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Energy Conversion and Management 47 (2006) 1247–1263

ENERGY CONVERSION & MANAGEMENT

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Effect of water side deposits on the energy performance of coal fired thermal power plants

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Received 7 July 2004; received in revised form 20 January 2005; accepted 28 July 2005
Available online 28 September 2005

Abstract

This paper presents the effects of water side deposits in the 210 MW coal fired thermal power plant components (viz., boiler, turbine, feed water heaters, condensers and lube oil coolers) on the energy efficiency of these components and that of the overall system at 100% maximum continuous rating (MCR). The origin, composition and rate of build up of deposits on the water side are presented. A linear growth rate of deposits is assumed for simplicity. The effects of the reduction in heat transfer, increased pressure drop and increased pumping power/reduced power output in the components are quantified in the form of curve fits as functions of the deposit thickness (μm). The reduction in heat transfer in the boiler components is in the range of 0.2–2.0% under normal scaling. The increased pumping power is of the order of 0.6–7.6% in the boiler components, 29% in the BFP circuit, 26% in the LPH circuit, 21% in the HPH circuit and 18% in the lube oil cooler circuits. The effects on the overall coal fired plant is quantified through functional relations between the efficiencies and the notional deposit thickness. The sensitivity indices to the notional deposit thickness are: boiler efficiency: −0.0021% points/μm, turbine circuit efficiency: −0.0037% points/μm, auxiliary power efficiency: −0.00129% points/μm, gross overall efficiency: −0.0039% points/μm and net overall efficiency: −0.0040% points/μm. The overall effect of scale build up is either increased power input of ~68 kW/μm (at a constant power output) or decreased power output ~25 kW/μm (at a constant power input). Successful contaminant control techniques are highlighted. Capacity reduction effects due to water side deposits are negligible.

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0196-8904/$ - see front matter © 2005 Published by Elsevier Ltd.
doi:10.1016/j.enconman.2005.07.002

Keywords: Water side deposits; Scaling; Heat transfer; Pressure drop; Boiler efficiency; Turbine efficiency; Gross overall efficiency; Net overall efficiency; Contaminant control

1. Introduction

Contamination control in thermal power plants is a stringent operational requirement that is essential for managing the power plant assets optimally. The main water contamination (demineralized water, bearing cooling water and auxiliary cooling water) results from:

(a) Inadequately treated water streams originating from poor quality of input stream, operation/maintenance problems of water purifying/transferring/pumping equipment, inability to handle transients, damaged moisture separators/deaerator/spray nozzles etc.
(b) In leak of condenser cooling water into demineralized water stream.
(c) In leak of raw water into auxiliary cooling water stream.
(d) Boiler carryover (physical entry of chemicals into steam during evaporation).
(e) Boiler hideout (deposition of chemicals used for contaminant control).
(f) Corrosion products of copper alloys from the pre-boiler systems (feed water heaters and condenser).
(g) Injection of main and reheat sprays into steam for attemperation.

Water contamination results in scaling (crystallization of dissolved substances from the flowing fluid onto the flow surfaces) on internal surfaces of the water/steam pressure parts of the boiler, turbine, regenerative feed water heaters, condenser, lube oil coolers etc. Deposit build up primarily depends on the water/steam composition, flow velocities (optimal velocities [1]: 0.5–4.0 ms^{-1} for water, 20–50 ms^{-1} for saturated steam and 40–80 ms^{-1} for superheated steam), tube substrate and the temperature of operation. As a rule of thumb, in power plant practice, deposits up to 100 μm are considered as inconsequential. Deposits in the range 100–300 μm are designated as moderate. Deposits in excess of 300 μm are viewed as desirous of attention for clean up for sub-critical boilers. For supercritical boilers, the upper limit between clean up intervals is 150 μm [2].

The characteristic properties of water side deposits can be represented by the ratio [3],

$$\phi = [\text{volume of deposit/volume of metal destroyed}]$$

If $\phi < 1$, the deposit is porous and useless. If $\phi > 2$, internal stresses tend to rupture it, causing uneven deposition with no benefit towards corrosion protection. If $1 < \phi < 2$, it is capable of providing corrosion resistance, but the effect is offset by the reduction in heat transferring capacity.

The effects of deposition can be quantified as follows:

- Decreased heat transfer in the boiler, feed heaters, turbines, condenser, auxiliaries and secondary cooling circuits. The thermal conductivity of heat exchanger tubing of thermal plants [4] is as follows:
    - Carbon steels: 28–32 $\mathrm{W\,m^{-1}\,K^{-1}}$.
    - Alloy steels: 24–30 $\mathrm{W\,m^{-1}\,K^{-1}}$.

Nomenclature

A	area of heat transfer (m^2)
$A_o, \ldots, A_2$	constants in curve fits
AR	area ratio (dimensionless: 0–1)
B_0, B_1	constants in curve fits
BFP	boiler feed pump
C	conversion factor (1E−06 if the scale thickness in μm; 1E−03 if it is in mm)
CON	condenser
d	tube inside diameter (mm)
D_0, D_1	constants in curve fits
ECO	economizer
f	fraction
F	Fanning friction factor (dimensionless)
HPH	high pressure regenerative feed water heater
HPT	high pressure turbine
IPT	intermediate pressure turbine
LMTD	log mean temperature difference
LOC	lube oil cooler
LPH	low pressure regenerative feed water heater
LPT	low pressure turbine
LTSH	low temperature superheaters
MCR	maximum continuous rating (MW)
p	pressure (MPa)
P	power input/output (kW or MW)
ppb	parts per billion
ppm	parts per million
Q	rate of heat addition (MW_t)
RH	reheater
SH	superheaters
T	temperature (°C)
t	time (h)
THR	turbine heat rate (kJ/kW h)
TUR	overall steam turbine
U	overall heat transfer coefficient ($W\,m^{-2}\,K^{-1}$)
WW	water walls
X	independent variable
Y	dependent variable

Greeks

δ	thickness (tube, deposit etc.) (μm)
ε	surface roughness (mm)

η	efficiency (dimensionless or %)
λ	thermal conductivity ($\mathrm{W\,m^{-1}\,K^{-1}}$)
ϕ	ratio of volume of deposit to volume of metal destroyed (dimensionless)

Subscripts

a	area affected by scaling/deposits
A	auxiliary
B	boiler
e	electric
fg	flue gas
G	generator
m	mechanical
N	net
o	clean condition (without deposit)
O	gross overall
s	scale/deposit on water side
S	steam
t	thermal
T	turbine
w/s	water side

  - ○ Stainless steels: 19–27 $\mathrm{W\,m^{-1}\,K^{-1}}$.
  - ○ Alloys of copper like brass: 125–150 $\mathrm{W\,m^{-1}\,K^{-1}}$.

  Deposits from water contaminants have thermal conductivities in the range of 0.75–1.5 $\mathrm{W\,m^{-1}\,K^{-1}}$ [4] and diminish the thermal response of heat transfer systems through reduction in the heat transfer rates.
- Higher hydrodynamic resistance in the flow circuits, leading to additional pumping power (in pumps) and reduced mechanical power output (in turbines).
- Tube failures in boiler caused by (a) corrosion due to CuO (above 5%) and (b) hot spots due to Na_2O.
- Mechanical unbalance, axial shift and vibration in turbines.
- Direct energy loss through continuous/intermittent blow down to control contaminants.
- Sluggish response of thermo-wells housing thermocouples.
- Incorrect response of thermostats.

2. Experimental work

The present work pertains to *coal fired thermal power stations of 210 MW*. The *analysis is restricted to full plant load (100% MCR)*. Detailed studies have been undertaken in over twenty units that are over 20 years old to obtain sufficiently representative conditions of scaling.

Based on field studies conducted in the units and studies at the laboratory, the results are obtained in the form of the following types of curve fits:

(i) *Curves of Type 1 (power series)*:

$$Y = A_0 + A_1X + A_2X^2 \tag{1}$$

(ii) *Curves of Type 2 (exponential)*:

$$Y = B_0 \exp(B_1X) \tag{2}$$

(iii) *Curves of Type 3 (non-linear)*:

$$Y = D_0X^{D1} \tag{3}$$

Efficiency is the ratio of the rate of energy output to the rate of energy input to the system under consideration. The various component efficiencies are defined as:

- *Boiler efficiency* (η_B) is the ratio of the rate of energy output of steam produced at the boiler outlet to the rate of energy input in raw coal at the mill inlet.
- *Turbine efficiency* (η_T) is the ratio of the rate of energy output at the shaft to the net rate of energy in steam supplied from the boiler to the turbine.
- *Auxiliary steam efficiency* (η_S) is the ratio of the rate of energy output in steam supplied to the turbine to the rate of energy output produced at the boiler outlet.
- *Generator efficiency* (η_G) is the ratio of the rate of electrical energy output at the generator terminal to the rate of energy output at the turbogenerator shaft.
- *Auxiliary power efficiency* (η_A) is the ratio of the rate of energy output exported from the station to the corresponding rate of energy output at the generator terminal.

The gross overall efficiency (η_O) is given by,

$$\eta_O = \eta_B\eta_T\eta_S\eta_G \tag{4}$$

The net overall efficiency is given by,

$$\eta_N = \eta_O\eta_A \tag{5}$$

Uniform (notional) scale thickness: The build up of scales is highly uneven or non-uniform along the flow surface. The scale thickness is higher in the high temperature zone and lower in the low temperature zone. Scaling is more pronounced in low velocity and stagnant zones like joints, bends, constrictions, etc., while it is less prominent in high velocity straight flowing zones. Even in a given local zone, it deposits unevenly. To relate the system performance to deposition, it is assumed that there is a scale of uniform thickness on the entire heat transferring surface. Since this is not the situation in reality, the uniform scale is denoted as the uniform (notional) scale to indicate that this is a form of theoretical equivalent.

3. Results and discussions

3.1. Composition of raw water used for power generation

Typical composition of raw water from bore wells/basins [5] and recent composition of raw water from various sources used in power generation (Table 1) indicate that over the years, the

Table 1
Typical composition of waters used in power plant operation

Sl. no.	Particular	Borewell water	Lake water	Canal water	River water
1	Alkalinity (pH)	8.0	8.0	8.1	8.0
2	Total dissolved solids (ppm)	355	250	160	453
3	Electrical conductivity (μS cm^{-1})	466	365	235	903
4	Turbidity (NTU)	3.0	10.0	6.0	6.0
5	Sodium (ppm)	27.0	38.0	11.0	93.7
6	Calcium (ppm)	38.0	28.0	30.0	68.8
7	Magnesium (ppm)	15.0	10.0	7.0	21.6
8	Potassium (ppm)	2.0	3.0	1.0	21.1
9	Silicon (ppm)	5.8	6.5	3.8	6.5
10	Aluminum (ppm)	0.2	0.4	0.1	2.4

contaminant level of raw water has increased due to industrial activity and human settlement. Representative concentrations of total dissolved solids are 500 ppm in fresh water, 5000 ppm in brackish water and as much as 50,000 ppm (5%) in sea water. The uncertainty in the measurement is ±1%.

3.2. Permissible limits in water/steam

The safe limits of contaminants in the feed water at the boiler entrance, drum water parameters and curve fits for the permissible concentration of contaminants (as functions of steam pressure) are given in Bhatt and Jothibasu [6]. The allowable limits of contaminants in the main steam entering steam turbines and the ingress of sea/river/treated water into the condenser are given in Bhatt and Rajkumar [7].

Table 2
Coefficients in the curve fits (Type 2) (exponential) of the solubility/permissible contaminants

Sl. no.	Particular	B_0	B_1
X: Temperature (°C)			
Y: Solubility of scaling salts in water (ppm)			
1	$CaSO_4$	1195.3200	−0.0138069
2	$CaCO_3$	61.5985	−0.0054957
3	$Mg(OH)_2$	6.2836	−0.0045763
X: Pressure of feed water (MPa)			
Y: Permissible level of contaminants (ppb)			
4	Hardness of $CaCO_3$ (ppb)	4421.36	−0.384737
5	Oil contamination (ppb)	7466.51	−0.517196
6	Organic contamination (ppb)	13267.70	−0.282514
7	Hardness of drum water (ppb)	34.38	−0.295007
X: Pressure (MPa)			
Y: Ratio of silica in steam to silica in water (dimensionless)			
8	Silica ratio in steam to water	0.00037	0.3030

The solubility/levels of the contaminants are given in Table 2. The uncertainty in solubility is ±0.2%.

3.3. Composition of deposits

Jayan and Mandal [8] have analyzed the contents of several thermal station deposit samples through X-ray diffraction. In the water wall deposits, they consistently detected Fe_3O_4, Fe_2O_3, Cu and $Ca_5(PO_4)_3(OH)$. SiO_2 was present only in a few samples.

In the HPT deposits, they identified Fe_3O_4, Fe_2O_3, Ca_2SiO_4, $CaCO_3$,FeO(OH) and SiO_2. Compounds of Na, Al, Ca etc. were found in individual samples, but there is no consistency among the samples for even a single compound.

In the LPT deposits, Fe_3O_4, Fe_2O_3 and SiO_2 were consistently observed. $FeCO_3$; compounds of Al, Ca, etc., were observed in individual samples but without any consistency.

In the condenser deposits, $CaCO_3$ was common, while SiO_2, Fe_3O_4, Fe_2O_3 and Cu_2O were detected in individual samples but without consistency.

The composition of boiler deposits is given in Table 3 and that of turbine related deposits is given in Table 4. The uncertainty in chemical composition is ±0.2%. Measurements of thermal conductivity of the deposit samples were undertaken and were in the range of 0.5–2.0 $W\ m^{-1}\ K^{-1}$ but without any consistency. Hence, it was decided to resort to the weighted averages of the various samples. The boiler related deposits are composed of Fe_3O_4, Cu and silica; and its thermal conductivity is around 1.3 $W\ m^{-1}\ K^{-1}$. Turbine related deposits have varying composition depending on the location in the turbine, and the average thermal conductivity can be taken as 1.2 $W\ m^{-1}\ K^{-1}$. Silica forms hard soluble deposits on the turbine blades. Copper and copper oxides reduce the turbine capacity significantly. For example, a deposit of 0.5 kg can reduce the power output by 0.3–1.5 MW [9]. Chlorides, sulphates, phosphates and hydroxides deposit on turbine blades, causing corrosion, and on superheaters/reheaters, causing tube failures due to corrosion and hot spots. Condenser scales are rich in $CaCO_3$ and silica, and the thermal conductivity is 1.1 $W\ m^{-1}\ K^{-1}$. The thermal response and coupling factor for the transfer of heat is governed, among other factors, by the thermal conductivity.

Table 3
Results of chemical analysis of deposits from internal surfaces of boiler (as % weight basis)

Sl. no.	Particular	Drum		Economizer		Water walls		Superheaters			
1	Years of Operation	13	24	13	13	24	20	22	23	32	24
2	SiO_2	1.67	6.31	0.90	0.70	21.86	0.70	21.22	14.00	1.88	0.70
3	Fe_2O_3	2.36	81.66	0.60	–	46.41	–	–	–	–	–
4	Fe_3O_4	78.69	4.20	73.20	79.10	3.62	91.7	42.19	65.67	76.5	79.10
5	Cu	13.50	–	17.40	16.20	28.09	5.60	28.09	10.55	15.58	16.20
6	CaO	1.31	–	1.30	0.80	–	1.20	2.79	7.59	2.23	0.80
7	MgO	0.44	1.68	0.10	–	–	–	0.52	–	0.83	–
8	Na_2O	0.13	0.67	1.40	0.30	–	0.20	0.89	0.67	0.74	0.30
9	MnO_2	0.46	0.06	–	–	–	0.10	–	–	0.83	–
10	NiO	0.34	0.04	–	–	–	–	–	0.14	–	–
11	Loss on ignition at 600 °C	1.10	5.38	5.10	2.90	0.02	0.50	4.30	1.38	1.41	2.90

Table 4
Results of chemical analysis of deposits from internal surfaces of turbines (as % weight basis)

Sl. no.	Particular	Turbine				Deaerator		CON
		HPT	LPT	HPT	LPT			
1	Years of operation	5	6	5	5	13	5	1
2	SiO_2	0.70	87.20	19.91	80.5	9.27	–	4.87
3	Fe_2O_3	–	–	63.81	0.03	65.29	97.46	4.25
4	Fe_3O_4	70.50	1.47	–	1.32	0.12	–	–
5	Cu_2O	23.80	2.36	–	–	0.65	0.27	–
6	$CaCO_3$	1.60	–	2.26	0.01	7.02	0.54	44.46
7	MgO	–	–	3.55	–	–	0.08	0.02
8	Al_2O_3	–	1.54	–	0.60	–	–	2.70
9	Na_2O	0.60	–	–	–	0.42	–	1.81
10	P_2O_5	1.40	0.21	0.76	0.18	–	–	0.10
11	Sulphate	–	–	–	0.06	–	0.02	–
12	Carbonate	–	–	–	0.01	–	–	1.30
13	Miscellaneous	0.60	0.02	4.15	0.79	0.08	0.21	0.02
14	Loss on ignition at 600 °C	0.80	7.20	5.56	16.5	17.15	1.42	40.47

3.4. Deposit build up

Deposit build up is either measured on a mass basis ($mg\ cm^{-2}$) or as the thickness of the deposit (μm). A deposit of $190\ mg\ cm^{-2}$ corresponds to a scale of 1 mm. The safe limits of deposits in pipes are given in Bhatt and Jothibasu [6]. The build up of deposits in economizer tubes, deposit build up between off line cleaning intervals, upper limits of deposits (for various heat loads/heating rates for clean/dirty tubes) and contaminant carry over ratio in boiler drums have been quantified in Bhatt et al. [5].

The maximum time span for build up of deposits is taken as 200,000 h for boiler pressure parts and regenerative feed water heaters; 60,000 h for steam turbines and 20,000 h for condensers. The operating time span between off line cleaning intervals is 20 years for boilers and feed heaters, 5 years for turbines and annual for condensers. It is to be kept in mind that for any unit, for a given time interval, the boiler operating hours are higher than the turbine operating hours.

Oxide growth laws can be represented by curves of Type 3 with the index in the range of -1 to -3. In this study, since the focus is on plant performance variables, *a linear growth rate is assumed for simplicity*. The measurement of deposit build up under normal operating conditions and under abnormal circumstances and the curve fits for normal build up are given in Table 5. The measurements are based on deposits from cut out tube samples or from ultrasonic oxide scale measurements. Fig. 1 gives a typical variation of deposits from the inlet to the exit of a steam turbine.

The upper bounds of the uncertainties of deposit thickness for the results given above are as follows:

(i) Measuring instruments, sampling and associated data processing: ±1% (5 μm).
(ii) Variation of scale across a single tube: ±6% (30 μm for a scale thickness of ~500 μm).
(iii) Variation of scale across a tube bank of the same power plant ±5% (25 μm for a scale thickness of ~500 μm).

Table 5
Measured deposit build up in components

Sl. no.	Particular	Normal build up (μm)	Abnormal build up (μm)	Normal build up	
				A_0	A_1
Normal cleaning interval: 1 year (6000 h)				$X = t/20{,}000$; t in h	
Maximum cleaning interval: 20,000 h				$Y = \delta_s$ (μm)	
1	CON	360	600	0.8334	1191.70
2	LOC	315	500	0.0834	1046.50
Normal cleaning interval: 5 year (30,000 h)				$X = t/60{,}000$; t in h	
Maximum cleaning interval: 60,000 h				$Y = \delta_s$ (μm)	
3	TUR	615	1000	0.0357	1230.70
Normal cleaning interval: 20 year (125,000 h)				$X = t/200{,}000$; t in h	
Maximum cleaning interval: 200,000 h				$Y = \delta_s$ (μm)	
4	ECO	235	400	0.1082	373.460
5	WW	340	500	0.0925	542.260
6	SH	365	500	0.3946	581.630
7	LTSH	155	300	0.6620	241.410
8	RH	350	500	0.1655	560.350
9	HPH	215	300	0.5960	341.200
10	LPH	130	300	0.1353	206.830

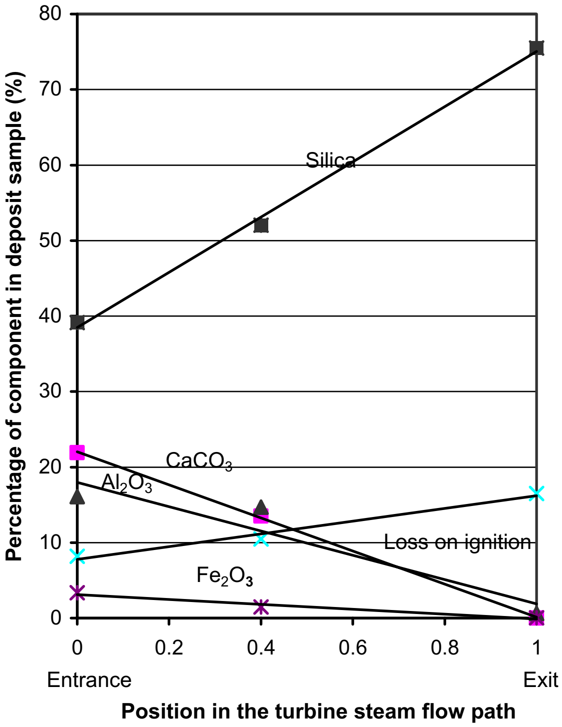

Fig. 1. Variation of composition of turbine deposits along the steam flow path after 30,000 h of operation.

Table 6
Coefficients in the curve fits (Type 1) of the metal surface temperatures of superheaters and reheaters

Sl. no.	Particular	A_0	A_1	A_2
Curve: Type 1 (power series)				
$X = \delta_s/2000$ (δ_s in μm; X=0–0.6)				
Y:ΔT between fluid and metal (0–125 °C)				
1	Temperature of metal below scale, inside tube (clean fire side)	0.0	239.6774	−152.6880
2	Temperature of metal outside tube (clean fire side)	0.0	399.2688	−328.3150
3	Temperature of metal below scale inside tube (dirty fire side)	0.0	112.3655	−58.0645
4	Temperature of metal below soot, outside tube (dirty fire side)	0.0	257.2688	−217.2040

(iv) Variations between normal scale build up in different power plant for nearly the same hours of operation ±10% (50 μm for a scale thickness of ~500 μm).

Hence, the maximum uncertainty of the data on scale build up is ±10% (50 μm for a scale thickness of ~500 μm).

3.5. Effect on heat transfer

The heat transfer effects of contaminant deposits are prominent in the fired and non-fired heat exchangers. The effect of scales of different compositions on the relative heat transfer rate is quantified in Bhatt et al. [5]. The tube inside and outside metal surface temperatures under clean and dirty fire side conditions (for superheaters and reheaters) are given in Table 6.

The reduction in heat transfer (in tube type heat exchange surfaces) can be quantified by the decrease in the overall heat transfer coefficient (based on LMTD and tube inside diameter) as,

$$Q_s/Q_o = [1 + C\delta_s U_o f_a \lambda_s^{-1} \mathrm{AR}^{-1}]^{-1} \tag{6}$$

where C is a conversion factor (1E−06 if the scale thickness is in μm; 1E−03 if it is in mm), δ_s is the scale thickness, U_o is the overall heat transfer coefficient in clean condition (W m^{-2} K^{-1}), f_a is the fraction of the area of the heat exchanger affected by scaling, λ_s is the thermal conductivity of the deposit and AR is the ratio of surface area reduced by scaling,

$$\mathrm{AR} = (d_o - 2\delta_s)/d_o \tag{7}$$

where d_o is the tube inside diameter in clean conditions. The reduction in heat transfer is on two counts—(a) introduction of an additional thermal resistance and (b) decrease in surface area for heat transfer due to effective reduction of tube internal diameter. Table 7 gives the reduction in heat transfer for normal and abnormal scaling. It can be seen from the table that the reduction in heat transfer rate in boilers is quite low, but it is very severe in the condensers, feed heaters and lube oil coolers. In the case of turbines, the reduction in heat transfer rate (to the blading and casing) is of no practical energy related consequence. The maximum area reduction ratio is around 0.98 in the boiler pressure parts, whereas in the feed heaters and condenser, it is around 0.96.

Table 7
Reduction in heat transfer rate for normal and abnormal scaling

Sl. no.	System	A (m^2)	Q_o (MW$_t$)	$T_{w/s,in}$ (°C)	$T_{w/s,out}$ (°C)	$T_{fg,in}$ (°C)	$T_{fg,out}$ (°C)	U_o (Wm^{-2} K^{-1})	d_o (mm)	Q_s/Q_o (normal)	Q_s/Q_o (ab normal)
1	ECO	4746	57.44	246	290	510	350	65	44.5	0.985	0.975
2	WW	6237	259.0	290	340	1250	850	65	63.5	0.978	0.969
3	SH	8398	35.62	430	540	1000	670	15	44.5	0.994	0.993
4	LTSH	6237	24.36	340	430	860	670	15	40.5	0.998	0.996
5	RH	2650	33.84	320	540	1050	780	35	60.3	0.988	0.983
6	HPH	–	63.34	–	–	–	–	2200	20.0	0.674	0.602
7	LPH	–	69.64	–	–	–	–	1800	20.0	0.808	0.649
8	CON	–	164.33	28–36	38–46	–	–	3300	20.0	0.513	0.396
9	LOC	–	–	–	–	–	–	350	20.0	0.898	0.851
10	TUR	–	–	540	60	–	–	10	–	0.993	0.990

3.6. Effect on flow hydrodynamics

3.6.1. Pressure drop and increased pumping power

The flow resistance affects the performance of both active flow elements (pumps) and heat exchangers. The hydrodynamic effects of contaminant deposits can be quantified in terms of increased pressure drop in the equipment. Since the power input for fluid flow is dependent on the pressure difference, excessive pressure drop results in corresponding reduction in flow or increase in power input. The increased power input is given by,

$$P_s/P_o = [1 + \{(\Delta p_o/p_o)(F_s/F_o)(d_o/d_s)^4 - 1\}]^{-1} \tag{8}$$

where Δp_o is the pressure drop across the system under clean conditions, p_o is the pressure developed at the system inlet under clean conditions and F is the Fanning friction factor. The Fanning friction factor is dependent on the surface roughness (ε), which under clean conditions is taken as 0.00152 mm for drawn tubing and 0.045 mm for commercial steel [10]. The surface roughness of tubes with deposits is measured and found to be almost 90–100% of δ due to uneven build up. For very rough surfaces, the Colebrook equation reduces to the classical Von Karman equation [11],

$$1/\sqrt{F} = -4\log(\varepsilon/3.7d_o) \tag{9}$$

Table 8 shows (F_s/F_o), $(d_o/d_s)^4$ and P_s/P_o for the systems considered. It is seen that friction is the predominant effect as compared to area reduction.

3.6.2. Deterioration in the turbine performance

The deterioration in heat rate of steam turbines due to deposits in the range of 30–70 μm is quantified in Bhatt and Rajkumar [7]. The decrease in turbine efficiency and turbine shaft output with contaminant deposits ranging from 15 to 100 μm is quantified in Bhatt et al. [5].

The deterioration in turbine performance is due to three main effects:

(i) *Excessive friction in the steam flow path.* The average loss of work in the turbine alone is measured as 10.4 MW under normal conditions and 15.1 MW under abnormal conditions from the turbine efficiency tests. Of this, gland leakage accounts for nearly 14%. Out of the

Table 8
Increased pumping power due to deposits

Sl. no.	System	F_s	F_o	f-ratio	$(d_o/d_s)^4$	Δp_o	p_o	$\Delta p/p_o$	P_s/P_o
Normal scaling									
1	ECO	0.007719	0.004922	1.5682	1.043387	2.0	18.2	0.10989	1.070
2	WW	0.007752	0.004522	1.714276	1.044006	0.8	16.2	0.049383	1.039
3	SH	0.008871	0.004922	1.802299	1.068400	1.2	15.2	0.078947	1.073
4	LTSH	0.007013	0.005037	1.392211	1.031212	0.2	15.4	0.012987	1.006
5	RH	0.007949	0.004577	1.736812	1.047868	0.25	2.7	0.092593	1.076
6	HPH	0.009712	0.006043	1.60719	1.090829	0.8	19.0	0.042105	1.032
7	BFP	–	–	–	–	–	–	–	1.295
8	LPH-CEP	0.008233	0.006043	1.362395	1.053735	1.0	1.7	0.588235	1.256
9	CON-CWP	0.011683	0.006043	1.933359	1.157955	0.05	0.3	0.166667	1.206
10	LOC-LOP	0.011118	0.006043	1.839937	1.136584	0.03	0.18	0.166667	1.182
Abnormal scaling									
11	ECO	0.009143	0.004922	1.857543	1.075262	2.0	18.2	0.10989	1.110
12	WW	0.008754	0.004522	1.935926	1.065552	0.8	16.2	0.049383	1.052
13	SH	0.009861	0.004922	2.003301	1.095174	1.2	15.2	0.078947	1.094
14	LTSH	0.008583	0.005037	1.703852	1.061521	0.2	15.4	0.012987	1.011
15	RH	0.008903	0.004577	1.945168	1.069179	0.25	2.7	0.092593	1.100
16	HPH	0.010922	0.006043	1.807485	1.12957	0.8	19.0	0.042105	1.044
17	BFP	–	–	–	–	–	–	–	1.411
18	LPH-CEP	0.010922	0.006043	1.807485	1.12957	1.0	1.7	0.588235	1.613
19	CON-CWP	0.014293	0.006043	2.365352	1.280821	0.05	0.3	0.166667	1.338
20	LOC-LOP	0.01327	0.006043	2.195902	1.227738	0.03	0.18	0.166667	1.283

balance, blade friction accounts for nearly 75% while the remainder is due to secondary eddy losses and tip leakage. The curve fits for the effect of deposits on turbine efficiency and heat rate are given in Table 9.

(ii) *Vacuum deterioration in the condenser.* The average loss of work in condensers is estimated at 0.82 MW under normal scaling and 1.52 MW under abnormal conditions. Scaling in condenser tubes results in vacuum deterioration resulting in shoot up of condenser absolute pressure, inadequate cooling and drop in turbine work, which is quantified in Table 9. Nagaich et al. [12,13] have confirmed that the terminal temperature difference shot up from 5.5 to 13.0 °C when deposits of 0.3–0.5 mm were present in the condenser.

Table 9
Effect of scaling on the turbine performance coefficients in the curve fits (Type 1)

Sl. no.	Particular of system	A_0	A_1	A_0	A_1
		X: δ_s (μm) Y: η_T (%)		X: δ_s (μm) Y: THR (% of design THR)	
1	Deposits in turbine proper	41.75	−0.0023	0.0023	+0.0079
2	Deposits in condenser	41.75	−0.0003	0.0056	+0.0007
3	Deposits in HP feed water heaters	41.75	−0.0024	0.0010	+0.0055
4	Deposits in LP feed water heaters	41.75	−0.0019	0.0065	+0.0047

(iii) *Ineffective performance of feed water heaters.* The deposits in feedwater heaters result in decreased heating load, the consequence of which is increased heating load on the boiler. Partial loss of regenerative feed heaters results in a drop in turbine efficiency, which is quantified in Table 9.

In Table 9, it is to be noted that the deposit build up rates are entirely different for turbines, condensers and feed water heaters.

3.7. Effect on the overall coal fired plant

3.7.1. Energy efficiency

The effect of contaminants on the overall power plant can be estimated based on the effects on boilers, turbine, auxiliary power and auxiliary steam. In each of these systems, the effects are multiple and inter-related. In a 210 MW unit at 100% MCR, the design efficiencies are as follows:

(i) Boiler efficiency: 86.00%.
(ii) Turbine efficiency: 41.75%.
(iii) Generator efficiency: 98.55%.
(iv) Auxiliary steam efficiency: 98.37%.
(v) Auxiliary power efficiency: 93.35%.
(vi) Gross overall efficiency (including auxiliary steam): 34.81%.
(vii) Net overall efficiency (including auxiliary power): 32.49%.

For a 210 MW unit, the rates of energy transfer at 100% MCR are as follows:

(i) Boiler fuel input: 603.31 $\mathrm{MW_t}$.
(ii) Energy in total steam generated from the boiler: 518.85 $\mathrm{MW_t}$.
(iii) Energy in steam supplied to the turbine: 510.39 $\mathrm{MW_t}$.
(iv) Mechanical shaft output of the turbine: 213.09 $\mathrm{MW_m}$.
(v) Auxiliary power: 13.965 $\mathrm{MW_e}$.

The effect of deposits on boilers is that of reduced heat transfer in the boiler components. The overall effect of scaling on the boiler efficiency (%) is given by,

$$\eta_{\mathrm{B,s}} = 86.00 - (0.0021\delta_{\mathrm{s}}) \tag{10}$$

where δ_{s} is the uniform (notional) scale width in the boiler (0–500 μm).

The effect on turbines is manifested as reduced power output, which is caused by different sub-effects such as: (a) poor entrance temperature conditions in main steam and reheat steam resulting from reduced heat transfer in the boiler and feed water heaters, (b) poor entrance pressure conditions resulting from pressure drop created in the boiler, (c) lower saturation temperature in the feed water heaters, (d) lower condenser vacuum due to inadequate heat transfer at the condenser and (e) loss of work in the turbine due to resistance induced by deposits on the blades. The overall effect on the turbine, condenser and feed water heaters for a notional uniform scale is given by the turbine efficiency (%) as,

$$\eta_{\mathrm{T,s}} = 41.75 - (0.0037\delta_{\mathrm{s}}) \tag{11}$$

where δ_{s} is the uniform (notional) deposit build up in the turbine (0–1000 μm).

The effect on auxiliary power is composed of two effects (a) additional pumping power for flow through the boiler, feed heaters (water side), condenser circuit (water side), bearing cooling water circuits (water side) and (b) reduced heat transfer in the bearing cooling water circuits of pumps, fans and mills leading to lower equipment efficiency and capacity drop. The auxiliary powers of the concerned pumps are as follows:

(i) Boiler feed pumps: 1.902% of MCR.
(ii) Condensate extraction pumps: 0.202% of MCR.
(iii) Cooling water pumps: 0.839% of MCR.
(iv) Lube oil pumps: 0.043% of MCR.

The total measured excessive pumping power under conditions of deposits is 0.794 MW under normal scaling and 1.201 MW under abnormal scaling.

For a uniform (notional) scale (δ_{s}) (0–500 μm), the reduction in auxiliary power efficiency (%) is given by,

$$\eta_{\mathrm{A,s}} = 93.35 - (0.00129\delta_{\mathrm{s}}) \tag{12}$$

The auxiliary steam efficiency decreases due to continuous/intermittent blow down, which is the resultant of higher than permissible contaminant levels.

The effects of deposit build up on the gross and net overall efficiency (%) can be quantified (as a product of the component efficiencies) by using a uniform (notional) deposit build up (δ_{s}) (0–500 μm) as,

$$\eta_{\mathrm{O,s}} = 34.808 - (0.0039\delta_{\mathrm{s}}) \tag{13}$$

$$\eta_{\mathrm{N,s}} = 32.493 - (0.0040\delta_{\mathrm{s}}) \tag{14}$$

The sensitivity index for scaling is, therefore, 0.0039% points of gross efficiency per unit scale thickness and 0.0040% points of net efficiency per unit scale thickness. The uncertainty in the gross and net overall efficiencies due to uncertainties in the scale thickness data is ±0.09% and ±0.1%, respectively.

For a constant electrical power output of the plant, the increase in power input (P_{in} in $\mathrm{kW_t}$) based on a notional uniform scale build up (0–500 μm) is given by,

$$P_{\mathrm{in}} = 68.158\delta_{\mathrm{s}} + [0.007(\delta_{\mathrm{s}})^2] \tag{15}$$

Likewise, for a constant thermal power input, the decrease in net electric power dispatched (P_{out} in $\mathrm{kW_e}$) is given by,

$$P_{\mathrm{out}} = 24.870\delta_{\mathrm{s}} - [0.007(\delta_{\mathrm{s}})^2] \tag{16}$$

The uncertainty in power input and power output due to uncertainty in the scale build up data is ±1.05 and 0.37 MW, respectively. It is to be remembered that in practice, the deposition rates and their time scales for cleaning are different in each component.

3.7.2. Capacity effects

The capacity effects are of two types:

(i) *Decrease in capacity of sub-systems due to scale formation leading to drop in plant load.* At the present level of normal contaminant build up, the capacity limitations are well within the design margins of the boilers, feed heaters, turbines and pumps. Even with an abnormal level of contaminants, the units can still be operated at 100% MCR, though at a lower conversion efficiency.

(ii) *Decrease in unit availability due to equipment failure originating from water contaminants.* Na_2O in deposits precipitates non-uniformly, creating abnormal increases of metal surface temperature (hot spots), which are sites for creep-rupture failure of tubes. CuO in deposits leads to corrosion induced tube punctures. The failure rate is significant only in the superheaters where the loss in operating availability due to deposit build is estimated at 1–2% for units of over 20 years service life (between clean up intervals). The failure rate is insignificant in other areas of deposit build up and for units below 20 years of operating life.

3.8. Contaminant control techniques

Timely cleaning and regeneration of de-mineralizers and resin beds are essential for controlling contaminants to a large extent. As an operating guideline, the ratio of the operating pressure drop to the design pressure drop ($\Delta p/\Delta p_{\text{design}}$) (1.5–2.2) across the ion exchangers must be below the following limit:

$$\Delta p/\Delta p_{\text{design}} = 1.5511 + (0.6079f) \qquad (17)$$

where f is the operating flow as a fraction of the design flow across the ion exchanger (0: no flow; 1: design flow).

For auxiliary cooling water, wherever untreated water is used, it must be changed over to a soft water system. Further, to ascertain if a soft water plant is adequate or a demineralizer is required, the make up water flow as a percentage of the feed water flow is measured. A demineralizer is required if it is greater than the following percentage,

$$Y = 1185.9X^{-1.0411} \qquad (18)$$

where Y is the make up water as a per cent of the feed water flow and X is the percentage of Ca and Mg in the total dissolved solids of the feed.

Besides operational optimization, repair and overhauling of defective equipment, up to date preventive maintenance, concentration upset management and renovation and modernization of contaminant control technology is required. Some of the recent and successful techniques/technologies are:

- Change over from conventional ion exchangers to (a) electro deionization [14] where a direct current field is used to regenerate the resin without use of chemicals, (b) reverse osmosis [14], (c) combination of ion exchange and membrane technology.
- Change over from all volatile treatment to oxygenated treatment for once through boilers.

- All organic boiler feed water treatment through the use of amines for film formation and corrosion protection.
- Control of non-uniform magnetic scales of 400–500 μm through (a) electrostatic fields involving low current (2–3 A), low power (<15 W) charging near scale forming zones, or (b) on line chemical cleaning using 'filming' amines in combination with polyacrylates [15] or (c) use of scale control polymers.
- Condensate polishing unit [9,16] using reverse osmosis or a continuous de-ionization process.
- Re-cycling cooling water through ozonation or non-chromate corrosion control polymer stabilized phosphate based inhibitors [14].
- Thermal evaporators are preferable to chemical demineralizers for input streams with total dissolved solids above 1000 ppm [17].
- Rainwater harvesting in areas around the thermal station for regions with medium and heavy rainfall.

The above techniques have been proved to achieve 25% decrease in the deposition rates in European and American power stations.

4. Conclusions

The major conclusions of the study are that:

(i) Deposit build up in Indian power stations is as follows: boilers: 300–500 μm over a 20 year period, turbines: 600–1000 μm over a 5 year period, condensers: 300–600 μm over a year and lube oil coolers: 300–500 μm over a year.
(ii) Among the boiler deposits, the most critical zone of deposition is the high temperature superheaters where deposition accelerates tube failures due to corrosion and hot spots.
(iii) Water side deposits hinder heat transfer in thermal power station equipment through increased thermal resistance and reduced contact area. The reduction in heat transfer in boiler components is in the range of 0.2–2.0% under normal scaling and 0.4–3.1% under abnormal conditions.
(iv) The deposits result in increased pumping power/decreased turbine power due to the increased hydrodynamic frictional resistance as well as the reduced cross sectional area. The increased pumping power is of the order of 0.6–7.6% in boiler components, 29% in BFP circuit, 26% in LPH circuit, 21% in HPH circuit and 18% in lube oil cooler circuits. Under abnormal conditions it is much more.
(v) Turbine performance deterioration due to deposits is almost 10–12 MW for a 210 MW turbine operating at 100% MCR. Besides, vacuum deterioration in the condenser and ineffective performance of feed water heaters also result in loss of mechanical output of the turbine.
(vi) The sensitivity indices to the notional deposit thickness at 210 MW and 100% MCR are: boiler efficiency: −0.0021% points/μm, turbine circuit efficiency: −0.0037% points/μm, auxiliary power efficiency: −0.00129% points/μm, gross overall efficiency: −0.0039% points/μm and net overall efficiency: −0.0040% points/μm.

(vii) The overall effect of scale build up is either increased power input of ∼68 kW/μm (at a constant power output of 100% MCR) or decreased power output ∼25 kW/μm (at a constant power input for 100% MCR).
(viii) Power output capacity reduction effects due to water side deposits are negligible.
(ix) Successful contaminant control techniques can reduce the deposition rates to almost 25% of the present value.

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