit switch, repair "NRV" test mechanism, replace air tubing, and test the "NRV".
"NRV" To LP Heater No. 4 -Counter Weight -Limit/Position Switch -Air Tubing/Supply -Test Mechanism	<ul style="list-style-type: none"> - Counter weight not installed. - Limit switch not mech. aligned/elec. conn. - Test mechanism not functional. - Air tubing in poor condition. 	DA R Install counter weights, align and connect limit switch, repair "NRV" test mechanism, replace air tubing, and test the "NRV".
"NRV" To LP Heater No. 5 -Counter Weight -Limit/Position Switch -Air Tubing/Supply -Test Mechanism	<ul style="list-style-type: none"> - Counter weight not installed. - Limit switch not mech. aligned/elec. conn. - Test mechanism not functional. - Air tubing in poor condition. 	DA R Install counter weights, align and connect limit switch, repair "NRV" test mechanism, replace air tubing, and test the "NRV".

"NRV" To LP Heater No. 6 -Counter Weight -Limit/Position Switch -Air Tubing/Supply -Test Mechanism	- Counter weight not installed. - Limit switch not mech. aligned/elec. conn. - Test mechanism not functional. - Air tubing in poor condition.	DA R Install counter weights, align and connect limit switch, repair "NRV" test mechanism, replace air tubing, and test the "NRV".
"NRV" To LP Heater No. 7 -Counter Weight -Limit/Position Switch -Air Tubing/Supply -Test Mechanism	- Counter weight not installed. - Limit switch not mech. aligned/elec. conn. - Test mechanism not functional. - Air tubing in poor condition.	DA R Install counter weights, align and connect limit switch, repair "NRV" test mechanism, replace air tubing, and test the "NRV".

Turbine Steam Path Assessment

HP MSV - Material In Screen
Fig. 2.3.1

HP/RH Inlet - Gasket Area
Fig. 2.3.2

Turbine Steam Path Assessment

HP Inlet - Showing Steam Leak
Fig. 2.3.3

HP Inlet - Manufacturing Defect
Fig. 2.3.4

Turbine Steam Path Assessment

SPA Measurement
Fig. 2.3.5

SPA Measurement
Fig. 2.3.6

Turbine Steam Path Assessment

SPA Measurement
Fig. 2.3.7

HP Nozzle - Eroded Partitions
Fig. 2.3.8

Turbine Steam Path Assessment

HP/RH Rotor - Notch Block Lifting

Fig. 2.3.9

RH Nozzle - Erosion of Partitions

Fig. 2.3.10

Turbine Steam Path Assessment

HP Inner Cylinder - Strut Crack
Fig. 2.3.11

HP/RH Rotor - N-1 Packing
Fig. 2.3.12

Turbine Steam Path Assessment

HP/RH Rotor - N-2 Packing
Fig. 2.3.13

HP/RH Rotor - N-2 Packing
Fig. 2.3.14

Turbine Steam Path Assessment

LPDF - L-0 Ballooned Diaphragms
Fig. 2.3.15

LPDF Rotor - Gen. End Eroded Balance Weights
Fig. 2.3.16

Turbine Steam Path Assessment

LPDF Rotor - Gen. End Eroded Balance Weights
Fig. 2.3.17

LPDF Rotor
Fig. 2.3.18

Turbine Steam Path Assessment

LPDF Rotor - L-0-G Blade Failure
Fig. 2.3.19

LPDF Rotor - L-0 Partition Damage
Fig. 2.3.20

Turbine Steam Path Assessment

LPDF Rotor - L-1-G Missing Bucket

Fig. 2.3.21

HP/RH Rotor - L-1-G Lowered Shroud

Fig. 2.3.22

Turbine Steam Path Assessment

LPDF Rotor - L-2-G Cover Damage
Fig. 2.3.23

LPDF Rotor Deposits
Fig. 2.3.24

Turbine Steam Path Assessment

Main Stop Valve - By-Pass Valve Erosion
Fig. 2.3.25

Main Stop Valve - By-Pass Valve Erosion
Fig. 2.3.26

Reheat Stop Valve
Fig. 2.3.27

Intercept Valve
Fig. 2.3.28

Turbine Steam Path Assessment

Top Control Valves
Fig. 2.3.29

Right MSV - Crack In Stellite
Fig. 2.3.30

Turbine Steam Path Assessment

Controls - Load Limit Motor Coupling
Fig. 2.3.31

Controls - Governor
Fig. 2.3.32

Turbine Audit Summary

Entire Turbine

Audit Section	Change In Power Loss (KW)	Change In Heat Rate (BTU/KWH)	Heat Rate Loss (%)
Interstage Packings	738.94	29.51	0.37
End Packings	307.28	8.55	0.11
Radial Spill Strips	1364.71	73.06	0.91
Miscellaneous Leakages	57.31	3.29	0.04
Flowpath Damages	5845.47	35.03	0.44
Surface Roughness	1190.71	54.70	0.68
Cover Deposits	17.63	1.01	0.01
Trailing Edge Thickness	0.00	0.00	0.00
Other (Hand Calculations)	0.00	0.00	0.00
Total	9522.05	217.41	2.71

Entire Turbine

Casing	Change In Power Loss (KW)	Change In Heat Rate (BTU/KWH)	Heat Rate Loss (%)	Change In Efficiency
HP Casing	1995.48	64.20	0.80	-3.88
IP Casing	1297.66	75.09	0.94	-3.10
LP Governor	713.60	41.12	0.51	-4.34
LP Generator	438.44	25.21	0.31	-2.47
Flow Change Impact	5076.88	-	-	-
Total	9522.05	217.41	2.71	-

HP Casing

Audit Section	Change In Power Loss (KW)	Change In Heat Rate (BTU/KWH)	Heat Rate Loss (%)
Interstage Packings	522.35	17.00	0.21
End Packings	307.28	8.55	0.11
Radial Spill Strips	236.54	7.68	0.10
Miscellaneous Leakages	0.00	0.00	0.00
Flowpath Damages	365.80	11.88	0.15
Surface Roughness	563.51	18.35	0.23
Cover Deposits	0.00	0.00	0.00
Trailing Edge Thickness	0.00	0.00	0.00
Other (Hand Calculations)	0.00	0.00	0.00
Total	195.48	64.20	0.80

Design Eff (%): 82.95

Audit Eff (%): 79.07

Difference: -3.88

IP Casing

Audit Section	Change In Power Loss (KW)	Change In Heat Rate (BTU/KWH)	Heat Rate Loss (%)
Interstage Packings	216.59	12.44	0.16
End Packings	0.00	0.00	0.00
Radial Spill Strips	637.93	36.74	0.46
Miscellaneous Leakages	57.31	3.29	0.04
Flowpath Damages	33.99	1.95	0.02
Surface Roughness	351.83	20.22	0.25
Cover Deposits	0.00	0.00	0.00
Trailing Edge Thickness	0.00	0.00	0.00
Other (Hand Calculations)	0.00	0.00	0.00

Total	1297.60	75.09	0.94
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Design Eff (%): 92.68

Audit Eff (%): 89.58

Difference: -3.10

LP Governor

Audit Section	Change In Power Loss (KW)	Change In Heat Rate (BTU/KWH)	Heat Rate Loss (%)
Interstage Packings	0.00	0.00	0.00
End Packings	0.00	0.00	0.00
Radial Spill Strips	396.31	22.80	0.28
Miscellaneous Leakages	0.00	0.00	0.00
Flowpath Damages	171.10	9.81	0.12
Surface Roughness	137.68	7.90	0.10
Cover Deposits	8.20	0.47	0.01
Trailing Edge Thickness	0.00	0.00	0.00
Other (Hand Calculations)	0.00	0.00	0.00
Total	713.60	41.12	0.51

Design Eff (%): 109.35

Audit Eff (%): 105.01

Difference: -4.34

LP Generator

Audit Section	Change In Power Loss (KW)	Change In Heat Rate (BTU/KWH)	Heat Rate Loss (%)
Interstage Packings	0.00	0.00	0.00
End Packings	0.00	0.00	0.00
Radial Spill Strips	93.63	5.37	0.07
Miscellaneous Leakages	0.00	0.00	0.00
Flowpath Damages	197.71	11.34	0.14
Surface Roughness	137.68	7.90	0.10
Cover Deposits	9.42	0.54	0.01

Trailing Edge Thickness	0.00	0.00	0.00
Other (Hand Calculations)	0.00	0.00	0.00
Total	438.44	25.21	0.31

Design Eff (%): 109.35

Audit Eff (%): 106.88

Difference: -2.47

All Data

All HP Casing Data

Thermodynamics
Leakage/Extraction
Misc Location Data
Stationary Blading
Rotating Blading
Interstage Packing
Root Spill Strip
Balance Hole
Radial Spill Strip
End Packing

All IP Casing Data

Thermodynamics
Leakage/Extraction
Misc Location Data
Stationary Blading
Rotating Blading
Interstage Packing
Root Spill Strip
Balance Hole
Radial Spill Strip
End Packing

All LP Casing Data

Thermodynamics
Leakage/Extraction
Misc Location Data
Stationary Blading
Rotating Blading
Interstage Packing
Root Spill Strip
Balance Hole
Radial Spill Strip
End Packing

General Data

Selected Casing Data

Heater Data

Misc. Data

Unselected

DESIGN DEFINITION
CHANDRAPURA

DATE: 10/14/1994
#2
HP Casing

Ln	Stage No.	Pressure (PSIA)	Enthalpy (BTU/LBM)	Temperature (°F)	Entropy (BTU/LB°F)	Sp. Vol. (FT ³ /LB)
1	0	1815.005	1480.10	999.99	1.5741	0.43861
2	1	1742.405	1480.10	996.22	1.5783	0.45699
3	2	1538.000	1460.90	953.68	1.5775	0.50275
4	3	1360.191	1447.07	920.35	1.5800	0.55642
5	4	1198.068	1433.13	886.81	1.5827	0.61794
6	5	1051.094	1419.07	853.08	1.5855	0.68854
7	6	918.205	1404.87	819.14	1.5883	0.76993
8	7	798.396	1390.51	784.97	1.5913	0.86422
9	8	690.229	1375.96	750.48	1.5944	0.97476
10	9	593.128	1361.21	715.64	1.5976	1.10490
11	0	506.200	1346.20	680.38	1.6010	1.25948

DESIGN DEFINITION
CHANDRAPURA

DATE: 10/14/1994
#2
HP Casing

Ln	Stage No.	First Lkg Flow	or Extr. Return	Second Lkg Flow	or Extr. Return	Third Lkg Flow	or Extr. Return
1	0	0	0	0	0	0	0
2	1	2730	11	900	51	0	0
3	2	20760	13	0	0	0	0
4	3	0	0	0	0	0	0
5	4	0	0	0	0	0	0
6	5	0	0	0	0	0	0
7	6	0	0	0	0	0	0
8	7	0	0	0	0	0	0
9	8	0	0	0	0	0	0
10	9	0	0	0	0	0	0
11	0	79650	57	-2730	2	7620	54

Ln	Stage No.	Fourth Lkg Flow	or Extr. Return	Fifth Lkg Flow	or Extr. Return	Sixth Lkg Flow	or Extr. Return
1	0	0	0	0	0	0	0
2	1	0	0	0	0	0	0
3	2	0	0	0	0	0	0
4	3	0	0	0	0	0	0
5	4	0	0	0	0	0	0
6	5	0	0	0	0	0	0
7	6	0	0	0	0	0	0
8	7	0	0	0	0	0	0
9	8	0	0	0	0	0	0
10	9	0	0	0	0	0	0
11	0	2500	51	0	0	0	0

Ln	Stage No.	# of Flows	Csg. Code	LNE	Flow (LBM/HR)	Sec.Eff. (%)	Stg.Eff. (%)
1	0	1	0	1	959250	0.000	0.000
2	1	1	1	1	955620	0.000	105.902
3	2	1	1	1	934860	80.161	79.758
4	3	1	1	0	934860	0.000	79.529
5	4	1	1	0	934860	0.000	79.563
6	5	1	1	0	934860	0.000	79.627
7	6	1	1	0	934860	0.000	79.729
8	7	1	1	0	934860	0.000	79.502
9	8	1	1	0	934860	0.000	79.473
10	9	1	1	0	934860	0.000	79.467
11	0	1	1	1	847820	81.353	0.000

10/14/94

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DESIGN DEFINITION
CHANDRAPURA

DATE: 10/14/1994
#2
HP Casing

Ln	Stage No.	Flow Function	Design Stg A.E. (BTU/LBM)	Velocity Ratio	Loss Factor
1	0	0	0.000	0.000000	0.792841
2	1	15476	18.134	0.509466	0.817077
3	2	16902	17.342	0.389963	0.835532
4	3	18908	17.528	0.389404	0.855005
5	4	21232	17.674	0.389485	0.875568
6	5	23927	17.835	0.389642	0.897357
7	6	27071	18.011	0.389891	0.920512
8	7	30757	18.292	0.389336	0.945199
9	8	35132	18.563	0.389266	0.971632
10	9	40349	18.888	0.389251	1.000000
11	0	0	0.000	0.000000	1.000000

<-----Stationary Blades----->					
Ln	Stage No.	Axial Wid. (IN)	Ex.Area (SQ.IN)	Reynolds Number	Height (IN)
1	0	0.000	0.000	0.0000e+000	0.00
2	1	1.369	15.871	1.0367e+007	0.68
3	2	0.331	23.417	2.2214e+006	0.99
4	3	0.397	26.167	2.4841e+006	1.10
5	4	0.475	29.352	2.7529e+006	1.22
6	5	0.565	33.032	3.0330e+006	1.36
7	6	0.672	37.297	3.3236e+006	1.52
8	7	0.798	42.257	3.6373e+006	1.70
9	8	0.946	48.084	3.9546e+006	1.90
10	9	1.129	55.385	4.3090e+006	2.15
11	0	0.000	0.000	0.0000e+000	0.00

<----- (Diam.) ----- Stationary Blades ----- (Exit Angles) ----->							
Ln	Stage No.	Root (IN)	Pitch (IN)	Tip (IN)	Root (DEG)	Pitch (DEG)	Tip (DEG)
1	0	0.00	0.00	0.00	0.00	0.00	0.00
2	1	36.40	37.09	37.77	10.77	10.91	11.06
3	2	26.77	27.76	28.75	14.47	14.89	15.28
4	3	26.77	27.87	28.97	14.52	14.95	15.38
5	4	26.77	27.99	29.21	14.54	15.02	15.50
6	5	26.77	28.13	29.49	14.57	15.11	15.64
7	6	26.77	28.29	29.81	14.60	15.21	15.80
8	7	26.77	28.47	30.16	14.66	15.31	15.96
9	8	26.77	28.67	30.57	14.72	15.43	16.16
10	9	26.77	28.92	31.07	14.77	15.58	16.39
11	0	0.00	0.00	0.00	0.00	0.00	0.00

DESIGN DEFINITION
CHANDRAPURA

DATE: 10/14/1994
#2
HP Casing

Ln	Stage No.	<----- (Misc) ----->		Rotating Blades		<----- (Reaction) ----->	
		Axial Wid. (IN)	Ex.Area (SQ.IN)	Reynolds Number	Root (%)	Pitch (%)	Tip (%)
1	0	0.000	0.000	0.0000e+000	0.00	0.00	0.00
2	1	1.369	33.232	4.9687e+006	-1.00	2.33	5.48
3	2	0.424	36.272	1.8323e+006	5.00	11.19	16.45
4	3	0.501	40.392	2.0284e+006	5.00	11.46	17.23
5	4	0.591	44.979	2.2354e+006	5.00	12.17	18.46
6	5	0.697	50.192	2.4554e+006	5.00	12.99	19.84
7	6	0.820	56.128	2.6887e+006	5.00	13.95	21.40
8	7	0.965	63.104	2.9411e+006	5.00	14.64	22.79
9	8	1.135	71.048	3.2060e+006	5.00	15.66	24.53
10	9	1.344	80.789	3.5125e+006	5.00	16.91	26.60
11	0	0.000	0.000	0.0000e+000	0.00	0.00	0.00

Ln	Stage No.	<----- (Static Pressure) ----->			Rotating Blades		<----- (Spec.Vol) ----->	
		Root	Pitch	Tip	Root	Pitch	Tip	Tip
1	0	0.000	0.000	0.000	0.00000	0.00000	0.00000	0.00000
2	1	1536.070	1542.539	1548.697	0.50511	0.50343	0.50184	0.50184
3	2	1369.293	1379.248	1388.283	0.55133	0.54821	0.54538	0.54538
4	3	1205.815	1215.843	1224.860	0.61233	0.60832	0.60475	0.60475
5	4	1058.162	1068.187	1077.101	0.68206	0.67697	0.67251	0.67251
6	5	924.686	934.689	943.473	0.76237	0.75590	0.75030	0.75030
7	6	804.370	814.329	822.950	0.85531	0.84705	0.83998	0.83998
8	7	695.327	705.302	713.806	0.96462	0.95375	0.94470	0.94470
9	8	597.658	607.582	615.895	1.09298	1.07874	1.06715	1.06715
10	9	510.240	520.154	528.284	1.24529	1.22636	1.21136	1.21136
11	0	0.000	0.000	0.000	0.00000	0.00000	0.00000	0.00000

Ln	Stage No.	<----- (Inlet Angle) ----->			Rotating Blades		<----- (Exit Angle) ----->	
		Root	Pitch	Tip	Root	Pitch	Tip	Tip
1	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	1	21.82	22.93	24.13	24.00	23.36	22.77	22.77
3	2	23.73	25.55	27.49	24.00	23.47	23.02	23.02
4	3	23.72	25.64	27.79	24.00	23.47	22.99	22.99
5	4	23.70	25.85	28.26	24.00	23.42	22.89	22.89
6	5	23.69	26.08	28.81	24.00	23.35	22.78	22.78
7	6	23.66	26.36	29.46	24.00	23.27	22.65	22.65
8	7	23.65	26.58	30.07	24.00	23.25	22.57	22.57
9	8	23.62	26.89	30.88	24.00	23.18	22.45	22.45
10	9	23.59	27.28	31.89	24.00	23.10	22.30	22.30
11	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00

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Ln	Stage No.	<----- (Enthalpy) ----->		Rotating Blades		<----- (Entropy) ----->	
		Root	Pitch	Tip	Root	Pitch	Tip
1	0	0.00	0.00	0.00	0.0000	0.0000	0.0000
2	1	1463.05	1463.61	1464.14	1.5791	1.5791	1.5791
3	2	1445.56	1446.56	1447.41	1.5783	1.5783	1.5782
4	3	1431.56	1432.62	1433.56	1.5809	1.5809	1.5808
5	4	1417.49	1418.67	1419.71	1.5836	1.5835	1.5835
6	5	1403.29	1404.62	1405.76	1.5864	1.5863	1.5862
7	6	1388.93	1390.43	1391.68	1.5892	1.5892	1.5891
8	7	1374.32	1375.96	1377.35	1.5923	1.5922	1.5921
9	8	1359.54	1361.38	1362.92	1.5954	1.5953	1.5952
10	9	1344.50	1346.59	1348.30	1.5987	1.5986	1.5985
11	0	0.00	0.00	0.00	0.0000	0.0000	0.0000

Ln	Stage No.	<----- Interstage Packing ----->		Sealing Diam.	
		Clearance (IN)	Tooth Type	Percent Round	#of Teeth
1	0	0.000	0	0.00	0
2	1	0.000	0	0.00	0
3	2	0.015	1	0.00	8
4	3	0.015	1	0.00	8
5	4	0.015	1	0.00	8
6	5	0.015	1	0.00	8
7	6	0.015	1	0.00	8
8	7	0.015	1	0.00	8
9	8	0.015	1	0.00	8
10	9	0.015	1	0.00	8
11	0	0.000	0	0.00	0

Ln	Stage No.	<----- Root Spill Strips ----->	
		Clearance (IN.)	Tooth Type
1	0	0.000	0
2	1	0.090	0
3	2	0.090	0
4	3	0.090	0
5	4	0.090	0
6	5	0.090	0
7	6	0.090	0
8	7	0.090	0
9	8	0.090	0
10	9	0.090	0
11	0	0.000	0

<-----Balance Holes----->							
Ln	Stage No.	Qty	Hole Type	Axial Length (IN.)	Radial Pos. (IN.)	Major Axis (IN.)	Minor Axis (IN.)
1	0	0	0	0.00	0.00	0.000	0.000
2	1	0	0	0.00	0.00	0.000	0.000
3	2	0	0	0.00	0.00	0.000	0.000
4	3	0	0	0.00	0.00	0.000	0.000
5	4	0	0	0.00	0.00	0.000	0.000
6	5	0	0	0.00	0.00	0.000	0.000
7	6	0	0	0.00	0.00	0.000	0.000
8	7	0	0	0.00	0.00	0.000	0.000
9	8	0	0	0.00	0.00	0.000	0.000
10	9	0	0	0.00	0.00	0.000	0.000
11	0	0	0	0.00	0.00	0.000	0.000

<-----Radial Spill Strips----->					
Ln	Stage No.	Clearance (IN.)	Tooth Type	# of Teeth	Percent Round
1	0	0.000	0	0	0.00
2	1	0.050	1	1	0.00
3	2	0.060	1	1	0.00
4	3	0.060	1	1	0.00
5	4	0.060	1	1	0.00
6	5	0.060	1	1	0.00
7	6	0.060	1	1	0.00
8	7	0.060	1	1	0.00
9	8	0.060	1	1	0.00
10	9	0.060	1	1	0.00
11	0	0.000	0	0	0.00

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<--(Shaft Diam. Between)--END PACKINGS--(Clearance Between)-->							
Ln	Stage No.	CSG & 1st Leakoff (IN.)	1st & 2nd Leakoff (IN.)	2nd & 3rd Leakoff (IN.)	CSG & 1st Leakoff (IN.)	1st & 2nd Leakoff (IN.)	2nd & 3rd Leakoff (IN.)
1	0	0.00	0.00	0.00	0.000	0.000	0.000
2	1	11.45	0.00	0.00	0.015	0.000	0.000
3	2	11.45	0.00	0.00	0.015	0.000	0.000
4	3	0.00	0.00	0.00	0.000	0.000	0.000
5	4	0.00	0.00	0.00	0.000	0.000	0.000
6	5	0.00	0.00	0.00	0.000	0.000	0.000
7	6	0.00	0.00	0.00	0.000	0.000	0.000
8	7	0.00	0.00	0.00	0.000	0.000	0.000
9	8	0.00	0.00	0.00	0.000	0.000	0.000
10	9	0.00	0.00	0.00	0.000	0.000	0.000
11	0	0.00	0.00	0.00	0.000	0.000	0.000

<--(Tot. #of Teeth Between)--END PACKING--(Tot. #of Rings Between)-->							
Ln	Stage No.	CSG & 1st Leakoff	1st & 2nd Leakoff	2nd & 3rd Leakoff	CSG & 1st Leakoff	1st & 2nd Leakoff	2nd & 3rd Leakoff
1	0	0	0	0	0	0	0
2	1	40	0	0	4	0	0
3	2	40	0	0	4	0	0
4	3	0	0	0	0	0	0
5	4	0	0	0	0	0	0
6	5	0	0	0	0	0	0
7	6	0	0	0	0	0	0
8	7	0	0	0	0	0	0
9	8	0	0	0	0	0	0
10	9	0	0	0	0	0	0
11	0	0	0	0	0	0	0

<--(Type of Teeth Between)--END PACKING--(Tooth %Round Between)-->							
Ln	Stage No.	CSG & 1st Leakoff	1st & 2nd Leakoff	2nd & 3rd Leakoff	CSG & 1st Leakoff	1st & 2nd Leakoff	2nd & 3rd Leakoff
1	0	0	0	0	0.00	0.00	0.00
2	1	1	0	0	0.00	0.00	0.00
3	2	1	0	0	0.00	0.00	0.00
4	3	0	0	0	0.00	0.00	0.00
5	4	0	0	0	0.00	0.00	0.00
6	5	0	0	0	0.00	0.00	0.00
7	6	0	0	0	0.00	0.00	0.00
8	7	0	0	0	0.00	0.00	0.00
9	8	0	0	0	0.00	0.00	0.00
10	9	0	0	0	0.00	0.00	0.00
11	0	0	0	0	0.00	0.00	0.00

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Ln	Stage No.	<--(Flow Through Packing)---END PACKING---(Ln of Leakage Return)-->					
		CSG & 1st Leakoff	1st & 2nd Leakoff	2nd & 3rd Leakoff	CSG & 1st Leakoff	1st & 2nd Leakoff	2nd & 3rd Leakoff
1	0	0	0	0	0	0	0
2	1	2730	0	0	11	0	0
3	2	20760	0	0	13	0	0
4	3	0	0	0	0	0	0
5	4	0	0	0	0	0	0
6	5	0	0	0	0	0	0
7	6	0	0	0	0	0	0
8	7	0	0	0	0	0	0
9	8	0	0	0	0	0	0
10	9	0	0	0	0	0	0
11	0	0	0	0	0	0	0

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Ln	Stage No.	Pressure (PSIA)	Enthalpy (BTU/LBM)	Temperature (°F)	Entropy (BTU/LB°F)	Sp. Vol. (FT ³ /LB)
12	0	452.900	1520.90	998.50	1.7482	1.87795
13	10	443.842	1520.90	998.00	1.7504	1.91638
14	11	384.104	1502.29	959.74	1.7530	2.15805
15	12	330.527	1483.45	920.83	1.7558	2.44115
16	13	282.629	1464.33	881.21	1.7587	2.77526
17	14	239.800	1444.90	840.75	1.7618	3.17500
18	15	204.328	1426.02	801.36	1.7644	3.61612
19	16	172.622	1406.74	760.98	1.7672	4.14648
20	17	144.400	1387.00	719.45	1.7701	4.79203
21	18	114.245	1362.59	667.81	1.7744	5.79750
22	19	88.400	1337.10	613.58	1.7791	7.13928
23	20	68.596	1312.10	560.23	1.7828	8.74994
24	21	51.600	1285.50	503.15	1.7870	10.98929
25	0	32.500	1245.00	415.58	1.7933	15.87459

Ln	Stage No.	First Lkg or Extr. Flow	Return	Second Lkg or Extr. Flow	Return	Third Lkg or Extr. Flow	Return
12	0	0	0	0	0	0	0
13	10	-20760	3	0	0	0	0
14	11	0	0	0	0	0	0
15	12	0	0	0	0	0	0
16	13	0	0	0	0	0	0
17	14	31240	56	0	0	0	0
18	15	0	0	0	0	0	0
19	16	0	0	0	0	0	0
20	17	28940	55	0	0	0	0
21	18	0	0	0	0	0	0
22	19	20070	54	0	0	0	0
23	20	0	0	0	0	0	0
24	21	36650	53	0	0	0	0
25	0	0	0	0	0	0	0

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Ln	Stage No.	Fourth Lkg Flow	or Extr. Return	Fifth Lkg Flow	or Extr. Return	Sixth Lkg Flow	or Extr. Return
12	0	0	0	0	0	0	0
13	10	0	0	0	0	0	0
14	11	0	0	0	0	0	0
15	12	0	0	0	0	0	0
16	13	0	0	0	0	0	0
17	14	0	0	0	0	0	0
18	15	0	0	0	0	0	0
19	16	0	0	0	0	0	0
20	17	0	0	0	0	0	0
21	18	0	0	0	0	0	0
22	19	0	0	0	0	0	0
23	20	0	0	0	0	0	0
24	21	0	0	0	0	0	0
25	0	0	0	0	0	0	0

Ln	Stage No.	# of Flows	Csg. Code	LNE	Flow (LBM/HR)	Sec.Eff. (%)	Stg.Eff. (%)
12	0	1	0	1	847820	0.000	0.000
13	10	1	2	1	868580	0.000	83.063
14	11	1	2	0	868580	0.000	83.114
15	12	1	2	0	868580	0.000	83.184
16	13	1	2	0	868580	0.000	82.963
17	14	1	2	1	837340	83.792	85.210
18	15	1	2	0	837340	0.000	85.194
19	16	1	2	0	837340	0.000	85.172
20	17	1	2	1	808400	85.666	83.533
21	18	1	2	0	808400	0.000	83.493
22	19	1	2	1	788330	83.896	86.885
23	20	1	2	0	788330	0.000	86.897
24	21	1	2	1	751680	87.246	88.073
25	0	1	2	1	751680	88.073	0.000

Ln	Stage No.	Flow Function	Design Stg A.E. (BTU/LBM)	Velocity Ratio	Loss Factor
12	0	0	0.000	0.000000	0.297262
13	10	57074	22.401	0.494615	0.306821
14	11	65105	22.671	0.494767	0.317081
15	12	74646	22.979	0.494975	0.328131
16	13	86070	23.427	0.494318	0.340100
17	14	96349	22.159	0.511651	0.352506
18	15	111393	22.627	0.511603	0.366049
19	16	129776	23.178	0.511535	0.380957
20	17	147266	29.216	0.462537	0.400964
21	18	182108	30.536	0.462427	0.424002
22	19	224031	28.778	0.487263	0.449063
23	20	281553	30.607	0.487296	0.478908
24	21	346891	45.984	0.418968	0.532159
25	0	0	0.000	0.000000	0.532159

<----- Stationary Blades ----->					
Ln	Stage No.	Axial Wid. (IN)	Ex.Area (SQ.IN)	Reynolds Number	Height (IN)
12	0	0.000	0.000	0.0000e+000	0.00
13	10	0.943	60.029	1.7950e+006	2.02
14	11	1.015	68.568	1.7663e+006	2.27
15	12	1.093	78.663	1.7330e+006	2.56
16	13	1.179	90.832	1.7018e+006	2.90
17	14	1.226	98.620	1.5543e+006	3.17
18	15	1.319	114.792	1.5210e+006	3.60
19	16	1.419	134.397	1.4812e+006	4.10
20	17	1.545	170.394	1.5777e+006	4.74
21	18	1.738	213.934	1.5459e+006	5.68
22	19	1.910	257.927	1.4006e+006	6.68
23	20	2.148	332.613	1.3655e+006	8.09
24	21	2.595	498.618	1.5718e+006	10.57
25	0	0.000	0.000	0.0000e+000	0.00

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Ln	Stage No.	<---(Diam.)--- Stationary Blades---(Exit Angles)--->					
		Root (IN)	Pitch (IN)	Tip (IN)	Root (DEG)	Pitch (DEG)	Tip (DEG)
12	0	0.00	0.00	0.00	0.00	0.00	0.00
13	10	38.00	40.02	42.04	12.50	12.97	13.44
14	11	38.00	40.27	42.54	12.55	13.09	13.61
15	12	38.00	40.56	43.12	12.61	13.21	13.81
16	13	38.00	40.90	43.80	12.70	13.36	14.02
17	14	38.00	41.17	44.35	12.44	13.16	13.88
18	15	38.00	41.60	45.20	12.54	13.34	14.16
19	16	38.00	42.10	46.20	12.65	13.55	14.48
20	17	38.00	42.74	47.48	13.65	14.65	15.69
21	18	38.00	43.68	49.37	13.81	14.98	16.21
22	19	38.00	44.69	51.37	13.59	14.97	16.43
23	20	38.00	46.09	54.17	13.82	15.43	17.16
24	21	38.00	48.57	59.14	15.24	16.73	18.63
25	0	0.00	0.00	0.00	0.00	0.00	0.00

Ln	Stage No.	<---(Misc)--- Rotating Blades---(Reaction)--->					
		Axial Wid. (IN)	Ex.Area (SQ.IN)	Reynolds Number	Root (%)	Pitch (%)	Tip (%)
	0	0.000	0.000	0.0000e+000	0.00	0.00	0.00
	10	1.188	103.495	1.3097e+006	5.00	13.44	20.66
14	11	1.263	116.582	1.2904e+006	5.00	14.45	22.36
15	12	1.341	131.670	1.2681e+006	5.00	15.60	24.26
16	13	1.425	149.877	1.2452e+006	5.00	16.61	26.10
17	14	1.457	163.285	1.1148e+006	5.00	17.60	27.74
18	15	1.538	186.113	1.0926e+006	5.00	19.09	30.12
19	16	1.619	212.914	1.0650e+006	5.00	20.75	32.73
20	17	1.718	253.507	1.1786e+006	5.00	22.68	35.64
21	18	1.878	308.245	1.1578e+006	5.00	25.55	39.82
22	19	1.993	362.983	1.0371e+006	5.00	28.66	44.04
23	20	2.150	448.255	1.0126e+006	5.00	32.43	48.94
24	21	2.470	632.947	1.1977e+006	5.00	38.05	55.75
25	0	0.000	0.000	0.0000e+000	0.00	0.00	0.00

Ln	Stage No.	<——(Static Pressure)——			Rotating Blades——(Spec.Vol)——>		
		Root	Pitch	Tip	Root	Pitch	Tip
12	0	0.000	0.000	0.000	0.00000	0.00000	0.00000
13	10	386.987	391.740	395.892	2.13822	2.11753	2.09976
14	11	333.138	337.883	341.964	2.41762	2.39061	2.36782
15	12	284.996	289.721	293.714	2.74705	2.71150	2.68209
16	13	241.805	246.536	250.454	3.14217	3.09409	3.05551
17	14	205.986	210.253	213.727	3.58268	3.52476	3.47918
18	15	174.094	178.355	181.738	4.10614	4.02806	3.96848
19	16	145.699	149.937	153.208	4.74279	4.63617	4.55761
20	17	115.597	120.610	124.369	5.71416	5.52530	5.39285
21	18	89.538	94.521	98.081	7.02730	6.73286	6.53934
22	19	69.502	73.881	76.842	8.62750	8.22270	7.97221
23	20	52.371	56.708	59.455	10.81584	10.16116	9.79062
24	21	33.310	38.980	42.313	15.48175	13.68998	12.83802
25	0	0.000	0.000	0.000	0.00000	0.00000	0.00000

Ln	Stage No.	<——(Inlet Angle)——			Rotating Blades——(Exit Angle)——>		
		Root	Pitch	Tip	Root	Pitch	Tip
12	0	0.00	0.00	0.00	0.00	0.00	0.00
13	10	24.40	27.92	32.27	24.00	22.78	21.74
14	11	24.36	28.34	33.38	24.00	22.65	21.53
15	12	24.32	28.83	34.71	24.00	22.51	21.30
16	13	24.28	29.28	36.12	24.00	22.43	21.12
17	14	24.42	30.29	38.74	24.00	22.16	20.67
18	15	24.37	31.02	41.09	24.00	22.00	20.40
19	16	24.30	31.88	43.99	24.00	21.84	20.13
20	17	23.81	30.90	42.13	24.00	22.18	20.69
21	18	23.72	32.18	46.80	24.00	21.98	20.35
22	19	23.84	35.05	57.06	24.00	21.47	19.54
23	20	23.72	37.28	67.07	24.00	21.23	19.16
24	21	23.10	35.33	64.42	24.00	21.78	20.03
25	0	0.00	0.00	0.00	0.00	0.00	0.00

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		Root	Pitch	Tip	Root	Pitch	Tip
12	0	0.00	0.00	0.00	0.0000	0.0000	0.0000
13	10	1501.08	1502.84	1504.35	1.7514	1.7513	1.7512
14	11	1482.24	1484.23	1485.90	1.7541	1.7540	1.7539
15	12	1463.12	1465.39	1467.24	1.7569	1.7568	1.7567
16	13	1443.61	1446.14	1448.21	1.7599	1.7598	1.7596
17	14	1425.30	1427.90	1429.99	1.7629	1.7628	1.7627
18	15	1406.00	1408.97	1411.29	1.7656	1.7654	1.7653
19	16	1386.24	1389.64	1392.22	1.7685	1.7682	1.7681
20	17	1361.15	1365.96	1369.49	1.7718	1.7715	1.7712
21	18	1335.58	1341.42	1345.48	1.7763	1.7758	1.7755
22	19	1311.64	1317.98	1322.10	1.7809	1.7805	1.7802
23	20	1285.02	1292.84	1297.54	1.7849	1.7843	1.7839
24	21	1244.82	1258.97	1266.55	1.7904	1.7891	1.7885
25	0	0.00	0.00	0.00	0.0000	0.0000	0.0000

Ln	Stage No.	Interstage		Packing		Sealing Diam. (IN)
		Clearance (IN)	Tooth Type	Percent Round	#of Teeth	
12	0	0.000	0	0.00	0	0.00
13	10	0.015	1	0.00	8	26.22
14	11	0.015	1	0.00	8	26.22
15	12	0.015	1	0.00	8	26.22
16	13	0.015	1	0.00	8	26.22
17	14	0.015	1	0.00	8	26.22
18	15	0.015	1	0.00	8	26.22
19	16	0.015	1	0.00	8	26.22
20	17	0.015	1	0.00	8	26.22
21	18	0.015	2	0.00	8	26.22
22	19	0.015	2	0.00	8	26.22
23	20	0.015	2	0.00	8	26.22
24	21	0.015	2	0.00	8	26.22
25	0	0.000	0	0.00	0	0.00

<-----Root Spill Strips----->				
Ln	Stage No.	Clearance (IN.)	Tooth Type	Percent Round
12	0	0.000	0	0.00
13	10	0.000	0	0.00
14	11	0.000	0	0.00
15	12	0.000	0	0.00
16	13	0.000	0	0.00
17	14	0.000	0	0.00
18	15	0.000	0	0.00
19	16	0.000	0	0.00
20	17	0.000	0	0.00
21	18	0.000	0	0.00
22	19	0.000	0	0.00
23	20	0.000	0	0.00
24	21	0.000	0	0.00
25	0	0.000	0	0.00

<-----Balance Holes----->							
Ln	Stage No.	Qty	Hole Type	Axial Length (IN.)	Radial Pos. (IN.)	Major Axis (IN.)	Minor Axis (IN.)
12	0	0	0	0.00	0.00	0.000	0.000
13	10	0	0	0.00	0.00	0.000	0.000
14	11	0	0	0.00	0.00	0.000	0.000
15	12	0	0	0.00	0.00	0.000	0.000
16	13	0	0	0.00	0.00	0.000	0.000
17	14	0	0	0.00	0.00	0.000	0.000
18	15	0	0	0.00	0.00	0.000	0.000
19	16	0	0	0.00	0.00	0.000	0.000
20	17	0	0	0.00	0.00	0.000	0.000
21	18	0	0	0.00	0.00	0.000	0.000
22	19	0	0	0.00	0.00	0.000	0.000
23	20	0	0	0.00	0.00	0.000	0.000
24	21	0	0	0.00	0.00	0.000	0.000
25	0	0	0	0.00	0.00	0.000	0.000

Ln	Stage No.	<-----Radial Spill Strips----->			
		Clearance (IN.)	Tooth Type	# of Teeth	Percent Round
12	0	0.000	0	0	0.00
13	10	0.060	3	2	0.00
14	11	0.060	3	2	0.00
15	12	0.060	3	2	0.00
16	13	0.060	3	2	0.00
17	14	0.060	3	2	0.00
18	15	0.060	3	2	0.00
19	16	0.060	3	2	0.00
20	17	0.060	3	2	0.00
21	18	0.060	3	2	0.00
22	19	0.060	3	2	0.00
23	20	0.060	3	2	0.00
24	21	0.060	3	2	0.00
25	0	0.000	0	0	0.00

I- Stage No.	<--(Shaft Diam. Between)---END PACKINGS---(Clearance Between)--->					
	CSG & 1st Leakoff (IN.)	1st & 2nd Leakoff (IN.)	2nd & 3rd Leakoff (IN.)	CSG & 1st Leakoff (IN.)	1st & 2nd Leakoff (IN.)	2nd & 3rd Leakoff (IN.)
12	0	0.00	0.00	0.00	0.000	0.000
13	10	0.00	0.00	0.00	0.000	0.000
14	11	0.00	0.00	0.00	0.000	0.000
15	12	0.00	0.00	0.00	0.000	0.000
16	13	0.00	0.00	0.00	0.000	0.000
17	14	0.00	0.00	0.00	0.000	0.000
18	15	0.00	0.00	0.00	0.000	0.000
19	16	0.00	0.00	0.00	0.000	0.000
20	17	0.00	0.00	0.00	0.000	0.000
21	18	0.00	0.00	0.00	0.000	0.000
22	19	0.00	0.00	0.00	0.000	0.000
23	20	0.00	0.00	0.00	0.000	0.000
24	21	0.00	0.00	0.00	0.000	0.000
25	0	0.00	0.00	0.00	0.000	0.000

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Ln	Stage No.	<--(Tot. #of Teeth Between)--END PACKING--(Tot. #of Rings Between)-->					
		CSG & 1st Leakoff	1st & 2nd Leakoff	2nd & 3rd Leakoff	CSG & 1st Leakoff	1st & 2nd Leakoff	2nd & 3rd Leakoff
12	0	0	0	0	0	0	0
13	10	0	0	0	0	0	0
14	11	0	0	0	0	0	0
15	12	0	0	0	0	0	0
16	13	0	0	0	0	0	0
17	14	0	0	0	0	0	0
18	15	0	0	0	0	0	0
19	16	0	0	0	0	0	0
20	17	0	0	0	0	0	0
21	18	0	0	0	0	0	0
22	19	0	0	0	0	0	0
23	20	0	0	0	0	0	0
24	21	0	0	0	0	0	0
25	0	0	0	0	0	0	0

Ln	Stage No.	<--(Type of Teeth Between)--END PACKING--(Tooth %Round Between)-->					
		CSG & 1st Leakoff	1st & 2nd Leakoff	2nd & 3rd Leakoff	CSG & 1st Leakoff	1st & 2nd Leakoff	2nd & 3rd Leakoff
12	0	0	0	0	0.00	0.00	0.00
13	10	0	0	0	0.00	0.00	0.00
14	11	0	0	0	0.00	0.00	0.00
15	12	0	0	0	0.00	0.00	0.00
16	13	0	0	0	0.00	0.00	0.00
17	14	0	0	0	0.00	0.00	0.00
18	15	0	0	0	0.00	0.00	0.00
19	16	0	0	0	0.00	0.00	0.00
20	17	0	0	0	0.00	0.00	0.00
21	18	0	0	0	0.00	0.00	0.00
22	19	0	0	0	0.00	0.00	0.00
23	20	0	0	0	0.00	0.00	0.00
24	21	0	0	0	0.00	0.00	0.00
25	0	0	0	0	0.00	0.00	0.00

Ln	Stage No.	<-(Flow Through Packing)——END PACKING——(Ln of Leakage Return)->					
		CSG & 1st Leakoff	1st & 2nd Leakoff	2nd & 3rd Leakoff	CSG & 1st Leakoff	1st & 2nd Leakoff	2nd & 3rd Leakoff
12	0	0	0	0	0	0	0
13	10	0	0	0	0	0	0
14	11	0	0	0	0	0	0
15	12	0	0	0	0	0	0
16	13	0	0	0	0	0	0
17	14	0	0	0	0	0	0
18	15	0	0	0	0	0	0
19	16	0	0	0	0	0	0
20	17	0	0	0	0	0	0
21	18	0	0	0	0	0	0
22	19	0	0	0	0	0	0
23	20	0	0	0	0	0	0
24	21	0	0	0	0	0	0
25	0	0	0	0	0	0	0

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Ln	Stage No.	Pressure (PSIA)	Enthalpy (BTU/LBM)	Temperature (°F)	Entropy (BTU/LB°F)	Sp. Vol. (FT ³ /LB)
26	22	31.850	1245.00	415.41	1.7955	16.19863
27	23	22.200	1216.70	353.61	1.8013	21.60950
28	24	13.549	1180.16	273.18	1.8080	31.91535
29	25	7.600	1142.00	188.19	1.8158	50.29706
30	26	5.126	1103.28	163.29	1.7970	69.81442
31	0	2.750	1045.50	138.09	1.7670	119.23116

Ln	Stage No.	First Lkg Flow	or Extr. Return	Second Lkg Flow	or Extr. Return	Third Lkg Flow	or Extr. Return
26	22	0	0	0	0	0	0
27	23	42330	52	0	0	0	0
28	24	0	0	0	0	0	0
29	25	34410	51	-900	2	-2500	11
30	26	0	0	0	0	0	0
31	0	0	0	0	0	0	0

Ln	Stage No.	Fourth Lkg Flow	or Extr. Return	Fifth Lkg Flow	or Extr. Return	Sixth Lkg Flow	or Extr. Return
26	22	0	0	0	0	0	0
27	23	0	0	0	0	0	0
28	24	0	0	0	0	0	0
29	25	0	0	0	0	0	0
30	26	0	0	0	0	0	0
31	0	0	0	0	0	0	0

Ln	Stage No.	# of Flows	Csg. Code	LNE	Flow (LBM/HR)	Sec.Eff. (%)	Stg.Eff. (%)
26	22	2	5	1	751680	0.000	85.678
27	23	2	5	1	709350	85.678	88.374
28	24	2	5	0	709350	0.000	88.401
29	25	2	5	1	678340	88.997	143.321
30	26	2	5	0	678340	0.000	145.015
31	0	2	5	1	678340	143.315	0.000

Ln	Stage No.	Flow Function	Design Stg A.E. (BTU/LBM)	Velocity Ratio	Loss Factor
26	22	536065	33.031	0.493406	0.576442
27	23	699852	41.349	0.463063	0.645033
28	24	1088718	43.165	0.463132	0.735262
29	25	1745066	27.019	0.593045	0.838060
30	26	2503515	39.838	0.596539	1.000000
31	0	0	0.000	0.000000	1.000000

<-----Stationary Blades----->					
Ln	Stage No.	Axial Wid. (IN)	Ex.Area (SQ.IN)	Reynolds Number	Height (IN)
26	22	1.336	285.932	5.6655e+005	7.11
27	23	1.631	427.751	5.8666e+005	9.54
28	24	1.643	486.718	4.4203e+005	10.65
29	25	1.558	486.815	1.8879e+005	11.33
30	26	2.777	1408.371	1.1831e+005	23.00
31	0	0.000	0.000	0.0000e+000	0.00

<----- (Diam.) ----- Stationary Blades ----- (Exit Angles) ----->							
Ln	Stage No.	Root (IN)	Pitch (IN)	Tip (IN)	Root (DEG)	Pitch (DEG)	Tip (DEG)
26	22	41.37	48.48	55.59	13.34	14.37	15.54
27	23	41.37	50.90	60.44	14.20	15.20	16.56
28	24	41.37	52.02	62.67	14.30	15.11	16.45
29	25	41.37	52.70	64.03	12.65	13.98	15.63
30	26	41.37	64.37	87.37	14.35	15.92	18.91
31	0	0.00	0.00	0.00	0.00	0.00	0.00

<----- (Misc) ----- Rotating Blades ----- (Reaction) ----->								
Ln	Stage No.	Axial Wid. (IN)	Ex.Area (SQ.IN)	Reynolds Number	Root (%)	Pitch (%)	Tip (%)	
26	22	1.194	418.352	3.4850e+005	5.00	28.29	43.57	
27	23	1.345	590.989	3.5781e+005	5.00	33.96	50.99	
28	24	1.217	671.465	2.4446e+005	5.00	36.40	53.99	
29	25	0.990	656.979	5.8032e+004	5.00	38.42	56.34	
30	26	1.393	1570.111	3.3093e+004	5.00	56.78	74.56	
31	0	0.000	0.000	0.0000e+000	0.00	0.00	0.00	

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Ln	Stage No.	< (Static Pressure) >			Rotating Blades		< (Spec.Vol) >	
		Root	Pitch	Tip	Root	Pitch	Tip	
26	22	22.630	24.665	26.080	21.14706	19.77506	18.93334	
27	23	13.905	16.129	17.555	31.09347	27.70646	25.93949	
28	24	7.837	9.469	10.489	48.77380	42.12477	38.91739	
29	25	5.230	5.976	6.414	69.52760	61.73513	57.96958	
30	26	2.840	3.937	4.392	118.38846	88.37209	80.12957	
31	0	0.000	0.000	0.000	0.00000	0.00000	0.00000	

Ln	Stage No.	< (Inlet Angle) >			Rotating Blades		< (Exit Angle) >	
		Root	Pitch	Tip	Root	Pitch	Tip	
26	22	23.70	34.23	55.67	24.00	21.44	19.50	
27	23	23.31	35.00	63.09	24.00	21.50	19.56	
28	24	23.16	35.64	69.37	24.00	21.40	19.38	
29	25	24.50	52.23	121.81	24.00	19.27	16.29	
30	26	23.82	85.54	155.69	24.00	18.65	15.22	
31	0	0.00	0.00	0.00	0.00	0.00	0.00	

Ln	Stage No.	< (Enthalpy) >			Rotating Blades		< (Entropy) >	
		Root	Pitch	Tip	Root	Pitch	Tip	
26	22	1215.78	1222.94	1227.64	1.7981	1.7975	1.7970	
27	23	1180.12	1191.27	1197.83	1.8051	1.8038	1.8032	
28	24	1141.97	1154.59	1161.67	1.8124	1.8108	1.8099	
29	25	1118.10	1126.51	1131.02	1.8186	1.8176	1.8170	
30	26	1068.03	1087.24	1093.84	1.8013	1.7989	1.7981	
31	0	0.00	0.00	0.00	0.0000	0.0000	0.0000	

Ln	Stage No.	< Interstage >		Packing		>	
		Clearance (IN)	Tooth Type	Percent Round	# of Teeth	Sealing Diam. (IN)	
26	22	0.025	2	0.00	8	27.34	
27	23	0.025	2	0.00	8	27.34	
28	24	0.025	2	0.00	8	27.34	
29	25	0.025	2	0.00	8	27.34	
30	26	0.025	2	0.00	8	24.69	
31	0	0.000	0	0.00	0	0.00	

<-----Root Spill Strips----->				
Ln	Stage No.	Clearance (IN.)	Tooth Type	Percent Round
26	22	0.000	0	0.00
27	23	0.000	0	0.00
28	24	0.000	0	0.00
29	25	0.000	0	0.00
30	26	0.000	0	0.00
31	0	0.000	0	0.00

<-----Balance Holes----->							
Ln	Stage No.	Qty	Hole Type	Axial Length (IN.)	Radial Pos. (IN.)	Major Axis (IN.)	Minor Axis (IN.)
26	22	0	0	0.00	0.00	0.000	0.000
27	23	0	0	0.00	0.00	0.000	0.000
28	24	0	0	0.00	0.00	0.000	0.000
29	25	0	0	0.00	0.00	0.000	0.000
30	26	0	0	0.00	0.00	0.000	0.000
31	0	0	0	0.00	0.00	0.000	0.000

<-----Radial Spill Strips----->						
Ln	Stage No.	Clearance (IN.)	Tooth Type	# of Teeth	Percent Round	
26	22	0.036	3	2	0.00	
27	23	0.039	3	2	0.00	
28	24	0.041	3	2	0.00	
29	25	0.042	1	1	0.00	
30	26	0.000	0	0	0.00	
31	0	0.000	0	0	0.00	

<--(Shaft Diam. Between)---END PACKINGS---(Clearance Between)--->							
Ln	Stage No.	CSG & 1st Leakoff (IN.)	1st & 2nd Leakoff (IN.)	2nd & 3rd Leakoff (IN.)	CSG & 1st Leakoff (IN.)	1st & 2nd Leakoff (IN.)	2nd & 3rd Leakoff (IN.)
26	22	0.00	0.00	0.00	0.000	0.000	0.000
27	23	0.00	0.00	0.00	0.000	0.000	0.000
28	24	0.00	0.00	0.00	0.000	0.000	0.000
29	25	0.00	0.00	0.00	0.000	0.000	0.000
30	26	0.00	0.00	0.00	0.000	0.000	0.000
31	0	0.00	0.00	0.00	0.000	0.000	0.000

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Ln	Stage No.	<-(Tot. #of Teeth Between)-END PACKING-			-(Tot. #of Rings Between)->		
		CSG & 1st Leakoff	1st & 2nd Leakoff	2nd & 3rd Leakoff	CSG & 1st Leakoff	1st & 2nd Leakoff	2nd & 3rd Leakoff
26	22	0	0	0	0	0	0
27	23	0	0	0	0	0	0
28	24	0	0	0	0	0	0
29	25	0	0	0	0	0	0
30	26	0	0	0	0	0	0
31	0	0	0	0	0	0	0

Ln	Stage No.	<-(Type of Teeth Between)-END PACKING-			-(Tooth %Round Between)->		
		CSG & 1st Leakoff	1st & 2nd Leakoff	2nd & 3rd Leakoff	CSG & 1st Leakoff	1st & 2nd Leakoff	2nd & 3rd Leakoff
26	22	0	0	0	0.00	0.00	0.00
27	23	0	0	0	0.00	0.00	0.00
28	24	0	0	0	0.00	0.00	0.00
29	25	0	0	0	0.00	0.00	0.00
30	26	0	0	0	0.00	0.00	0.00
31	0	0	0	0	0.00	0.00	0.00

Ln	Stage No.	<-(Flow Through Packing)-END PACKING-			-(Ln of Leakage Return)->		
		CSG & 1st Leakoff	1st & 2nd Leakoff	2nd & 3rd Leakoff	CSG & 1st Leakoff	1st & 2nd Leakoff	2nd & 3rd Leakoff
26	22	0	0	0	0	0	0
27	23	0	0	0	0	0	0
28	24	0	0	0	0	0	0
29	25	0	0	0	0	0	0
30	26	0	0	0	0	0	0
31	0	0	0	0	0	0	0

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Csg Name	Inlet Ln	Exhaust Ln	# of Stages	# of Flows	Casing Efficiency	Developed Power	Manuf. Margin	Exh. Bef.	Leak Therm.
HP	2	11	9	1	82.954	36804.1	1.50	N	
IP	13	25	12	1	92.680	66220.6	2.00		
LP	26	31	5	2	109.352	39516.8			

<-----Feedwater Heaters----->					
Ln	Ln of Source	Shell Pressure (PSIA)	Temp. In (°F)	Feedwater Out (°F)	Temp. Drains Out (°F)
51	28	7.000	122.80	171.90	176.90
52	26	20.400	171.90	224.00	229.00
53	23	47.500	224.00	272.80	234.00
54	21	81.300	272.80	308.10	282.80
55	19	132.800	308.10	348.90	0.00
56	16	220.600	353.30	394.10	363.30
57	11	491.000	394.10	467.10	404.10

Generator Output (KW).....139760
 Developed Shaft Power (KW).....142541.4
 Generator and Mechanical Efficiency (%).....98.05
 Rate (BTU/KWH).....8012
 Rate Manufacturer's Margin (%).....1.50
 Inlet Pressure (PSIG).....1800.790
 Inlet Temperature (°F).....999.992
 Station Ambient Pressure (IN. HGA).....28.940
 Exhaust Pressure (IN. HGA).....5.599
 Used Energy End Point (BTU/LBM).....1052.70
 HP Shaft Speed (RPM).....3000
 LP Shaft Speed (Cross-Compound Only) (RPM).....0
 Reference Feedwater Flow Meter Reading (LBM/HR).0
 Annulus Velocity (FT/S).....341.436
 Ln. From Which Steam Seal Regulator Is Supplied.0
 Ln. To Which Steam Seal Regulator Is Relieved...0
 Steam Seal Regulator Pressure (PSIG).....0.000
 Final Feedwater Enthalpy (BTU/LBM).....450.29
 Manufacturer.....General Electric Impulse
 LP Flows are Interconnected

Section 2.4

Component Cooling Water System

Condenser Cooling Water System

Problem Statement

High back-pressures, at the exhaust of the low pressure section, is reducing the capacity of the unit.

System Description

Unit No.1, of CTPS, is provided with a recirculating type cooling water system. The unit has a dedicated cooling tower. The design data of the cooling tower is placed in attachment II. The block diagram of the Cooling Water System is shown in attachment I. The condenser, circulating water pumps, and valves were investigated.

Analysis

Poor condenser vacuum has been a perennial problem in CTPS. In Unit No.1, while operating at a load of about 85MW, the condenser vacuum was 600mm HG (vac.)(i.e., 135mm HG(abs) with a barometric pressure of 735mm HG). The design condenser pressure is 63mm HG at 140MW. This is an extremely poor back pressure condition for the turbine and is also one of the major impediments to the achievement of full load capacity of the machine. It is estimated that an output reduction of about 6MW is attributed to the poor vacuum for the given value of main steam flow or a heat rate deterioration of about 90 kcal/KWHR. An analysis was carried out to identify the major factors contributing to the poor condenser vacuum. Details are placed in attachment III. According to the data recorded and plant records, the condenser and the steam jet air pump are operating within design limits at the given load. However, if the load was increased to 140MW, the condenser fouling and the condition of the steam jet air pump could limit power. These components could not be evaluated at this time, due to the failure of the condenser isolation valve. The cooling tower is the major contributor to the very high cooling water inlet temperatures to the condenser. Therefore, the cooling tower system was analyzed in detail using the "Fish-Bone" technique of root cause analysis. Attachment IV indicates the parameters analyzed. The following Potential root causes were identified:

- A.1 Wear and blockage of nozzles
- B.1 Improper blade angle of cooling tower fans
- B.2 Low fan speed
- C.1 Fouling/blockage of cooling tower fills
- D.1 High wet bulb temperatures

These potential root causes were verified based on the measurements taken of various components and records retained by the plant. The root cause verification matrix is presented in attachment V. The potential root causes are discussed below:

- A.1 **Wear and blockage of cooling tower fans** (See Photo: Fig. 2.4.1)
Plant records show that the nozzles are being replaced regularly. Thus, the nozzles are not blocked or worn out, making the flow dispersion from the nozzles

considered to be normal and adequate. Therefore, the nozzle condition can not be the root cause of the problem.

B.1 Improper blade angle of cooling tower fans

Each cooling tower cell is equipped with a fan to provide the induced draft. Out of the five cells, three have original fans supplied by the OEM and two have fans supplied by Paharpur Cooling Towers. As indicated in attachment II, the design value of the blade angle is 13 degrees. On the contrary, the fans are presently set at an angle of 11 degrees. The reduction in blade angle causes a reduction in air flow. According to the design manual, for each one degree change in blade angle the power consumption of the fan changes by 20KW (10%). The current rating of the fan drives is 50 amps each. At present, the current, drawn by the fans, is as follows:

CT Fan 1A	30 Amps
CT Fan 1B	29 Amps
CT Fan 1C	33 Amps
CT Fan 1D	33 Amps
CT Fan 1E	30 Amps

The relatively low current, drawn by the motors, is also an indication of the reduced blade angle and the reduced air flow handled by the fans. Therefore, a reduced blade angle setting is considered to be one of the root causes. The blade angle was altered due to the failure of the aluminum blades.

B.2 Low Fan Speed

The fans are rated at 100 RPM. A reduction in fan speed would cause a reduction in the air flow. The reduction in fan speed could be due to a reduction in the quality of power, overload on the motor induced by the fan due to various reasons like change in blade angle, and an increase in bearing friction/friction drag etc.. The fan speed could not be checked during this visit.

C.1 Fouling/Blockage of Cooling Tower Fills (See Photo: Fig. 2.4.2 thru Fig. 2.4.6)

A visual inspection of the cooling tower in operation indicated non-uniform flow distribution from the fills in all cells. Temperature measurements made, revealed wide variation in temperature at different locations in each cell (attachment VII). Therefore, each was shut down in sequence and the condition of the fills was examined. Considerable blockage of the fills was noted. Details are placed in attachment VIII. While the extent of blockage varied from cell to cell, an overall blockage of approximately 36% was noted. This is considered to be a very poor condition for the cooling tower. Plant records indicate that the CT fills have not been replaced, and cleaning of the fills, by high pressure water, has only been done once. Some of the fills are damaged. Fouling/blockage of CT fills is

considered to be normal and adequate. Therefore, the nozzle condition can not be the root cause of the problem.

B.1 Improper blade angle of cooling tower fans

Each cooling tower cell is equipped with a fan to provide the induced draft. Out of the five cells, three have original fans supplied by the OEM and two have fans supplied by Paharpur Cooling Towers. As indicated in attachment II, the design value of the blade angle is 13 degrees. On the contrary, the fans are presently set at an angle of 11 degrees. The reduction in blade angle causes a reduction in air flow. According to the design manual, for each one degree change in blade angle the power consumption of the fan changes by 20KW (10%). The current rating of the fan drives is 50 amps each. At present, the current, drawn by the fans, is as follows:

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C.1 Fouling/Blockage of Cooling Tower Fills (See Photo: Fig. 2.4.2 thru Fig. 2.4.6)

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D.1 High Wet Bulb Temperature

The highest recorded wet bulb temperature occurs during the July-August time frame and is 26 degrees Celsius. The cooling tower design is for a wet bulb temperature of 26.1 degrees Celsius (attachment II). Therefore, a high wet bulb temperature is not considered to be a root cause.

The identified root causes are:

- * Blockage of CT fills leading to an improper water distribution.
- * Improper blade angle, leading to reduced air flow.

Solutions

The solution matrix is placed in attachment VI.

1. To increase the air flow, either the blade angle or the fan speed can be increased. The feasibility is very low for increasing the fan speed. However, increasing the blade angle will increase the KW consumption of the fans and accordingly increase the current drawn. This should be within 10% of the rated current. Since the capacity of the motors is above the current drawn at present, increasing the blade angle will not over load the motors. Changing the blade angle is feasible and should be considered as one of the solutions. Along with changing blade angles, the blade material can be changed to a Fibre Reinforced Plastic (FRP), which is being extensively used in cooling towers, now. This will have additional benefits, either:
 - A. Air flow can be increased by 20% (increase blade angle), or
 - B. Power consumption can be reduced by 20%
2. Suggested methods of removing the fouling/blockage are:
 - A. Cleaning the fins with high pressure water.
 - B. Chemical dosing of cool water. (Preventative Maintenance)
 - C. Taking out the fills and manual cleaning of fills.
 - D. Replace the fill material and install chemical dosing system to maintain a clean system.

Solution "A" May not be effective, since the blockage has accumulated over a long period of time and is too hard. Further, the water jet will not reach the upper layer of hills.

Solution "B" Also will lack adequate effectiveness, since the fouling/blockage has already occurred.

Solution "C" Is one of the most feasible solutions. However, it involves down time of the respective cell and certain replacement of damaged fills. Also, the blockage may be too hard to be removed from the fill without damaging all the fills. Replacement fills and supports must be available.

Solution "D" Is the best solution. However, this is also the most costly solution.

3. After the cooling tower is returned to design operating conditions, a performance test should be carried out as per the procedure along with this report. Based on the results, a future course of action can be decided.
4. The isolation valve for the condenser is not working, therefore, the condenser condition could not be evaluated. The review of data from the plant maintenance records revealed that fouling in the condenser should be cleaned. The condition of the steam jet air pump was not evaluated, however, this component should be evaluated for cleanliness and capacity.

Component Cooling Water System

Component Cooling Water - Fan Blades
Fig. 2.4.1

Component Cooling Water System

Component Cooling Water - Fill Blockage
Fig. 2.4.2

Component Cooling Water System

Component Cooling Water - Fill Blockage
Fig. 2.4.3

Component Cooling Water - Fill Blockage
Fig. 2.4.4

Component Cooling Water System

Component Cooling Water - Fill Blockage
Fig. 2.4.5

Component Cooling Water - Fill Blockage
Fig. 2.4.6

BLOCK DIAGRAM
ATTACHMENT I

Design Data of Cooling Tower

Attachment II

Type: Induced Draft

Number of Cells: 5

Design Cooling Water Flow: 18,000 Cubic Meters/Hour

Hot Water Inlet Temperature: 40.8 Degrees C

Cold Water Outlet Temperature: 31.3 Degrees C

Approach: 5.2 Degrees C

Wet Bulb Temperature: 26.1 Degrees C

Cooling Range: 9.5 Degrees C

Air Flow: 10,500 Kg/Square Meter Hour

Fill Material: Asbestos Cement

Number of Fans: 1 per Cell, Total 5 for 1 Cooling Tower

Number of Blades per Fan: 6

Power Required for Each Fan: 198 Kw

Blade Angle: 13 Degrees

Fan Motor Data: 200 Kw / 3000 V / 50 Amp

Attachment III

PG150.DRW

Fish Bone Analysis For Cooling Tower Unit #1 - Attachment IV

Root Cause Verification Matrix Attachment V

PRC	Verification Method	Results	Conclusion
A.1. Wear and Blockage of Nozzles	<ul style="list-style-type: none"> - Maintenance Records - Visual Inspection 	Based on Maintenance Records, replacement of worn out nozzles is done regularly. No blockage in nozzles found.	Nozzles are not a root cause of the problem.
B.1. C.T. Fans Have Improper Blade Angle	<ul style="list-style-type: none"> - Visual Inspection - Review of Design - Plant Records - Current TO Motors 	The blade angle is set at 11 degrees and the design is 13 degrees. Reduction in blade angle results in reduction in air flow and reduction in motor current.	Improper blade angles are a root cause.
B.2. Low Fan Speed	<ul style="list-style-type: none"> - Tachometer - Review of Design 	Design speed is 100 RPM. Could not measure actual speed.	
C.1. Fouling/Blockage of CT Fill	<ul style="list-style-type: none"> - Visual Inspection of Water - Visual Inspection of Fills - Temperature Mapping 	Uneven dispersion of water was observed. Visual inspection revealed fouling/blockage of the cells at approximately 36%. Temperature mapping showed wide variations in temperature at different zones of cells.	Fouling/blockage of CT Fills is a root cause.
D.1. Wet Bulb Temperature High	<ul style="list-style-type: none"> - History of Wet Bulb Testing - Review of Design 	History review shows the highest wet bulb temperature to be 26 degrees C. The design of the tower is for 26.1 degrees C.	High wet bulb temperature is not a root cause.

Solution Matrix

System: **Fuel Processing**

Total = Effectiveness x Feasibility; Cost data impacts Feasibility

RC	Potential Solution	Effectiveness	Cost	Feasibility	Total	Comments
A1-2 & B3-2 High Coal Moisture	A) Wash coal to reduce % fines in coal. Fines are a result of the open pit mining practices that may be difficult to change.	9	5	4	36	A coal wash facility would help, but is not likely to be cost effective. Try to effect better mining practices.
	B) Change coal pile management from bottom grate loading to Stacker Reclaimer.	6	3	7	42	
	C) Reconfigure coal yard for: a)Efficient operation b)Minimize number of storage areas c)Improve grading to enhance drainage d)Install truck ramp and a truck tippler that facilitates unloading over the hopper gate. This will eliminate coal trucks from driving over the coal and causing the coal to cake. Residence time in the coal yard reduces thus reducing moisture pickup. Coal should be pushed not driven.	8	2	8	64	This is a simple device frequently used in U.S. to tip grain truck load into silos.

Solution Matrix

System: Fuel Processing

Total = Effectiveness x Feasibility; Cost data impacts Feasibility

RC	Potential Solution	Effectiveness	Cost	Feasibility	Total	Comments
A1-3 & B2-4 Poor Exhauster Spider Rebuild Practice	A) Set-up exhauster spider rebuild in a fabrication shop that is set up for handling and rebuilding the spider. <u>Establish a rebuild process / data for:</u> - Blade Replacement - Spider Warpage Correction - Spider Integrity This will require a mechanical handling system for moving the spiders to and from the fabrication shop.	10	3	8	80	This may be a short term option if the milling system is replaced. <i>Note:</i> Failure to rebuild the rotors and check for structural integrity can result in an in-service catastrophic failure.
	B) "A" and replace blades with ceramic blades. This will require a complete replacement of spiders, high quality rebuild, and an inventory of spares.	10	3	5	50	This will reduce frequency of rebuild.
	C) Contract out spider rebuild.	5	2	4	20	Unless the shop is close to CTPC, the frequent rebuilds will require a large number of spares.
A2-1 Low Design Selection Temperature For Coal Conditions Impacts Low APH Outlet Temperature	A) <u>For the high % coal moisture change. CTPC coal yard management practices:</u> Reduce % moisture to 7-8% (see solution "C", % Moist Control)	8	2	8	64	
	B) <u>Redesign second pass pressure parts (primary superheater & economizer).</u> This will require a complete evaluation of the boiler absorption surfaces. (see solution "B", for Low Flue Gas APH Inlet Temperature.)	9	1*	10	90	This will restore the second pass exit temperature. The APH exit temperature will be raised to meet drying requirements. * Assumes only second pass modification.

Solution Matrix

System: Fuel Processing

Total = Effectiveness x Feasibility; Cost data impacts Feasibility

RC	Potential Solution	Effectiveness	Cost	Feasibility	Total	Comments
A1-4 & A2-2 Low Flue Gas APH Inlet Temperature Impacts APH Outlet Temperature	A) <u>Redesign second pass pressure parts to increase flue gas inlet temperature to APH.</u> The second pass inlet temperatures are acceptable, where as the exit temperature is 100F below design. A clear indication that there is too much PSH surface.	9	1*	10	90	This scope was discussed with BHEL & NTPC. They will provide an estimate to evaluate boiler heating surfaces, redesign the PSH and economizer surfaces, and execute resurfacing of second pass. * Assume only second pass modification.
A3-1 & B1-2 High % of Fines In Coal (This Impacts Low Mill Grinding Output and Increases % Moisture Carryover)	A) Reduce fines from coal mines . (see solution A1-2)					Open pit mining results in high % fines. Not likely to change mining practice.
	B) Improve Coal Pile Management. (see solution B1-1)					
	C) Alternate coal supply.	10	?	1	10	Changing coal supplier is not likely in the near future.
A1-5 APH Blockage	A) <u>Change APH hot basket to a dual basket design.</u> This will facilitate easy removal of the baskets for cleaning.	8	1	10	80	This is a relatively simple change that can be accomplished by ordering dual replacement baskets.
	B) <u>Reactivate the bottom soot blowing system. If bottom blowing is inadequate, add a top mounted system. Initiate frequency of cleaning after every economizer tube leaks.</u> Develop in-situ APH steam / high pressure air cleaning when the pressure drop across the APH increases.	8	1	9	72	DVC has initiated this effort to check out the manually operated bottom blowing system. The system will need to be upgraded along with the reheat soot blowing system.

Solution Matrix

System: Fuel Processing

Total = Effectiveness x Feasibility; Cost data impacts Feasibility

RC	Potential Solution	Effectiveness	Cost	Feasibility	Total	Comments
A3-2 & B1-1 Coal Pile Management (This Contributes to High Moisture Carryover and Caking of Coal. This Is a Primary Contributor to Low Mill Output.)	A) Install a coal truck tippler to facilitate coal unloading into hoppers and regrade the coal yard such that water drains away from the hoppers.	8	2	8	64	Initial survey of the coal yard indicates that this effort can be readily executed.
	This would reduce the residence time of coal from delivery to coal bunkers. It can minimize coal movement in the yard and eliminate driving over coal. Coal moisture carryover and caking will be significantly reduced.					
B1-5 Exhauster Design (CRC)	A) Select a higher HP motor to power the exhauster and mill.	6	2	7	42	The mills are undersized and suitable for these coal conditions. This should be addressed as part of the mill upgrade.
	B) High performance exhauster wheel.	6	3	6	36	
B1-3 & B2-2 Roll to Bowl Clearances	A) Improve maintenance practices	7	2	8	56	This will be effective but a good maintenance program will be difficult to sustain.
B1-4 & B2-3 High Spring Pressure	A) Improve maintenance practices	7	1	8	56	Method of setting spring pressure should be changed from measurement to hydraulic pump.
B3-3 Bunker Design	A) Line bunker with 10 gauge stainless steel, grade 304, type B, will provide corrosion protection and improved flow characteristics.	8	3	6	48	
	B) Install vibrators	7	1	8	56	

PRC	Verif. Process	Analysis / Results	Conclusions	Comments
B2-4 Exhauster Clearances	<ul style="list-style-type: none"> - Visual Obs. - Interviews 	(see A1-3)		
B3-1 Feeder Drives	<ul style="list-style-type: none"> - Visual Obs. - Interview 	Feeder drives fail due to excessive feeder jams / overload from debris and coal caking. These are being repaired and or replaced. Plant indicated that these are high maintenance item.	<p>This is not a "RC".</p> <p>Feeder drive maintenance could be reduced by changing over to a variable speed drive.</p>	In the U.S. these drives have been replaced by variable speed motors.
B3-2 High % Moisture in Coal	<ul style="list-style-type: none"> - Visual Obs. - Interview 	<p>High moisture in coal results in coal caking. This causes feeder jams and subsequent fireouts.</p> <p>This coal has a tendency to cake readily. Coal pile management aggravates this condition. See coal pile management.</p>	This is a "RC" that contributes to feeder jams.	Since feeder jams are frequent, the feeder doors are kept open to clear jams. This reduces air temperature to the mill.
B3-3 Bunker Design	<ul style="list-style-type: none"> - Evaluate design - Interview 	<p>The bunker design is similar to that found in other TVA sites. Bunkers are carbon steel lined and the slopes are shallower than would be specified today.</p> <p>Even though there have been hopper jams caused by wet coal bridging, this is not a major problem. Coal caking is being aggravated by the coal management.</p>	Not a "RC".	Recommendations for reducing hopper bridging should be evaluated.
B3-4 Wet Coal	(see B3-2)			

Solution Matrix

System: Fuel Processing

Total = Effectiveness x Feasibility; Cost data impacts Feasibility

RC	Potential Solution	Effectiveness	Cost	Feasibility	Total	Comments
D1-1 High Inerts	A) Wash Coal	9	5	4	36	
D1-2	(see B2-)					
D1-3 & D1-4 Suitability For Coal Type and Mill Capacity	Upgrade Mill Processing to a 31 t / hr / mill:					
	A) Convert existing mill to an increased capacity pressurized mill operation.	6	4	5	30	
	B) Upgrade existing mill capacity by modifying the internals.	5	3	5	25	
	C) Replace milling system. C1) Pressurized Bowl Mill. C2) Race and Ball Mill. C3) Other System.	8	5	7	56	

PRC	Verif. Process	Analysis / Results	Conclusions	Comments
D1-1 High % of Inerts	<ul style="list-style-type: none"> - Visual Obs. - Coal Analysis Data 	<p>Coal analysis indicates high ash 49%.</p> <p>Open pit mining leads to high % of inerts (rocks) that are high in quartz. The regions coal has high quartz content.</p> <p>Coal and ash are to be analyzed by ntpc to establish percent quartz / inerts content.</p>	This is a "RC" for accelerated wear of the mill rolls and exhaustor blades. This contributes to reduced mill output.	
D1-2 Mill Maint.	(see B2 Mill Setting)	<p>As discussed in section B2 Mill Setting, the mill performance can be improved with better mill maintenance.</p> <p>The excessive wear rates makes it difficult to establish an adequate Mill Preventive Maintenance Program.</p>	This is a "CRC" that contributes to reduced milling capacity and overall performance of the milling system.	DVC needs to establish mill performance test procedure. The mill performance should be evaluated as part of the upgrade.
D1-3 Suitability For Coal Type	<ul style="list-style-type: none"> - Coal Analysis - Maint. Information 	<p>As discussed in D1-1~2 and B2, the wear rates for the mill components are very high. A loss of 3" of Ni-Hard 4 material in 3000 hours is high and is consistent with other RB 733 bowl mills grinding similar coal. These high wear rates preclude on optimized mill maintenance program.</p> <p>The race ball mills in Units 4~6 operate satisfactory for 12,000 hrs between overhauls with same coal used in Units 1~3. The mills are not delivering the rated capacity due to bypass leakage. There are no exhaustor maintenance problems, because the primary air fan is upstream of the mill.</p>	This is a "RC" for low mill output.	Investigate feasibility of replacing mills with other milling processes.

PRC	Verif. Process	Analysis / Results	Conclusions	Comments
D1-4 RB 733 Mill Capacity	<ul style="list-style-type: none"> - Design Data - Plant Statistics 	<p>Mill capacity per design = 24 t / hr (<i>ideal condition</i>)</p> <p>In order to operate unit with four mills and one mill under maintenance, each mill should have a 20% margin.</p> <p>Based on fuel HHV of 4100 Kcal/kg, each mill should produce 21.6 t / hr. With a 20% margin, each should be sized at 25.92 t / hr.</p> <p>Based on fuel HHV of 3550 Kcal / Kg, minimum capacity per mill 24.9 t / hr. With a 20% margin, each should be sized at 31 t / hr.</p>	Mills Selection is a "RC" for poor mill capacity and maintenance problems.	<p>These mills must either be upgraded or replaced with at least 27 t / hr milling capacity.</p> <p>A 30 t / hr mill would be preferred.</p> <p>It will be prudent to evaluate other milling processes.</p>

Attachment VI

PG153.DRW

Temperature Mapping Of "CT" Cells *Attachment VII*

Cell 1A

Cell 1B

Cell 1C

Cell 1D

Cell 1E

Mapping of Fin Fouling/Blockage **Attachment VIII**

50%	60%	60%	10%	40%	40%	50%
80%	30%	30%	10%	15%	20%	20%
100%	100%	10%	5%	40%	10%	10%

Cell 1A Average 38%

70%	80%	80%	40%	60%	30%	15%
40%	40%	20%	10%	15%	15%	5%
70%	70%	50%	20%	15%	40%	50%

Cell 1B Average 40%

90%	60%	15%	15%	15%	65%	85%
30%	30%	10%	15%	10%	70%	80%
85%	20%	20%	10%	20%	60%	90%

Cell 1C Average 43%

50%	40%	50%	10%	5%	30%	40%
20%	60%	20%	10%	10%	5%	10%
10%	30%	30%	15%	10%	5%	5%

Cell 1D Average 22%

90%	30%	40%	20%	25%	30%	50%
60%	40%	50%	30%	30%	60%	15%
40%	50%	15%	10%	40%	40%	20%

Cell 1E Average 37%

Percentage Indicated Is The Blockage/Fouling.

Section 2.5

Feedwater System

Feedwater Pump / Motor

2.5.1

Problem Statement

Availability of BFP is poor.

System Description

Three fifty percent BFP's have been provided on Unit 2. These pumps have been supplied by Worthington France, and are of constant speed barrel type with seven stages.

Pump:

Capacity: 250 t/hr.
Head: 159.3 kg/cubic meter
Pump speed: 3975 rpm

Motor:

Make: Le Material Electrique Frame
Hp: 2340
Volt: 3.15 KV, rated current 390 amps
RPM: 1585

Analysis

Overhauling of pumps is done departmentally by CTPS. Generally the wearing rings are replaced, shaft run out is checked and cartridge assembled with the clearances specified by the manufacturer.

The average life between overhauls is 8 - 10 years, which is very good.

In the last 3 - 4 years, the failure rate has increased leading to higher consumption of spares. Presently only one pump will be available in Unit 2 when it returns to service.

The increased failure rate can be attributed to the fact that these pumps have been operating for the past thirty years, and the components may be reaching end of life, especially the shafts. One shaft sheared at the portion where the balancing drum / disc is mounted. As per the maintenance engineers, this is the first shaft failure in the BFP since commissioning.

As per the O&M engineer, one pump is able to sustain generation up to 60 -70 MW. In Unit 1, the pumps were drawing 310 amps against the rated current of 390 amps, when the load on the unit was 55 MW and the frequency was ranging from 47.27 to 48.63 Hz.

The gland packing on the pump need to be replaced every six months. Change of gland packing to mechanical seals is under trial.

Recommendations

- Carry out the R.L.A. Of each BFP as per the procedure following this section (attachment 1).
- Order a minimum of two spare cartridges and two shafts. Impellers and other fast-moving components may be ordered depending on stock position.
- Carry out regular condition monitoring on all the pumps (vibration, temperature, etc.).
- Refurbish existing cartridges through an indigenous pump repair organization and establish local suppliers for pump wear and shaft components.

Residual Life Assessment of Boiler Feed Pump

Introduction

Boiler Feed Pump (BFP) is one of the vital auxiliaries in a thermal power station. Reliable feed pump operation is essential to steam power plant availability and generation.

In order to avoid costly down time, as well as to prevent accidents, it is necessary to carry out Remaining Life Assessment (RLA) of BFP components.

General Description of B.F.P.

The BFP is a horizontal multistage variable speed centrifugal pump with forged outer barrel and welded-on suction and discharge nozzles. The nozzles can be upward or downward oriented depending on the plant feed water piping design.

A typical "barrel pull out type" pump consists of an external casing called the barrel, an internal casing which forms the inner cartridge together with the rotor assembly, the discharge and suction covers, the bearing and sealing system. A cut away section of BFP showing its major components is as shown in Fig. 1.

NTPC has adopted the 3 x 50% capacity BFP configuration. For 200/210 MW units, 3 x 50% motor driven pumps have been provided, whereas for the 500 MW units, 2 x 50% turbine driven BFP plus 1 x 50% motor driven BFP (MDBFP) have been provided, except at Rihand where even in the 500 MW unit, 3 x 50% MDBFP have been provided. In all the units, booster pumps have been provided.

Speed variation in the case of MDBFP is achieved by means of a hydraulic coupling.

Maintenance Practice

Present NTPC practice with respect to maintenance of BFP are:

- 1) Preventive maintenance
- 2) Predictive maintenance/routine overhaul

Recent feed back from respective site indicates a shift to predictive maintenance, rather than routine overhaul. It is the general practice not to open the pump for overhaul, unless the parameters warrant it, i.e. condition based maintenance.

This has resulted in an increase in Mean Time Between Overhaul. So it is very much necessary to ensure the integrity of the components of BFP such as the shaft, impeller, barrel, etc., especially from the aspect of aging.

BFP components are not only expensive, but also have long lead time, especially in the case of imported pumps.

Remanent Life Analysis

In order to ensure safe, reliable, and continuous operations of BFP, it is necessary to carry out certain extra checks to determine Residual Life of BFP components.

Format for carrying out RLA of various components is given below. The parts to be inspected are as shown in Fig. 2.

Section	Component	Critical Location	Check For	Technique	Remarks
A	Barrel HP Cover	Corners & Welds	Cracks	DPT, UT in case of cracks. MPI	Repair in case of cracks
B	Bolt	Threads	Cracks	DPT & MPI	Replace in case of cracks
C	Shaft	Steps	Cracks, Fretting Corrosion	DPT & MPI Replica Test UT in case of crack. Dimensions & run out	Repair / replace shaft if necessary
D	Impeller Diffuser & Wearing Ring	Full	Cracks, wear, cavitation, erosion	MPI & DPT Dimensions	Repair / replace if necessary
E	Barrel	Inlet & Outlet Nozzles, Welds	Wear, corrosion, and cracks	Dimensions DPT	Repair if necessary
F	Ring Section	Socket and Spigot	Change of fitting dimension, crack	Dimensions DPT	Repair if necessary
G	Bearing	White metal	Wear and Crack	Dimensions DPT	Repair if necessary
H	Rotor	Complete	Balancing	Dynamic Balancing	
I	Suction and Discharge Cover	Corners	Cracks	DPT and UT in case of cracks	Repair in case of cracks
J	Diffuser	Full	Crack, Wear	DPT and UT in case of crack	Repair / replace if necessary

The checks given in the above format are to be carried out over and beyond the maintenance instructions given in the O&M manual.

Figure 1. Barrel Type Boiler Feed Pump

Figure 2. Precision Inspection of Boiler Feed Pump

Problem Statement

The feed-water temperature is 45°C below design at the entrance to the economizer.

System Description

Unit 2, of CTPS, is provided with 4 LP heaters, 1 deaerator, and 2 HP heaters. The schematic is enclosed as attachment I. There are two condensate extraction pumps of 100% capacity each. The LP heaters 1 and 2 are installed in the condenser.

Analysis

The various parameters of unit 1 (operating at 85 MW) were reviewed for condensate, extraction, and drains system data. Poor condenser cooling (see sections on cooling water) results in hotwell and LP heater inlet temperatures that are higher than design. The performance of the LP heaters (the temperature rise) and the condensate pump (both flow and head) is satisfactory. The principal problem is that the HP heaters have been removed from service for tube failures. The tube material of the HP heaters is reported to be copper alloy 715 (UNS C71500), nominally 70 Cu, 30 Ni. TVA has used 715, Monel 400, 304Nss, 304ss, Inconel 600, and carbon steel in HP heater applications. In our drum units, we have had good success retubing 715-tubed HP heaters with 304 ss.

A thorough investigation of the root cause of the HP heater failures is needed. This should include verification of the tubing alloy and identification of the tube failure mechanism and operational concerns that could contribute to the problem.

Solutions

The following alternatives need to be investigated for techno-economic feasibility:

- If the leakage problem were confined to the tube-tubesheet joint area, sleeving the tubes at the tubesheet area could be an economic solution.
- Retubing the heaters with new tubes using the same heater internals. The technical factors to be considered in selecting a replacement alloy are:
 - * Root cause of the current failures.
 - * Feedwater chemistry and control. Chloride levels from condenser in-leakage or high ammonia levels from chemical treatment would affect material choice.
 - * The heat transfer differences between the copper alloy and the replacement alloy.
 - * The strength requirement for the service temperature and pressure.
 - * Support plate spacing for the new material in the existing shell.
- Manufacturing a replacement tube bundle to fit into the present shell. This would allow a redesign of the feedwater heater that could minimize efficiency losses from a change in tube material. This may not be a substantial savings over a completely new heater.

- Install new HP heaters.

It is important to note that after the HP heaters are made available the control and instrumentation system needs to be made reliable for consistent operation of the heaters. Operation of the HP heaters without reliable controls may lead to water induction in the HP turbines and resultant damage.

- The only recommendation for this outage is to inspect the temperature and pressure instrumentation for all in-service heaters.

ATTACHMENT 1

System : Regenerative
Sub System: Condensate

Unit 1
C.T.P.S.
DVC

S. No.	Parameter and Location	Plant Inst. Reading	Prob. Value Ref. HBD	Deviation	Remarks
1	Condensate Temp. Inlet to LPH-1	62°C	43.5°C	+18.5°C	High due to poor cond. Vac.
2	Condensate Temp. Outlet to LPH-1	90°C	66°C	+24°C	
3	Condensate Temp. Inlet to LPH-2	62°C	66°C	-4°C	
4	Condensate Temp. Outlet to LPH-2	90°C	90°C	0	
5	Condensate Temp. Inlet to LPH-3	78°C	90°C	-12°C	Inst. not o.k.
6	Condensate Temp. Outlet to LPH-3	104°C	115°C	-11°C	
7	Condensate Temp. Inlet to LPH-4	107°C	115°C	-8°C	
8	Condensate Temp. Outlet to LPH-4	124°C	133°C	-9°C	
9	Condensate Temp. Inlet to D/A	110°C	133°C	-23°C	Inst. not o.k.
10	Feed Water Temp. D/A Storage	158°C	151°C	+7°C	
11	CEP Discharge Pressure	12 kg/cm		✓	
12	Condensate Pressure LPH-1 (In)	8.5 kg/cm		✓	
13	Condensate Pressure LPH-1 (Out)	8.2 kg/cm		✓	
14	Condensate Pressure LPH-2 (In)	8.5 kg/cm		✓	
15	Condensate Pressure LPH-2 (Out)	8.2 kg/cm		✓	
16	Condensate Pressure LPH-3 (In)	7.5 kg/cm		✓	
17	Condensate Pressure LPH-3 (Out)	5.2 kg/cm			Not Reliable (should be 7.0)
18	Condensate Pressure LPH-4 (In)	6.5 kg/cm		✓	
19	Condensate Pressure LPH-4 (Out)	6.0 kg/cm		✓	
20	Condensate Pressure D/A (In)	5.5 kg/cm		✓	
21	D/A Pressure	5.2 kg/cm	4.89 kg/cm	✓	
22	Final Feed Water Temp. at Eco (In)	158°C	203°C	-45°C	Due to HPH out of service

System : Regenerative
Sub System: Condensate

Unit 1
C.T.P.S.
DVC

S. No.	Parameter and Location	Plant Inst. Reading	Prob. Value Ref. HBD	Deviation	Remarks
1	Extn. to LPH-1 Temp. °C				
2	Extn. to LPH-2 Temp. °C				
3	Extn. to LPH-3 Temp. °C	230°C	258°C	-28°C	
4	Extn. to LPH-4 Temp. °C	275°C	310°C	-35°C	
5	Extn. to D/A Temp. °C				
6	Extn. to HP Heaters Temp. °C	NA	NA	NA	Not Charged since long due to tube failures.
7	Extn. to LPH-1				
8	Extn. to LPH-2				
9	Extn. to LPH-3 (kg/cm**2)	0.95	0.84		
10	Extn. to LPH-4 (kg/cm**2)	2.51	2.10		
11	Extn. to D/A (kg/cm**2)	5.2			
12	Extn. to HP Heaters	NA	NA	NA	Same as S. No. 6
13	LPH-1 Shell Pressure (mm of Hg)	-270	-195		
14	LPH-2 Shell Pressure (mm of Hg)	-75			
15	LPH-3 Shell Pressure (kg/cm**2)	1.2	0.74		
16	LPH-4 Shell Pressure (kg/cm**2)	3.61	1.95		
17	D/A Shell Pressure (kg/cm**2)	5.2			
18	HP Heaters Shell Pressure (kg/cm**2)	NA	NA	NA	

System : Regenerative
Sub System: Condensate

Unit 1
C.T.P.S.
DVC

S. No.	Parameter and Location	Plant Inst. Reading	Prob. Value Ref. HBD	Deviation	Remarks
1	Drain Inlet to LPH-1 Temp. °C	75°C	82°C		
2	Drain Outlet to LPH-1 Temp. °C	72°C	65.4°C		
3	Drain Inlet to LPH-2 Temp. °C	90°C	93°C	✓	
4	Drain Outlet to LPH-2 Temp. °C	93°C	92°C	✓	
5	Drain Inlet to LPH-3 Temp. °C	162°C	96°C		Inst. not correct
6	Drain Outlet to LPH-3 Temp. °C	89°C	92°C	✓	
7	Drain Inlet to LPH-4 Temp. °C	115°C	117°C	✓	
8	Drain Inlet to LPH-1 Pressure kg/cm**2				
9	Drain Outlet to LPH-1 Pressure kg/cm**2				
10	Drain Inlet to LPH-2 Pressure kg/cm**2				
11	Drain Outlet to LPH-2 Pressure kg/cm**2	0.10			
12	Drain Inlet to LPH-3 Pressure kg/cm**2	0.75			
13	Drain Outlet to LPH-3 Pressure kg/cm**2	0.75			
14	Drain Outlet to LPH-4 Pressure kg/cm2 - **2	2.40			

Section 2.6

Generator Stator and Field Assessment

Generator Stator and Field (Rotor)

System Evaluation

The overall condition of the generator stator and the generator field (rotor) was found to be very good. Each phase of the stator winding passed a full high voltage test. This test strongly indicated that there were no major weaknesses in the insulation system. Other electrical tests confirmed that the stator winding was in exceptionally good condition. The stator iron also appeared to be in very good condition with no evidence of overheating or looseness.

The generator field (rotor) winding passed all electrical tests. Comparison with previous results indicated no development of turn-to-turn shorts or top turn cracking (a common problem experienced with this class of GE fields). Visual inspection revealed no abnormal conditions.

The generator bushings were found to be in good condition, showing no cracks or porcelain chipping. The R-phase bus riser standoff insulator at the generator side showed excessive greasing at the porcelain to base plate lead seal. This is a generic problem with this type of insulator. It is recommended that the insulator be replaced with a new type that uses epoxy instead of lead to form the seal. General Electric has a recommended TIL which addresses this problem.

The hydrogen coolers were visually inspected. Most of the tubes were found to be blocked with mud, rocks, and other river debris. If the unit had been running at full capacity for an extended period of time, the generator would have overheated due to the condition of the cooling system. It is strongly recommended that the water be filtered and incorporate better water treatment.

The generator current transformer wiring circuits and all generator protection systems were inspected and found to be in good condition.

The Volts per Hertz generator relay protection was installed several years ago. The relay is set to annunciate at 15 percent above rated voltage. It is strongly recommended that the relay be reset to annunciate at 7 percent. This is the General Electric recommendation and the TVA practice. In addition, it is recommended that automatic run-back be incorporated in the Volts per Hertz relay protection scheme.

It is strongly recommended that two levels of reverse power relaying (reverse and backup) be incorporated in the generator relay protection design. At times the generator is motored (acts as a synchronous motor) for twenty minutes or longer. Reverse power relaying would discourage this practice.

The hydrogen circuits for all running units at the plant were inspected for hydrogen leaks using a very sensitive hydrogen leak detector. No leakage was found on Unit 1. Unit 5 showed slight leakage at the main feeder valves. Unit 3 main feeding valve indicated high "red alarm" condition, and a slight leakage was indicated at the Unit 3 regulating valve. It is recommended that the Unit 3 main feeding valve be periodically checked for increased hydrogen leakage using a soap solution. At the next available outage, this leak should be repaired.

System: Generator**Component: Generator Stator Insulation System****Assessment Method: Electrical Test**

Sub Component	Damage/Condition Found	Damage Assessment/Recommendation
- Gen. Bridge Test, R-phase	- 0.001337 ohms at 33° C. Acceptable	- Repeat tests during next regular scheduled outage.
- Gen. Bridge Test, Y-phase	- 0.001437 ohms at 33° C. Acceptable	- Repeat tests during next regular scheduled outage.
- Gen. Bridge Test, B-phase	- 0.001337 ohms at 33° C. Acceptable	- Repeat tests during next regular scheduled outage.
- Gen. Stator 5kV DC PI Test, 10 minute, R-phase	- PI = 4.00 (Excellent); 800 Megaohms at 1 min., 3,200 Megaohms at 10 min. Acceptable	- Repeat tests during next regular scheduled outage.
- Gen. Stator 5kV DC PI Test, 10 minute, Y-phase	- PI = 3.97 (Excellent); 880 Megaohms at 1 min, 3,500 Megaohms at 10 min. Acceptable	- Repeat tests during next regular scheduled outage.
- Gen. Stator 5kV DC PI Test, 10 minute, B-phase	- PI = 3.40 (Excellent); 870 Megaohms at 1 min, 3,500 Megaohms at 10 min. Acceptable	- Repeat tests during next regular scheduled outage.
- Gen. Stator Insulation High-pot Test	- All three phases tested at 32kV DC for 1 min each, with the other two phases grounded. Test results fully acceptable.	- Repeat tests during next regular scheduled outage.
- Gen. Stator Insulation Controlled DC step voltage leakage test, each phase	- Test results fully acceptable. Initial voltage was 5kV. Final test voltage was 25kV. Increments made in steps of 5kV. See data chart for details.	- Repeat tests during next regular scheduled outage.
- Power Factor Test, all phases	- Test results fully acceptable. All phases tested at 10kV AC. No significant difference between phases.	- Repeat tests during next regular scheduled outage.

INSLIFE.DRW

DAMODAR VALLEY CORPORATION
CHANDRAPURA UNIT 2 GENERATOR

CHANDRAPURA UNIT 2 GENERATOR ASSESSMENT
STATOR VOLTAGE DISCHARGE TEST RESULTS

CHANDRAPURA UNIT 2 GENERATOR ASSESSMENT REPORT
DC STEP VOLTAGE HIGH POTENTIAL TEST
COMPARISON OF PHASES (1994)

CHAND_2.DRW

TIME IN MINUTES

TEST PERFORMED BY: DVC & BHEL ENGINEERS

DAMODAR VALLEY CORPORATION

CHANDRAPURA UNIT 2 GENERATOR

Plant: Chandrapura Unit: 2

Date: August 2, 1994

Equipment Tested: Generator Stator

DC STATOR BRIDGE RESISTANCE TEST

Amb. Temp 33C

Correction Temp:

TEST RUN	R - PHASE		Y - PHASE		B - PHASE	
	MEASURED	CORRECTED	MEASURED	CORRECTED	MEASURED	CORRECTED
1	1.337		1.437		1.337	
2	1.37 Elect. Bridge		1.5 Elect. Bridge		1.41 Elect. Bridge	

Results of Test: Good. No difference from previous tests.

KELVSTAT.DRW

System: Generator**Component: Generator Stator End-Basket Region****Assessment Method: Visual Test**

Sub Component	Damage/Condition Found	Damage Assessment/Recommendation
- Exciter End, End-turn Winding	- Very light greasing, black in color. No significant evidence of movement indicated. No cracked insulation found.	- Repeat tests during next regular scheduled outage.
- Exciter End, End-turn Bracing	- Very light greasing on a few braces and along several spacer blocks. Minor greasing found along sausages (conformable packing).	- Repeat tests during next regular scheduled outage.
- Turbine End, End-turn Winding	- Very light greasing, black in color. No significant evidence of movement indicated. No cracked insulation found.	- Repeat tests during next regular scheduled outage.
- Turbine End, End-turn Bracing	- Very light greasing on a few braces and along several spacer blocks. Minor greasing found along sausages (conformable packing).	- Repeat tests during next regular scheduled outage.

System: Generator	Component: Generator Bushing Box and Insulators	Assessment Method: Visual Test
Sub Component	Damage/Condition Found	Damage Assessment/Recommendation
<ul style="list-style-type: none"> - Generator Bushing Box 	<ul style="list-style-type: none"> - Overall condition was found to be clean, with a very light oil film deposit. All bushings appeared good. Seals looked good. R-phase stand-off insulator showed signs of fretting movement at the porcelain to base fitting. The lead seal is working itself loose. 	<p>Potential Root Cause: The standoff insulator greasing is a generic problem with this type of insulator. The porcelain to base plate seal is made of lead. After many years, this lead seal starts to work loose.</p> <p>DA The greasing and movement does not appear serious at this time. GE has issued a TIL concerning this problem with some large water cooled units. If no action is taken then eventually the insulator could become loose enough to cause serious movement of the bus riser it supports. This could lead to bus failure through insulation failure, due to excessive friction, rubbing, and movement.</p> <p>R Replace this bushing with a new Lapp, epoxy sealed bushing.</p>

System: Generator**Component: Generator Stator Iron & Stator Wedges****Assessment Method: Visual/Elec. Tests**

Sub Component	Damage/Condition Found	Damage Assessment/Recommendation
- Core Iron Test	<ul style="list-style-type: none">- Very light to medium greasing around wedges. Rusting marks found on the 8th iron pack, at the exciter and turbine ends.- Fresh rubbing mark of a sharp object found at three locations near the exciter end at the 6 O'clock position.- EL-Cid test conducted and revealed no problems in the iron.- Fibroscope inspection of stator core ventilation ducts found all vents to be free from blockage.- Iron tightness was tested by insertion of a very thin knife blade between the iron punchings. However, the iron was very tight and it was not possible to make the insertion.	<p>Potential Root Cause: Fresh rubbing marks appear to be caused by the removal of the generator rotor during disassembly.</p> <p>DA Not serious.</p> <p>R IGE to use more care in rotor removal.</p>
- Stator Wedges	<ul style="list-style-type: none">- Overall stator wedge condition was good. Few wedges were found to be loose. About 40% of the wedges were found to have some light greasing indications along the wedge length.	<p>Potential Root Cause: The light greasing around many of the wedge edges indicates that some fretting is occurring.</p> <p>R Do full wedge check again during next inspection.</p>

DAMODAR VALLEY CORPORATION
CHANDRAPURA TPS UNIT 2 GENERATOR
EL_CID TEST RESULTS

AUGUST, 1994

Evaluation of the iron condition is made by analyzing the fault currents produced by the EL_Cid equipment. A large departure from the average data indicates possible hot spots in the iron. For instance, a maximum fault current in a slot of 100 mA or greater would indicate possible trouble. As can be seen from the data, all values are within acceptable limits.

Simple faults producing an indicated 100 mA current in a EL_Cid test at 4 percent excitation often corresponds to a typical temperature rise of the order of 5 degrees centegrade in an 80 percent ring flux test. In the present test, maximum leakage current produced in different slots are 11 mA to 58 mA. These readings indicate that the core iron condition is good.

DAMODAR VALLEY CORPORATION
CHANDRAPURA TPS UNIT 2 GENERATOR
STATOR WEDGE CONDITION ASSESSMENT

AUGUST, 1994

System: Generator**Component: Miscellaneous Generator Auxiliary Components****Assessment Method: Visual/Elec. Test**

Sub Component	Damage/Condition Found	Damage Assessment/Recommendation
- Gen. Bushing Enclosure Transformer Side	- All bushings looked good. No significant oil accumulation found.	- Repeat inspection next outage.
- Liquid Level Detector	- No water found, indicating hydrogen dryers not leaking.	- Repeat inspection next outage.
- Generator RTD & Wiring Harness	- All RTD's operating correctly. Wiring harness found good, no fraying or cracked insulation.	- Repeat inspection next outage.
- Generator CT Junction Terminal Boxes	- All six inspected and found to be clean and free corrosion.	- Repeat inspection next outage.
- Gen. Bus Condition	- Visual appearance looked good.	- Repeat inspection next outage.
- Bus Shunts, Flexible Connections	- Appearance good. No fraying or breaks.	- Repeat inspection next outage.
- Gen. CT Condition	- Visually looked good. Operations informs that there are no relaying or metering operational problems.	- Repeat inspection next outage.
- Potential Transformers	- Visual indications good. Megger testing showed good values.	- Repeat inspection next outage.
- Lightning Arrestors	- Visual condition good. Electrical tests indicate good also.	- Repeat inspection next outage.
- Exciter Electrical Tests	- All tests confirmed exciter good electrically.	- Repeat inspection next outage.
- Exciter Commutator	- Some burning and unevenness	DA Serious unevenness an segments. R Recommend turning. Recommendation implemented.

System: Generator**Component: Generator Field (Rotor) & Hydrogen Coolers****Assessment Method: Visual/Elec. Test**

Sub Component	Damage/Condition Found	Damage Assessment/Recommendation
- Generator Field Visual Inspection	- Visual inspection revealed no significant problems with rotor. Some slight movement of a spacer block noted on the turbine end.	DA Spacer block movement was very small. R IGE to fix (implemented).
- Generator Field Electrical Tests	- 500 volt megger used. PI = 1.5, 600 Megaohms at 1 min, 900 Megaohms at 10 min. results are satisfactory. - Impedance test performed from 40 to 230 volts. Test results are acceptable and comparable with earlier values. See data charts. - Generator field bridge tests (Kelvin) were acceptable and comparable with earlier values.	- Repeat tests during next regular scheduled outage.
- Hydrogen Coolers	- Very poor condition. Tubes blocked with mud and rocks and river debris. Severe constrictions for water flow.	Potential Root Cause: Very poor water filtering. DA Did not appear to be leaking. Since units seldom run to capacity, overheating, from lack of water flow, did not occur. R Design and install an improved water filtering system.

DAMODAR VALLEY CORPORATION

Plant: Chandrapura Unit: 2 Date: Aug 8, 1994
 Equipment Tested: GENERATOR ROTOR (FIELD WINDING)

Test frequency = 50 HZ

Ambient Temp 33C

AC IMPEDANCE TEST

POLE BALANCE/ AC SPLIT VOLTAGE TEST Voltage applied between inner & outer collector rings = 93 Volts AC Voltage applied between outer collector ring to shaft (forging) = 47 Volts AC Voltage applied between inner slip ring to shaft (forging) = 46 Volts AC RESULTS: Good. No voltage imbalance between poles.	
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VOLTS	CURRENT	PH ANGLE	IMPEDANCE
40	2 amps		20 ohms
80	6 amps		13.33 ohms
120	8.4 amps		14.25 ohms
160	10.6 amps		15 ohms
200	12.3 amps		16.26 ohms
230	13.4 amps		17.16 ohms
200	12.2 amps		16.39 ohms
160	10.2 amps		15.68 ohms

FIELD WINDING 10 MINUTE PI

Amb. Temp: _____

TIME MINUTES	MEASURED MEGGER	TMP CORRECTED MEGGER
0.25	350	
0.5	425	
0.75	500	
1	600	
2	700	
3	780	
4	800	
5	820	
6	850	
7	850	
8	880	
9	880	
10	900	
PI VALUE	1.5	

KELVIN BRIDGE TEST

TEST No.	MEASURED RESISTANCE	CORRECTED RESISTANCE
1	0.2091 Kelvin Bridge	
2	0.21 Elect. Bridge	

Notes: All test results good. Megger values and PI acceptable.

CHANDRAPURA UNIT 2 GENERATOR ASSESSMENT REPORT
500 VOLT DC MEGGER TEST
GENERATOR FIELD (ROTOR) TEST

Section 2.7

Electrical Motor Control Center

Station Battery Evaluation

There are two 250 volt station batteries and one 250 volt control battery. One of the station batteries is a lead plante battery. The other battery is a recently purchased Exide-Chloride lead calcium battery.

All batteries, including telephone and annunciation (48 volt), appeared to be in very good condition. There was no evidence of plate buckling, shedding, or hydration (undercharging). Specific gravity readings were within acceptable limits. There was some corrosion on the connectors, but this was to be corrected during the outage.

Interviews with the plant electrical engineer revealed that the new Exide-Chloride was not able to maintain adequate voltage levels when required. The battery voltage drops quickly to below acceptable levels, during emergency load conditions.

The most probable cause for this, is the under-sizing of the battery. A station battery is sized according to the required ampere-hour need. However, the specification must state the 8-hour ampere-hour rating for a specific voltage at the 8th hour. The typical discharge characteristics, of battery cells, change as a function of the final cell voltage at the 8th hour. The final volts per cell may be 1.75V, 1.80V, 1.85V (typically TVA choice), 1.90V, and 1.95V.

A 250 volt system operates reliably for voltages within 10 percent of 250V. The tolerable range then is between 225V and 275V. Below the 225V level will often cause relays to "drop out". Above 275V or 280V may damage or shorten the life of the relay coils.

The new Exide-Chloride battery is a lead-calcium battery. Calcium is the hardening agent. The advantage of this design is that re-watering is minimized and thus labor costs are reduced. The disadvantage of the lead-calcium design is that its life is greatly shortened in hot tropical climates. Also, lead-calcium batteries have, at most, 100 deep discharge cycles. If the powerhouse is prone to loss of station service, then a lead-calcium battery is an inappropriate selection.

For hot tropical climates, the battery of choice is lead-plante (all lead) and lead-antimony. Lead-plante design is the best, but also the most expensive. It has a potential life expectancy approaching 40 years.

Recommendation

Maintain the existing large plante battery. Perform a full load test on this battery to determine its remaining capacity.

Select only plante, lead-antimony or lead-selenium battery replacements.

The Exide-Chloride battery capacity is a function of several variables among which are:

- Plate size.

- Separator hole size.
- Plate to plate distance separation.
- Specific gravity

It is possible to increase the battery capacity by increasing the specific gravity level. The penalty in doing this is that the battery life is shortened.

Always size the station and control batteries for both 8-hour and final voltage per cell at the 8th hour.

**DVC CHANDRAPURA THERMAL POWER STATION
STATION BATTERY ASSESSMENT
AMP-HOUR CAPACITY / FINAL CELL VOLTS**

DVC CHANDRAPURA THERMAL POWER STATION
STATION BATTERY ASSESSMENT
AMPERE CAPACITY PER PLATE

2 - 271

System Evaluation

The 3kV motor control centers supply power for large motors driving pumps, fans conveyors, etc. For logistical reasons, the inspection and assessment were limited to using plant maintenance records, interviews with plant engineers, and some megger testing of cables. Basically, it can be said that the assessment is based on Level 1 assessment, in a four part assessment process for life extension determinations.

Seven major sub-components were evaluated for each breaker serving an essential load:

1. Motor control circuits.
2. Cables, both power feed and control cables.
3. Breaker/Contactor inside the cubicle.
4. Equipment protection such as overloads, fuses, etc.
5. Safety, such as interlocks, locked or closed cubicles.
6. Motor load.
7. Foundation condition.
8. Equipment grounding.

Based on interviews, records and personal inspection, the overall condition of the motor control centers is marginal to poor. The cables are in poor condition due to age, physical placement, and fly ash contamination. The cable condition presents potential fire hazards for the future. The breakers could not be properly tested due to time, lack of proper test equipment and scheduling requirements. Equipment protection schemes are antiquated and do not provide sufficient protection for costly, large motors.

Recommendation

- Perform a complete Level 1 through 4 life extension assessment of all 3kV motor control centers and associated circuits.
- Perform a complete Level 1 through 4 life extension assessment of all 400 Volt MCC boards that could impact plant EFOR.

Damodar Valley Corporation
Chandrapura Thermal Power Station Unit 2
Component Condition Assessment

3Kv_U2A.DRW

System: 3kV Unit Bd 2A**Component: Condensate Pump 2A (400 HP)****Assessment Method: Records, Interviews, Tests**

Sub Component	Damage/Condition Found	Damage Assessment/Recommendation
1. Controls	Controls appeared to be in acceptable condition.	R Provisions should be made for electronic monitoring of body temperature and bearing vibration.
2. Cables	Cables are acceptable.	
3. Breaker Condition	Visual inspection and past history indicate breaker condition acceptable.	
4. Equipment Protection	Fuses in proper place, O/L protection working satisfactory.	
5. Safety	Safety condition found acceptable	
6. Equipment Served By Breaker /Feeder	Acceptable	
7. Foundation Condition	Acceptable	
8. Equipment Grounding	Equipment properly grounded	

System: 3kV Unit Bd 2A

**Component: TIE To S.E-1, Supply to-
3kV Aux. Unit Bd. 2A**

Assessment Method: Records, Interviews, Tests

Sub Component	Damage/Condition Found	Damage Assessment/Recommendation
1. Controls	Controls appeared to be in acceptable condition.	
2. Cables	Cables are in an acceptable condition, but quite aged.	
3. Breaker Condition	Visual inspection and past history indicate breaker condition acceptable.	
4. Protection	Protection circuit ok.	

System: 3kV Unit Bd 2A**Component: I.D. Fan 229A****Assessment Method: Records, Interviews, Tests**

Sub Component	Damage/Condition Found	Damage Assessment/Recommendation
1. Controls	Lockout station controls cause problems with reliability indicators also causing problems.	R Replace all control components with new. Provide spare parts for controls.
2. Cables	Megger testing indicates cables are in poor condition. This includes both control cables and also the power feed cables.	R Replaces both cables during next outage or earlier when convenient.
3. Breaker Condition	Visual inspection and past history indicate breaker condition acceptable.	
4. Equipment Protection	Fuses in proper place, O/L protection working satisfactory.	
5. Safety	Safety condition found acceptable.	
6. Equipment Served by Breaker/Feeder	ID fan and rotor were rewound several times. The reliability is still in doubt.	Consider changing to BHEL design motors.
7. Foundation Condition	Acceptable.	
8. Equipment Grounding	Equipment properly grounded.	

System: 3kV Unit Bd 2A**Component: Boiler Feed Pump (2370HP)****Assessment Method: Records, Interviews, Tests**

Sub Component	Damage/Condition Found	Damage Assessment/Recommendation
1. Controls	Controls appeared to be in acceptable condition.	R Provisions should be made to electronically monitor body temperature and bearing vibration, and coolant inlet & outlet temperatures.
2. Cables	Cable very aged and worn.	R Replace cable at convenient time.
3. Breaker Condition	Visual inspection and past history indicate breaker condition acceptable.	
4. Protection	Fuses in proper place, O/L protection working satisfactory.	
5. Safety	Safety condition found acceptable.	
6. Equipment Served by Breaker/Feeder	Boiler feed pump motor is operating without problems.	R Install electronic body temperature monitoring and bearing vibration monitoring.
7. Foundation Condition	Acceptable.	R Bolts need to be checked metallurgically.
8. Equipment Grounding	Equipment properly grounded.	

**Damodar Valley Corporation
Chandrapura Thermal Power Station Unit 2
Component Condition Assessment**

3Kv_U2B.DRW

System: 3kV Unit Bd 2B

Component: I.D. Fan 229B

Assessment Method: Records, Interviews, Tests

Sub Component	Damage/Condition Found	Damage Assessment/Recommendation
1. Controls	Lockout station controls cause problems with reliability. Annunciation indicators also causing problems.	R Replace all control components with new. Provide spare parts for control.
2. Cables	Megger testing indicates cables are in poor condition. This includes both control cables and also the power feed cables.	R Replace both cables during next outage or earlier when convenient.
3. Breaker Condition	Visual inspection and past history indicate breaker condition acceptable.	
4. Equipment Protection	Fuses in proper place, O/L protection working satisfactory.	
5. Safety	Safety condition found acceptable	
6. Equipment Served By Breaker /Feeder	ID fan and rotor were rewound several times. The reliability is still in doubt.	R Consider changing to BHEL design motors.
7. Foundation Condition	Acceptable	
8. Equipment Grounding	Equipment properly grounded	

System: 3kV Unit Bd 2B**Component: Feeder to 400V Unit Aux, Bd, 2****Assessment Method: Records, Interviews, Tests**

Sub Component	Damage/Condition Found	Damage Assessment/Recommendation
1. Controls	General condition of control circuits, ok.	
2. Cables	Megger testing confirmed cables acceptable.	
3. Breaker Condition	Visual inspection and past history indicate breaker condition acceptable.	
4. Equipment Protection	Fuses in proper place, O/L protection working satisfactory.	
5. Safety	Safety condition found acceptable	
6. Equipment Served By Breaker /Feeder	Feeder to 400V unit aux. board 2, 1000 KVA XFMR	
7. Foundation Condition	Acceptable	
8. Equipment Grounding	Equipment properly grounded	

System: 3kV Unit Bd 2B**Component: Condensate Pump (400HP)****Assessment Method: Records, Interviews, Tests**

Sub Component	Damage/Condition Found	Damage Assessment/Recommendation
1. Controls	Controls appeared to be in acceptable condition.	
2. Cables	Cable very aged and worn.	DA Meggered, ok, but cable is physically deteriorated, due to age. R Replace feeder cable with new, at earliest opportunity.
3. Breaker Condition	Visual inspection and past history indicate breaker condition acceptable.	
4. Equipment Protection	Fuses in proper place, O/L protection working satisfactory.	R Install motor bearing vibration monitoring equipment.
5. Safety	Safety condition found acceptable.	
6. Equipment Served by Breaker/Feeder	Condensate motor is operating without problems.	
7. Foundation Condition	Acceptable.	R Bolts need to be checked metallurgically.
8. Equipment Grounding	Equipment properly grounded.	

System: 3kV Unit Bd 2B**Component: Incoming Feeder F214 Tie to SE-2****Assessment Method: Records, Interviews, Tests**

Sub Component	Damage/Condition Found	Damage Assessment/Recommendation
1. Controls	Controls appeared to be in acceptable condition.	
2. Cables	Cable very aged and worn.	
3. Breaker Condition	Visual inspection and past history indicate breaker condition acceptable.	
4. Equipment Protection	Fuses in proper place, O/L protection working satisfactory.	R Install motor bearing vibration monitoring equipment.
5. Safety	Safety condition found acceptable.	
6. Equipment Served by Breaker/Feeder	Condensate motor is operating without problems.	
7. Foundation Condition	Acceptable.	R Bolts need to be checked metallurgically.
8. Equipment Grounding	Equipment properly grounded.	

System: 3kV Unit Bd 2B

Component: Boiler Feed Pump (2370HP)

Assessment Method: Records, Interviews, Tests

Sub Component	Damage/Condition Found	Damage Assessment/Recommendation
1. Controls	Controls appeared to be in acceptable condition.	
2. Cables	Cable very aged and worn.	
3. Breaker Condition	Visual inspection and past history indicate breaker condition acceptable.	
4. Equipment Protection	Fuses in proper place, O/L protection working satisfactory.	
5. Safety	Safety condition found acceptable.	
6. Equipment Served by Breaker/Feeder	Boiler feed pump motor is operating without problems.	R Install electronic body temperature and bearing vibration monitoring.
7. Foundation Condition	Acceptable.	R Bolts need to be checked metallurgically.
8. Equipment Grounding	Equipment properly grounded.	

System: 3kV Unit Bd 2B Component: Boiler Feed Pump (2370HP) Assessment Method: Records, Interviews, Tests

Sub Component	Damage/Condition Found	Damage Assessment/Recommendation
1. Controls	Controls appeared to be in acceptable condition.	R Lockout switch required.
2. Cables	Cables are in acceptable condition.	
3. Breaker Condition	Visual inspection and past history indicate breaker condition acceptable.	R New auxiliary contact blocks are required.
4. Equipment Protection	Fuses in proper place, O/L protection working satisfactory.	
5. Safety	Safety condition found acceptable.	
6. Equipment Served by Breaker/Feeder	Ash water pump motor is operating without problems.	R Install electronic body temperature and bearing vibration monitoring.
7. Foundation Condition	Acceptable.	
8. Equipment Grounding	Equipment properly grounded.	

System: 3kV Unit Bd 2B

Component: Boiler Feed Pump (2370HP)

Assessment Method: Records, Interviews, Tests

Sub Component	Damage/Condition Found	Damage Assessment/Recommendation
1. Controls	Controls appeared to be in acceptable condition.	
2. Cables	Cable are in acceptable condition, but quite aged.	R Power cables should be replaced at a convenient time.
3. Breaker Condition	Visual inspection and past history indicate breaker condition acceptable.	
4. Protection	Protection circuit, ok.	

Damodar Valley Corporation
Chandrapura Thermal Power Station Unit 2
Component Condition Assessment

3Kv_U2C.DRW

System: 3kV Unit Bd 2C**Component: Cooling Tower Fan Mtr, 270 HP (246A)****Assessment Method: Records, Interviews, Tests**

Sub Component	Damage/Condition Found	Damage Assessment/Recommendation
1. Controls	General condition of control circuits, ok.	
2. Cables	Megger testing confirmed cables acceptable. PVC insulation of control cables in clg. twr. fan flr is damaged.	DA Control cable is in poor condition. R Replace cable at next convenient outage.
3. Breaker Condition	Visual inspection and past history indicate breaker condition acceptable.	
4. Equipment Protection	Fuses in proper place, O/L protection working satisfactory.	
5. Safety	Safety condition found acceptable.	
6. Equipment Served By Breaker /Feeder	Cooling tower fan motor.	
7. Foundation Condition	Acceptable	
8. Equipment Grounding	Equipment properly grounded.	

System: 3kV Unit Bd 2C**Component: Cooling Tower Fan Mtr, 270 HP (246B)****Assessment Method: Records, Interviews, Tests**

Sub Component	Damage/Condition Found	Damage Assessment/Recommendation
1. Controls	General condition of control circuits, ok.	
2. Cables	Megger testing confirmed cables acceptable. Parts of control cable insulation is damaged.	DA Condition not serious. R Replace next outage.
3. Breaker Condition	Visual inspection and past history indicate breaker condition acceptable.	
4. Equipment Protection	Fuses in proper place, O/L protection working satisfactory.	
5. Safety	Safety condition found acceptable	
6. Equipment Served By Breaker /Feeder	Cooling tower fan motor.	
7. Foundation Condition	Acceptable	
8. Equipment Grounding	Equipment properly grounded	

System: 3kV Unit Bd 2C**Component: Cooling Tower Fan Mtr, 270 HP (246C)****Assessment Method: Records, Interviews, Tests**

Sub Component	Damage/Condition Found	Damage Assessment/Recommendation
1. Controls	General condition of control circuits, ok.	
2. Cables	Megger testing confirmed cables are acceptable.	
3. Breaker Condition	Visual inspection and past history indicate breaker condition acceptable.	
4. Equipment Protection	Fuses in proper place, O/L protection working satisfactory.	
5. Safety	Safety condition found acceptable.	
6. Equipment Served by Breaker/Feeder	Cooling tower fan motor.	
7. Foundation Condition	Acceptable	
8. Equipment Grounding	Equipment properly grounded.	

System: 3kV Unit Bd 2C**Component: Cooling Tower Fan Mtr. 270 HP (246D)****Assessment Method: Records, Interviews, Tests**

Sub Component	Damage/Condition Found	Damage Assessment/Recommendation
1. Controls	General condition of control circuit, ok.	
2. Cables	Megger testing confirmed cables are acceptable.	
3. Breaker Condition	Visual inspection and past history indicate breaker condition acceptable.	
4. Equipment Protection	Fuses in proper place, O/L protection working satisfactory.	
5. Safety	Safety condition found acceptable.	
6. Equipment Served by Breaker/Feeder	Cooling tower fan motor.	
7. Foundation Condition	Acceptable.	
8. Equipment Grounding	Equipment properly grounded.	

System: 3kV Unit Bd 2C**Component: Cooling Tower Fan Mtr. 270 HP (246C)****Assessment Method: Records, Interviews, Tests**

Sub Component	Damage/Condition Found	Damage Assessment/Recommendation
1. Controls	General condition of control circuit, ok.	
2. Cables	Megger testing confirmed cables are acceptable.	
3. Breaker Condition	Visual inspection and past history indicate breaker condition acceptable.	
4. Equipment Protection	Fuses in proper place, O/L protection working satisfactory.	
5. Safety	Safety condition found acceptable.	
6. Equipment Served by Breaker/Feeder	Cooling tower fan motor.	
7. Foundation Condition	Acceptable.	
8. Equipment Grounding	Equipment properly grounded.	

System: 3kV Unit Bd 2C**Component: F215 Tie To Reserve (Backup) Board****Assessment Method: Records, Interviews, Tests**

Sub Component	Damage/Condition Found	Damage Assessment/Recommendation
1. Controls	General condition of control circuit, ok.	
2. Cables	Megger testing confirmed cables are acceptable.	
3. Breaker Condition	Visual inspection and past history indicate breaker condition acceptable.	
4. Equipment Protection	Fuses in proper place, O/L protection working satisfactory.	
5. Safety	Safety condition found acceptable.	
6. Equipment Served by Breaker/Feeder	F215 tie to reserve (backup) board.	
7. Foundation Condition	Acceptable.	
8. Equipment Grounding	Equipment properly grounded.	

System: 3kV Unit Bd 2C**Component: CW Pump, 850 HP, (244A)****Assessment Method: Records, Interviews, Tests**

Sub Component	Damage/Condition Found	Damage Assessment/Recommendation
1. Controls	General condition of control circuit, ok.	
2. Cables	Megger testing confirmed cables are acceptable.	
3. Breaker Condition	Visual inspection and past history indicate breaker condition acceptable.	
4. Equipment Protection	Fuses in proper place, O/L protection working satisfactory.	
5. Safety	Safety condition found acceptable.	
6. Equipment Served by Breaker/Feeder	CW Pump Motor	
7. Foundation Condition	Acceptable.	
8. Equipment Grounding	Equipment properly grounded.	

Damodar Valley Corporation
Chandrapura Thermal Power Station Unit 2
Component Condition Assessment

3Kv_com2.DRW

System: 3kV Common Aux. Bd. 2

**Component: Ash Water Recirculating
Pump, 250HP, (013C)**

Assessment Method: Records, Interviews, Tests

Sub Component	Damage/Condition Found	Damage Assessment/Recommendation
1. Controls	General condition of control circuits, ok. Some trouble found with lockout switch.	R New lockout switch is required.
2. Cables	Megger testing confirmed cables acceptable.	
3. Breaker Condition	Visual inspection and past history indicate breaker condition acceptable.	
4. Equipment Protection	Fuses in proper place, O/L protection working satisfactory.	
5. Safety	Safety condition found acceptable.	
6. Equipment Served By Breaker /Feeder	Ash Water RC Pump.	
7. Foundation Condition	Acceptable	
8. Equipment Grounding	Equipment properly grounded.	

System: 3kV Common Aux. Bd. 2 Component: CW Pump House Board (F218) Assessment Method: Records, Interviews, Tests

Sub Component	Damage/Condition Found	Damage Assessment/Recommendation
1. Controls	General condition of control circuits, ok.	
2. Cables	Megger testing confirmed cables acceptable. Parts of control cable insulation is damaged.	
3. Breaker Condition	Visual inspection and past history indicate breaker condition acceptable.	
4. Equipment Protection	Fuses in proper place, O/L protection working satisfactory.	
5. Safety	Safety condition found acceptable	
6. Equipment Served By Breaker /Feeder	CW Pump House Board (F128)	
7. Foundation Condition	Acceptable	
8. Equipment Grounding	Equipment properly grounded	

Section 2.8

I & C System

Instrumentation & Control Systems

Assessment Summary

Purpose

To observe the operation of the major unit control loops for Chandrapura Thermal Power Station unit 2, evaluate the functionality of these control systems, and provide recommendations to enhance the performance of the systems.

Methodology

- 1) Conduct interviews with station operating personnel and station instrumentation personnel addressing operational and maintenance deficiencies of the present unit control systems.
- 2) Monitor the operation of the unit two (2) control system and record data from the unit control room instrumentation.
- 3) Review control system schematic diagrams and current calibration data.

Observations/Findings

The unit was commissioned in the early 1960's and was provided with Bailey Meter Company pneumatic controls. Findings and observations on individual control loops is as follows:

Feedwater Controls - A three element control scheme, which utilizes steam flow, feedwater flow, and drum level, regulates a feedwater inlet valve to maintain drum level at desired setpoint. These controls are operating in automatic but level is very erratic at reduced loads. This is probably due to either inadequate tuning of the controls or the lack of density correction for drum level as temperatures and/or pressures vary. Calibrations appeared to be performed regularly and the indications were accurate.

Combustion Controls - Consists of both air flow and fuel flow control.

- 1) Air flow is controlled by regulating the FD fan inlet vanes. The air flow setpoint is a function of steam flow and generated boiler master demand. The excess oxygen transmitter failed and the plant replaced it with an electronic transmitter that was not interfaced with the pneumatic controls. The FD fan inlet vanes were operated in automatic for only the first four or five years the unit was in service. The primary reason for this is unclear, but it could have been a result of the failure of the excess oxygen transmitter.
- 2) Fuel flow is controlled by regulating the pulverizer exhausters dampers and the coal feeder speeds. Fuel flow setpoint is the result of the generated boiler master demand to control the turbine inlet steam pressure at setpoint. Limiting relays and a fuel to air ratio relay are also included in the control scheme. Both the exhausters dampers and the feeder speeds have been operated in manual since the early 1970's. The reason for reverting these

control loops to manual was; 1) The ability to maintain the devices, 2) The unavailability of spare parts, and 3) The amount of oil / moisture in the control air system. Problems have been encountered with flame instability when the loss of a coal feeder occurs due to pluggage. Often, total loss of flame occurs, especially, if only two feeders are in service at the time. Operations personnel have successfully prevented this "flame out" by manually closing the secondary air damper associated with the lost feeder and inserting oil guns located between burner elevations "A" and "B" to provide better flame stabilization. Also, with the fuel to air ratio controller inoperative and the FD fans in manual, the air flow cannot vary to maintain excess oxygen levels at desired levels when excursions in the coal flow rate occur. The coal feeders were reported to be calibrated at 0 to 5.5 RPM's. This is equivalent to 0 to 65.2 percent of the pulverizer's capacity of 18,973 Kg/Hr, based on an average of 37.5 Kg per revolution. It is not recommended to operate the feeder speed below 25 percent of the pulverizer rated capacity. A mechanical stop on the exhaust damper is set at approximately 20 percent open. This is to maintain minimum burner line velocities so coal will not settle in the pipes. With this minimum damper position and the coal feed rate below 25 percent, the fuel-air mixture will become too lean to maintain combustion.

Draft Controls - Regulates the ID fan inlet vanes and the ID fan coupling to maintain furnace draft at desired setpoint. These devices are also operated in manual due to contamination of the control air system and unavailability of spare parts to repair them. It was reported that the inlet vane drive cylinders were worn, the mechanical locking devices were broken, and the positioners were worn with no replacement parts available.

Steam Temperature Controls - Consists of burner tilt drives, superheater attemperation valves, and reheat attemperation valves. All three of these control subpanels are in manual. The burner tilts are fixed in position due to mechanical problems. The reheat attemperators are not needed because reheat outlet temperature averages well below desired setpoint. The superheat attemperators are operated manually, as needed. Normally, below 70 megawatts, superheat temperature runs below desired setpoint. While observing the unit operation, load was at 56 megawatts due to boiler feedpump problems. The spray valves were closed and no concerns were identified other than manual operation. Plant personnel could not locate the control system drawings for the steam temperature controls or the miscellaneous controls systems supplied by Bailey Meter Company.

Turbine controls - No automatic interface exists between the turbine controls and the boiler controls. As the turbine valves are opened and steam flow is increased or the steam pressure decays, the combustion controls will not respond because the boilermaster, along with all of the other devices are operated in manual. Drum level controls, only, would respond to a change in steam flow.

Safety Interlocks & Trips - No automatic tripping functions such as; high furnace draft, drum level, loss of flame were identified. Operations personnel indicated that these tripping functions are manually performed by the unit operators. Air failure interlocks were provided with the

pneumatic control devices but it was not determined if these were still functional. Starting and stopping interlocks of major equipment was not discussed. No automatic unit runbacks associated with loss of major equipment such as ID fans, FD fans, and boiler feed pumps were identified during discussions with plant personnel. Single fan maximum capability was included as a function of the automatic combustion controls, but with everything in manual this feature is no longer functional.

Recommendations

- 1) Check the "as found" calibration and condition of every device in the pneumatic control system during the outage tentatively scheduled for 11 July 1994. Repair and calibrate as many devices as possible. Document the spare parts needed. This could be used, in part, as a justification for replacement or determination for the type of replacement loop(s) that would be most cost effective.
- 2) Recalibrate the coal feeder controls to 25 percent minimum speed. The upper speed would be dependent upon pulverizer motor current limitations. Consideration should be given to automatic operation of the coal feeder and exhaust damper if the pluggage problems are remedied and the feeders are recalibrated.
- 3) Maintain the feedwater controls in automatic and consider adding density correction for drum level with level transmitters located at both ends of the boiler drum. Then consider placing as many other control loops in automatic as possible. The number of loops capable of automatic would be dependent upon the results of recommendation 1, above.

Recommended priorities would be;

- a) Draft - Furnace draft is difficult to maintain in manual. During lightoff and shutdown operations this control function will require more operator intervention than other control loops to maintain the furnace pressure within the structural integrity of the boiler and/or ductwork.
- b) Fuel flow - Due to the poor quality of the coal and the difficulty of maintaining combustion in the boiler, fuel flow should be the next control loop to be operated in automatic. Operators have to closely watch the fuel to air ratios and the entire combustion process.
- c) Air flow (without excess oxygen correction) - This would allow automatic correction to the secondary air flow when coal flow excursions occur. This would help the combustion process by maintaining excess oxygen levels, at some setpoint, during these excursions.
- d) Mill temperatures - If the air preheater performance is improved during the outage, normal pulverizer temperatures should be achievable and would require more operator attention than present operating conditions. With the

fuel flow controls in automatic, increased operator intervention would be expected due to changing pulverizer demands.

- e) Superheat attemperators - Following an outage, normal operating ranges for unit load should average well above the 70 megawatt threshold where secondary superheater attemperation is needed. Operators would not have to "manually" maintain control of superheat temperature. If it is decided to replace these controls, consider better integration with the other control loops with proper feedforward and feedback signals.
- 4) Pursue the installation of remote operators for the secondary air dampers. This could be done as an operator function or automatically as a result of placing the associated burners in service.
- 5) Pursue the installation of oil guns between burners "C" and "D". Currently, only one set of guns are installed between burners "A" and "B". The current guns will not adequately support flame stabilization if, for example, "A" and "D" are in service and "A" trips. This additional set would better support combustion at the "D" firing level. These could be placed in service individually, dependent on the proximity to the burners in service, or together. The percentage of oil usage as compared to coal flow and/or the need for smaller oil tips should be addressed if it is decided to place oil burners in service together. Also, consider the installation of a minimal flame detection system in lieu of the flame instability problems experienced at this station. This would help in determining the flame stability during any operating mode.
- 6) If the burner tilts are made operational, new drives should be considered as part of the scope of work. Also, consider the use of a programmable type controller for this application. Along with the control flexibility this will allow, superheat and/or reheat attemperation spray control could be accomplished and coordinated within the same controller.
- 7) A full control system tuning should be performed if the controls are placed in automatic. The feedwater controls should be tuned regardless of the decisions made for the other control loops. Pressure gages should be installed in the pneumatic tubing between the control components to allow better diagnostics of controllability problems. The instrument technicians need to be provided control component training and both the unit operators and the instrument technician need refresher training in the configuration of the control systems. The plant needs access to all of the unit control system drawings, consider purchasing them from Bailey Controls or assign someone to draw a set from the present as-built configuration.
- 8) Consider the installation of important automatic boiler side tripping features. These would include; 1) Drum level low to trip fuel supply, 2) High furnace pressure to trip fuel supply, 3) Loss of fans to trip fuel supply, 4) Loss of stable flame to trip fuel supply (Note: only if

flame detection is installed as mentioned in recommendation #5 above). Also, starting and stopping interlocks should be closely scrutinized since this was not included in this report. Maximum fan capabilities will be functional if the decision is made to reinstate the automatic control for the FD and ID fans as mentioned in recommendations #3a and #3c above. Automatic load limitations, due to availability of a sufficient feedwater source, should be reviewed and a decision made as to the benefits of installing such a feature. Presently, this decision is made by the unit operator.

- 9) The ID fan inlet drive mechanical locking devices should be replaced with pneumatic locks, the cylinders could be honed and sleeves installed, and pneumatic positioners are readily available as replacements.
- 10) Consider installing a small filter and air dryer in the unit control room specifically for the pneumatic control devices located there. The unit was furnished with separate control air and service air compressors. There is a valve installed between these air supplies which allows plant personnel to supplement either system if the need arises. This is typically done throughout the utility industry although the service air supply is normally contaminated with oil and moisture. If the practice of supplementing control air with service air is not discontinued, consider installation of more control air capacity.
- 11) Development of a preventive maintenance program is advisable regardless of the extent of repairs or upgrade.

Attachments

- I.) Assessment work sheets for; A)Feedwater, B)Air Flow, C)Fuel Flow, D)Furnace Draft, E)Steam Temperature control loops.
- II.) Sample questionnaire for I&C assessments.
- III.) Summary of Unit Overall Protection for Boiler and Turbine - Taken from IEEE Standard 502-1985.
- IV.) Generic instrumentation and control system preventive maintenance program.

System: Instrumentation & Control
System Functionality

Component: Feedwater Flow Control

Topics Addressed		Condition Found	Recommendations
1.1	System Purpose	Regulates a control valve in the feedwater supply piping to maintain boiler drum level at desired setpoint.	
1.2	Function(s) Performed	Utilizes a three element control scheme consisting of steam flow, feedwater flow, & drum level. Monitors changes in steam flow from the boiler to change the feedwater flow before the drum level changes.	See item 1.4 recommendation below.
1.3	System Importance	Critical - loss of this control function would greatly increase the possibility of damage to the boiler drum.	
1.4	Critical Operating Conditions	Drum level indications fluctuate as temperatures and/or pressures change. It is extremely difficult to manually control level, especially at lower loads.	Consider adding density correction circuitry to these controls to compensate for the changes in temperatures and/or pressures.
1.5	Economic Consequences of Failure	Catastrophic damage to boiler drum could occur.	
1.6	Operational Consequences of Failure	Would require a full time operator.	
1.7	Fault Tolerance/Redundancy	None	
1.8	Failure Models or Characteristics	None Noted	Install an automatic fuel trip upon low boiler drum level.
1.9	System Information Available & Use	Drum level, feedwater flow, and steam flow indication and recording.	
1.10	System Accuracy	+ or - 5%	
1.11	Current Normal Operating Mode	Only control loop that is operating in automatic.	
1.12	Associated Secondary Control Functions	None	

System: Instrumentation & Control
System Upgrade Potential

Component: Feedwater Flow Control

Topics Addressed	Condition Found	Recommendations
2.1 Reason For Replacement Consideration	Pneumatic controls are no longer commercially available. System is presently operating in automatic, which would indicate no parts are needed.	Check the "as found" calibration of all control devices during the outage scheduled to begin July 11, 1994. document the results of this check.
2.2 Choice of Replacement Type	Distributed Control System (DCS)	Type of replacement system should be based on the findings of the calibration and functional tests performed during the present outage. If a large majority of the system is discovered to be performing unacceptably, a DCS may be the most cost effective option.
2.3 Functionality/Configuration Upgrade	None	Three element drum level control is still the industry choice, but level corrections due to changing water density is presently being applied with current control upgrades. See item 1.4 above. Also, unit load crosslimit, based on availability of sufficient feedwater pump capacity, should be considered.
2.4 Technical Cost Improvements	None	Differences in level across the length of the drum due to temperature differentials across the boiler. Consider the addition of drum level transmitters at both ends of the boiler drum.
2.5 Potential Cost Improvements	None	Reduction in water carryover to superheat if density correction is added to drum level controls, there by increasing tube life expectancy.
2.6 Regulatory Concerns or Issues	None	
2.7 Potential Liability Of Not Upgrading	None	
2.8 Significant Weakness Of Present System	Spare Parts Availability	
2.9 System Strengths To Be Maintained	None	

System: Instrumentation & Control
Maintenance Issues

Component: Feedwater Flow Control

Topics Addressed	Condition Found	Recommendations
3.1 Staff's Understanding & Interaction	Limited	Provided control component training to the instrument technicians.
3.2 Maintenance & Failure History	Field transmitters have failed and small filters have been installed "locally" at important field equipment.	
3.3 Available Diagnostic Tools	A limited number of pressure gauges are installed. This limits the effectiveness of using them as a diagnostic tool.	Install small pressure gauges in the control tubing if the current control system is retained.
3.4 Calibration Requirements	Transmitters and indicators are regularly calibrated. The exact frequency was not documented.	Establish a "documented" preventive maintenance program.
3.5 Maintenance Difficulties	Obtaining spare parts, since this system is the only loop operated in automatic, all other control devices can be used as spares.	

System: Instrumentation & Control
Power Source Needs

Component: Feedwater Flow Control

Topics Addressed	Condition Found	Recommendations
4.1 Power Source(s)	Control air supply; 30 psig for control system, 40 psig for field devices.	
4.2 Special Needs For Power Source	Water separation and oil removal. The service air system and the control air system are joined for redundancy. There is a manual valve between the systems which the operators can open if either system pressure decays. This is a common practice among the utility industry but, the service air system is very contaminated with oil and moisture.	Do not use the service air system to back up the control air system. Install more control air capacity if needed. Also, consider installation of filters and moisture traps behind the unit control board, specifically for the control system components.
4.3 Environmental Requirements For Power Source	None	

Interaction with Other Control Loops

Topics Addressed	Condition Found	Recommendations
5.1 Impact To Other Interactive Systems	None	
5.2 Interface Requirements With Other Systems	None	

Miscellaneous Issues

Topics Addressed	Condition Found	Recommendations
6.1 Other Considerations		

System: Instrumentation & Control
System Functionality

Component: Boiler Air Flow Control

Topics Addressed	Condition Found	Recommendations
1.1 System Purpose	Modulates FD fan inlet vanes to maintain combustion air flow through the boiler. Uses a feed-forward signal from the boilermaster derived from steam flow and expected turbine inlet steam pressure. The FD fan outlet dampers are operated for isolation purposes only. Errors in excess oxygen levels generate a change in the air flow demand signal to maintain desired boiler O2 levels.	
1.2 Function(s) Performed	Maintains secondary air above stoichiometric needs when operated in automatic. Positions FD fan inlet vanes, only, in manual. Maximum fan capability and fuel crosslimits will not function in manual mode of operation. Secondary air dampers are positioned manually at the boiler, not from the control room.	Consider installation of remote operations for the secondary air dampers.
1.3 System Importance	Important but manual control is possible.	Consider placing this control loop in automatic if sufficient devices are identified during the calibration checks identified in item 2.1 below. the severity of feeder loss would be lessened if the fuel to air ratio controls were functional.
1.4 Critical Operating Conditions	Not critical, but when operating in manual, air flow requires a lot of the operator's attention during load swings.	
1.5 Economic Consequences Of Failure	No automatic tripping functions. System would crosslimit fuel, if it was in automatic, and loss of air flow indication would occur. Loss of flame and/or explosive furnace conditions would exist. Manual operation of this system contributes to boiler efficiency losses if the operator does not maintain the proper excess air.	

1.6	Operational Consequences Of Failure	Operator inconvenience during load changes. Maximum F/D fan capability circuitry and fuel to air crosslimits are not functional when in manual mode.	
1.7	Fault Tolerance/Redundancy	None. Unit was supplied with two(2) forced draft fans, but both are needed for full load operation.	
1.8	Failure Modes or Characteristics	Inlet vane damper drives have pneumatic air failure locks. Maximum fan capability crosslimits exist in the control scheme, but are not functional when this loop is operated in manual.	
1.9	System Information Available & Use	Air flow is recorded and excess oxygen is available as an indication on the unit control board.	
1.10	System Accuracy	+ or - 5%	
1.11	Current Normal Operating Mode	System has been operated in manual mode for the past twenty five plus years. The reason for this is unclear, but is could have been a result of the failure of the excess oxygen transmitter which was replaced but not interconnected with the control system.	See recommendation in item 1.3 above. It is not recommended to place the excess oxygen controls back in automatic.
1.12	Associated Secondary Control Functions	None	

System: Instrumentation & Control
System Upgrade Potential

Component: Boiler Air Flow Control

Topics Addressed	Condition Found	Recommendations
2.1 Reason For Replacement Considerations	Pneumatic controls are no longer commercially available and spare parts are needed. No document exists which identifies which or how many parts are actually bad.	Check the "as found" calibration of all control devices during the outage scheduled to begin July 11, 1994. Prepare a list of damaged or broken components to determine exactly what spare parts are needed.
2.2 Recommended Replacement Type	Distributed Control System (DCS)	Undetermined
2.3 Functionality/Configuration Upgrade	None Identified	
2.4 Technical Specifications To Consider	None	
2.5 Potential Cost Improvements	Improvement in unit net heat rate but not quantifiable.	
2.6 Regulatory Concerns or Issues	None	
2.7 Potential Liability Of Not Upgrading	None	
2.8 Significant Weakness Of Present System	Spare parts availability.	
2.9 System Strengths To Be Maintained	None	

System: Instrumentation & Control
Maintenance Issues

Component: Boiler Air Flow Control

Topics Addressed	Condition Found	Recommendations
3.1 Staff's Understanding & Interaction	The system has been operated in manual for so long, the operations personnel and technicians need exposure to systems training. This would better the understanding of the process being performed in an automatic control system.	Provide systems training to the unit operators and the instrument technicians.
3.2 Maintenance & Failure History	Field transmitters have failed and small filters have been installed "locally" at important field equipment.	Consider installing small filters and air dryers behind the unit control board specifically for the control devices if these controls are retained.
3.3 Available Diagnostic Tools	None. The air isolated to the controls and the few pressure gauges which are installed, are of no use.	Install pressure gauges in the tubing between the pneumatic devices.
3.4 Calibration Requirements	Transmitters and indicators are regularly calibrated. The exact frequency was not documented.	Develop a preventive maintenance schedule for all control components with a frequency less than yearly.
3.5 Maintenance Difficulties	Obtaining Spare Parts.	

Power Source Needs

Topics Addressed	Condition Found	Recommendations
4.1 Power Source(s)	Control air supply; 30 psig for control system, 40 psig for field devices.	
4.2 Special Needs For Power Source	Water separation and oil removal. The service air and control air system are joined for redundancy. There is a manual valve between the systems which the operators can open if either system pressure decays. This is a common practice among the utility industry, but the service air system is very contaminated with oil and moisture.	Do not use the service air system to back up the control air system. Install more control air capacity if needed. Also, consider installation of filters and moisture traps behind the unit control board, specifically for the control system components.
4.3 Environmental Requirements For Power Source	None	

System: Instrumentation & Control**Component: Boiler Air Flow Control*****Interaction with Other Control Loops***

Topics Addressed	Condition Found	Recommendations
5.1 Impact To Other Interactive Systems	Air flow controls operating in automatic will cause furnace draft excursions, if the draft controls are not in automatic, also.	If the air flow controls are placed in automatic, as recommended in item 1.3, draft controls will require closer operator intervention if they are not operated in automatic also.
5.2 Interface Requirements With Other Systems	Part of combustion control scheme which includes fuel flow control and fuel to air ratio control.	

Miscellaneous Issues

Topics Addressed	Condition Found	Recommendations
6.1 Other Considerations		

Instrumentation & Control System

Assessment Questionnaire

1. System Functionality

- 1.1 What is the purpose of this system?
- 1.2 What major functions does it perform?
- 1.3 How would you characterize the importance of this system?
Critical: Required for safe plant operation. Loss would impair plant operation or cause outage.
Important: Normally used in automatic but manual control is possible.
Other: System loss is an inconvenience.
- 1.4 Is there any mode of operation or operational situation when this system is especially important?
- 1.5 What are the economic consequences of failure of this system?
- 1.6 What are the operational consequences of failure of the system?
Complicate the operator's duties?
Require special procedures?
Require special monitoring?
- 1.7 What type of fault tolerance or redundancy does the system include?
- 1.8 What failure characteristics or failure mode requirements does the system have?
- 1.9 How is and how should the system information be used?
Operations?
Maintenance?
Engineering?
Security?
- 1.10 Is the system sufficiently accurate?
Absolute accuracy?
Resolution?
Repeatability?
Drift?
Noise sensitivity?
- 1.11 Was this system intended to operate automatically? Does it? Does the system transition smoothly from manual to automatic operation? Has manual override become the normal mode of operation? If so, why?
- 1.12 Are there any secondary functions that this system does? If so, should they be moved to another system?
Could they?

2. System Upgrade Potential

- 2.1 Is this system a candidate for future replacement and, if so, why?
 - Improved accuracy or performance?
 - Increased automation or new control strategies?
 - Information integration?
 - Maintenance?
- 2.2 If this system were replaced, what type of system would be most desirable?
 - Analog?
 - Hardwired digital?
 - Software based digital?
- 2.3 What new functionality should be considered for this system?
 - Desired?
 - Required?
 - Optional?
- 2.4 Are there any technical specifications that govern the operation of this system?
- 2.5 Are there any known potential cost improvements?
- 2.6 Are there regulatory concerns or impacts?
- 2.7 What is the impact of not upgrading the system?
 - Plant availability?
 - Life extension?
 - Cost (operations and maintenance)?
- 2.8 Are there any significant weaknesses, problem areas, or unaddressed issues that should be considered when this system is upgraded or replaced?
 - Functionality?
 - Accuracy?
 - Procedures?
 - Training?
 - Reliability?
 - Maintainability?
- 2.9 Does the system have any significant strengths that should be retained?
 - Functionality?
 - Accuracy?
 - Procedures?
 - Training?
 - Reliability?
 - Maintainability?

3. Maintenance Issues

- 3.1 How does the maintenance staff interact with this system?
- 3.2 What information does the system provide for maintenance purposes?
- 3.3 What types of diagnostics are available for this system?
- 3.4 Does the system require calibration? How often? Equipment needed?
- 3.5 Are there any unusually difficult items or components to maintain, such as; Packaging? Location? Parts availability?

4. Power and Environmental Issues

- 4.1 What are the power sources for the system?
- 4.2 Are there any special considerations required for the power source, such as; Un-interruptible source? Regulated source?
- 4.3 What are the environmental requirements for this system, such as; HVAC? Seismic?

5. Interaction with other systems

- 5.1 Does this system have significant functional interaction with other systems? Used together to coordinate a plant control function? Support the function of another plant system or component? Function as a combination of systems?

6. Miscellaneous

- 6.1 Are there any other issues concerning this system that should be considered?

Table 1
Summary of Unit Overall Protection for Boiler

Hazard or Alarm Condition	Type of Boiler	Sensor	Action
(1) Low Water Supply	<ul style="list-style-type: none"> - All drum type - Controlled circulation - Once through 	<ul style="list-style-type: none"> - Drum low level switch - Drum low low level switch - Different pressure switch - Low flow switch - High superheat temperature switch 	<ul style="list-style-type: none"> - Alarm - Trip - Trip fuel supply - Trip fuel supply
(2) High Steam Temperature	<ul style="list-style-type: none"> - All 	<ul style="list-style-type: none"> - Thermocouple in superheat and reheat lines - Safety valves 	<ul style="list-style-type: none"> - Alarm
(3) High Steam Pressure	<ul style="list-style-type: none"> - All 	<ul style="list-style-type: none"> - Safety valves 	<ul style="list-style-type: none"> - Release pressure
(4) Low Steam Pressure	<ul style="list-style-type: none"> - All 	<ul style="list-style-type: none"> - Pressure sensors 	<ul style="list-style-type: none"> - Alarm
(5) Loss of Fans (a) Two forced draft fans * (i) One off (ii) Two off (b) Two forced and two induced * (i) One forced or one induced off ** (ii) Two forced off ** (iii) Two induced off	<ul style="list-style-type: none"> - Pressure furnace - Balanced draft furnace 	<ul style="list-style-type: none"> - Fan breaker aux. switch - Fan breaker aux. switch - Fan breaker aux. switch - Fan breaker aux. switch - Fan breaker aux. switch 	<ul style="list-style-type: none"> - Run-back load - Trip fuel supply - Run-back loads - Trip fuel supply, induced Draft fans optional - Trip forced draft fans - Trip fuel supply
(6) Fuel Supply Conditions	<ul style="list-style-type: none"> - Gas - Oil - Coal 	<ul style="list-style-type: none"> - Low pressure - High pressure - Low pressure - Low temperature - Loss of atomizing medium - Coal flow detector 	<ul style="list-style-type: none"> - Trip fuel supply - Alarm - Trip fuel supply - Alarm - Trip fuel supply - Alarm

(7) Furnace Pressure	High Low High-Low	<ul style="list-style-type: none"> - All - All - Balanced draft 	<ul style="list-style-type: none"> - Pressure switch - Pressure switch - Vacuum switch 	<ul style="list-style-type: none"> - Trip fuel supply - Alarm or trip fuel supply - H-trip fuel supply - L-alarm
(8) Loss of Stable Flame		<ul style="list-style-type: none"> - Gas or oil fired - Coal fired 	<ul style="list-style-type: none"> - Flame detectors or mirrors or boiler TV - Flame detectors or mirrors or boiler TV 	<ul style="list-style-type: none"> - Trip fuel supply - Trip fuel supply
(9) Combustibles Too High		<ul style="list-style-type: none"> - Gas, oil, or coal fired 	<ul style="list-style-type: none"> - Combustible and oxygen analyzer or both (Optional) 	<ul style="list-style-type: none"> - Alarm
(10) Loss of Control Systems Power Supply		<ul style="list-style-type: none"> - Gas, oil, or coal fired 	<ul style="list-style-type: none"> - Low-voltage relay or low air-pressure 	<ul style="list-style-type: none"> - Alarm or fuel trip
(11) Feedwater Quality		<ul style="list-style-type: none"> - All 	<ul style="list-style-type: none"> - Conductivity - Oxygen 	<ul style="list-style-type: none"> - Alarm or fuel trip - Alarm
(12) Combinations of 1 through 10		<ul style="list-style-type: none"> - All types 	<ul style="list-style-type: none"> - Operator by observation 	<ul style="list-style-type: none"> - Trip fuel supply

Table 2
Steam Turbine

Hazard or Alarm Condition	Sensor	Action
(1) Low Lube Oil Pressure	- Oil-pressure device	- Trip unit
(2) Overspeed	- Governors, mechanical, or electrical	- Close control and intercept valves to reduce steam flow. Trip unit if trip speed is reached.
(3) High Vibration	- Vibration pickup	- Trip unit
(4) High Differential Expansion	- Differential expansion detector	- Trip unit
(5) Stage Overheating	- Thermocouples	- Trip unit
(6) Low Condenser Vacuum	- Vacuum device	- Trip unit
(7) Thrust Bearing Failure	- Differential oil-pressure device or spindle position sensor	- Trip unit
(8) Generator Motoring	- Both stop valves closed with generator breakers closed - Exhaust-hood temperature switch - Reverse power relay - Differential pressure switch	- Closed all valves and trip generator breaker and excitation and enable breaker failure protection.
(9) Low Throttle Pressure	- Instruments or pressure transducer	- If initial pressure regulator is in service, trip generator breaker at low limit; otherwise trip turbine immediately.
(10) System Under Frequency Operation	- Frequency relay and timer	- Trip generator breaker.
(11) Turbine Water Damage (a) From Reheat Sprays (b) Feedwater heater water induction (c) Water Carryover From Drum	- Reheat spray valves position - Feedwater heater high level - High drum level switch	- (See text, Section 10.1, part 7) - Close extraction valves on high water level or turbine trip per vendor recommendation. - Trip alarm
(12) Loss of Power Supply to EHC System	- Undervoltage relay	- Trip
(13) Any one of (1) through (12)	- Operator by observation	- Trip all valves closed, then trip unit

**Preventive Maintenance Program
Boiler Controls
PM Activities List**

Adjustment/Calibration (On-line)

MPAC Code: IAC-AR2BL

Activity	Purpose	Method	Frequency	Duration	Material Needed
Instrument Power Supplies: - Clean Air Filters - Check Output Voltages	- Prevent overheating - Ensure proper function	- Maintain using approved plant procedures.	- Monthly	- 2 men, 1hr/unit	- Basic instr. mech tools - Filters - Test equip.
Instru. Room Air Conditioning (where applicable): - Clean Filters - Grease Bearings - Adjust Belts	- Prevent overheating	- Maintain using approved plant procedures.	- Monthly	- 2 men, 1hr/unit	- Basic instr. mech. tools - Grease & filters
Demineralizer System: - Conductivity Cells - pH Cells	- Maintain proper ranges and settings.	- Calibrate using approved plant procedures.	- Monthly	- 2 men, 2hr/unit	- Basic instr. mech. tools - Test equip./Chem. solutions

Adjustment/Calibration (On-line)**MPAC Code: IAC-AR3BL**

Activity	Purpose	Method	Frequency	Duration	Material Needed
Combustion Air: - Process Sensing Lines	- Ensure proper readings.	- Inspect, clean, leak check.	- Quarterly	- 2 men, 1hr/unit	- Basic instr. mech. tools
Furnace Draft: - Furnace Sensing Lines	- Ensure proper readings.	- Inspect, clean, leak check.	- Quarterly	- 2 men, 1hr/unit	- Basic instr. mech. tools
Secondary Air: - Furnace Sensing Lines - Flow Trans. & Rec. (Once-Through units Only)	- Ensure proper readings. - Maintain proper ranges and settings.	- Inspect, clean, leak check.	- Quarterly	- 2 men, 1hr/unit - 2 men, 2hr/unit	- Basic instr. mech. tools - Test equip.
Fuel Oil: - Ignitors	- Verify proper function.	- Maintain using approved plant procedures.	- Quarterly	- 2 men, 2hr/unit	- Basic instr. mech. tools
Coal Feeders: - Gravimetric Feeders & Scales (where applicable) - Feeder Speed Controls (where applicable)	- Maintain proper ranges and settings.	- Calibrate using approved plant procedures.	- Quarterly	- 2 men, 2hr/unit	- Basic instr. mech. tools - Test equip.
Pulverizers: - Sensing Lines	- Ensure proper readings.	- Inspect, clean, leak check.	- Quarterly	- 2 men, 1hr/unit	- Basic instr. mech. tools
Distributed Control System (where applicable): - Power Supplies - Air Filters - Control Logic Backups	- Verify proper function. - Prevent overheating. - Program security.	- Maintain using approved plant procedures.	- Quarterly - Quarterly - Quarterly	- 2 men, 1hr/unit - 2 men, 1hr/unit - 1 man, 2hr/unit	- Basic instr. mech. tools - Test equip. - Magnetic media

Adjustment/Calibration (On-line) MPAC Code: IAC-AR4BL

Activity	Purpose	Method	Frequency	Duration	Material Needed
Boiler Feedwater: - BFP Suction Switches (Pump Off-Line). - Drum Level Transmitters, Recorders, Ind.	- Maintain proper ranges and settings.	- Calibrate using approved plant procedures.	- Yearly	- 2 men, 2 hr/unit	- Basic instr. mech. tools - Test equip.
Secondary Air: - Press. Transmitters, Recorders, Indicators (where applicable).	- Maintain proper ranges and settings.	- Calibrate using approved plant procedures.	- Yearly	- 2 men, 2 hr/unit	- Basic instr. mech. tools - Test equip.
Fuel Oil (where applicable): - Pressure Control Loops - Flow Control Loops - Warmup Guns	- Maintain proper ranges and settings.	- Calibrate using approved plant procedures.	- Yearly	- 2 men, 1 hr/unit	- Basic instr. mech. tools - Test equip

Adjustment/Calibration (On-line) MPAC Code: IAC-AX1BL

Activity	Purpose	Method	Frequency	Duration	Material Needed
Boiler Feedwater: - Flow Transmitters, Recorders, Indicators - Press. Transmitters, Recorders, Indicators - Lube Oil Press. Switches (where applicable) - Hydraulic Speed Controls, Drives, Linkage - Control Valves, Drives, Linkage (incl. recirc. vlv.) - Shaft Position Trips (where applicable)	- Maintain proper ranges and settings.	- Calibrate using approved plant procedures.	- Outage	- 2 men, 16 hr/unit	- Basic instr. mech. tools - Test equip.
Combustion Air: - Flow Transmitters, Recorders, Indicators - Dampers, Drives, Linkage	- Maintain proper ranges and settings.	- Calibrate using approved plant procedures.	- Outage	- 2 men, 2 hr/unit	- Basic instr. mech. tools - Test equip.
Furnace Draft: - Flow Transmitters, Recorders, Indicators - Dampers, Drives, Linkage	- Maintain proper ranges and settings.	- Calibrate using approved plant procedures.	- Outage	- 2 men, 2 hr/unit	- Basic instr. mech. tools - Test equip.

Adjustment/Calibration (On-line)**MPAC Code: IAC-AX1BL**

Activity	Purpose	Method	Frequency	Duration	Material Needed
Secondary Air (where applicable): <ul style="list-style-type: none">- Flow Transmitters, Recorders, Indicators- Dampers, Drives, Linkage	<ul style="list-style-type: none">- Maintain proper ranges and settings.	<ul style="list-style-type: none">- Calibrate using approved plant procedures.	<ul style="list-style-type: none">- Outage	<ul style="list-style-type: none">- 2 men, 2 hr/unit	<ul style="list-style-type: none">- Basic instr. mech. tools- Test equip
Master Fuel Trip Circuits (where applicable): <ul style="list-style-type: none">- Furnace Draft Switches- BCWP DP Trip- ID/FD Fan Trip Relays- Combustion Airflow Switches- Flame Scanners- Control Relays- MCR Alarms	<ul style="list-style-type: none">- Maintain proper ranges and settings.	<ul style="list-style-type: none">- Calibrate using approved plant procedures.	<ul style="list-style-type: none">- Outage	<ul style="list-style-type: none">- 2 men, 16 hr/unit	<ul style="list-style-type: none">- Basic instr. mech. tools- Test equip
Pulverizer: <ul style="list-style-type: none">- Dampers, Drives, Linkage	<ul style="list-style-type: none">- Maintain proper ranges and settings.	<ul style="list-style-type: none">- Calibrate using approved plant procedures.	<ul style="list-style-type: none">- Outage	<ul style="list-style-type: none">- 2 men, 4 hr/unit	<ul style="list-style-type: none">- Basic instr. mech. tools- Test equip

Adjustment/Calibration (On-line)**MPAC Code: IAC-AX1BL**

Activity	Purpose	Method	Frequency	Duration	Material Needed
Main Turbine: <ul style="list-style-type: none">- Hydraulic Speed Controls (where applicable)- Control Valves, Drives, Linkage (where applicable)- Lube Oil Pressure Switches- Thrust Bearing Switches- Shaft Position Trips & Other Supv. Instr.- Condenser Vacuum Trips- Water Induction Trip (where applicable)	<ul style="list-style-type: none">- Maintain proper ranges and settings.	<ul style="list-style-type: none">- Calibrate using approved plant procedures.	<ul style="list-style-type: none">- Outage	<ul style="list-style-type: none">- 2 men, 16 hr/unit	<ul style="list-style-type: none">- Basic instr. mech. tools- Test equip
Steam Flow: <ul style="list-style-type: none">- Transmitters, Recorders, Indicators	<ul style="list-style-type: none">- Maintain proper ranges and settings.	<ul style="list-style-type: none">- Calibrate using approved plant procedures.	<ul style="list-style-type: none">- Outage	<ul style="list-style-type: none">- 2 men, 4 hr/unit	<ul style="list-style-type: none">- Basic instr. mech. tools- Test equip
Steam Temperature: <ul style="list-style-type: none">- Transmitters, Recorders, Indicators	<ul style="list-style-type: none">- Maintain proper ranges and settings.	<ul style="list-style-type: none">- Calibrate using approved plant procedures.	<ul style="list-style-type: none">- Outage	<ul style="list-style-type: none">- 2 men, 4 hr/unit	<ul style="list-style-type: none">- Basic instr. mech. tools- Test equip
Boiler Temperature: <ul style="list-style-type: none">- Temp. Elements, Recorders, Indicators	<ul style="list-style-type: none">- Maintain proper ranges and settings.	<ul style="list-style-type: none">- Calibrate using approved plant procedures.	<ul style="list-style-type: none">- Outage	<ul style="list-style-type: none">- 2 men, 8 hr/unit	<ul style="list-style-type: none">- Basic instr. mech. tools- Test equip

Adjustment/Calibration (On-line)**MPAC Code: IAC-AX1BL**

Activity	Purpose	Method	Frequency	Duration	Material Needed
Turbine Temperature: - Temp. Elements, Recorders, Indicators	- Maintain proper ranges and settings.	- Calibrate using approved plant procedures.	- Outage	- 2 men, 8 hr/unit	- Basic instr. mech. tools - Test equip
Combustion Air Temperature: - Transmitters, Recorders, Indicators	- Maintain proper ranges and settings.	- Calibrate using approved plant procedures.	- Outage	- 2 men, 4 hr/unit	- Basic instr. mech. tools - Test equip
Main Steam, SH, & RH Pressure: - Transmitters, Recorders, Indicators	- Maintain proper ranges and settings.	- Calibrate using approved plant procedures.	- Outage	- 2 men, 8 hr/unit	- Basic instr. mech. tools - Test equip
High-Pressure Heaters: - Level Control & Drain Valves	- Maintain proper ranges and settings.	- Calibrate using approved plant procedures.	- Outage	- 2 men, 4 hr/unit	- Basic instr. mech. tools - Test equip
Low-Pressure Heaters: - Level Control & Drain Valves	- Maintain proper ranges and settings.	- Calibrate using approved plant procedures.	- Outage	- 2 men, 4 hr/unit	- Basic instr. mech. tools - Test equip
Startup System Valves (once-through units only): - Control Valves, Drives, Linkage	- Maintain proper ranges and settings.	- Calibrate using approved plant procedures.	- Outage	- 2 men, 16 hr/unit	- Basic instr. mech. tools - Test equip
Waterwall (once-through units only): - Pressure Switches and Trips - Temperature Switches and Trips	- Maintain proper ranges and settings.	- Calibrate using approved plant procedures.	- Outage	- 2 men, 2 hr/unit	- Basic instr. mech. tools - Test equip

Adjustment/Calibration (On-line)**MPAC Code: IAC-AX1BL**

Activity	Purpose	Method	Frequency	Duration	Material Needed
O2 System: - Transmitters, Recorders, Indicators	- Maintain proper ranges and settings.	- Calibrate using approved plant procedures.	- Outage	- 2 men, 2 hr/unit	- Basic instr. mech. tools - Test equip

Chapter 3.0

Boiler Non-Destructive Testing

Section 3.1

Waterwalls

Evaluation of Waterwalls

Elevation 707 Feet (Top Elevation)

On the bottom of the upper deflection arch, on the rear "WW", there are tubes which have 4" (10cm) to 12" (30cm) long padwelds. The padwelds are horizontal (2.5" or 6cm wide) and thick. These padwelds were made as result of failures because of water level problems in the steam drum. The following tubes have padwelds: 10 (2 padwelds), 11, 81, 83, 105, 113, 133, and 141 (2 padwelds). These tubes, with padwelds, should be removed and replaced on a planned outage.

The following table contains tubes that are out of plane with the waterwall, at this elevation.

Location	Tube	How Much	Recommendation
Front "WW"	74	1/2 Diameter	Re-align with "WW"
Left "WW"	2	1/2 Diameter	Re-align with "WW"

Elevation 693 Feet

The following table contains the location, tubes, and recommendation for waterwall tubes with padwelds at this elevation.

Location	Tubes	Recommendation
Left "WW"	43, 76, 77, 89	Cut-out and replace
Right "WW"	48	Cut-out and replace
Rear "WW"	117, 118	Cut-out and replace

The following table contains the tubes that are out of plane with the waterwalls at this elevation.

Location	Tube	How Much	Recommendation
Front "WW"	74	1/2 Diameter	Re-align
Front "WW"	134	1/2 Diameter	Re-align
Right "WW"	70	3/4 Diameter	Re-align
Rear "WW"	68	3/4 Diameter	Re-align

Elevation 683 Feet (Top of the Burners)

The following table contains the location, tubes, and recommendation for waterwall tubes with padwelds at this location.

Location	Tubes	Recommendation
Front "WW"	43, 44, 45	Cut-out and replace
Right "WW"	3, 21, 42, 52, 55, & 69	Cut-out and replace

Rear "WW"	115	Cut-out and replace
Left "WW"	32, 35	Cut-out and replace

Rear waterwall tube 4 is swollen about 5" or 13cm above a weld line, at elevation 688'. Tube 4, along with a weld, will be cut-out and used as a tube sample.

A weld line, that runs around all four waterwalls, is located 59" or 150cm above the top of the burners, at elevation 688'.

Elevation 674 Feet

The following table contains the location, tubes, and recommendation for waterwall tubes with padwelds at this location.

Location	Tubes	Recommendation
Front "WW"	64	Cut-out and replace
Left "WW"	14 & 83	Cut-out and replace
Rear "WW"	59	Cut-out and replace

There are coal eroded tubes in the right rear burner box at E and D coal nozzles. Thickness measurements were taken on the tubes that were accessible. Some tubes could not be UT, because the secondary air nozzles were not removed. The lowest measurement was taken on the right rear corner, on rear "WW" tube 146 - 0.220" (5.6mm). The original tube is 0.300" MWT. It would be advisable that all nozzles be removed and all burner boxes be thoroughly inspected for tube damage. A scaffold would have to be built at elevation 663'. The following is a list of eroded at E and D coal nozzle elevations; right rear burner 146, 147, 148, and on the left rear burner tubes 2 & 3, as marked.

Elevation 652 Feet

The following table contains the tubes that are out of plane with the waterwalls at this elevation.

Location	Tube	How Much	Recommendation
Front "WW"	12	1/2 Diameter for 8' or 3M	Re-align
Rear "WW"	12 & 13	1/2 Diameter for 15' or 5M	Re-align
Rear "WW"	138, 139, 140	1/2 Diameter for 8' or 3M	Re-align

Replace all lower corner slope sidewall seals with refractory. A large portion of these are deteriorated, broken, and missing.

Dead Air Spaces

The dead air space, under the upper deflection arch, was inspected. The fly ash and debris had been cleaned out. The casing, both overhead and on the sidewalls, was in satisfactory condition.

The rear, lower slope, dead air space was cleaned of fly ash. The casing, rear waterwall header, and ring header were visually inspected. All of the items mentioned were found to be in satisfactory condition. An area in the third casing panel, 2' x 2' (61cm x 61cm), was cut and removed. The refractory was removed and the bottom side of the rear "WW" tubes were UT for possible external corrosion. A total of ten tubes were UT. All thickness measurements were satisfactory. The original tube is 3" OD x 0.300" MWT, SA 192 material. The following is a list of the tubes and their measurements.

<u>Tubes</u>	<u>UT Measurements</u>
1	0.337" (8.55mm)
2	0.324" (8.22mm)
3	0.326" (8.28mm)
4	0.312" (7.92mm)
5	0.320" (8.12mm)
6	0.315" (8.00mm)
7	0.329" (8.35mm)
8	0.311" (7.90mm)
9	0.322" (8.17mm)
10	0.323" (8.20mm)

Section 3.2

Steam Side Tubing

Steam Side Tubing

Executive Summary

Secondary Superheater

In each of the secondary superheater platen elements, tube 10 was out of alignment into the gas line. This is normal distortion for stainless steel material and is not severe enough for repair at this time. This should be monitored at each scheduled outage. If the distortion becomes severe, the tubes should be replaced. All broken tube lugs should be repaired. There were no tube thinning problems. Dissimilar metal welds should be monitored during each scheduled outage. Increased operating temperatures and pressures may necessitate the replacement of these welds for long term operation.

The thickest steam side oxide scale thickness was 0.0129". Based on the operating history of this unit, and the calculated operating temperature of this component is 1010 to 1015 degrees F in the gas pass. The measured main steam temperature is 1000 degrees F. This component is in sufficient condition to operate another 20 years.

Reheater

There were only a few missing lugs and mild flyash erosion in the reheater. There was one missing circuit in one element. This circuit has been missing for at least 16 years.

The thickest steam side oxide scale measured was 0.0094". Based on the operating history of this unit, the calculated operating temperature of this component is 980 degrees F. The measured reheat temperature reheat temperature is 950 degrees F.

The reheater outlet bank was partially plugged with flyash when the unit was removed from service. The sootblowers, on this unit, have been out of service for many years. This could explain the reduced outlet temperature. Returning the sootblowers, in the reheater, to service would probably prevent this pluggage and increase reheater efficiency and temperature.

It has not been the normal practice for the reheater to be preserved for long term storage during outages. Normally, this results in ID pitting in the lower bends of the elements. Two samples were removed from this reheater and no pitting was discovered. However, in order for the reheater to operate another 20 years, out of service preservation should be considered.

Horizontal Primary Superheater

The primary superheater is a boiler component that will limit 20 year operation. There are many broken lugs in the body of all three banks of elements. There is misalignment and localized flyash erosion in the elements. All elements should be raised and repaired during this outage. Lugs should be rewelded, thin tubes replaced, and shields installed to prevent future fly ash erosion. A recommendation for a new tube spacer design has been included in this report.

Screen Wall Tubes

The water cooled screen wall tubes had some fly ash erosion. These tubes should be shielded. The shields should be inspected and repaired during each scheduled outage. The steam cooled screen wall tubes had flyash erosion severe enough to require three tubes to be replaced. In order to operate 20 years, the screen wall tubes should be shielded and the shields regularly maintained.

Section 3.3

Drums

Steam Drum

Executive Summary

The steam drum was in excellent condition with only minor blot tightening required. Minor deposits were found in the bottom of the drum. A small sample was removed and analyzed by the plant chemical lab. It was found to contain about 40% copper.

Steam Drum

- Replace the missing "U" bolt nuts on the chemical feed piping by front separators 13 and 14.
- Tighten all overhead bolts and nuts as marked on the drying screens.
- Tighten nuts on "J" bolts on the front secondary separators 16 and 27.
- Tighten the primary separator clamping bolt on the bottom of the rear separator 18.
- Tighten all "U" bolt nuts as marked on the continuous blowdown piping.
- Wet fluorescent magnetic particle testing was performed on the interior and exterior of the drum head girth welds. These MT examinations revealed no indications.
- The overall condition of the steam drum was very satisfactory. There were no signs of deterioration on the inner liner plates, nuts, "J" bolts, separators, blowdown piping, chemical feed piping, or welds. Note, some deposits were collected by DVC from the inside bottom of the steam drum.

Test Results of Drum Deposit of Blr #2

1. Iron (as Fe ₂ O ₃)	57.84%
2. Copper (as CuO)	39.12%
3. Nickel (as NiO)	1.45%
4. Chromium	Not detectable
5. Water Soluble Silica (as SiO ₂)	0.01%
6. Water Soluble Phosphate (as PO ₄)	NIL

Section 3.4

Headers

Headers

Executive Summary

All high temperature headers were inspected. In addition, the economizer inlet and outlet headers were inspected. The only header with major surface indications was the primary superheater outlet heater.

The primary superheater outlet header had OD originated cracking at the outlet tees and at some tube stub welds. The tees had been previously repaired. To operate 20 years without major problems, the overheating in the primary superheater must be solved and the header repaired or replaced. If it is replaced, the new header should be made of P22 material instead of the original P11 material.

Chapter 4.0

Turbine Non-Destructive Testing

Turbine Non-Destructive Testing typically employs several methods of inspection and covers many different components that make up the turbine-generator assembly. The selection of the test method is dependent upon the component size, shape and material, as well as the suspected defect to be found during the testing. Those components subject to high stresses during inservice operation and subject to damage during the tear-down are inspected to prevent problems during re-assembly and/or during operation.

The methods of testing usually employed during an outage include visual, magnetic particle, penetrant, ultrasonic testing, and metallurgical testing.

Visual Testing is primarily used to detect defects that are large and open at the component surface. This method is the first line inspection of any component. Visual testing can locate those flaws which may be large and undetectable (due to size and/or orientation) by other NDT methods. VT is also used to determine if the component is prepared properly for the other NDT method to be used to complete the inspection.

Magnetic particle and Penetrant Testing methods are limited to surface or near-surface defects. Defects which lie slight beneath the surface may be detectable with magnetic particle testing, however, the type of magnetizing current and defect size/orientation limits this ability. Those components which are non-ferric and require a surface examination inspected using the penetrant testing method.

Ultrasonic testing is used to examine components on the hidden side when only one side is accessible or the defects are suspected to be sub-surface (embedded). Component/defect configuration may also lend itself to ultrasonic testing better than other methods.

Metallurgical testing may include alloy identification using a portable alloy analyzer, hardness testing, and microstructural characterization using either direct viewing or plastic replication of sites that have been metallographically prepared (micropolished and etched).

Components which are typically inspected during an outage include the turbine and generator rotors, diaphragms, studs/bolts, cylinders/nozzles, valves, bearings and retaining rings. The selection of a component for testing may be dependent on operation history of the unit, results of the last inspection, OEM's recommendation and/or the results of testing on other comparable units.

Non-destructive testing of turbine/generator rotors is usually performed in a two phase approach. The first phase is typically performed during all outages in which the rotor is removed from the cylinder. This includes inspection of any and all of the external surface of the rotor. The second phase, although not performed during every outage, consists of examination from the bore surface of the rotor forging.

Rotor Surface

4.1.1

Executive Summary

The rotor may be tested using any and all the methods of non-destructive testing. Visual Testing is performed to find damage which may not be detectable by other test methods and to determine the readiness of the part for additional NDT methods. The shaft, blades, wheels, covers and coupling flanges are typically examined using the magnetic particle method. Usually the fluorescent technique is employed. This allows for coverage of large areas and is most sensitive to the small stress cracks one expects to find on parts of the rotor. Ultrasonic testing may be performed on the blade/cover tenons.

HP/IP - UNIT 2 ROTOR (S/N 5337-010)

Fluorescent magnetic particle testing was performed on this rotor during the unit outage of the Chandrapura Thermal Power Station. Cracking was detected in the grooves of the seal areas. Additionally, a DC Potential Drop Technique was performed to determine the depth of the cracks. The crack locations and depth determinations are shown in FIGURE 4.1.1. These cracks were to be removed prior to returning the rotor to service.

LPDF ROTOR (S/N 55089)

Although this rotor was to be magnetic particle tested during the outage, no report of findings was available at the time of departure.

HP/IP SPARE ROTOR (S/N 123K176VA1)

This rotor was not magnetic particle tested during this outage.

CRACK DEPTH MEASUREMENT BY D.C. POTENTIAL DROP
TECHNIQUE
UNIT # 2, CTPS, DVC, INDIA, AUG. 1994

FIG. A.	POINTS ON THE PERIPHERY OF ROTOR												
LOCATION	0	1	2	3	4	5	6	7	8	9	10	11	12
A	1.7	2.1	1.8	2.0	1.6	1.0	1.7	2.1	2.4	1.5	1.5		
B	2.1	2.0	2.1	1.9	1.8	1.5	1.6	1.5	1.7	2.0	2.2		
C	2.3	1.5	1.9	2.5	2.6	1.9	2.6	2.9	2.2	1.9	2.5		
D	0.0	0.8	0.8	1.4	1.5	1.4	1.3	1.0	1.2	1.2	1.3		
E	1.5	1.6	1.6	1.6	2.3	2.2	2.0	2.3	2.8	2.0	2.4	2.0	2.4

(ALL READINGS IN MM)

* MINUTE CRACKS

FIG. A

Figure 4.1.1

Boresonic

4.1.2

Executive Summary

During the Unit 2 outage of the Chandrapura Thermal Power Station, boresonic examination was performed to determine the condition of the forging for continued operation and to estimate forging life.

Boresonic examination of a forging includes visual, magnetic particle, and ultrasonic examination of the near bore region and a radial volume of five inches. These examinations are performed after the bore surface is prepared for examination by manual or power honing. Diameter measurements are taken to insure proper wedge contact during the ultrasonic examination portion.

The primary purpose of the visual examination is to detect flaws that may be open to, or present at, the bore surface. The secondary purpose of the visual examination is to determine if the bore surface finish is acceptable for conducting an ultrasonic examination of the rotor. The visual examination is usually performed with the aid of a borescope.

A magnetic particle inspection of the bore surface is performed using the central conductor technique and continuous method. Black visible particles are generally used to detect flaws on the honed surface. The primary flaw orientation of concern is axial.

The ultrasonic examination is performed using an array of transducers. Ultrasound is introduced into the forging three different ways. Two transducers are mounted such that the beam enters the forging, from the bore surface, in a circumferential direction (clockwise and counter-clockwise) at 45° to a radial line from the bore center. Another pair of transducers introduces the sound in a radial-axial (forward and backward) direction at 45° to the radial perpendicular of the bore surface. These four transducers produce shear waves in the forging. The final pair of transducers are the longitudinal type, producing a sound beam into the forging perpendicular to the bore surface. If two straight beam transducers are used, one is calibrated for the near volume and the other is calibrated for far volume.

The WesDyne International UDRPS II boresonic system was used to perform the examination of the LPDF (S/N 55089) and HP/IP Spare (S/N 123K176VA1) rotors during the outage. The Ultrasonic Data Recording and Processing System is a field deployable, multi-channel, production oriented data acquisition and analysis system. The system is capable of performing automatic flaw detection and location. During the examination, UDRPS II provides:

- * Complete recording of each entire A-scan, pulse by pulse on an optical disk.
- * Target detection on a well proven, highly reliable, amplitude insensitive, signal to noise ratio, and pattern recognition algorithm performed in real time as data are taken.

- * A, B, C and D scan data presentations.
- * Three dimensional target displays of the inspected volume of material.
- * Spatial and temporal averaging of data for enhanced signal to noise.
- * Multiple B scan views at near motion picture framing rates.
- * Edge enhancement routines to improve signal to noise.
- * Spatial correlation routines for the separation of significant from benign indications, i.e. "deworming" techniques. This technique is used to formulate potential flaw sizes.
- * All examination data are recorded in real time and reviewed for accuracy and validity at the end of each scan section.

LPDF ROTOR (S/N 55089)

The entire boresonic examination process was performed on this rotor. No defects were noted during the exam. The light to moderate pitting noted during the visual portion of the examination could be removed by power honing. It is estimated that 0.050" of material would need to be removed in the honing process. The operational restrictions and reinspection interval are noted in the ROTOR FORGING DAMAGE ASSESSMENT section of this report.

HP/IP SPARE ROTOR (S/N 123K176VA1)

The entire boresonic examination process was performed on this rotor. One indication was flagged (centroid) during the ultrasonic portion of the examination and that indication was reported for Damage Assessment. The outside surface damage was not noted as part of the boresonic examination and is not part of this report. The operational restrictions and reinspection interval, as addressed by the boresonic examination, are noted in the ROTOR FORGING DAMAGE ASSESSMENT section of this report.

HP/IP - UNIT 2 ROTOR (S/N 5337-010)

This rotor was examined using only the visual and surface methods. No ultrasonic examination performed. The moderate honing spirals and scratches noted during the visual exam should be removed prior to any ultrasonic examination. Additional power honing should render the surface acceptable. The operational restrictions and reinspection interval are noted in the ROTOR FORGING DAMAGE ASSESSMENT section of this report.

Diaphragm

4.2

Executive Summary

The diaphragms (stationary blading) are typically examined using the fluorescent magnetic particle testing method. In a few cases, the stationary blading may be non-magnetic and penetrant testing would be used to perform the examination. The primary area of interest is the blades. Visual testing is performed prior to the magnetic particle test.

UNIT 2 - STATIONARY BLADING

The stationary blading of Unit 2 - Chandrapura Thermal Power Station were inspected using the fluorescent magnetic particle method. The results of the inspection of those diaphragms which had been inspected prior to departure of the US team members are listed in ATTACHMENT 4.2. Thereafter, this inspection activity was continued by BHEL and NTPC teams and any liabilities were presumably dealt with in an appropriate manner.

NONDESTRUCTIVE TESTING EXAMINATION REPORT

PLANT CTPS LOCATION CHANDRAPURA UNIT 2 DATE 17 AUGUST, 94

TYPE OF EXAMINATION MT X VT UT VT ET HT

ITEM SECTION OR STAGE	LOCATION OR BLADE No.	INDICATIONS
DIAPHRAGM	2 TOP	
DIAPHRAGM	2 BOTTOM	
DIAPHRAGM	3 TOP	
DIAPHRAGM	3 BOTTOM	No indication
DIAPHRAGM	4 TOP	No indication
DIAPHRAGM	4 BOTTOM	Crack observed (FIGURE 4.2.1)
DIAPHRAGM	5 TOP	Crack observed in one blade (FIGURE 4.2.2)
DIAPHRAGM	5 BOTTOM	No indication
DIAPHRAGM	6 TOP	No indication
DIAPHRAGM	6 BOTTOM	No indication
DIAPHRAGM	7 TOP	Crack observed in one blade (FIGURE 4.2.3)
DIAPHRAGM	7 BOTTOM	No indication

ATTACHMENT 4.2

NONDESTRUCTIVE TESTING EXAMINATION REPORT

PLANT CTPS LOCATION CHANDRAPURA UNIT 2 DATE 17 AUGUST, 94

TYPE OF EXAMINATION MT X VT UT VT ET HT

ITEM SECTION OR STAGE	LOCATION OR BLADE No.	INDICATIONS
DIAPHRAGM	8 TOP	No indication
DIAPHRAGM	8 BOTTOM	
DIAPHRAGM	9 TOP	No indication
DIAPHRAGM	9 BOTTOM	No indication
DIAPHRAGM	10 TOP	
DIAPHRAGM	10 BOTTOM	
DIAPHRAGM	11 TOP	Indication observed (FIGURE 4.2.4)
DIAPHRAGM	11 BOTTOM	No indication
DIAPHRAGM	12 TOP	No indication
DIAPHRAGM	12 BOTTOM	No indication
DIAPHRAGM	13 TOP	Indications observed (FIGURE 4.2.5)
DIAPHRAGM	13 BOTTOM	Minor cracks observed in blades (FIGURE 4.2.6)

ATTACHMENT 4.2 (continued)

NONDESTRUCTIVE TESTING EXAMINATION REPORT

PLANT CTPS LOCATION CHANDRAPURA UNIT 2 DATE 17 AUGUST, 94

TYPE OF EXAMINATION MT X VT UT VT ET HT

ITEM SECTION OR STAGE	LOCATION OR BLADE No.	INDICATIONS
DIAPHRAGM	14 TOP	No indication
DIAPHRAGM	14 BOTTOM	No indication
DIAPHRAGM	15 TOP	Indications observed (FIGURE 4.2.7)
DIAPHRAGM	15 BOTTOM	
DIAPHRAGM	16 TOP	Crack of 20mm length observed in the right hand side parting plane repaired weld.
DIAPHRAGM	16 BOTTOM	Indication observed (FIGURE 4.2.8)
DIAPHRAGM	17 TOP	No indication
DIAPHRAGM	17 BOTTOM	
DIAPHRAGM	18 TOP	
DIAPHRAGM	18 BOTTOM	
DIAPHRAGM	19 TOP	No indication
DIAPHRAGM	19 BOTTOM	No indication

ATTACHMENT 4.2 (continued)

NONDESTRUCTIVE TESTING EXAMINATION REPORT

PLANT CTPS LOCATION CHANDRAPURA UNIT 2 DATE 17 AUGUST, 94

TYPE OF EXAMINATION MT X VT UT VT ET HT

ITEM SECTION OR STAGE	LOCATION OR BLADE No.	INDICATIONS
DIAPHRAGM	20 TOP	No indication
DIAPHRAGM	20 BOTTOM	No indication
DIAPHRAGM	21 TOP	
DIAPHRAGM	21 BOTTOM	
DIAPHRAGM	22 TOP	
DIAPHRAGM	22 BOTTOM	
DIAPHRAGM	23 GS TOP	
DIAPHRAGM	23 GS BOTTOM	
DIAPHRAGM	23 TS TOP	
DIAPHRAGM	23 TS BOTTOM	
DIAPHRAGM	24 GS TOP	
DIAPHRAGM	24 GS BOTTOM	

ATTACHMENT 4.2 (continued)

NONDESTRUCTIVE TESTING EXAMINATION REPORT

PLANT CTPS LOCATION CHANDRAPURA UNIT 2 DATE 17 AUGUST, 94

TYPE OF EXAMINATION MT X VT UT VT ET HT

ITEM SECTION OR STAGE	LOCATION OR BLADE No.	INDICATIONS
DIAPHRAGM	24 TS TOP	
DIAPHRAGM	24 TS BOTTOM	
DIAPHRAGM	25 GS TOP	
DIAPHRAGM	25 GS BOTTOM	
DIAPHRAGM	25 TS TOP	
DIAPHRAGM	25 TS BOTTOM	
DIAPHRAGM	26 GS TOP	
DIAPHRAGM	26 GS BOTTOM	
DIAPHRAGM	26 TS TOP	
DIAPHRAGM	26 TS BOTTOM	

ATTACHMENT 4.2 (continued)

NONDESTRUCTIVE TESTING EXAMINATION REPORT

PLANT: CTPS

LOCATION: CHANDRAPURA

UNIT: 2

DATE: 13/08/94

TYPE OF EXAMINATION: MT X PT UT VT ET SHEET OF

OBSERVED INDICATION DESCRIPTIONS

FIGURE 4.2.1

OUTLET

DIAPHRAGM - 4 BOTTOM

*CRACK ON THE 27TH BLADE. LOCATION: 3MM FROM BOTTOM ROOT:STARTING FROM TRAILING EDGE; CRACK LENGTH - 35MM. (CRACK MAY BE DUE TO MISHANDLING WHILE SHIFTING).

INLET

NO INDICATIONS

NONDESTRUCTIVE TESTING EXAMINATION REPORT

PLANT: CTPS

LOCATION: CHANDRAPURA

UNIT: 2

DATE: 09/08/94

TYPE OF EXAMINATION: MT X PT UT VT ET SHEET OF

OBSERVED INDICATION DESCRIPTIONS

FIGURE 4.2.2

OUTLET

DIAPHRAGM 5 TOP

ON BLADE NO. 1 A TRANSVERSE CRACK OF 8MM LENGTH WAS OBSERVED NEAR THE TOP NECK OF THE BLADE.

INLET

NO INDICATIONS.

NONDESTRUCTIVE TESTING EXAMINATION REPORT

PLANT: CTPS

LOCATION: CHANDRAPURA

UNIT: 2

DATE: 09/08/94

TYPE OF EXAMINATION: MT X PT___ UT___ VT___ ET___ SHEET___ OF___

OBSERVED INDICATION DESCRIPTIONS

FIGURE 4.2.3

OUTLET

DIAPHRAGM 7 TOP

IN BLADE NO. 1 CRACK OF 10MM LENGTH AT THE TOP
ROOT OF THE BLADE. AS SHOWN IN THE SKETCH.

INLET

NONDESTRUCTIVE TESTING EXAMINATION REPORT

PLANT: CTPS

LOCATION: CHANDRAPURA

UNIT: 2

DATE:

TYPE OF EXAMINATION: MT X PT___ UT___ VT___ ET___ SHEET___ OF___

OBSERVED INDICATION DESCRIPTIONS

FIGURE 4.2.4

OUTLET

DIAPHRAGM 11 TOP

NOTE: ORIGINAL DATA SHEET UNAVAILABLE

INLET

NONDESTRUCTIVE TESTING EXAMINATION REPORT

PLANT: CTPS

LOCATION: CHANDRAPURA

UNIT: 2

DATE: 15/08/94

TYPE OF EXAMINATION: MT X PT UT VT ET SHEET OF

OBSERVED INDICATION DESCRIPTIONS

FIGURE 4.2.5

OUTLET

DIAPHRAGM 13 TOP

- BLADE NO. 14 – LENGTH CRACK OF 30MM LENGTH - AT THE TRAILING EDGE MIDDLE.
19 – TRANSVERSE CRACK OF 6MM LENGTH - 8MM FROM BOTTOM ROOT.
24 – LONG. CRACK OF 30MM LENGTH – AT THE TRAILING EDGE TOP.
29 – LONG. CRACK OF 20MM LENGTH – AT THE TRAILING EDGE BOTTOM.
39 – TRANSVERSE CRACK OF 3MM LENGTH – 10MM FROM TOP ROOT.

*ALL THE LONGITUDINAL CRACKS
ARE DUE TO HITTING OF SOME
FOREIGN OBJECT.

INLET

NONDESTRUCTIVE TESTING EXAMINATION REPORT

PLANT: CTPS

LOCATION: CHANDRAPURA

UNIT: 2

DATE: 14/08/94

TYPE OF EXAMINATION: MT X PT___ UT___ VT___ ET___ SHEET___ OF___

OBSERVED INDICATION DESCRIPTIONS

FIGURE 4.2.6

OUTLET

DIAPHRAGM 13 - BOTTOM

BLADE NO. 50 - MIDDLE OF TRAILING EDGE - MINOR CRACK OF 9MM LENGTH.

54 - TOP ROOT OF BLADE - MINOR CRACK OF 1MM LENGTH.

56 - TOP ROOT OF BLADE - MINOR CRACK OF 1MM LENGTH.

INLET

NO INDICATIONS.

NONDESTRUCTIVE TESTING EXAMINATION REPORT

PLANT: CTPS

LOCATION: CHANDRAPURA

UNIT: 2

DATE: 16/08/94

TYPE OF EXAMINATION: MT X PT___ UT___ VT___ ET___ SHEET ___ OF ___

OBSERVED INDICATION DESCRIPTIONS

FIGURE 4.2.7

OUTLET

DIAPHRAGM 15 - TOP

NO INDICATIONS.

INLET

BLADE - 63 - CRACK OF 30MM LENGTH AT THE TOP ROOT OF THE BLADE.

NONDESTRUCTIVE TESTING EXAMINATION REPORT

PLANT: CTPS

LOCATION: CHANDRAPURA

UNIT: 2

DATE: 15/08/94

TYPE OF EXAMINATION: MT X PT UT VT ET SHEET OF

OBSERVED INDICATION DESCRIPTIONS

FIGURE 4.2.8

OUTLET

DIAPHRAGM - 16 BOTTOM

BLADE NO. 2 LONGITUDINAL CRACK OF 80MM LENGTH (DAMAGED)
AT ROOT TRAILING EDGE.

INLET

NO INDICATIONS.

Studs and Bolts

4.3

Executive Summary

Studs and bolts are used to assemble and/or connect the various parts of the turbine/generator system. The cylinder (inner and outer) joints and valve (bonnet to body) joints are assembled with studs having threads on each end. Some of the flange and casing joints are assembled with bolts having all thread and a head. No matter which is used, the area of concern is cracks emanating from the thread root. Penetrant may be used to inspect the studs and bolts, but much time will be spent pre-cleaning the threads and much time cleaning the penetrant material from the threads during the examination. The cracks of major concern in studs and bolts are oriented perpendicular to the long axis of the stud or bolt. This make for an ideal situation for the use of ultrasonic testing.

The studs or bolts are examined using the zero degree longitudinal wave. The sound is passed through the part from end to end. Many of the studs are only accessible from one end. This would prevent the use of penetrant testing or the studs would have to be removed for the inspection. Typically, these studs do not remove easily and are usually damaged during the removal process. Ultrasonic testing can inspect the region which is not visible for cracks in the thread root region.

Visual testing is performed to locate other damage associated with the disassemble and reassemble of threaded components.

UNIT 2 - STUDS/BOLTS

ATTACHMENT 4.3 list those studs/bolts which were ultrasonic tested during the outage.

NONDESTRUCTIVE TESTING EXAMINATION REPORT

PLANT CTPS LOCATION CHANDRAPURA UNIT 2 DATE SEE BELOW

TYPE OF EXAMINATION MT PT UT X VT ET HT

ITEM SECTION OR STAGE	LOCATION OR BLADE No.	INDICATIONS	
HP / RH	52 OUTER CYLINDER STUDS	N.A.D.	3-Aug-94
HP / RH	24 INNER CYLINDER STUDS	N.A.D.	8-Aug-94
H P / RH	23 UPPER CONTROL VALVE STUDS	N.A.D.	3-Aug-94 Had one stud missing.
HP / RH	24 MAIN STEAM STOP VALVE STUDS	N.A.D.	3-Aug-94
HP / RH	40 REHEAT VALVE STUDS	N.A.D.	4-Aug-94
HP / RH	38 INTERCEPT VALVE STUDS	N.A.D.	4-Aug-94
HP / RH	16 REHEAT INNER CYLINDER STUDS	N.A.D.	4-Aug-94
HP / RH	24 MAIN STEAM FLANGE BOLTS	N.A.D.	4-Aug-94
HP / RH	24 REHEAT FLANGE BOLTS	N.A.D.	4-Aug-94 Had 12 bolts out of 36 missing. There were reported to have been cut.
HP STUDS	24 Nos. LOWER CONTROL VALVE	N.A.D.	8-Aug-94

UT of studs and bolts have been carried out as per the procedure recommended by Shri Don Harvey/TVA

ATTACHMENT 4.3

Casing and Cylinders

4.4

Executive Summary

The cylinders and casings provide containment of the steam around the turbine rotors. These are typically heavy wall castings. Visual testing is typically performed on these components. The expected flaws are large and open. The visual testing is usually supplemented with magnetic particle testing or penetrant testing. The inner cylinder has a nozzle block which directs or channels the steam into the cylinder. The nozzle block area is typically inspected using the fluorescent magnetic particle method.

HP INNER CYLINDER

The HP Inner cylinder was fluorescent magnetic particle tested during the Unit 2 outage. Cracks were found in the cylinder body and nozzle block region. FIGURE 4.4 shows the results of the MT examination. The cracks should be monitored at future outages and appropriate decisions reached based on their growth rate. A formal assessment of the strut cracking was performed and is contained in the HP INLET BOWL STRUT CRACKING portion of this report.

FIGURE 4.4

HP INNER CYLINDER [BOTTOM]

- a - 50 mm length
- b - 25 mm "
- c - 15 mm "
- d - 40 mm "
- e - 30 mm "
- f - 15 mm "
- (minor in nature)

CTPS
UNIT: 2
MT
DATE: 08-15-94

FIGURE 4.4 (continued)

HP INNER CYLINDER [TOP]

- (a) THROUGHOUT INTERMITTENT
- (b) THROUGHOUT INTERMITTENT
- (c) 6 MM LENGTH LOCATION
BOLT NO. 65
- (d) LENGTH COULD NOT BE MEASURES
- (e) LENGTH COULD NOT BE MEASURES
- (f) 80 MM LENGTH
- (G) 30 MM LENGTH
- (H) 30 MM LENGTH
- (I) 10 MM LENGTH
- (J THRU L) 100 TO 150 MM
LENGTH EACH
- (m) 2 MM LENGTH

CTPS
UNIT: 2
MT
DATE: 08-15-94

Valves

4.5

Executive Summary

The steam flow to the turbine is controlled by valves. The valves are the main stop, reheat, intercept and control valves. Typically these valves are disassemble during an outage. Visual testing is the primary examination method. Other NDT methods are used to supplement the visual examination. Magnetic particle testing is performed on the valve body and stem section. Penetrant testing is performed on the valve seats (stellite) or the plug seats.

UNIT 2 - VALVES

During the Unit 2 outage, the disassemble valves were inspected. Visual and penetrant tests were performed on the valves listed in ATTACHMENT 4.5. A crack was found in the stellite (plug) of the Left Side Main Stop valve. No repair was necessary and the valves were released for return to service.

NONDESTRUCTIVE TESTING EXAMINATION REPORT

PLANT CTPS LOCATION CHANDRAPURA UNIT 2 DATE AUG. 5, 1994

TYPE OF EXAMINATION MT PT X UT VT ET HT

ITEM SECTION OR STAGE	LOCATION OR BLADE No.	INDICATIONS
MAIN STM. STOP VALVE	LEFT SIDE	SEAT - N.A.D. VALVE - Crack detected in the stellite.
MAIN STM. STOP VALVE	RIGHT SIDE	SEAT - N.A.D. VALVE - N.A.D.
CONTROL VALVE	UPPER FOUR Nos.	SEATS - N.A.D. VALVES - N.A.D.
INTERCEPT VALVE	LEFT SIDE	SEAT - N.A.D. VALVE - N.A.D.
INTERCEPT VALVE	RIGHT SIDE	SEAT - N.A.D. VALVE - N.A.D.
REHEAT VALVE	LEFT SIDE	N.A.D.
REHEAT VALVE	RIGHT SIDE	N.A.D.
HP/IP	4 Nos. Lower control Valve	N.A.D. 13-Aug-94

ATTACHMENT 4.5

Bearings

4.6

Executive Summary

The turbine bearing system is composed of journal and thrust bearings. Each of the bearings are coated (on contact side) with a soft material called babbitt. The babbitt prevents serious damage to the rotors should the lube system fail. The babbitt is bonded to the journal or shoes. A disbond condition can lead to local overheating and spalling of the babbitt. Ultrasonic testing is performed to ensure that the babbitt is sufficiently bonded to the shoes. The ultrasonic test is performed with a zero degree longitudinal wave transducer from the babbitt surface.

THRUST BEARING - TURBINE SIDE

Bond inspection was performed on the Unit 2 turbine side thrust bearing. A total of 5.85% of area was determined to be unbonded and is shown in FIGURE 4.6.1. This bearing was accepted for continued use.

THRUST BEARING - GENERATOR SIDE

Bond inspection was performed on the Unit 2 generator side thrust bearing. A total of 41.69% of area was determined to be unbonded and is shown in FIGURE 4.6.2. This bearing was not accepted for continued use.

JOURNAL BEARINGS - #'s 3, 4, 5

Bond inspection was performed on the Unit 2 journal bearings. The unbond area was determined to be in a range of 6.8% to 18.33% per journal half and is shown in FIGURE 4.6.3a-f. These bearings were accepted for continued use.

Journal bearings #1 and #2 were to be replaced during the outage and no inspection was performed.

CHANDRAPURA THERMAL POWER STATION UNIT 2

TURBINE THRUST BEARING TURBINE SIDE

Denotes Unbond

All dimensions in mm.

Examiner/Date D. D. N. Verma/26 Jul 94

FIGURE 4.6.1

CHANDRAPURA THERMAL POWER STATION UNIT 2

TURBINE THRUST BEARING GENERATOR SIDE

Denotes Unbond

All dimensions in mm.

Examiner/Date D. D. N. Verma/27 Jul 94

FIGURE 4.6.2

CHANDRAPURA THERMAL POWER STATION

UNIT 2 JOURNAL BEARING

No exam in grooves.

4 - 32

Denotes unbond

All dimensions in mm.

Total area: 1,666 cm²

Bearing #3 - Top

FIGURE 4.6.3a

Examiner/Date: D. D. N Verma/30 Jul 94

CHANDRAPURA THERMAL POWER STATION

UNIT 2 JOURNAL BEARING

Bearing #3 - Bottom

FIGURE 4.6.3b

Examiner/Date: D. D. N Verma/30 Jul 94

All dimensions in mm.
Total area: 1,666 cm²

UNIT 2 JOURNAL BEARING

Bearing #4 - Top

All dimensions in mm.
Total area: 2,082.5 cm²

Examiner/Date: D. D. N Verma/30 Jul 94

CHANDRAPURA THERMAL POWER STATION

UNIT 2 JOURNAL BEARING

Denotes unbond

All dimensions in mm.

Total area: 2,082.5 cm²

Bearing #4 - Bottom

FIGURE 4.6.3d

Examiner/Date: D. D. N Verma/30 Jul 94

CHANDRAPURA THERMAL POWER STATION

UNIT 2 JOURNAL BEARING

Denotes unbond

All dimensions in mm.

Total area: 2,082.5 cm²

Bearing #5 - Top

FIGURE 4.6.3e

Examiner/Date: D. D. N Verma/30 Jul 94

UNIT 2 JOURNAL BEARING

Technical drawing of a mechanical assembly, likely a shaft or axle, showing various components and dimensions. The drawing includes the following elements:

- Top Section:** A horizontal bar with five circular holes, labeled 200×7 .
- Second Section:** A horizontal bar labeled 35×10 .
- Third Section:** A horizontal bar labeled 230×10 . Above it, a dimension line indicates a distance of 10ϕ between two circular features.
- Fourth Section:** A horizontal bar labeled 510×10 .
- Fifth Section:** A horizontal bar labeled 510×10 .
- Sixth Section:** A horizontal bar labeled 595×10 .
- Seventh Section:** A horizontal bar labeled 280×10 .
- Eighth Section:** A horizontal bar labeled 595×10 .
- Ninth Section:** A horizontal bar labeled 90×10 .
- Tenth Section:** A horizontal bar labeled 400×20 .

The drawing uses standard mechanical notation, including dimension lines and circular features, to specify the geometry and dimensions of the assembly.

Denotes unbond

Total area: 2,082.5 cm²

Bearing #5 - Bottom

FIGURE 4.6.3f

Examiner/Date: D. D. N Verma/30 Jul 94

Retaining Rings

4.7

Executive Summary

The electric generator has coils which are wound in axially oriented slots that run the length of the rotor body. The coils are retained against outward movement by wedges secured in the slots above the coils. The retaining rings provide support where the coils extend out of the slots at each end of the rotor body. The retaining rings can be made of either magnetic or non-magnetic material. For the 18Mn-5Cr type non-magnetic rings which are vulnerable to moisture and failure by stress corrosion cracking, inspection would consist of a surface examination (penetrant testing) and ultrasonic testing (rings in place on rotor). For other type rings which have minimal threat of failure from stress corrosion cracking, inspection would consist of a surface examination (penetrant).

An angle-beam (typically 45°) shear wave transducer is used to perform the ultrasonic examination. The ring is scanned with the beam oriented axially in two directions and circumferentially in two directions, each 180° apart.

RETAINING RINGS - UNIT 2

The Unit 2 generator retaining rings are magnetic and are not susceptible to the stress corrosion cracking threat from moisture that causes concern for the 18Mn-5Cr material. The retaining ring material is reportedly AISI 4340 which is nominally 0.40C-1.8 Ni-0.8Cr-0.25Mo that is capable of achieving the high strength levels required for retaining rings by appropriate heat treatment. The rings were penetrant tested during the outage. No defects were reported and the rings are suitable for return to service.

ATTACHMENT 4.7.1 and ATTACHMENT 4.7.2 shows the results of the visual and penetrant testing, respectively.

NONDESTRUCTIVE TESTING EXAMINATION REPORT

PLANT CTPS / DVC LOCATION CHANDRAPURA UNIT 2 DATE AUG. 13, 1994

TYPE OF EXAMINATION MT PT UT VT X ET HT

ITEM SECTION OR STAGE	LOCATION OR BLADE No.	INDICATIONS
GENERATOR	RETAINING RING EXCITER END	N.A.D.
GENERATOR	RETAINING RING TURBINE END	N.A.D. Except for a few small dent marks on the coupling side edge at hole No. 12 position and one small dent mark on the other edge of the same ring between coupling hole position 10 and 11.
HP / IP	4 Nos. LOWER CONTROL VALVE SEATS	N.A.D.

ATTACHMENT 4.7.1

NONDESTRUCTIVE TESTING EXAMINATION REPORT

PLANT CTPS LOCATION CHANDRAPURA UNIT 2 DATE AUG. 5, 1994

TYPE OF EXAMINATION MT PT X UT VT ET HT

ITEM SECTION OR STAGE	LOCATION OR BLADE No.	INDICATIONS
GENERATOR	RETAINING RINGS	GENERATOR END RING - N.A.D. TURBINE END RING - N.A.D.

ATTACHMENT 4.7.2

Metallurgical

4.8

Executive Summary

The metallurgical investigation consisted of alloy identification, hardness measurements, and microstructural characterization using plastic replication.

The alloy identification was performed by BHEL using an xray fluorescence instrument made by Texas Nuclear with results as shown in Attachment 4.8.1. Since the explicit material specifications were generally not known, the basis for comparison is the general practice used by General Electric for steam turbines fabricated in the 1960s era as shown in the following table:

Description	Similar Alloy	Nominal Composition
Low-Pressure Rotor	ASTM A293 Cl 3	2Ni-0.5Mo
Reheat Rotor, High-Pressure Rotor	ASTM A293 Cl 6	1Cr-1.25Mo-0.25V
Outer & Intermediate Shells, Intercept Valve Casing, First-Stage Nozzle, Stop Valve Casing, High-Pressure Inner Shell & Steam Chest, Steam Inlet Flanges	ASTM A389 Gr C24	1Cr-1Mo-0.25V
High Pressure Pipes	ASTM A405	1Cr-1Mo-0.2V
Nuts, Studs, & Washers	ASTM A193 B16	1Cr-0.5Mo-0.2V
Inlet, Intermediate, & Inner Shell Studs, Buckets, and Cover Stock	AISI Type 422 SS	12Cr-1Ni-1Mo-1W-0.25V
Reheat Valve Casing		1Cr-1Mo

Except for the IP Inner Cylinder, all the readings in Attachment 4.8.1 appear to match reasonably well to the GE practice. For the IP Inner Cylinder, there is either a recording error, an instrument error, or the component is nominally carbon steel. Considering the service duty for this component, carbon steel would be an adequate material and the ambiguity is no cause for concern.

Attachment 4.8.2 indicates that Vickers hardness is in the expected range for bolting and casings with implied tensile strengths of 125-150 ksi (860-1030 MPa) for bolting and around 80 ksi (550 MPa) for the HP/RH casing. The implied tensile strength of the generator retaining rings is in the range of 150-195 ksi (1030-1340 MPa) which is reasonable for magnetic rings. The retaining rings showed small areas of flame impingement from heating in prior installation or removal operations. Hardness measurements showed these areas of flame impingement to be slightly harder, most likely from secondary hardening. Plastic replicas showed only subtle

microstructural differences between the impingement areas and unaffected areas. The rings are judged suitable for return to service.

Hardness measurements made on the HP/IP rotor and disk and the LP rotor and disk show comparable values among all components with an implied tensile strength range of 112-131 ksi (770-900 MPa) as shown in Attachment 4.8.4. Similarly, the main steam stop valve, reheat stop valve, and intercept valve bodies all show comparable hardness levels with an implied tensile strength range of 110-125 ksi (760-860 MPa) as shown in Attachment 4.8.5.

Plastic replicas were taken on thirteen sites and an interpretation of the microstructures is shown in Attachment 4.8.6. In all cases, the microstructures are within the normal limits expected for the components examined with no substantial degradation due to service exposure. The microstructures indicate all components can continue operation with the expectation of long remaining life.

BHARAT HEAVY ELECTRICAL LIMITED

Corporate Research and Development Division, Hyderabad 500 593

Chemical Analysis Using Texas Nuclear Alloy Analyser (TNAA)-Model 9266

Site: Chandrapura Thermal Power station

Unit: II

COMPONENT AND LOCATION	GRADE	Cr%	Mo%	V%	Ni%	Ti%	OTHERS
ROTOR HP SIDE		1.33	1.38	0.26	0.55		
ROTOR IP SIDE		1.3	1.2	0.3	0.6		
REHEAT VALVE		1.16	1.06				
INTERCEPTOR VALVE		1.18	1				
MAIN STEAM STOP VALVE		0.98	1.01				
HP OUTER CYLINDER		1.17	1.03				
HP OUTER CYLINDER No. 1		0.97	1.05				
HP OUTER CYLINDER No. 2		1.02	1.08				
HP INNER CYLINDER No. 1		1.25	0.94	0.2			
HP INNER CYLINDER No. 2		1.31	1	0.17			
IP INNER CYLINDER No. 1		1.2	1.03				
IP INNER CYLINDER No. 2		0.17					
HP CYLINDER STUD No. 55		1.08	0.48	0.25			
HP CYLINDER STUD No. 63		1.16	0.44	0.22			
HP CYLINDER STUD No. 69		11.7	1.03	0.2	0.82		1.26 W
HP CYLINDER STUD No. 71		12	1.1	0.2	0.73		1.13 W
LP ROTOR			0.48	0.2	2.31		

Date: 8/8/94

G. Jayaraman

ATTACHMENT 4.8.1

NONDESTRUCTIVE TESTING EXAMINATION REPORT

PLANT CTPS LOCATION CHANDRAPURA UNIT 2 DATE JUNE 8, 1994

TYPE OF EXAMINATION MT PT UT VT ET HT X

ITEM SECTION OR STAGE	LOCATION OR BLADE No.	No.	HARDNESS (HV)					
HP / RH	OUTER CYLINDER STUDS	30 27	325 330	320 300	300 280	300 300	320 285	
"	"	25 23	355 295	330 300	335 300	330 305		
"	CASING	N/A	170	174	162	172	166	172
"	STUDS (TOP)	N/A	280 275	290 280	295 280			
HP	INNER TOP 2nd GROVE	N/A	236	238	250			
"	INNER BOTTOM	N/A	270	275	290	280		
"	"	52 60	295 285	295 290	305 275			
"	"	63 65	295	285	285			
"	"	69 71	300 295	285 310	265 285	265 285	290	295
"	TOP	T-13 T-15	260 310	280 285	275 285	275 275	275 305	280

ATTACHMENT 4.8.2

NONDESTRUCTIVE TESTING EXAMINATION REPORT

PLANT CTPS LOCATION CHANDRAPURA UNIT 2 DATE JUNE 8, 1994

TYPE OF EXAMINATION MT PT UT VT ET HT X

ITEM SECTION OR STAGE	LOCATION OR BLADE No.	HARDNESS (HV)						
RETAINING RING	GENERATOR END	410 X	390 X	390	355	360	345	
		355	345	380 X	380 X	335	345	
	GENERATOR END (cont)	350						
		The numbers with a (x) next to it had localized spots due to burner placement.						

ATTACHMENT 4.8.3

NONDESTRUCTIVE TESTING EXAMINATION REPORT

PLANT CTPS LOCATION CHANDRAPURA UNIT 2 DATE JUNE 8, 1994

TYPE OF EXAMINATION MT PT UT VT ET HT X

ITEM SECTION OR STAGE	LOCATION OR BLADE No.	HARDNESS (HV)					
HP	ROTOR	250	265	265	256		
HP	DISC	265 254	250 265	280 260	268 LAST	258	CURTIS WHEEL
IP	ROTOR	256	246	250			
IP	DISC FIRST	246	245	250	285		
LP	ROTOR	254	250	256	260	258	
LP	DISC FIRST	260	246	254			

ATTACHMENT 4.8.4

NONDESTRUCTIVE TESTING EXAMINATION REPORT

PLAN CTPS LOCATION CHANDRAPURA UNIT 2 DATE JUNE 8, 1994

TYPE OF EXAMINATION MT PT UT VT ET HT X

ITEM SECTION OR STAGE	LOCATION OR BLADE No.	HARDNESS (HV)			
MAIN STM. STOP VALVE	BODY	248	268	250	248
REHEAT STOP VALVE	BODY	234	236	260	236
INTERCEPT VALVE	BODY	256	260	255	260

ATTACHMENT 4.8.5

NONDESTRUCTIVE TESTING EXAMINATION REPORT

PLA CTPS / DVC LOCATION TURBINE UNIT 2 DATE OCT. 8, 1994

TYPE OF EXAMINATION MT PT UT VT ET HT
X REPLICATION/METALLOGRAPHY

ITEM SECTION OR STAGE	LOCATION OR BLADE No.	REPLICATION / METALLOGRAPHY
MAIN STEAM. STOP VALVE (LHS)	I.D. SURFACE NEAR TOP # 12	Upper bainite and ferrite with very fine size and spheroidization of carbides. No cavities or cracks.
INTERCEPTOR VALVE (LHS)	I.D. SURFACE NEAR TOP # 10	Upper bainite and ferrite. No significant degradation.
REHEAT STOP VALVE (LHS)	I.D. SURFACE NEAR TOP # 11	Predominantly upper bainite with some amount of acicular ferrite. No appreciable degradation. Free from GB cavities and cracks.
MAIN STEAM PIPE FLANGE WELD (LHS)	COVERING, PIPE SIDE HAZ # 8	Pipe parent metal - predominantly ferrite with some coarse carbides at the grain boundaries weld metal. Upper bainite and acicular ferrite. No cavities or cracks observed including HAZ region.
REHEAT STM. PIPE WELD JOINT (LHS)	COVERING, PIPE SIDE HAZ # 9	Pipe parent metal - predominantly ferrite with some coarse carbides at the grain boundaries weld metal. Upper bainite and acicular ferrite. No cavities or cracks observed including HAZ region.
MAIN STEAM TURBINE LEADS	BETWEEN FLANGE AND SHELL. # 2 CLOSE TO SHELL # 3 CENTRAL	Predominantly ferrite with a few coarse carbides. Surface appears to have been decarburized presumably during original heat treatment.
HP TURBINE INNER CYLINDER	HORIZONTAL FACE COVERING. CRACK ON THE RADIAL STRUT. # 4	Crack is transgranular with filled-in oxide. Structure predominantly ferrite with some reminiscence of bainite. Baintic carbides appeared to have diffused to the GB's.
HP TURBINE INNER CYLINDER # 13	CIRCUMFERENTIAL CRACK OF STAGE No.2 DIAPHRAGM LOCATING GROOVE	Cracks were also observed in axial direction initiating from the original circumferential crack. Other structural features same as above.
CONTROL VALVE (UPPERS)	I.D. SURFACE NEAR TOP OF (RHS) VALVE. # 1	Upper bainite and ferrite. No appreciable degradation except for some spheroidization of carbides.
HP ROTOR	GROOVE A BEFORE STAGE ONE. CURTIS WHEEL COVERING CRACK. # 5	Predominantly upper bainite and acicular ferrite. No cognizable degradation in microstructure except for transgranular discontinuous cracks observed with filled-in oxides and blunt crack fronts (thermal fatigue crack).
HP ROTOR	FLAT SHAFT PORTION BEFORE CURTIS WHEEL GROOVE. # 6	Predominantly upper bainite with acicular ferrite. No cognizable degradation.
HP ROTOR	SECOND GROOVE (C) BEFORE STAGE TEN. # 7	Transgranular discontinuous cracks filled-in oxide and blunt crack fronts and thermal fatigue cracks. Microstructural features same as above.
		Note: # indicates replica numbers

ATTACHMENT 4.8.6

Chapter 5.0

Plans to Address Liabilities and Recover Capacity

Section 5.1

Recommended Solutions

Recommended Solutions

5.1

At the conclusion of the site work at CTPS, a 240 page report titled "Condition Assessment Summary Report - Chandrapura Thermal Power Station Unit 2 - Damodar Valley Corporation" was issued with a report date of August 19, 1994. Copies of this report were made available to PFC, NTPC, BHEL, and DVC/CTPS. A close-out meeting with all the parties involved was held at BHEL headquarters in New Delhi on August 22, 1994 to discuss the findings and develop a plan to address the liabilities identified in the assessment. As an outgrowth of the meeting, a "Task Team of Indian Specialists" from PFC, NTPC, BHEL, and DVC/CTPS was formed to evaluate the various options and select those that were identified as most cost-effective for the constraints appropriate to the Indian situation. The Task Team members were as follows:

PFC	R. K. Gupta
NTPC	Chandan Roy
BHEL	L. Nagarajan
DVC/CTPS	G. K. Upadhyay

The Task Force met several times between August - November, 1994 and issued a "preliminary" report in early November, 1994. Two members, Messrs Nagarajan and Upadhyay, visited the staff at TVA from November 28 - December 2, 1994 for in-depth discussions on points of agreement and disagreement between the Task Force report and the TVA report. The goal of the meetings was to reach a set of "consensus recommendation" which would form the basis for future planning for CTPS unit 2. Tables 5.1.1 to 5.1.5 summarize the initial TVA recommendations, the Task Team review, and the TVA/Task Team consensus recommendations.

It should be emphasized that TVA did not perform an independent financial analysis or critically evaluate the assumptions and analysis methods in the Task Team techno-economic evaluation. In broad terms, the Task Team sought to select the options that gave an "internal rate of return" that was favorable for the Indian economic environment, which is essentially the same approach used by TVA to justify capital improvements. From TVA's standpoint, reasonability and sanity checks were made subjectively based on the discussions and interactions between TVA experts and members of the Task Team. Therefore, TVA is confident that the consensus recommendations form a strong basis for addressing liabilities and the restoration of capacity at CTPS unit 2.

Table 5.1.1 Recommendations for the Boiler and Auxiliary Systems

No.	Component & Problem Statement	TVA Initial Recommendations	Task Team Review	Consensus TVA/Task Team Recommendation
1.0	Primary S.H. Outlet Header and Stub Tubes Cracking	<ul style="list-style-type: none"> - Weld Repair Tee & Tube Cracks - Replace Tee Sections & Weld Repair Stub Tube Cracks - Replace Entire Header and Stub Tubes In Kind - Replace Entire Header and Stub Tubes with an Upgrade to P22 Header Material and T22 Stub Tubes 	Replace Entire Header & Tubes With the Spares Available with DVC Which are P11 Pipe and T11 Tube Material.	Replacement with P11/T11 Acceptable Provided Backpass Surface Modifications and Restoration of HP Heater Brings Metal Temperature to Intended Level (about 524C (976F Max)). Otherwise P22/T22 Advised .
2.0	Economizer Inlet Header			
	Stub Tubes and Header Cracking	<ul style="list-style-type: none"> - Weld Repair Stub Tubes with Indications - Weld Repair All Stub Tubes In Area of Cracking - Replace Stub Tubes That Are Cracked - Replace All Stub Tubes 	Replace All Stub Tubes During Current Overhaul	Replace All Stub Tubes During Current Overhaul
	Rigid Attachments of Header to Side Wall Does Not Permit Relative Movement	Redesign of the Attachment	Clarifications to Be Sought from TVA	Review of Similar CE Units in TVA Shows a Similar Rigid Attachment to Sidewall. However, Lower Tubes Were Allowed to "Float" to Accommodate Vertical Expansion. Drawings Are Unclear on this Question for CTPS. Long-Term Resolution Should Be Reached with OEM. Elimination of Fire-Outs May Resolve the Problem.
	Header Loading Due to Outside Valve	Improvement in the Support	Improvement in the Support	Improvement in the Support

No.	Component & Problem Statement	TVA Initial Recommendations	Task Team Review	Consensus TVA/Task Team Recommendation
3.0	Excessive Internal Deposits in Platen Waterwall Tubes	Acid Cleaning	Deposits to be Examined for Recommendations	Acid Cleaning Being Performed this Outage. The TVA Criteria for Initiating an Acid Clean Is $\geq 15 \text{ Mg/Ft}^2$ in Water Walls. Under this Criteria, Acid Cleaning Typically Occurs Every 3-7 Years. CTPS 2 Was Last Acid Cleaned 10 Years Ago.
4.0	Fuel Processing System			
	High Coal Moisture	<ul style="list-style-type: none"> Change Coal Pile Management from Bottom Grate Loading to Stacker Reclaimer Install Truck Ramp and Truck Tippler 	<ul style="list-style-type: none"> Stacker Reclaimer Installation Is Recommended. DVC to Take up this Job Departmentally on Short Term Basis 	<ul style="list-style-type: none"> Stacker Reclaimer Installation Is Recommended. DVC to Take up this Job Departmentally on Short Term Basis
	Frequent Exhauster Spider Outage	<ul style="list-style-type: none"> Establish Rebuild Process in DVC Replace Blades with Ceramic Lined Blades 	<ul style="list-style-type: none"> A Short Term Recommendation If Milling System Is to Be Replaced DVC to Try Ceramic Blades in One of the Mill Exhausters 	<ul style="list-style-type: none"> To Achieve 140mw, Milling System Will Have to Be Replaced. In the Interim, a Rebuild Process Is Still Advised To Achieve Adequate Flatness for Ceramic Tiling, a New Spider Will Have to Be Bought. Existing Spiders Too Distorted to Convert to a Ceramic Lined Blade
	Low Design Selection Temperature for Coal Conditions	Reduction of Moisture to 7 & 8%	Reduction of Moisture to 8% Not Practical; 15% Is More Realistic. However DVC to Confirm.	DVC Concur That 8% Not Achievable. Raising Mill Inlet Temperature Will Partially Accommodate High Moisture Backpass Surface Modifications and Restoration of HP Heater to Raise Temperature Essential to Accommodate 12-15% Moisture.

No.	Component & Problem Statement	TVA Initial Recommendations	Task Team Review	Consensus TVA/Task Team Recommendation
4.0	Low Air-Preheater Outlet Temp	Redesign Second Pass Pressure Parts	Study/Performance Test Needs to Be Carried out Before Giving Final Recommendations.	Redesign of Second Pass to Address this Problem. Redesign Should Consider Effect on APH, ESP, Other Boiler Surfacing, and ID Fans and Properly Resolve Any Issues.
5.0	Air Preheater			
	Air Preheater Blockage	Change Air Preheater Hot Basket to a Dual Basket Design	Change Air Preheater Hot Basket to a Dual Basket Design	Change Air Preheater Hot Basket to a Dual Basket Design
	Soot Blowers Not Available	Reactivate Soot Blowing System	Reactivate Soot Blowing System	Sootblow with Superheated Steam (Not Saturated Steam)
6.0	Coal Mills and Feeders			
	Coal Mills Undersized	<ul style="list-style-type: none"> - Convert Existing Mills to Pressurized Mill Operation of Higher Capacity. - Upgrade Existing Mill Capacity by Modifying the Internals. - Replace Milling System with RP Bowl Mills or Ball & Race Mills. 	Replace Existing Mills with Pressurized Mills of 31 Tonnes per Hour Capacity.	Pressurized Mill with Capacity Adequate to Achieve 140mw (4 Mills) with 12-15% Moisture Coal Is Recommended.
	Coal Flow Interruptions	<ul style="list-style-type: none"> - Provide Bunker Lining with SS - Increase Bunker Opening. 	Only Bunker Lining Should Be Provided	<ul style="list-style-type: none"> - Provide Bunker Lining with SS - Bunker Opening Will Be Considered in the Mill Capacity Increase.
7.0	Coal Handling System			
	Coal Storage Area	<ul style="list-style-type: none"> - Cleaning of Coal Area Required - Tippler to Be Installed - Install a Silo Over Main Hopper Area. - To Be Studied by a Coal Yard Specialist. 	Complete Coal Handling System to Be Evaluated by a Specialist for Upgrades and Implementation Plan	Complete Coal Handling System to Be Evaluated by a Specialist for Upgrades and Implementation Plan
8.0	Ash Handling System	Redesign Discharge Pump and Piping System for Slower Speed Pumps & Higher Size Discharge Pipeline	DVC to Take up Feasibility Study Followed by Implementation Plan	DVC to Take up Feasibility Study Followed by Implementation Plan

No.	Component & Problem Statement	TVA Initial Recommendations	Task Team Review	Consensus TVA/Task Team Recommendation
9.0	Fuel Burner System			
	Burner Alignment	Redesign Burner Wind Box & Install New Burner System with Automatic Tilt Mechanisms and Controls	<ul style="list-style-type: none"> - Redesign Complete Milling System along with Burner System, Windbox and SADC System. - Performance Evaluation Test of the Unit to Be Carried Out Prior to Redesign 	Redesign Complete Milling System along with Burner System, Windbox and SADC System.
	Mill Air Flow Control	Engineer and Install New Mill Air Flow Control	No Comment	Redesign of Pressurized Milling System Should Address this Consideration
	Lack of Secondary Air Distribution Control (SADC) System	Engineer and Install SADC System	No Comment	Redesign of Pressurized Milling System Should Address this Consideration

Table 5.1.2 Recommendations for the Turbine and Auxiliary Systems

No.	Component & Problem Statement	TVA Initial Recommendations	Task Team Review	Consensus TVA/Task Team Recommendation
1.0	HP/IP Rotor O.D. Groove Cracking	<ul style="list-style-type: none"> - Quantify the Severity of the Thermal Shock - Minimize the Number of Fireouts - OD Groove Cracks Should Be Machined out and Increased Groove Radii to Minimize Stress Concentration Effects - Procure or Refurbish One HP/IP Spare Rotor 	<ul style="list-style-type: none"> - No Comment - Install Burner Management System and Flame Scanners to Minimize Flame Outs - Groove Cracks to be Machined Out and Geometry Contoured as Recommended by OEM - One HP/IP Spare Rotor to be Kept 	<ul style="list-style-type: none"> - A Combined Experimental and Analytical Solution Is Needed. TVA Does Not Have the Expertise to Precisely Solve this Problem. Engagement of OEM Probably Needed. - Minimize the Number of Fireouts - Groove Cracks to be Machined Out and Geometry Contoured as Recommended by OEM - One HP/IP Spare Rotor to be Kept
2.0	HP Inner Cylinder Inlet Bowl Strut Cracking	<ul style="list-style-type: none"> - Leave Cracks and Reinspect After Five Years - Minimize Number of Flame Outs - Install Thermocouples for Turbine Metal Temperature Measurement 	<ul style="list-style-type: none"> - Leave Cracks and Reinspect After Five Years - Minimize Number of Flame Outs - Install Thermocouples for Turbine Metal Temperature Measurement 	<ul style="list-style-type: none"> - Leave Cracks and Reinspect After Five Years - Minimize Number of Flame Outs - Install Thermocouples for Turbine Metal Temperature Measurement
3.0	Damaged L-0 & L-1 Blades of LP Rotor at Generator End	Refurbish Blades by Weld Repair	Replace Damaged Blade Row	Either Refurbish or Replace Blades is Acceptable
	Damaged L-2 Covers (Shrouds) in Rotor at Generator End	Replace the Damaged Covers	Replace the Damaged Covers	Replace the Damaged Covers
4.0	Efficiency Loss Based on Calculations in Steam Path Audit	Replace Packings and Clean Turbine	Replace Packings and Clean Turbine	<ul style="list-style-type: none"> - Replace Packings and Clean Turbine - In Addition, Water Treatment and Control Should Be Closely Maintained to Minimize Deposits, Especially Silica.
5.0	Cooling Water System			

No.	Component & Problem Statement	TVA Initial Recommendations	Task Team Review	Consensus TVA/Task Team Recommendation
5.0	Degradation of Cooling Tower Efficiency Due to Inadequate Air Flow	<ul style="list-style-type: none"> - Increase Blade Angle to Design Value - Change Fan Speed 	Performance Test of the Cooling Tower Recommended after Attending to the Fill Blockage Cleaning and Blade Angle Adjustment.	Performance Test of the Cooling Tower Recommended after Attending to the Fill Blockage Cleaning and Blade Angle Adjustment.
	Blockage of Fills	<ul style="list-style-type: none"> - Manual Cleaning with High Pressure Water - Removal of Fills and Cleaning - Replace Fills and Install Chemical Dosing 		
6.0	Poor Availability of Boiler Feed Pumps	<ul style="list-style-type: none"> - Carry out R.L.A. Of Each BFP - Order Two Spare Cartridges and Shafts - Regular Condition Monitoring on All Pumps - Refurbish Existing Cartridges Indigenously 	All Three Pumps on Unit 2 to Be Replaced by New Pumps and Old Pumps to Be Refurbished and Used on Unit 1	All Three Pumps on Unit 2 to Be Replaced by New Pumps and Old Pumps to Be Refurbished and Used on Unit 1
7.0	Regenerative System			
	Low Economizer Inlet Temperature	<ul style="list-style-type: none"> - Retubing HP Heaters with SS Tubes - Changing the Complete Tube Nest - Install New HP Heaters 	<ul style="list-style-type: none"> - Retubing HP Heaters with SS Tubes - Changing the Complete Tube Nest - Install New HP Heaters 	<ul style="list-style-type: none"> - Retubing HP Heaters with SS Tubes - Changing the Complete Tube Nest - Install New HP Heaters
8.0	Low Purity of Oil in Lube Oil System	<ul style="list-style-type: none"> - Relocate Oil Drain Piping in LP Casing - Modify Piping Arrangement of Vapor Extractor 	<ul style="list-style-type: none"> - Relocate Oil Drain Piping in LP Casing - Modify Piping Arrangement of Vapor Extractor 	<ul style="list-style-type: none"> - Relocate Oil Drain Piping in LP Casing - Modify Piping Arrangement of Vapor Extractor
9.0	High Energy Piping			
	Main Steam Hangers	<ul style="list-style-type: none"> - Readjust Hangers - Replaced Overstressed Bolts 	<ul style="list-style-type: none"> - Readjust Hangers - Replaced Overstressed Bolts 	<ul style="list-style-type: none"> - Readjust Hangers - Replaced Overstressed Bolts
	Main Steam Pipe Supports	Replace Three (3) Overstressed Bolts	Replace Three (3) Overstressed Bolts	Replace Three (3) Overstressed Bolts
	Hot Reheat Pipe Supports	Replace Six (6) Supports	Replace Six (6) Supports	Replace Six (6) Supports

Table 5.1.3 Recommendations for the Generator

No.	Component & Problem Statement	TVA Initial Recommendations	Task Team Review	Consensus TVA/Task Team Recommendation
1.0	Stator	<ul style="list-style-type: none">- Replace Bushing Insulators- Introduction of Clarified Water in Place of Raw Water in Hydrogen Gas Coolers- Generator Protection System is Inadequate	<ul style="list-style-type: none">- Replace Bushing Insulators- Introduction of Clarified Water in Place of Raw Water in Hydrogen Gas Coolers- TVA to Review Generator Protection System and to Give Recommendations	<ul style="list-style-type: none">- Replace Bushing Insulators- Introduction of Clarified Water in Place of Raw Water in Hydrogen Gas Coolers- DVC to Document Protection Scheme and Provide Drawings for TVA Review

Table 5.1.4 Recommendations for Electrical/Mechanical Systems

No.	Component & Problem Statement	TVA Initial Recommendations	Task Team Review	Consensus TVA/Task Team Recommendation
1.0	Useful Life of Power and Control Cables is Over	Systematic Replacement of Power and Control Cables	Power and Control Cable to be Replaced in Phases	Power and Control Cables to Be Replaced in Phases. TVA Recommends That Equipment Be Procured for a Low Voltage Test (Biddle Instrument)
2.0	Coal Conveyor System	Conveyer Belts Should be Checked for Potential Problems	Conveyer Belts Should be Checked for Potential Problems	Conveyer Belts Should be Checked for Potential Problems

Table 5.1.5 Recommendations for the Instrumentation and Control Systems

No.	Component & Problem Statement	TVA Initial Recommendations	Task Force Review	Consensus TVA/Task Force Recommendation
1.0	I&C System	<ul style="list-style-type: none"> - Following Loops to Be Put on Automatic <ul style="list-style-type: none"> • Air Flow Control • Draft Control • Mill Temp Control • Superheater Temp Control • Feed Water Control • Interface Boiler and Turbine Controls However Maximum Auto Loops to Be Made Operational - Recalibrate Feeder Controls to 25% Min Speed - Install Oil Guns at Cd Elevation - Install Burner Management System - Install Flame Detection System - Install Automatic Safety Interlocks and Trips of the Unit - Isolate Control and Instrumentation Air from Service Air System 	<ul style="list-style-type: none"> - Install Complete Burner Management System - Automatic Control Loops in Boiler and Turbine to Be Made Operational - Augment Compressed Air System for Instrument Air - Data Acquisition/Sequence of Event Recorder System to Be Installed - Upgrade Turbovisory System 	<p>TVA Recommendation Was Basically to Restore Pneumatic Control System to Operational Status.</p> <p>The Task Force Recommended a Modernized System. If 140mw Is Achieved, a Modernized System Will Definitely Be a Cost Effective Asset.</p>

Section 5.2

Cost Estimate to Recover Capacity

Cost Estimate to Recover Capacity

5.2

As previously stated, the 140MW units 1 - 3 at CTPS have typically produced 80 - 90MW for most of their operational period. At the time of initiation of the current project, the intent was to perform a demonstration "remanent life assessment " or "condition assessment." However, as awareness of the lost capacity emerged from the initial check of records, it became apparent that a major benefit would accrue to DVC if partial or full capacity could be restored.

US experts from TVA and ABB-CE and India experts from PFC, NTPC, BHEL, and DVC/CTPS focussed on identifying the reasons for lost capacity and developing cost-effective solutions for restoration of capacity. Table 5.2.1 is a summary list of remedial measures to recover full capacity and the associated cost estimate in Indian currency (Crores of Rupees is equivalent to 10,000,000 Rupees). These cost estimates were developed by the Task Team of Indian Specialists and will undoubtedly change some as hard figures are obtained for effecting the improvements. The cost to regain approximately 50MW of capacity is on the order of twenty percent of new construction. Hence, the restoration of capacity for CTPS unit 2 is technically viable and economically attractive.

Table 5.2.1 Cost Estimates for CTPS Unit 2 for Recovery of Capacity to 140MW

Area	Activity	Purpose	Cost Rs (Cr)	Sub Total (Cr)
Boiler and Auxiliaries	Back Pass Pressure Parts Modification	- Reliability - Partial Capacity Recovery	4.0	
	Replace With Pressurized Milling System, Upgrade Soot Blowing System, Add Two Addl. Burner Oil Elev. Add HEA, BMS & SADC Controls	- Capacity Recovery to 140MW - Reliability - Safety	36.0	
	Replace Higher Capacity ID Fans	- Reliability - Capacity Recovery	3.0	43.0
Turbine and Auxiliaries, High Energy Piping	Add HP Heaters, Three Boiler Feed Pumps, Two Condensate Extraction Pumps. Repair Piping Hangers & Supports	- Efficiency - Capacity Recovery - Reliability	16.0	16.0
Controls & Inst.	Replace Station Controls, Add Data Acquisition System, And Sequence of Events Recorder	- Life Extension - Operations Savings - Safety - Reliability	10.0	10.0
Electrical & Cooling Water System	Cables & Electrical Systems Identified by TVA for Replacement, Upgrade Cooling Water System Install Generator Protection System	- Reliability - Safety	3.0	3.0
Civil Works	Included in Individual Projects. Foundation Adequacy for Upgrade to Pressurized Mill Must by Investigated.			
Coal Handling System	Add Stacker Reclaimer, Silos, And Rock Removal Systems	- Reliability - Capacity Recovery - Minimize Flame Outs	5.0	5.0
Ash Handling System	High Capacity/Low RPM Pumps And Larger Transfer Lines	- Reliability - Capacity Recovery	2.0	2.0
Incidental	Contingency Funds @3%		3.0	3.0

Grand Total 82.0

HEA - High Energy Arc Ignitors (Replaces Oil Ignitors)

BMC - Burner Management System

SADC - Secondary Air Distribution Controls

Note: DVC must investigate the need to Augment ESP And Monitoring System