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ENERGY AUDIT MANUAL FOR THERMAL POWER PLANT (TPP)

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ENERGY AUDIT MANUAL FOR THERMAL POWER PLANTS (TPP)- ANNEXURES

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List of Acronyms or Abbreviations

AAS	Actual Air Supplied
AHP	Ash Handling Plant
AHU	Air Handling Unit
AI & IoT	Artificial Intelligence and Internet of Things
APC	Auxiliary Power Consumption
APH	Air Preheater
APSCL	Ashuganj Power Station Company Limited
APR	APR Energy Bangladesh
BACW	Boiler Auxiliary Cooling Water
BCPCL	Bangladesh-China Power Company (Pvt) Limited
BPDB	Bangladesh Power Development Board
BDT	Bangladeshi Taka
BFP	Boiler Feed Water Pump
BTF	Boiler Tube Failure
BTL	Boiler Tube Leakages
Btu/Scf	British Thermal Unit/ per standard cubic foot
CC	Closed Cycle
CCPP	Combined Cycle Power Plant
CEP	Condensate Extraction Pump
CCUP	Closed Cycle Utility Plant
CFL	Compact Fluorescent Lamp
CHP	Coal Handling Plant
CIWP	Clarified Water Pump
CIPP	Commercial Independent Power Producer
CLC	CLC Power Company Ltd.
COC	Cycles of Concentration
COP	Coefficient of Performance
CRH	Cold Reheat Line
CT	Cooling Tower
CW	Cooling Water
DBT	Dry Bulb Temperature
DCA	Drain Cooler Approach
DG	Diesel Generator
DMWP	DM Water Pump
dP	Pressure Drop
DSM	Demand Side Management
EAS	Excess Air Supplied
ECM	Energy Conservation Measure
ECPV	ECPV Energypac Power Plant
EE	Energy Efficiency
EFOR	Equivalent Forced Outage Rate
EGCB	Electricity Generation Company of Bangladesh Limited
ENCON	Energy Conservation
ER	Evaporation Ratio
ESCO	Energy Service Company
ESP	Electrostatic Precipitator
FAD	Free Air Delivery
FD	Forced Draft
fg	Flue Gas
FOF	Forced Outage Factor
FOH	Forced Outage Hour

FRP	Fiberglass Reinforced Plastic
FTL	Fluorescent Tubular Lamp
FY	Fiscal Year
GBB	GBB Power Limited
GCV	Gross Calorific Value
GF	Generation Factor
GT	Gas Turbine
GTPP	Gas Turbine Power Plant
HFO	Heavy Fuel Oil
HP	High Pressure
HPH	HP Heater
HPMV	High Pressure Mercury Vapor Lamp
HPL	Haripur Power Station
HPSV	High Pressure Sodium Vapour Lamps
hr	Hours
HR	Heat Rate
HRH	Hot Reheat Line
HRSG	Heat Recovery Steam Generator
HSD	High Speed Diesel
HT	High Tension
HVAC	Heating, Ventilation, and Air Conditioning
HVDC	High Voltage Direct current transmission
IAC	Instrument Air Compressor
ID	Induced Draft
IEL	Instrumentation Engineers Limited
IPP	Independent Power Producers
IP	Intermediate Pressure
ITD	Initial Temperature Difference
Kcal	Kilocalorie
kg	Kilogram
kJ	Kilojoule
KP	Kushiara Plant
KPCL II	Khulna Power Company Ltd.
kV	Kilovolt
kWh	Kilowatt Hour
LCC	Lifecycle Costing
LDO	Light Diesel Oil
LMTD	Logarithmic Mean Temperature Difference
LP	Low Pressure
LPH	LP Heater
LT	Low Tension
mmWC	Millimeters of Water Column
MPL	Meghnaghat Power Ltd
MPGL	Manikganj Power Generations Ltd
MU	Million Unit
MW	Megawatt
NARUC	National Association of Regulatory Utility Commissioners
NCV	Net Calorific Value
NG	Natural Gas
NLDC	National Load Dispatch Centre
NPSH	Net Positive Suction Head
NPV	Net Present Value
NWPGCL	North-West Power Generation Company Ltd.
O&M	Operations and Maintenance

OC	Open Cycle
OEM	Original Equipment Manufacturer
PPGL	Palli Power Generation Ltd.
PA/SA	Primary Air/Secondary Air
P/S	Price to Sales ratio
PAC	Plant Air Compressor
PDB	Power Development Board
PG	Performance Guarantee
PLF	Plant Load Factor
PP	Power Plant
PPA	Power Purchase Agreement
POF	Planned Outage Factor
POH	Planned Outage Hour
PRDS	Pressure Reducing and De-Superheating System
QRPP	Quick Rental Power Plant
RAC	Refrigeration and Air Conditioning
RDF	Refuse Derived Fuel
REB	Rural Electrification Board
ROI	Return on Investment
RPM	Revolutions Per Minute
RPP	Rampal Power Plant
RPCL	Patuakhali Power Station
RWP	Raw Water Pump
SCADA	Supervisory Control and Data Acquisition
SEC	Specific Energy Consumption
SIPP	Sagamu Independent Power Plant Limited
SIR	Savings/Investment Ratio
Sm^3	Standard Cubic Metre
SPC	Specific Power Consumption
SPDP	Screen-Protected Drip-Proof
SPP	Simple Payback Period
SPV	Solar Photovoltaic
SR	Steam Rate
SSC	Specific Steam Consumption
ST	Steam Turbine
T_a	Ambient Air Temperature
TACW	Turbine Auxiliary Cooling Water
TDH	Total Differential Head
TDS	Total Dissolved Solids
TEFC	Temperature Enclosed, Fan-Cooled
THR-G	Turbine Heat Rate-Gross
THR-N	Turbine Heat Rate-Net
T_i	Inlet Air Temperature
TOD	Time of Day
TOU	Time of Use
TPH	Tonnes per Hour
TPP	Thermal Power Plant
TPP-EP	TPP Energy Performance
TR	Temperature Rise
TTD	Terminal Temperature Difference
UAT	Unit Auxiliary Transformer
UCR	Uniform Capital Recovery
UPV	Uniform Present Value
UPPL	United Payra Power Ltd

USAID	United States Agency for International Development
UST	Unit Service Transformer
VFD	Variable Frequency Drive
WBT	Wet-bulb temperature
WHRB	Waste Heat Recovery Boiler
w.r.t	With Respect To

1 Annexure 1: Details of different types of power plants in Bangladesh

1.1 Power plants in Bangladesh

Table 1 lists the power plants in Bangladesh, including the ones in operation and the ones with expired maintenance contracts.

Table 1. Power plants in Bangladesh

Serial Number	Name of power station			Number of units X capacity	Installed capacity (MW)	Derated/ present capacity (MW)
	(A) Plants in operation					
1.	Ghorasal Repowered CCPP Unit-3 (GT)	Gas	(PDB)	1X260	260	260
2.	a) Ghorasal Repowered CCPP Unit-4	Gas	(PDB)	1X210	210	180
	b) Ghorasal 365 MW CCPP Unit-5	Gas	(PDB)	1X210	210	190
3.	Ghorasal 365 MW CCPP Unit-7	Gas	(PDB)	1X254+1X126	365	365
4.	Ghorasal 108 MW PP (Regent)	Gas	(IPP)	34X3.35	108	108
5.	Tongi 80 MW GTPP	Gas	(PDB)	1X105	105	105
6.	Haripur GTPP	Gas	(PDB)	1X32	32	20
7.	Haripur 360 MW CCPP (HPL)	Gas	(IPP)	1X235+1X125	360	360
8.	Meghnaghat 450 MW CCPP (MPL)	Gas	(IPP)	2X140+1X170	450	450
9.	Siddhirgonj 210 MW TPP	Gas	(PDB)	1X210	210	115
10.	Haripur 412 MW CCPP	Gas	(EGCB)	1X273+1X139	412	412
11.	Siddhirgonj 2*120 MW GTPP	Gas	(EGCB)	2X105	210	210
12.	Siddhirgonj 335 MW GTPP	Gas	(EGCB)	1X217+1X118	335	335
13.	Meghnaghat CCPP (Summit)	Gas	(IPP)	2X110+1X110	335	335
14.	Madanganj 55 MW PP (Summit)	HFO	(IPP)	5X17.08+1X11.3	55	55
15.	Keranigonj 100 MW PP (Powerpac)	HFO	(QRPP)	8X13.45	100	100
16.	Gagnagar 102 MW PP (Digital Power)	HFO	(IPP)	12X8.924	102	102
17.	Narshingdi 22 MW PP (Doreen)	Gas	(SIPP, REB)	8X2.90	22	22
18.	Summit Power, (Madhabdi + Ashuli)	Gas	(SIPP, REB)	6X3.67+7X8.73	80	80
19.	Maona 33 MW PP (Summit)	Gas	(SIPP, REB)	4X8.73	33	33
20.	Rupganj 33 MW PP (Summit)	Gas	(SIPP, REB)	4X8.73	33	33
21.	Gazipur 52 MW PP	HFO	(RPCL)	6X8.90	52	52
22.	Gazipur 100 MW PP	HFO	(RPCL)	6X18.415	105	105

Serial Number	Name of power station			Number of units X capacity	Installed capacity (MW)	Derated/ present capacity (MW)
23.	Kodda 150 MW PP	HFO	(BPDB-RPCL)	9X17.06	149	149
24.	Kamalaghat 54 MW PP (Banco Energy)	HFO	(IPP)	3X18.69	54	54
25.	Kodda 300 MW PP Unit-2 (Summit)	HFO	(IPP)	18x17.076	300	300
26.	Kodda 149 MW PP Unit-1 (Summit)	HFO	(IPP)	8X18.415+1X8.97	149	149
27.	Keranigonj 300 MW PP (APR)	HSD	(IPP)	256X1.4	300	300
28.	Bramhangoan 100 MW PP (Aggreko)	HSD	(IPP)	23X0.85+91X959	100	100
29.	Aurahati 100 MW PP (Aggreko)	HSD	(IPP)	23X0.85+91x959	100	100
30.	Nebabganj 55 MW (Southern Power)	HFO	(IPP)	3X19.3	55	55
31.	Manikganj 55 MW PP (Northern)	HFO	(IPP)	3X19.3	55	55
32.	Meghnaghat 104 MW PP (MPGL)	HFO	(IPP)	6X18.5	104	104
33.	Meghnaghat 162 MW PP (MPGL)	HFO	(IPP)	9X18	162	162
34.	Manikgonj 35 MW Solar PP (Inspectra)	Solar	(IPP)	1X35	35	35
35.	Kanchan Purbachal Power Generation	HFO	(IPP)		55	55
36.	Katpotti	HFO	(IPP)	7X7.90	51	51
	Dhaka zone total				**5,853**	**5,696**
37.	Karnaphuli Hydro PP Unit-1, -2, -3, -4, & -5	Hydro	(PDB)	2X40,3X50	230	230
38.	a) Chattogram TPP-1	Gas	(PDB)	1X210	210	180
	b) Chattogram TPP-2	Gas	(PDB)	1X210	210	180
39.	Kaptai 7 MW Solar PP	Solar	(PDB)		7	7
40.	Raozan 25 MW PP	HFO	(RPCL)	3X8.9	25	25
41.	Teknaf 20 MW PP (Solartech)	Solar	(IPP)	1X20	20	20
42.	Petenga 50 MW PP (Baraka)	HFO	(IPP)	8X6.89	50	50
43.	Sikalbaha 105 MW PP (Baraka Sikaib)	HFO	(IPP)	6X18.415	105	105
44.	Sikalbaha Peaking GT	Gas	(PDB)	1X150	150	150
45.	Sikalbaha 225 MW CCPP	Gas	(PDB)	1X150+1X75	225	225
46.	Anwara 300 MW PP (United)	HFO	(IPP)	17X17.076+3X8.04	300	300
47.	Juldah 100 MW PP Unit-1 (Acorn)	HFO	(QRPP)	8X13.45	100	100
48.	Juldah 100 MW PP Unit-3 (Acorn)	HFO	(IPP)	8X13.45	100	100
49.	Dohazari-Kalaish 100 MW Peaking PP	Gas	(PDB)	6X17.0	102	102

Serial Number	Name of power station			Number of units X capacity	Installed capacity (MW)	Derated/ present capacity (MW)
50.	Hathazari 100 MW Peaking PP	HFO	(PDB)	11X8.9	98	98
51.	Barabkunda 22 MW PP (Regent)	Gas	(SIPP, PDB)	8X2.90	22	22
52.	Chattogram 108 MW PP (ECPV)	HFO	(IPP)	16X7.00	108	108
53.	Sikalbaha 54 MW PP (Jodiac Power)	HFO	(IPP)	3X18.55+1X3.6	54	54
54.	Karnaphuli Power Ltd.	HFO	(IPP)	6X18.41+1X6.4	110	110
55.	Juldah Unit-2 (Acom)	HFO	(IPP)	8X13.6	100	100
56.	Chattogram 116 MW PP (Anlima Ener)	HFO	(IPP)	6X21.06	116	116
Chattogram zone total					**2,442**	**2,382**
57.	a) Ashuganj TPP Unit-4	Gas	(APSCL)	1X150	150	129
	b) Ashuganj TPP Unit-5	Gas	(APSCL)	1X150	150	134
58.	Ashuganj 50 MW PP	Gas	(APSCL)	14X3.968	53	45
59.	Ashuganj 225 MW CCPP	Gas	(APSCL)	1X142+1*75	221	221
60.	Ashuganj 450 MW CCPP (South)	Gas	(APSCL)	1X360	360	360
61.	Ashuganj 450 MW CCPP (North)	Gas	(APSCL)	1X361	360	360
62.	Ashuganj 55 MW PP (Precision)	Gas	(RPP)	15*4	55	55
63.	Ashuganj 195 MW PP (APSCL-United)	Gas	(IPP)	20*9.73+1*16	195	195
64.	Ashuganj 51 MW PP (Midland)	Gas	(IPP)	6X9.34	51	51
65.	Ashuganj 150 MW PP (Midland)	HFO	(IPP)	23X7.015	150	150
66.	Titas 150 MW Peaking PP	HFO	(PDB)	6X6.92	52	52
67.	Chandpur 150 MW CCPP	Gas	(PDB)	1X106+1X57	163	163
68.	Chandpur 200 MW PP (Desh Energy)	HFO	(IPP)	12X18.415	200	200
69.	Feni 22 MW PP (Doreen)	Gas	(SIPP, PDB)	8X2.90	22	22
70.	Feni 11 MW PP (Doreen)	Gas	(SIPP, PDB)	4X2.90	11	11
71.	Jangalia 33 MW PP (Summit)	Gas	(SIPP, PDB)	4X8.73	33	33
72.	Jangalia 52 MW PP (Lakdanavi)	HFO	(IPP)	6X8.92	52	52
73.	Cumilia 25 MW PP (Summit)	Gas	(SIPP, REB)	3X3.67+2X6.97	25	25
74.	Daudkandi 200 MW PP (B. Trac)	HSD	(IPP)	99X1.4+40X1.515+15X1.056	200	200
75.	Feni 114 MW PP (Lakdanavi)	HFO	(IPP)	7*18.415+1*9.78	114	114
76.	Chowmuhani 113 MW PP	HFO	(IPP)	12*9.78+2*3.1	113	113

Serial Number	Name of power station			Number of units X capacity	Installed capacity (MW)	Derated/ present capacity (MW)
77.	Bhairob 54 MW PP	HFO	(IPP)	3X18.2	54	54
78.	Chandpur 115 (Doreen)	HFO	(IPP)			
	Import (Tripura)		India		160	160
	Comilla zone total				**2,944**	**2,699**
79.	RPCL 210 MW CCPP	Gas	(IPP)	4X35+1X70	210	202
80.	Tangali 22 MW PP (Doreen)	Gas	(SIPP, PDB)	8X2.90	22	22
81.	Jamalpur 95 MW PP (Powerpac)	HFO	(IPP)	12X8.924	95	8
82.	Jamalpur 115 MW PP (United)	HFO	(IPP)	12X9.87	115	115
83.	Mymensingh 200 MW PP (United)	HFO	(IPP)	21X9.780	200	200
84.	Sanshabari 3 MW Solar PP	Solar	(IPP)	1X3	3	3
85.	Sutaikhali 50 MW Solar PP	Solar	(IPP)	1X50	50	50
86.	Tangali 22 MW PP (PPGL)	HFO	(IPP)	4X6.7	22	22
	Mymensing zone total				**717**	**622**
87.	Fenchugonj CCPP Phase-1	Gas	(PDB)	2X32+1X33	97	70
88.	Fenchugonj CCPP Phase-2	Gas	(PDB)	2X35+1X35	104	90
89.	Fenchugonj 51 MW PP (Barakfullah)	Gas	(RPP)	19X2.90	51	51
90.	Kushiara 163 MW CCPP (KP)	Gas	(IPP)	1X109+1X54	163	163
91.	Hobibganj 11 MW PP Cofidence-E	Gas	(SIPP, REB)	4X2.90	11	11
92.	Shahjibazar GTPP Unit-8 & -9	Gas	(PDB)	2X35	70	66
93.	Shahjibazar 330 MW CCPP	Gas	(PDB)	2x1 10+ 1x110	330	330
94.	Shahjibazar 86 MW PP (Shahjlbazar)	Gas	(RPP)	32x2.94	86	86
95.	Sylhet 225 MW CCPP	Gas	(PDB)	1x142+1x89	231	231
96.	Sylhet 20 MW GTPP	Gas	(PDB)	1x20	20	20
97.	Sylhet 10 MW PP (Desh)	Gas	(RPP)	6X1.95	10	10
98.	Shahjahanulla 25 MW PP	Gas	(CIPP, REB)	3X 9.34	25	25
99.	Bibiana 11,341 MW CCPP (Summit)	Gas	(IPP)	1X222+1X119	341	341
100.	Bibiana-III 400 MW CCPP	Gas	(PDB)	1X285+1X115	400	400
101.	Bibiana South 383 MW CCPP	Gas	(PDB)	1X252+1X131	383	383
102.	Shahjibazar 100 MW GTPP	Gas	(PDB)	1X100	100	100
	Sylhet zone total				**2,422**	**2,377**

Serial Number	Name of power station			Number of units X capacity	Installed capacity (MW)	Derated/ present capacity (MW)
103.	Bheramara GTPP Unit-3	HSD	(PDB)	1X20	20	16
104.	Bheramara 410 MW CCPP	Gas	(NWPGCL)	1X278+1X132	410	410
105.	Faridpur 50 MW Peaking PP	HFO	(PDB)	8X6.98	54	54
106.	Gopalganj 100 MW Peaking PP	HFO	(PDB)	16X6.98	109	109
107.	Khulna 225 MW CCPP	HSD	(NWPGCL)	1X150+1X75	230	230
108.	Noapara 100 MW PP (Bangla Trac)	HSD	(IPP)	70X1.4+7X1.515	100	100
109.	Rupsha 105 MW PP (Orion rupsha)	HFO	(IPP)	6X18.445	105	105
110.	Madhumati 100 MW PP	HFO	(NWPGCL)	6X18.445	105	105
111.	Mongla Orion 100 MW Solar PP	Solar	(IPP)		100	100
112.	Bheramara (HVDC)		India		1000	1000
Khulna zone total					**2,233**	**2,229**
113.	Barisal 110 MW PP (Summit)	HFO	(IPP)	7x17.076	110	110
114.	Bhola 33 MW PP (Venture)	Gas	(RPP)	1X34.50	33	33
115.	Bhola 225 MW CCPP	Gas	(PDB)	2X63+1X68	194	194
116.	Bhola 95 MW PP (Aggreko)	Gas	(QRPP)	1.1X96	95	95
117.	Payra 1,320 MW TPP	Coal	(BCPCL)	2X622	1,244	1,244
118.	Potuakhali 150 MW PP (UPPL)	HFO	(IPP)	8x18.415+1x9.78	150	150
119.	Bhola 220 MW CCPP (Nutan Bidyut B)	Gas/HSD	(IPP)	2X75+1X70	220	220
Barisha zone total					**2,046**	**2,046**
120.	a) Baghabari 71 MW GTPP	Gas	(PDB)	1X71	71	71
	b) Bashabari 100 MW GTPP	Gas	(PDB)	1X100	100	100
121.	Baghabari 50 MW Peaking PP	HFO	(PDB)	6X8.9	52	52
122.	Baghabari 200 MW PP (Paramount)	HSD	(IPP)	135x1.6	200	200
123.	Bera 70 MW Peaking PP	HFO	(PDB)	9X8.29	71	71
124.	Chapainawabganj 100 MW Peaking PP	HFO	(PDB)	12x8.924	104	104
125.	Katakhali 50 MW Peaking PP	HFO	(PDB)	6X8.7	50	50
126.	Katakhali 50 MW PP (Northern)	HFO	(QRPP)	6X8.9	50	50
127.	Santahar 50 MW Peaking PP	HFO	(PDB)	6X8.7	50	50
128.	Sirajgonj 225 MW CCPP Unit1	Gas	(NWPGCL)	1X150+1X75	210	210
129.	Sirajgonj 225 MW CCPP Unit-2	Gas	(NWPGCL)	1X150+1X75	220	220

Serial Number	Name of power station			Number of units X capacity	Installed capacity (MW)	Derated/ present capacity (MW)
130.	Sirajgonj 225 MW CCPP Unit-3	Gas	(NWPGCL)	1X141+1X79	220	220
131.	Sirajgonj 400 MW CCPP Unit-4	Gas	(IPP)	1X282+1X132	414	414
132.	Bogra 22 MW PP (GBB)	Gas	(RPP)	6X4.0	22	22
133.	Ullapara 11 MW PP (Summit)	Gas	(SIPP, REB)	4X2.90	11	11
134.	Natore 52 MW PP (Rajlanka)	HFO	(IPP)	6X8.92	52	52
135.	Bagura 113 MW PP (Confidence) Unit-1	HFO	(IPP)	6*18.55	113	113
136.	Bagura 113 MW PP (Confidence) Unit-2	HFO	(IPP)	6*18.55	113	113
137.	Sirajgonj 6.55 MW Solar PP	Solar	(NWPGCL)	1X6	6	6
Rajshahi zone total					**2,129**	**2,129**
138.	a) Barapukuria TPP Unit-1	Coal	(PDB)	1X125	125	85
	b) Barapukuria TPP Unit-2	Coal	(PDB)	1X125	125	85
139.	Barapukuria 275 MW Unit-3	Coal	(PDB)	1X20	274	274
140.	Rangpur 20 MW GTPP	HSD	(PDB)	1X20	20	20
141.	Rangpur 113 MW PP (Confidence)	HFO	(IPP)	7*18X2*3	113	113
142.	Saidpur 20 MW GTPP	HSD	(PDB)	1X20	20	20
143.	Majipara, Tatulia 8 MW Solar PP (Sympa Power)	Solar	(IPP)	1X8	8	8
144.	Energypac Power Venture Thakurgaon Ltd	HFO	(IPP)			
Rangpur zone total					**685**	**605**
Subtotal: Plants in operation					**21,471**	**20,985**
Available power at substation end, excluding Price/Sales auxiliary use and transmission loss.						
(B) Plants under long-term maintenance/contract expired						
145.	Bosila 108 MW PP (CLC)	HFO	(IPP)	12X8.775+1X3.5	108	0
146.	Siddhirganj 100 MW PP (Dutch Bangla)	HFO	(QRPP)	12X8.9	100	0
147.	Madanganj 102 MW PP (Summit)	HFO	(QRPP)	6X17	102	0
148.	Bogura 20 MW PP (Energyprima)	Gas	(RPP)	5X3.3+5X2.0	20	0
149.	Meghnaghal 100 MW PP (IEL)	HFO	(QRPP)	12X8.9	100	0
150.	Khulna 115 MW PP (KPCL-2)	HFO	(QRPP)	7X17	115	115
151.	Amnura 50 MW PP (Sinha)	HFO	(QRPP)	7X7.79	50	50
Subtotal: Plants under long-term maintenance/contract expired					**595**	**50**
Grand total					**22,066**	**21,035**

In 2021, the total installed power generation capacity in Bangladesh was 22,066 megawatts (MW); 21,471 MW was in operation, and 595 MW was not in operation because these power plants are undergoing long-term maintenance or have expired contracts. While the total installed capacity was 22,066 MW, the derated capacity was 21,035 MW. Of the operational power plants, the installed capacity was 21,471 MW, and the corresponding derated capacity was 20,985 MW.

Table 2 lists the capacities and percentage spread of operating power plants by zone.

Table 2. Operating power plants' capacities by zone

Serial No.	Zone	Installed capacity (MW)	Derated capacity (MW)	% Spread (derated basis)
1	Dhaka	5,853	5,696	27.14%
2	Comilla	2,944	2,899	13.82%
3	Chattogram	2,442	2,382	11.35%
4	Sylhet	2,422	2,377	11.33%
5	Khulna	2,233	2,229	10.62%
6	Rajshahi	2,129	2,129	10.15%
7	Barishal	2,046	2,046	9.75%
8	Mymensing	717	622	2.96%
9	Rangpur	685	605	2.88%
		21,471	**20,985**	

There are nine zones, comprising 142 power plants (2021):

- Dhaka zone: 36 plants in operation—17 are gas, 15 are heavy fuel oil (HFO), 3 are high speed diesel (HSD), and 1 is solar.
- Comilla zone: 22 plants in operation—13 are gas, 8 are HFO, and 1 is HSD.
- Chattogram zone: 21 plants in operation—12 are HFO, 6 are gas, 2 are hydro, and 1 is solar.
- Sylhet zone: 16 plants in operation and all are gas-based, including PDB, IPP, CIPP, REB, RPP, and SIPP.
- Khulna zone: 8 plants in operation—1 is solar, 2 are HSD, 1 is gas, and 4 are HFO.
- Rajshahi zone: 19 plants in operation—8 are gas, 9 are HFO, 1 is solar, and 1 is HSD.
- Barishal zone: 7 plants in operation—3 are gas, 2 are HFO, 1 is coal, and 1 is gas/HSD.
- Mymensing zone: 8 plants in operation—2 are gas, 4 are HFO, and 2 are solar.
- Rangpur zone: 8 plants in operation—3 are coal, 2 are HSD, 2 are HFO, and 1 is solar.

Table 3 presents the capacities and % share of total installed capacity and operating power plants by type.

Table 3. Operating power plants' capacities by type

Serial No.	Type of power plant	Installed capacity (MW)	(Amount)	% Share of total installed MW	Ranking
NG-based power plants					
1.	Gas-based CCPPs (GT + ST)	8,598	29	39.0%	1
2.	Gas-based OC gas PPs (GT only)	1,188	12	5.4%	5

Serial No.	Type of power plant	Installed capacity (MW)	(Amount)	% Share of total installed MW	Ranking
3.	Gas-based conventional TPPs (boiler & ST)	1,804	25	8.2%	3
Liquid fuel-based power plants					
4.	HFO-based conventional TPPs (boiler & ST)	6,979	56	31.6%	2
5.	HSD-based diesel engine OC TPPs (diesel engine & ST)	1,110	10	5.0%	6
Solid fuel-based power plants					
6.	Coal-based conventional TPPs (boiler & ST)	1,768	4	8.0%	4
Other types of power plants					
7.	Hydro-based PPs	230	1	1.04%	7
8.	SPV PPs	229	7	1.03%	8
Miscellaneous					
9.	Import of power from India (Tripura)	160	1	0.73%	9

- 52.6% of the total installed power (MW) in Bangladesh is based on natural gas (NG), out of which 39% (of total installed MW) are NG-based combined cycle power plants (CCPPs) with gas turbine (GT) + steam turbine (ST) combination, 5.4% are NG GT open cycle (OC) thermal power plants (TPPs), whereas 8.2% are NG-fired conventional TPPs.
- 36.6% of the total installed power (MW) in Bangladesh is liquid fuel fired, out of which 31.6% (of total installed MW) is HFO-based conventional TPPs (boiler and ST), whereas 5% (of total) is HSD-based diesel engine OC TPPs (diesel engine and ST).
- 8.0% of the total installed power (MW) in Bangladesh is solid fuel, coal-fired conventional TPPs (boiler and ST).

The abovementioned power plants constitute the TPPs in Bangladesh. Besides the TPPs, the other sources of power feeding the grid are:

- 1.04% of the total installed power (MW) in Bangladesh is generated from hydropower plants.
- 1.03% of the total installed power (MW) in Bangladesh is from solar photovoltaic (SPV) power plants.
- Around 0.73% of the total power (MW) is imported, specifically from Tripura in India.

Currently, 8% of the power generation is based on coal, which is expected to grow to 50% by 2030, while 10% (2030) will be nuclear power.

There are some isolated diesel power stations at remote places and islands that are not connected with the national grid. The terminal voltage of different generators is 11 kilovolts (kV), 11.5 kV, and 15.75 kV. In the eastern zone (eastern side of the Jamuna River), the electricity is generated from indigenous gas, and a small percentage through hydropower. In the western zone, coal and imported liquid fuel are used for electricity generation. The fuel cost per unit generation in the western zone is much higher than that of the eastern zone. Therefore, as a policy, low-cost electricity generated in the eastern zone is transferred to the western zone through the 230 kV east-west interconnector transmission line.

2 Annexure 2: Sample of key operating parameters of a few types of TPPs in Bangladesh

2.1 Comparison of operating parameters of a small sample of four types of TPPs in Bangladesh

Based on a questionnaire survey, a few TPPs in Bangladesh responded, and these are presented here as a comparison featuring key operating parameters of these four TPPs.

- CCPP: This is the first TPP that is gas fired, a GT- and ST-based CCPP.
- GT OC and GT closed cycle (CC), presently GT CC on diesel (CCPP): This is the second TPP that has both OC and CC systems. OC is GT only, whereas the CC is GT and ST. Presently, this TPP is operating with diesel firing on CC mode only.
- Diesel/NG engine CC: This is a Combined Cycle Power Plant (CCPP) powered by an engine that can operate on diesel firing mode, as well as NG firing mode in Closed Cycle.
- GT OC power station: This is purely a GT-based, NG-fired, OC TPP.

The station capacities vary from 66 MW to 230 MW. The fuels used are NG, HSD, and HFO. The auxiliary power consumption (APC) for CCPP varies between 2.8% and 2.93% of the total generation. Exit flue gas temperature from the GTs is around 550°C. Exit flue gas temperature from the heat recovery steam generator (HRSG) boiler ranges between 125°C and 130°C. Generation voltage is 10.5–15 kV. The typical air pressure drop across the air filter of the GT is around 30–160 millimeters of water column (mmWC).

The specific fuel consumption of one of the CCPPs based on NG is 0.2282 Sm^3/kilowatt hours (kWh), whereas for an HSD-based CCPP, the specific fuel consumption is 0.198 kilograms (kg)/kWh. The cycle efficiencies are reported to be 31.1% and 35.8%, respectively, on OC, whereas 46% and 52%, respectively, on CC. The gross heat rates (HRs) on OC are reported as 2,760 kilocalories (Kcal)/kWh and 2,479 Kcal/kWh, respectively, and the gross HRs on the combined cycle are reported as 1,953 Kcal/kWh and 1,872 Kcal/kWh, respectively.

The net HRs on combined cycle are reported as 2,006 Kcal/kWh and 2,163 Kcal/kWh, respectively. The typical lower heating value of NG is 8,352 Kcal/Sm^3. The generator power factor is of the order of 0.8–0.85, and in OC, in one of the cases, it is 0.99. The amount of steam generated in the CCPPs varies from 61 Tonnes Per Hour (TPH) to 198 TPH of high-pressure (HP) steam, and 13 TPH to 38 TPH of low-pressure (LP) steam. The HP steam pressure varies from 102 bar to 198 bar—the temperature for HP steam is around 510–520°C.

The cost of generation of CCPPs fired by NG is 2.9 Bangladeshi Taka (BDT)/kWh, whereas for HSD-fired plants the cost of generation is much higher at 16.7–16.8 BDT/kWh when the plant load factor (PLF) is around 84%, and the HSD price is around 68.8 BDT/liter. None of the TPPs that responded to the questionnaire survey claim to have a separate energy efficiency (EE)/audit cell. None of them had conducted an energy audit, either. ***A list of operating parameters of a small sample of four types of TPPs in Bangladesh is mentioned below in the table.***

Table 4.Operating parameters of a small sample of four types of TPPs in Bangladesh

Parameters of gas power plant	Unit	CCPP	GT OC and GT CC, presently GT CC on diesel (CCPP)	Diesel/NG engine CCPP	GT OC PP
Technical details					
Station capacity	MW	210 MW	230 MW	104 MW	Installed: 70 MW, Dependable Capacity (A.C. test on 12.11.19): 66 MW
Total number of units	Nos.	4 GTs, 35 MW each, and 1 ST of 70 MW	1	12	2
Capacity of each unit	MW	GTs, 35 MW each, and 1 ST of 70 MW	230 MW	8.924	33 MW
Fuels used (names)	Gas/Oil	NG	HSD (Plant is not yet commissioned with NG.)	HFO & Diesel	3,096 Kcal/kWh
GCV of fuels	Kcal/kg or Kcal/Sm^3	8,382 Kcal/Sm^3	10,151.73 Kcal/kg	N/A	N/A
Density of fuels used	kg/liter, or kg/m^3, or kg/Sm^3	0.7494 kg/Nm^3	826.24 kg/m^3	N/A	N/A
Station generation	MW	210 MW	230 MW	N/A	N/A
	MU/year	1,216,386.93 MWh in 2021	290,858.600 MWh (in Fiscal Year [FY] 2020–2021)	N/A	N/A
Unit-wise generation	MW	GT, 35 MW each, and an ST of 70 MW	230 MW	N/A	N/A
	MU/year	GT-1: 188,196 MWh, GT-2: 210,291.6 MWh, GT-3: 209,281.5 MWh, GT-4: 193,688.7 MWh, ST: 448,429.5 MWh in 2021	290,858.600 MWh (in FY 2020–2021)	N/A	N/A
Average annual gas or fuel oil consumption	Sm^3/year or kg/year	288,862,382 Sm^3 in 2021	55,783,800.52 kg (in FY 2020–2021)	N/A	N/A
Average PLF	%	68.44% in 2021	59.39% (in October 2021)	N/A	N/A
Specific fuel consumption	kg fuel or Sm^3 gas/kWh	0.2382 Sm^3/kWh	0.198 Kg/kWh (in October 2021)	N/A	N/A
Annual down time	Hours/year	GT-1: 0 Hr, GT-2: 210,291.6 MWh, GT-3: 209,281.5 MWh, GT-4: 193,688.7 MWh, STG: 448,429.5 MWh in 2021	117.2 hours (in FY 2020–2021)	N/A	N/A
Operating in OC or CC	O/CC	Combined cycle	OC & CC (depends on NLDC requirement)	N/A	N/A
GT or engine OC efficiency	%	31.06%	35.80%	N/A	N/A
GT or engine combined cycle efficiency	%	46%	52%	N/A	N/A
Gross HR-design	Kcal/kWh	11,590 kJ/kWh (OC GT)	2,478.48 Kcal/kWh (for simple cycle)	N/A	N/A
Gross HR-actual	Kcal/kWh	1,953 Kcal/kWh	2,513.37 Kcal/kWh (for combined cycle); 1,871.76 Kcal/kWh (for simple cycle)	N/A	N/A

Parameters of gas power plant	Unit	CCPP	GT OC and GT CC, presently GT CC on diesel (CCPP)	Diesel/NG engine CCPP	GT OC PP
Net HR-design	Kcal/kWh	7,804 KJ/kWh (as per Power Purchase Agreement)	Data is not available	N/A	N/A
Net HR-actual	Kcal/kWh	2,006 Kcal/kWh	2,163 Kcal/kWh	N/A	N/A
APC	% Total generation	2.78% in 2021	2.929% of total generation	N/A	N/A
Annual additional fuel used in HRSG (boiler)	kg fuel/year or Sm^3 gas/year	N/A	N/A	N/A	N/A
Flue gas outlet temperature of GT or gas engine	°C	548	550°C	N/A	N/A
Flue gas outlet temperature from HRSG (boiler)	°C	127	124°C	N/A	N/A
Fuel gas inlet temperature to HRSG (boiler)	°C	547	550°C	N/A	N/A
Generation voltage	kV	11	GT: 15 kV, ST: 10.5 kV	11	N/A
GT compressor inlet conditions					
Air temperature	°C	32	35°C (Design)	N/A	N/A
Pressure	kg/cm^2 g	1,012	1.0329 kg/cm^2 (Design)	N/A	N/A
Dry bulb temperature	°C	32	35°C	N/A	N/A
Wet bulb temperature	°C		34.7°C	N/A	N/A
Differential pressure inlet air filter	mmWC	30 to 160 mm H_2O	76,478.71 mmWC	N/A	N/A
Fuel data					
Type of fuel fired	Gas/liquid	NG	HSD	N/A	NG
Fuel flow rate	Sm^3/hr	11,600 Sm^3/hr (each GT)	11 kg/s	N/A	2.22 kg/s of GT#8 & 2.10 kg/s of GT#9
Lower heating value	$Kcal/Sm^3$	8,352 $Kcal/Sm^3$	10,151.73 Kcal/kg	N/A	950 Btu/scf
Auxiliary fuel for HRSG		None	Not used	N/A	N/A
Exhaust flue gas conditions					
Flow	kg/s	121.2 kg/s (each GT)	39.92 liter/min	N/A	N/A
Temperature	°C	548°C	124°C	N/A	543°C of GT#8 & 542°C of GT#9
Specific heat of flue gas	Kcal/kg °C	N/A	Data not available	N/A	N/A
Generator data					
Average power output	kW	GT: 35,570 kW; ST: 77,356 kW	140,000 kW (GT: 93,800 kW; ST: 46,200 kW)	100	66,000 kW
Power factor		0.85	0.8	0.8	0.99
WHRB data					

Parameters of gas power plant	Unit	CCPP	GT OC and GT CC, presently GT CC on diesel (CCPP)	Diesel/NG engine CCPP	GT OC PP
Exhaust gas temperature at inlet	°C	547	550°C (Maximum)	370	N/A
Exhaust gas temperature at boiler exit	°C	127	124°C		N/A
Steam parameters at WHRB exit					
Parameters	**Unit**	**CCPP**	**GT OC and GT CC, presently GT CC on diesel (CCPP)**	**Diesel/NG engine CCPP**	**GT OC PP**
Flow	tons/hr	HP: 61.02 tons/hr; LP: 13.28 tons/hr	HP: 198.18; IP: 32.72; LP: 38.196 tons/hr	3	N/A
Temperature	°C	HP: 520°C; LP: 200°C	HP: 515; IP: 504.5; LP: 229°C	165	N/A
Pressure	kg/cm^2g	HP: 82.5 bar; LP: 5.3 bar	HP: 7.89; IP: 3.46; LP: 0.51 MPa	7	N/A
Feed water inlet parameters					
Flow	Kg/hr	HP: 61.02 tons/hr; LP: 13.28 tons/hr	278,000 kg/hr		N/A
Temperature at drum inlet	°C	HP: 261°C; LP: 128°C	46°C		N/A
Pressure	kg/cm^2g	HP: 102 bar; LP: 17.6 bar	2.03 MPa, 20.7 kg/cm^2		N/A
Enthalpy at drum inlet	Kcal/kg		46.03 Kcal/kg		N/A
End-user profile of power/energy sold	All		National Grid		N/A
Cost of generation	BDT/kWh		16.7429 BDT/kWh (if plant factor 84.6% and HSD price 68.81 BDT/liter)	16.80 in December 2021	N/A
Selling price	BDT/kWh	2.90 BDT/kWh	16.7429 BDT/kWh (if plant factor 84.6% and HSD price 68.81 BDT/liter)		N/A
Does the PP have a separate energy efficiency/audit cell?	Yes/No		No		N/A
Has the PP hitherto been regularly doing energy audits?	Yes/No		No		N/A
If yes, can a soft copy of their energy audit report be obtained and sent to us please?			N/A		N/A

3 Annexure 3: Energy audit procedures for key energy consuming equipment in TPPs

3.1 Energy audit procedure for GT OC efficiency (on NCV)

List of contents

1. Objective

To access the existing performance of GT units (ST system is not included), an interunit comparison gives meaningful inputs for selective loading of GTs for fuel optimization as well as permitting early interference in case of a drop in performance.

2. Instruments required

- Online instruments (calibrated within the last 12 months at least).
- Calibrated fuel flow measurement devices.
- Gas chromatograph for fuel gas calorific value.

3. Audit procedure

- Combine design, performance guarantee (PG) test, previous best, and last energy audit value of efficiency of the individual GT.
- Ensure all online instruments are calibrated within the last 12 months. Compile the calibration dates/data for all instruments. All the instruments must comply with the designed accuracy levels after calibration.
- Observe and fill the data sheet for 1 hour at 10-minute intervals in five sets for 1 day only.
- The period suggested for noting the readings is only 1 hour for trial, with trials repeating five times over different time periods of the day—preferably maintaining the same MW load to capture variation due to ambient condition changes.
- Compute OC efficiency as per the calculation sheet in the Annexure.
- Compare the results with design and PG test/previous best/last energy audit value.
- Investigations for abnormality are to be carried out for problems related to combustion.
- Enlist a scope of improvement with extensive checks.
- Enlist recommendations for actions to be taken for improvement.
- Cost analysis with savings potential for taking improvement measures.

4. Report preparation format

The audit report should be prepared in the following format:

- Foreword
- Audit team
- Technical specifications
- Present practices: Explain in detail the present status
- Observation and remarks: Refer to the data and conclusion sheets and note observations and remarks about the energy audit carried out
- Recommendations: Energy conservation options along with savings potential sheet, including estimated expenditure, payback period, and other related expected benefits
- Single line diagram

- Data regarding calibration of instruments used, indicating dates of last calibration (calibration more than 12 months old is not acceptable)

5. Audit tools for auditors

GT OC efficiency (on NCV) = {(GT load (kW) * 860 * 100)} / fuel gas flow (Sm^3/hr) * (GCV of fuel Kcal/Sm^3)}

The OC efficiency of GTs deteriorates with the extent of partial loading. As per original equipment manufacturer (OEM) guidelines, all types of GT have a degradation curve. It is required to compare the percent of degradation with the actual power output or HR.

6. Annexure: (Energy audit procedure for GT OC efficiency)

OC efficiency (Data collection sheet)

Table 5. Data collection sheet for GT OC efficiency

Unit	OC efficiency				
	Design value	PG test value	Previous best value	Last energy audit value	Present energy audit actual value
GT#1					
GT#2					

*During an energy audit, it is customary to request the TPP to provide the rated load conditions or design load conditions (as the case may be) for a short duration of 1 hour only.

Data sheet

GT OC efficiency assessment

GT Unit-1/2/3/4 Date:

Table 6. Data sheet for GT OC efficiency assessment

S. No.	Time	GT load (kW)	Ambient air temperature (°C)	Fuel gas flow rate (Sm^3/hr)	Fuel gas calorific value (Kcal/Sm^3)

Calculation sheet

GT OC efficiency assessment

Project:

GT Unit-1/2/3/4 Date:

- Duration of observations =
- Average GT load (kW) =
- Average ambient air temperature (°C) =
- Average fuel gas flow rate (Sm^3/hr) =
- Average gross calorific value (GCV) of fuel gas (Kcal/Sm^3) =
- GT OC efficiency (%) = {(Average GT load * (860) * (100))} / {(Average fuel gas fuel) * (Average GCV of fuel gas)}
- Design efficiency at part load conditions =

*The OC efficiency will be calculated up to six digits.

* Fuel gas will be measured at standard conditions—15°C and ambient pressure, so fuel gas flow will be in Sm^3/hr, and Gross Calorific Value (GCV) / Net Calorific Value (NCV) of fuel gas will be in

$Kcal/Sm^3$ In the baseline case, as well as in present as run trial case. If fuel gas is expressed in kg/hr and fuel gas GCV or NCV in Kcal/kg, then that would be no issue.

Saving potential sheet

Table 7. Saving potential sheet for GT OC efficiency assessment

S. No.	Activity	Savings (kWh/year)	Savings (BDT/year)
1	Efficiency improvement potential		

3.2 Energy audit procedure for GT compressor

List of contents

1. Objective
2. Instruments required
3. Audit procedure
4. Report preparation format
5. Audit tools for auditors
6. Annexures

1. Objective

To access the existing performance of the GT compressor, which is a key energy consumer in the combined cycle system. Interunit comparison gives an impression about the evolution between two inspections and permits early interference in case of fall in the performance.

2. Instruments required

- Online instruments.
- Additional temperature/pressure gauges with an appropriate range of measurement and calibrated before an audit.

3. Audit procedure

- Combine design, PG test, previous best, and last energy audit value of compressor efficiency of the individual GT.
- Ensure all online instruments are calibrated within the last 12 months. Compile the calibration dates/data for all the instruments. All the instruments must comply with the designed accuracy levels after calibration.
- Observe and fill the data sheet for 1 hour at 5-minute intervals in five sets for 1 day only.
- The period suggested for noting the readings is only 1 hour for trial, with trials repeating five times over different time periods of the day—preferably maintaining the same MW load to capture variation due to ambient condition changes.
- Calculate the compressor efficiency as per the calculation sheet.
- Compare the results with design, PG test, previous data, and last energy audit data annexure.
- A detailed investigation into abnormalities may be carried out. The likely problems could be compressor fouling air leakages, air intake system, related defects, etc.
- Enlist scope of improvement.
- Enlist recommendations for action to be taken for improvement.
- Cost analysis with savings potential for taking improvement measures.

4. Report preparation format

The audit report should be prepared in the following format:

- Foreword
- Audit team
- Technical specifications
- Present practices: Explain in detail the present status

- Observation and remarks: Refer to the data and conclusion sheets and note observations and remarks about the energy audit carried out
- Recommendations: Energy conservation options along with the savings potential sheet, including estimated expenditure, payback period, and other related expected benefits
- Single line diagram
- Data regarding calibration of instruments used, indicating dates of last calibration (calibration more than 12 months old is not acceptable)

5. Audit tools for auditors

Adiabatic discharge air temperature T2s for the measured average inlet air temperature can be calculated through the formula:

$$T_{2s} / T_1 = P^{(r-1)/r}$$

- Consider compression coefficient: r = 1.4
- Compressor efficiency (η)%

$$\eta\ \% = (T_{2s} - T_1) * 100 / (T_2 - T_1)$$

T_{2s} = Adiabatic discharge air temperature (K)
T_2 = Compressor discharge air temperature (K)
T_1 =Compressor inlet air temperature (K)
r = Compression coefficient
P = Compression ratio = (discharge pressure/suction pressure)

6. Annexure (Energy audit procedure for GT compressor)

Compressor efficiency (data collection sheet)

Table 8. Data collection sheet for compressor efficiency assessment

GT ref.	Compressor efficiency				
	Design value	PG test value	Previous best value	Last energy audit value	Present audit actual value
GT#1					
GT#2					
GT#3					
GT#4					

Data sheet

Compressor efficiency assessment
GT Unit-1/2/3/4 Date:

Table 9. Data sheet for compressor efficiency assessment

S. No.	Time	GT load (kW)	Frequency (Hz)	Compressor inlet air temperature (°C)	Compressor discharge pressure (Bar)	Compressor discharge air temperature (°C)

Calculation sheet

1. Duration of observations = (hr)
2. Average GT load = (MW)
3. Average compressor inlet temperature (T_1) = (K)
4. Average compressor discharge pressure = bar

5. Average compressor discharge temperature (T_2) = (K)
6. Compression ratio P (Item 5/Item 4)
7. Adiabatic discharge air temperature (T_{2s}) for above inlet air temperature and compression coefficient of r = 1.40 = (K)
8. Calculated actual compressor efficiency % = x
9. Compressor design efficiency % = y
10. Difference in design and calculated efficiency = (y - x) %
11. Running hours of compressor = Z
12. Cost of power (BDT/kwh) = C
13. Loss in terms of BDT = (kW of compressor) * (y - x) * Z * C
14. Loss in terms of BDT

Saving potential sheet

Table 10. Saving potential sheet for GT compressor

S. No.	Activity	Savings (kWh/year)	Savings (BDT/year)
1	Efficiency improvement potential through • Compressor washing, and/or • Attending to air intake system problems, and/or • Other corrective measures: if any, please specify.		

3.3 Energy audit procedure for HRSG: Waste heat boiler system and associated auxiliary equipment

List of contents

1. Objective
2. Instruments required
3. Audit procedure
4. Report preparation format
5. Audit tools for auditors
6. Annexures

1. Objective

To assess the prevalent performance of waste heat recovery boiler (WHRB] or HRSG), which constitutes a key linkage in the combined cycle system. Various indicators yield valuable information regarding performance and help in planning corrective measures for the upkeep of efficiency.

2. Instruments required

- Online instruments (calibrated within the last 12 months at least).
- Flue gas temperature measurement devices.
- HP/LP steam temperature measurement devices.
- HP/LP steam pressure measurement devices.

3. Audit procedure

- Compile design PG test, previous best, and last energy audit value of WHRB performance indicators.
- Ensure all online instruments have been calibrated within the last 12 months. Compile the calibration dates/data for all instruments.
- Fill the data sheet for 3 days, taking five sets on each day. The timing for taking a set of readings will be observed as follows:
  - ✓ 0900 hr
  - ✓ 1400 hr

- ✓ 1900 hr
- ✓ 0000 hr
- ✓ 0600 hr

The calculation will be carried out as per the data computation sheet.

4. Report preparation format

The audit report may be prepared in the following format:

- Foreword
- Audit team
- Technical specifications
- Present practices: Explain in detail the present status
- Observation and remarks: Refer to the data and conclusion sheets annexed and put down your observations and remarks about the energy audit carried out
- Recommendations: Energy conservation options along with savings potential sheet, including estimated expenditure, payback period, and other related expected benefits
- Single line diagram
- Data regarding calibration of instruments used, indicating dates of the last calibration (calibration more than 12 months old is not acceptable)

5. Audit tools for auditors—Data computation sheet

1. GT output (MW)
2. ST output (MW)
3. HP steam flow (TPH)
4. LP steam flow (TPH)
5. HP steam pressure (bar)
6. LP steam pressure (bar)
7. HP super heater temperature (°C)
8. HP super heater steam (H_{sHs}) enthalpy (Kcal/kg)
9. HP saturated steam (H_{ss}) enthalpy (Kcal/kg)
10. Flue gas temperature to HP super heater inlet (°C)
11. Flue gas temperature to HP super heater outlet (°C)
    $\{(TPH * 10^3 * (H_{sHs} - H_{ss})\} / 10^6$ = Item 3 * $10^{(-3)}$ * (Item 8 - Item 9)
12. Heat pickup in HP super heater in million Kcal/hr
13. Flue gas temperature at HP evaporator inlet (°C)
14. Flue gas temperature at HP evaporator outlet (°C)
15. Economiser-2 outlet water enthalpy (Kcal/kg)
16. Heat pickup in HP evaporator in million Kcal/hr
    $\{(TPH * 10^3 * (H_{ss} - H_{eva-out})\} / 10^6$ = Item 3 * $10^{(-3)}$ * (Item 9 - Item 15)
17. Flue gas temperature at the inlet to HP economizer-2 (°C)
18. Flue gas temperature at the outlet of HP economizer-2 (°C)
19. Water temperature and water enthalpy at HP economizer-1 inlet (Kcal/kg)
20. HP economizers-1 and -2 heat pickup in million Kcal/hr
    $\{(TPH * 10^3 * (H_{eco2out} - H_{eco1in})\} / 10^6$ = Item 3 * $10^{(-3)}$ * (Item 15 - Item 19)
21. Flue gas temperature at LP super heater inlet °C
22. Flue gas temperature at LP super heater outlet °C
23. LP super heater steam temperature °C
24. Enthalpy of LP super heater (Kcal/kg)
25. Enthalpy of LP saturated steam (Kcal/kg)
26. Heat pickup in LP super heater in million Kcal/hr
    $\{(TPH * 10^3 * (H_{LPsHs} - H_{LPss}))\} / 10^6$ = Item 4 * $10^{(-3)}$ * (Item 24 - Item 25)
27. Flue gas temperature at LP evaporator inlet °C
28. Flue gas temperature at LP evaporator outlet °C
29. Feed water enthalpy at evaporator inlet (Kcal/kg)

30. Heat pickup in LP evaporator inlet in million Kcal/hr
    {(TPH * 10^3 * (H_{ss} - H_{ecoout}))} / 10^6 = Item 4 * $10^{(-3)}$ * (Item 25 - Item 29)
31. Flue gas temperature at LP/HP-1 economizer inlet °C (flue gas, fg)
32. Flue gas temperature at LP/HP-1 (flue gas) economizer outlet °C
33. Flue water enthalpy LP/HP-1 economizer outlet Kcal/kg
34. Heat pickup in LP/HP-1 economizer in Kcal/hr
    {(TPH * 10^3 * (H_{ss} - H_{ecoout}))} / 10^6 = Item 4 * $10^{(-3)}$ * (Item 29 - Item 33)
35. Flue water (fg) temperature at condensate preheater inlet °C
36. Flue water (fg) temperature at condensate preheater outlet °C
37. Flow-through condensate preheater (TPH) (Item 3 + Item 4)
38. Feed water temperature at the inlet to condensate preheater °C
39. Feed water temperature at the outlet to condensate preheater °C
40. Condensate preheater heat pickup in million Kcal/hr
    {(Total TPH * 10^3 * (T_{out} - T_{in}))} / 10^6 = Item 37 * $10^{(-3)}$ * (Item 39 - Item 38)
41. Total heat pickup in HRSG by water and steam circuit in million Kcal/hr
    (Item 12 + Item 16 + Item 20 + Item 26 + Item 30 + Item 34 + Item 40)
42. Percentage breakup of heat pickup in various heat transfer sub equipment
    - HP super heater
    - HP evaporator
    - HP economizer-1 and -2
    - LP super heater
    - LP evaporator
    - LP economizer
    - Condensate preheater
43. Ambient air temperature (°C)
44. Thermal efficiency of WHRB (Item 10 - Item 36) * 100 / (Item 10 - Item 43)
45. Design efficiency of WHRB
46. The difference in efficiency (Item 45 - Item 44)

6. Annexure

HRSG waste heat boiler system and associated auxiliary equipment.

Savings Potential Sheet

Table 11. Savings potential sheet for HRSG

S. No.	Activity	Annual energy savings (kWh/year)	Savings (BDT/year)
1	Thermal efficiency improvement potential		

3.4 Energy audit procedure for boiler[1]

List of contents

1. Objectives
2. Instruments required
3. Audit procedure
4. Report preparation format
5. Audit tools for auditors
6. Annexures

1. Objectives

[1] Energy Efficiency in thermal Utilities- BEE https://s3.ap-south-1.amazonaws.com/aipnpc.org/downloads/T_5119_ENERGY_EFFICIENCY_IN_THERMAL_UTILITIES.pdf

- To determine the thermal efficiency of the boiler(s). This is assessed by indirect method, wherein the various losses are identified, measured, and quantified, thereby allowing for objective and meaningful interventions, leading to energy savings.
- Based on thermal efficiency, to determine the evaporation ratio (ER) of the boiler(s) and calculate the expected fuel consumption rate and compare it with the actual.

2. Instruments required

- Online instruments (calibrated within the last 12 months at least)
- Calibrated fuel flow measurement device (online)
- Calibrated steam flow measurement device online)
- Power analyzer
- Ultrasonic flow meter
- Pitot tube and digital manometer
- Total dissolved solids (TDS) meter
- Stroboscope
- Fuel testing/analysis services (internal or external lab; both need to be accredited)

3. Audit procedure

- Compile design, PG test, previous best, and last energy audit value of thermal efficiencies of individual boilers.
- Ensure all online instruments have been calibrated within the last 12 months. Compile the calibration dates/data for all the instruments. All instruments must comply with the designed accuracy levels after calibration.
- Normally, for a boiler, a 6-hour as-run trial is conducted, including the first hour for stabilization and the last hour for graceful trial closure. While observations are made and recorded, at a steady load for 6 hours, at 10- to 15-minute intervals, the calculations are based on readings from the 2nd to the 5th hours. Observe and fill data sheet (as per Annexure 1).
- Compute boiler thermal efficiency as per calculation sheet (Annexure 2).
- Compute boiler evaporation ratio and expected fuel consumption rate as per calculation sheet (Annexure 3).
- Prepare a comparative table of boiler-wise thermal efficiency, present versus design, PG test, previous best, and last energy audit value (Annexure 4).

Table 12: Comparative table of boiler-wise thermal efficiency

Boiler reference	Thermal efficiency (%)			
	Design value	PG test value	Previous best value	Last energy audit value
Boiler number-1				
Boiler number-2				

a) The investigations for abnormality are to be carried out related to various operating parameters.
b) Enlist scope for improvement with extensive checks.
c) Enlist recommendations for action to be taken for improvements.
d) Cost analysis with savings potential for the improvement measures.

4. Report preparation format

The audit report will be prepared in the following format:

- Foreword
- Audit team
- Technical specifications
- Present practices: Explain in detail the present status

- Observation and remarks: Refer to the data and conclusion sheets and note observations and remarks about the energy audit carried out
- Recommendations: Energy conservation options along with savings potential sheet, including estimated expenditures, payback period, and other related expected benefits
- Single line diagram
- Data regarding calibration of instruments used, indicating dates of last calibration (calibration more than 12 months old is not acceptable)

5. <u>Audit tools for auditors</u>

Boiler efficiency by indirect method

Step 1: Find theoretical air requirement

= [(11.6 x C) + {34.8 x (H_2 - (O_2 / 8))} + (4.35 x S)] / 100, kg theoretical air/kg fuel.
Where: C, O_2, H_2, S are in % age by weight

Step 2: To find excess air supplied (EAS)

Actual O_2 measured in flue gas = X%
% EAS = (X%) * 100 / (21 - X%)

Step 3: To find actual mass of air supplied (AAS)

AAS = {1 + (EA% / 100)} * (theoretical air required), (kg actual air/kg fuel)

Step 4: To find actual mass of dry flue gas

= Mass of dry flue gas (m) = Mass of CO_2 in flue gas + Mass of N_2 content in the fuel + Mass of N_2 in the combustion air supplied + Mass of oxygen in flue gas + Mass of SO_2 in flue gas.
= [%C in fuel / 100) * (44 / 12)] + [% N_2 in fuel / 100)] + [(Actual mass of air, kg/kg) * (77 / 100)] + [{(Actual mass of air supplied) – (Theoretical air required)} * (23 / 100)] + [(%S in fuel / 100) * (64 / 32)], (kg dry flue gas/kg fuel)

Step 5: To find all losses

1) *% Heat loss in dry flue gas (L1) = m x C_p x (T_f - T_a) * 100 / GCV of fuel*
   Where: m = mass of exit flue gas, kg/kg fuel; C_p = specific heat of exit flue gas, Kcal/kg °C; T_f = Temperature of exit flue gas (°C); T_a = Temperature of ambient air (°C); GCV of fuel, Kcal/kg fuel

2) *% Heat loss due to formation of water from H_2 in fuel (L2)*
   *= [(9 * H_2% / 100) * {584 + C_p (T_f - T_a)}] * 100 / (GCV of fuel)*
   Where: H_2% = H_2 % by weight in fuel; C_p = specific heat of exit flue gas, Kcal/kg °C; T_f = Temperature of exit flue gas (°C); T_a = Temperature of ambient air (°C); GCV of fuel, Kcal/kg fuel

3) *% Heat loss due to moisture in fuel (L3) = [(M% / 100) x {584 + C_p (T_f - T_a)}] * 100 / GCV of fuel*
   Where: M% = Moisture % by weight in fuel; C_p = specific heat of exit flue gas, Kcal/kg °C; T_f = Temperature of exit flue gas (°C); T_a = Temperature of ambient air (°C); GCV of fuel, Kcal/kg fuel

4) *% Heat loss due to moisture in air (L4) = AAS x H_a x C_p x (T_f-T_a) / GCV of fuel*
   Where: AAS = Actual air supplied, kg/kg fuel; H_a = Absolute humidity of ambient air, kg moisture / kg dry air; C_p = specific heat of exit flue gas, Kcal/kg °C; T_f = Temperature of exit flue gas (°C); T_a = Temperature of ambient air (°C); GCV of fuel, Kcal/kg fuel

5) *% Heat loss due to partial conversion of C to CO (L5) = [(%CO * C) * (5654)] * 100 / [(%CO + %CO_2) * (GCV of fuel)]*

Where: % CO = (ppm CO in flue gas / 10^6) * 100; C = (Carbon % in fuel by weight / 100); CO_2 % = Equivalent % CO_2 in flue gas; GCV of fuel, Kcal/kg fuel

6) *Heat loss due to radiation and convection and other unaccounted losses (L6) = Assumed as 1% (0.35–1.0% for power boilers)*

7) *% Heat loss due to unburnt in fly ash (L7) = [(% Unburnts in fly ash / 100) * (% Ash in fuel / 100) * (GCV of fly ash, Kcal/kg fly ash)] * 100 / (GCV of fuel, Kcal/kg fuel)*

8) *% Heat loss due to unburnt in bottom ash (L8) = [(% Unburnts in Bottom ash / 100) * (% Ash in fuel / 100) * (GCV of fly ash, Kcal/kg fly ash)] * 100 / (GCV of fuel, Kcal/kg fuel)*

Boiler thermal efficiency by indirect method (%) = 100 - (L1 + L2 + L3 + L4 + L5 + L6 + L7 + L8)

Note:

- In the case of oil- or gas-fired boilers, items (7) and (8) may be ignored.
- Radiation and convection loss can be calculated if the surface area of the boiler and its surface temperature are known/measured. Invariably, different sections of the boiler (roof, front and side walls, exposed surfaces, etc.) have different surface temperatures. It is, hence, prudent to measure the different surface temperatures (average) alongside the corresponding areas.

$L6 = 0.548 * [(T_s / 55.55)^4 - (T_a / 55.55)^4] + [1.957 * (T_s – T_a)^{1.25} * \text{sq. rt} \{(196.85\ V_m + 68.9) / 68.9\}]$
Where: L6 = Radiation and convection loss in W/m^2 (1 W/m^2 = 0.86 (Kcal/hr) / m^2); V_m = Wind velocity in m/second; T_s = Surface temperature in (K); T_a = Ambient temperature in (K)

6. Annexures

Observation sheet

With as-run operating parameters to be recorded at intervals of 15 minutes for 6 hours.

Steam:			
Steam output (F)	=	TPH	from DCS
Steam pressure (P)	=	kg/cm^2	from DCS
Steam temperature (T)	=	°C	from DCS
Feed water temperature to boiler from Eco	=	°C	
Flue gas:			
O_2 in flue gas	=	% by Volume	from DCS/measured
CO_2 in flue gas	=	% by Volume	from DCS/measured
CO in flue gas	=	Ppm	measured
Average flue gas temperature	=	°C	from DCS
Specific heat	=	Kcal/kg °C	Reference data books
Atmospheric air:			
Ambient dry bulb temperature	=	°C	measured
Ambient wet bulb temperature	=	°C	measured
Absolute humidity in ambient air t	=	kg moisture/kg dry air	psychometric charts
Wind velocity around the blower	=	m/second	measured

Figure 1: Observation sheet for boiler

Laboratory analysis report sheet

With key as-run fuel composition and combustion data. Fuel and ash samples are to be collected (each a representative sample weighing 1 kg) at intervals of 1 hour during the trial.

Fuel analysis:			
Carbon	=	% by weight	lab report
Hydrogen	=	% by weight	lab report
Nitrogen	=	% by weight	lab report
Oxygen	=	% by weight	lab report
Sulphur	=	% by weight	lab report
Moisture	=	% by weight	lab report
Ash content	=	% by weight	lab report

GCV of coal	=	Kcal/kg fuel	lab report
Ash analysis:			
Unburnts in bottom ash	=	% by weight	lab report
Unburnts in fly ash	=	% by weight	lab report
GCV of bottom ash	=	Kcal/kg	lab report
GCV of fly ash	=	Kcal/kg	lab report

Figure 2: Laboratory fuel analysis report sheet

Calculation sheet

Table 13. Calculation sheet for boiler efficiency

Input/output parameters		Kcal/kg of fuel	% loss	
			As-run	**Design**
Heat Input	**I**	GCV fuel	-	
Heat output or losses in boiler	**O**			
1. Dry flue gas	L1			
2. Loss due to hydrogen in fuel	L2			
3. Loss due to moisture in hydrogen	L3			
4. Loss due to moisture in air	L4			
5. Partial combustion of C to CO	L5			
6. Surface heat losses	L6			
7. Loss due to unburnt in fly ash	L7			
8. Loss due to unburnt in bottom ash	L8			
Boiler efficiency = 100 - (L1 + L2 + L3 + L4 + L5 + L6 + L7 + L8)				

Calculation sheet

(1) ER, (kg steam/kg fuel)
= [(% boiler thermal efficiency / 100) * (GCV fuel)] / [(Enthalpy of steam at boiler inlet conditions - Enthalpy of boiler feed water)]

(2) Expected fuel consumption rate, (TPH)
= Steam generation rate, (TPH) / (Evaporation ratio, kg steam/kg fuel)

Comparison of results

Table 14: Comparison of boiler-wise thermal efficiency

Boiler reference	Thermal efficiency (%)				
	Design value	PG test value	Previous best value	Last energy audit value	Present energy audit value
Boiler No-1					
Boiler No-2					

3.5 Energy audit procedure for ST

List of contents

1. Objective
2. Instruments required
3. Audit procedure
4. Report preparation format
5. Audit tools for auditors

6. Annexures

1. Objective

To conduct an as-run performance assessment of the turbine system to determine the following, with the objective of validation against design values, to identify inefficiencies, factors, and parameters affecting performance, if any:

- Gross-turbine heat rate (THR-G), Kcal/kWh
- Net-turbine heat rate (THR-N), Kcal/kWh
- Turbine cycle efficiency (thermal efficiency) (η_t), %
- Steam rate (SR) or specific steam consumption (SSC), kg/hr steam / kW or kg steam / kWh
- Turbine cylinder or stage (isentropic) efficiency, %

2. Instruments required

- Power analyzer
- Calibrated steam flow measurement devices (online)
- Taco meter
- Revolutions per minute (RPM) meter

3. Audit procedure

- Compile design, PG test, previous best and last energy audit value of individual ST efficiencies, HRs, SRs, and cylinder/stage efficiencies (isentropic).
- Ensure all online instruments have been calibrated within the last 12 months. Compile the calibration dates/data for all the instruments. All the instruments must comply with the designed accuracy levels after calibration.
- In connection with the requirements of the as-run performance test, six turbine trials, each of 1 hour duration, are to be conducted on the same date. The requisite number of readings taken for the relevant operating parameters during the trial period are to be averaged, for computing HP, intermediate pressure (IP), and LP cylinder efficiencies. During the as-run performance tests, key station parameters such as MW load and condenser vacuum need to be noted.
- Observe and fill data sheet (Annexure).
- The as-run parameters obtained during trial are to be compared with the corresponding design data for any variations. Based on the respective inlet and outlet steam condition at HP cylinder, the IP cylinder efficiency needs to be computed and compared against the design value.
- Comparison of as-run trial values of HP and IP turbine cylinder efficiency with respect to design values.
- Compute ST efficiency as per calculation sheet (Annexure).
- Compute the ST or SSC value (kg/hr steam / kW) as per the calculation sheet (Annexure).
- Check whether the performance parameters show that the performance of the HP and IP turbines are close to design value or have drifted away.
- Prepare a comparative table of STs by THRs-G and THRs-N, turbine cycle or thermal efficiency, turbine cylinder and stage efficiencies, and SRs or SSC, present versus design, PG test, previous best, and last energy audit values (Annexure).
- Turbine stage (isentropic) efficiency, (%) = [(Actual enthalpy drop) * 100] / (Isentropic enthalpy drop across the turbine). This procedure is the enthalpy drop efficiency method. It determines the ratio of actual enthalpy drop across the turbine section to the isentropic enthalpy drop across the same section. This method provides a good measure for monitoring purposes.

Each section of the turbine must be considered as a separate turbine. Each section should be tested, and the results should be trended separately. While conducting the tests, it must be ensured that they are conducted over the normal operating load range. The enthalpy drop test is performed at the wide-open valve condition. The test at wide-open valve provides a baseline, and the test at similar pre- and postcondition are used to evaluate the improvements made during the turbine overhaul.

While it is very difficult to make immediate corrections to turbine performance degradation, the information can be used as part of the cost-benefit analysis to determine the optimum point at which the losses due to decreased performance are greater than the costs associated with the turbine maintenance.

4. Report preparation format

The audit report will be prepared in the following format:

- Foreword.
- Audit team.
- Technical specifications.
- Present practices: Explain in detail the present status.
- Observation and remarks: Refer to the data and conclusion sheets, and note observations and remarks about the energy audit carried out.
- Recommendations: Energy conservation options along with savings potential sheet, including estimated expenditure, payback period, and other related expected benefits.
- Single line diagram.
- Data regarding calibration of instruments used, indicating dates of last calibration (calibration more than 12 months old is not acceptable).

5. Audit tools for auditors

- **THR-G, Kcal/kWh:**
  $= [Q_1 * (H_1 - h_2)] + [Q_2 * (H_3 - H_2)] / (E_g)$
- **THR-N, Kcal/kWh:**
  $= [Q_1 * (H_1 - h_2)] + [Q_2 * (H_3 - H_2)] / [(E_g) * \{1 - (APC\ \% / 100)\}]$

  Where:
  Q_1 = Average main steam flow, kg/hr
  H_1 = Main steam enthalpy at average pressure and Temperature, Kcal/kg
  h_2 = Average feed water enthalpy at average pressure and temperature, Kcal/kg
  Q_2 = Average reheat steam flow, kg/hr
  H_3 = Average hot reheat enthalpy at average pressure and temperature, Kcal/kg
  H_2 = Average cold reheat enthalpy at average pressure and temperature, Kcal/kg
  E_g = Average generator output, kW
  APC % = % of APC (for auxiliary power consumption)

- **Turbine cycle efficiency** (thermal efficiency) **(η_t) %:**
  $= [860 * 100] / [\text{Turbine HR}]$
  Turbine cycle efficiency is defined as the amount of electricity produced by the heat input to the turbine. It is the reciprocal of HR in consistent units.
- **Turbine cylinder or stage (isentropic) efficiency, %:**
  = [(Actual enthalpy drop across the turbine or a particular stage, Kcal/kg) * 100] / (Isentropic enthalpy drop across the turbine or a particular stage, Kcal/kg)
- **SSC, (kg/hr steam) / (kW) or (kg steam) / (kWh):**
  $= 860 / \{(H_1 - H_2) * (\eta_{mech} * \eta_{gen} * \eta_{gear})\}$

  Where:
  H_{in} or H_1 = Enthalpy of steam at turbine inlet conditions of pressure and temperature, Kcal/kg
  H_{out} = Enthalpy of steam at turbine outlet conditions of pressure and temperature, Kcal/kg

$\eta_{mech} = 0.985$
$\eta_{gen} = 0.95$
$\eta_{gear} = 0.98$

6. Annexures

I. Evaluation of overall turbine HR

Table 15: Evaluation of overall turbine HR

Parameters	Units	PG test value	As-run values
Main steam flow to turbine	kg/hr		
Enthalpy of main steam flow to turbine	Kcal/kg		
Feed water flow to boiler	kg/hr		
Enthalpy of feed water to boiler	Kcal/kg		
Steam flow to extraction	kg/hr		
Enthalpy of process steam	Kcal/kg		
Generation	kW		
Turbine HR = {[Main steam flow to turbine * Enthalpy of main steam flow to turbine] – [Feed water flow to boiler * Enthalpy of feed water to boiler] – [Steam flow to extraction * Enthalpy of extraction steam]} / [Generation in kW]	Kcal/kWh		
Thermal efficiency of boiler	%		
Unit HR [Turbine HR / thermal efficiency of boiler]	Kcal/kwh		
Rankine cycle efficiency	%		
SR (or) SSC	(kg/hr) / (kW) or (kg/kWh)		

After evaluating the turbine HR and efficiency (HP and IP), the deviation from the design, if any, should be assessed, and the factors contributing to the deviations must be identified. The major factors to be investigated are:

- Main steam and reheat steam inlet parameters,
- Turbine exhaust steam parameters,
- Reheater and super heater spray parameters,
- Passing/draining of high energy,
- Insufficient loading on the turbine,
- Insufficient boiler loading, and as a result, lower boiler performance,
- Operations and maintenance (O&M) constraints,
- Inadequate condenser performance and cooling water (CW) parameters,
- Nonfunctioning of any of the LP heaters (LPHs) or HP heaters (HPHs; and get them back into service as soon as possible for HR improvement),
- Silica deposition and its impact on the turbine efficiency,
- Inter stage sealing, balance drum, and gland sealing,
- Turbine blade erosion/deposits,
- Improper functioning of the valves,
- Inadequate performance of reheaters,
- Reheater bypass valve leakage,
- Excess gland seal leakage,

- Strip seal leakages,
- Nozzle block erosion/deposits,
- Deposits on nozzles, and
- Malfunctioning of control valve.

II. Evaluation of turbine heat load—one extraction

Table 16: Turbine heat load calculations

Turbine heat load calculations—One extraction			
Parameter reference	**Units**	**PG test value**	**As-run values**
Inlet steam enthalpy	Kcal/kg		
Feed water enthalpy	Kcal/kg		
Inlet steam flow	kg/hr		
Extraction steam flow	kg/hr		
Extraction steam enthalpy	Kcal/kg		
Generation	kW		
Generator efficiency	%		
Turbo generator coupling losses	kW		
Heat load = [Inlet steam flow * (Inlet steam enthalpy - Feed water enthalpy)] - [(Extraction steam flow * (Inlet steam enthalpy - Extraction steam enthalpy)] – [(Generation / (Generator efficiency / 100)] – [Turbo generator coupling losses * 860]	Kcal/hr		

- The heat load of the turbine is at as-run condition = xxxxx million Kcal/hr.
- In comparison, the design heat load is = yyyyy million Kcal/hr.

III. Rationale for calculation of HR loss in turbine

Table 17: Rationale for calculation of HR loss in turbine

S. No.	Item reference	Units	Value	Calculation
1	Average annual PLF	%		
2	Average load	MW		
3	Design load	MW		
4	Average annual generation	MU		
5	Design turbine HR	Kcal/kWh		
6	As-run turbine HR	Kcal/kWh		
7	Gap in turbine HR between design and as-run	Kcal/kWh		
8	Equivalent loss in generation due to increased turbine HR	MU		
9	Achievable HR gap reduction target	%		Say 50%
10	Avoidable loss generation potential	MU		
11	Equivalent saving in coal consumption (considering xxxx Kcal/kg coal CV)	Tonnes coal/year		
11	Envisaged annual monetary benefit @ BDT xxxx/ton coal	BDT		

IV. Evaluation of stage-wise efficiency and overall cylinder efficiency

A. Turbine inlet parameters

Table 18: Turbine inlet parameters

Parameter	Units	Symbol	Design	As-run
Pressure	kg/cm²(a)	P_I		
Temperature	°C	T_I		
Flow	TPH	F_I		
Enthalpy (actual)	Kcal/kg	h_I		
Entropy	Kcal/kg °C	S_I		
Enthalpy (isentropic)	Kcal/kg	-	-	-

Overall cycle efficiency	%	-	-	-

B. First extraction from turbine

Table 19: Details of first extraction from turbine

Parameter	Units	Symbol	Design	As-run
Pressure	$kg/cm^2(a)$	P_2		
Temperature	^oC	T_2		
Flow	TPH	F_2		
Enthalpy (actual)	Kcal/kg	H_2		
Entropy	Kcal/kg ^oC	S_2		
Enthalpy (isentropic)	Kcal/kg	H_2		
Overall cycle efficiency	%	Inlet to first extraction		

C. Second extraction from turbine

Table 20: Details of second extraction from turbine

Parameter	Units	Symbol	Design	As-run
Pressure	$kg/cm^2(a)$	P_3		
Temperature	^oC	T_3		
Flow	TPH	F_3		
Enthalpy (actual)	Kcal/kg	h_3		
Entropy	Kcal/kg ^oC	S_3		
Enthalpy (isentropic)	Kcal/kg	H_2		
Overall cycle efficiency	%	First extraction to second extraction		

D. Condenser (turbine exhaust)

Table 21: Details of condenser (turbine exhaust)

Parameter	Units	Symbol	Design	As-run
Pressure	$kg/cm^2(a)$	P_4		
Temperature	^oC	T_4		
Flow	TPH	F_4		
Enthalpy (actual)	Kcal/kg	h_4		
Entropy	Kcal/kg ^oC	S_4		
Enthalpy (isentropic)	Kcal/kg	H_3		
Overall cycle efficiency	%	Second extraction to condenser		

E. Overall turbine cylinder efficiency

Table 22: Details of overall turbine cylinder efficiency

Parameter	Units	Symbol	Inlet conditions		Outlet conditions	
			Design	As-run	Design	As-run
Pressure	$kg/cm^2(a)$	P_4				
Temperature	^oC	T_4				
Flow	TPH	F_4				
Enthalpy (actual)	Kcal/kg	h_4				
Entropy	Kcal/kg °C	S_4				
Enthalpy (isentropic)	Kcal/kg	H_3		-		
Overall cycle efficiency	%	-		-		

V. Summary of turbine cylinder efficiency (isentropic)

Table 23: Summary of turbine cylinder efficiency (isentropic)

Reference parameter	Units	Design	As-run operating values
Turbine inlet to first extraction stage—cylinder efficiency	%		

First extraction to second extraction stage—cylinder efficiency	%		
Second extraction to turbine exhaust (condenser) stage—cylinder efficiency	%		
Overall turbine cylinder efficiency	%		

VI. Overall performance comparison of as-run trial values with benchmark values

Table 24: Comparison of THR-G

Sl. No.	THR-G (Kcal / kWh)			
	Design value	PG test value	Previous best value	Last energy audit value

Table 25: Comparison of turbine cycle efficiency (%)

Turbine reference	Turbine cycle efficiency (%)			
	Design value	PG test value	Previous best value	Last energy audit value

Table 26: Comparison of overall turbine SR

Turbine reference	Overall turbine SR (OR) SSC (kg/hr) / (kW) or (kg/kWh)			
	Design value	PG test value	Previous best value	Last energy audit value

3.6 Energy audit procedure for CW pumps and condenser system

List of contents

1. Objectives
2. Instruments required
3. Audit procedure
4. Report preparation format
5. Audit tools for auditors
6. Annexures

1. Objectives

- To assess CW pump efficiencies.
- To assess the circulating water flow to the condensers and to evaluate condenser effectiveness.
- Interunit comparison gives an impression of performance trends.

2. Instruments required

- Ultrasonic flow meter
- Turbine type flow meter for open channels
- Online control room instruments (calibrated at least within the last 12 months)
- Whirling psychrometer
- Accurate digital thermometers
- High Tension (HT) /Low Tension (LT) load analyzers

3. <u>Audit procedure</u>

- Compile design/PG test values of CW (or circulating water) pumps along with previous and last energy audit values of the above equipment.
- Collect CW pump curves along with technical specifications.
- Ensure that all CW line instruments are calibrated within the last 12 months. Compile the calibration dates/data for all instruments. All the instruments must comply with the designed accuracy levels after calibration.
- Observe and compile the data sheet (Annexure) for 4 hours at half-hour intervals and two sets of readings in a day.
  - First set: 1000–1400 hr
  - Second set: 1800–2200 hr
- Measure CW flow to each cooling tower (CT) riser and calculate the condenser effectiveness and CW pump efficiency as per the calculation sheet (Annexures).
- Compare the results with design, PG test, previous data, and last energy audit data.
  - The investigations for abnormality are to be carried out for problem identification.
  - List out scope for improvement. The checklist presented in Annexure 3 may be referred to as an aid to identify energy conservation opportunities.
  - List recommendations for actions to be taken for improvement.
  - Cost-benefit analysis with savings potential for initiating improvement measures.

4. <u>Report preparation format</u>

The audit report will be prepared in the following format:

- Foreword
- Audit team
- Technical specifications
- Present practices: Explain in detail the present status.
- Observation and remarks: Refer to the data and conclusion sheets and note observations and remarks about the energy audit carried out.
- Recommendations: Energy conservation options along with savings potential sheet, including estimated expenditure, payback period, and other related expected benefits.
- Single line diagram
- Data regarding calibration of instruments used, indicating dates of last calibration (calibration more than 12 months old is not acceptable).

5. <u>Audit tools for auditors</u>

A. <u>CW pumps</u>

- Motor input power (P_i) (kW)
  = 1.732 * V * I * P_f (or measured value)
- Total differential head (TDH) (mWC)
  = [(Pump discharge head, kg/cm²g) – (Pump suction head, kg/cm²g)] / (10)
- Fluid flow, F, (m^3/hr)
  = measured with an ultrasonic flow meter (or) an online flow meter (or) assessed from pump characteristic curves
- Combined pump-motor efficiency— $\eta_{\text{p-m}}$ (%)
  = [(F / 3,600) * (TDH) * (9.81) * (100)] / (P_i)

  Where:
  P_i = Pump motor input power (kW)
  F = Fluid flow (m^3/hr)
  TDH = Total differential head (mWC)
  9.81 = Gravitational constant

- Motor load % = $(I_m / I_r) * (V_m / V_r) * 100$

  Where:
  Motor load % = Output power (operating) as a % of rated nameplate power
  I_m = Measured operating current
  I_r = Rated current
  V_m = Measured voltage
  V_r = Rated voltage

- **Motor efficiency – $\eta_{m\text{-}op}$ = [(P_{ro}) * (Motor load % / 100) * 100] / (P_i)**

  Where:
  $\eta_{m\text{-}op}$ = Motor efficiency at operating conditions (%)
  P_{ro} = Nameplate rated output power (kW)
  Motor load % = Output power (operating) as a % of rated nameplate power
  P_i = Measured input power 3-ph (kW)

- Pump efficiency - η_{pp}
  = (Combined pump-motor efficiency, $\eta_{p\text{-}m}$) * (100) / (motor efficiency, $\eta_{m\text{-}op}$)
- Specific power consumption (SPC) [(kW) / (m^3/hr)]
  = (Motor input power, P_i in kW) / (Fluid flow, F, in m^3/hr)
- Specific energy consumption (SEC) [(kWh) / (m^3)]
  = (Motor input power, P_i in kW) / (Fluid flow F in m^3/hr)
- % Margin available with respect to rated motor input power
  = (Measured motor input power, P_i in kW) * 100 / (Rated motor input power)
- % Margin available with respect to rated pump flow
  = (Measured fluid flow, F, in m^3/hr) * 100 / (Rated pump flow)
- % Margin available with respect to rated pump head
  = (Measured fluid head, TDH, in mWC) * 100 / (Rated pump head)

B. Condenser

1. Audit procedure

During the audit of the condenser, the following needs to be adopted:

- The trial is to be carried out for 1 hour.
- The TPP unit should be maintained at steady full load condition.
- The steam flow rate should be maintained steady.
- Condenser back pressure to be maintained steady.
- The pressure drop (dP) across condenser to be kept steady.
- CW flow to be made using an ultrasonic flow meter.
- Condensate temperature to be maintained steady.

2. Observations

Key technical details regarding the condenser are required to be compiled as shown in Table 26.

Table 27: Technical details about condenser

Particulars	Units
Unit load	MW
Turbine HR	Kcal/kWh
Condenser type	

Number of tube passes	
Number of circulating water passes	
Tube length	m
Tube material	
Total number of tubes	
OD of condenser tube	mm
Tube thickness	mm
Cooling surface area	m^2

The as-run trial is to be carried out with an objective of arriving at performance indicators and scope areas for improvement.

Table 28: As-run details of condenser

S. No.	Description	Units	Nomenclature	Design values	As-run values
1	Unit load	MW			
2	Frequency	Hz			
3	Condenser back pressure (vacuum)	kg/cm^2			
	Condenser back pressure	kg/cm^2_a			
4	CW inlet temperature (average)	°C	t_1		
5	CW outlet temperature (average)		t_2		
6	CW temperature rise (average)	°C	$(t_2 – t_1)$		
7	Saturation temperature	°C	(T_s)		
8	Terminal temperature difference (TTD) (Approach)	°C	$(T_s – t_2)$		
9	Condenser effectiveness	Factor	$\{(t_2 - t_1) / (T_s - t_1)\} * 100$		
10	Condenser CW flow	m^3/hr			
11	Condensate temperature (average)	°C			
12	LMTD	°C			
13	Condenser thermal load	MKcal/hr	H*		
14	Heat transfer coefficient	$Kcal/m^2hr^0C$	U**		
15	Pressure drop on CW side	mWC			
16	Cleanliness factor				

The as-run performance indicators observed during trial are summarized as follows:

3. <u>Some good practices</u>

- Install accurate vacuum gauges for regular monitoring of performance (with mbar reading).
- Regular measurement and monitoring of CW flow through the condenser. One indicator of performance and flow adequacy is that the pressure drop across condenser should always be greater than rated 5 mWC.
- Around 20% additional heat transfer area could be factored in by way of installing an additional parallel condenser.

- State-of-the-art measures for performance upkeep like chlorination (for bio fouling), online cleaning of condenser tubes, and opportunity-based back wash of condenser, may be taken up from time to time.

4. Audit tools for auditors

- Initial temperature difference (ITD) = $(T – t_1)$
- Terminal temperature difference (TTD) = $(T - t_2)$

Condenser effectiveness (%) = $(t_2 – t_1) * 100 / (T – t_1)$

Where:

T = Saturation temperature of steam in condenser (°C)
t_1 = Condenser CW inlet temperature (°C)
t_2 = Condenser CW outlet temperature (°C)

Based on the performance trial data, the following key operational parameters should be keenly assessed.

- CW flow adequacy
- CW differential pressure and flow estimate
- Condenser effectiveness
- TTD (approach)
- Logarithmic mean temperature difference (LMTD)
- Heat transfer coefficient

5. Annexures (CW pumps and condenser)

CW pump efficiency and SEC—As-run trial observation sheet

- Motor input power (P_i) (kW) = (or measured or evaluated)
- Pump suction pressure (P_1) (kg/cm²g) = (measured)
- Pump discharge pressure (P_2) (kg/cm²g) = (measured)
- TDH (mWC) = (evaluated)
- Discharge valve position (% open) = (measured)
- CW flow (F) (m³/hr) = (measured)
- Combined pump-motor efficiency - $\eta_{p\text{-}m}$ (%) = (evaluated)
- Motor load - as-run % = (evaluated)
- Motor efficiency - operating - $\eta_{m\text{-}op}$ = (evaluated)
- Pump efficiency - operating - η_{pp} = (evaluated)
- SPC [(kW) / (m³/hr)] = (evaluated)
- SEC [(kWh) / (m³)] = (evaluated)
- % Margin available with respect to rated motor power input = (evaluated)
- % Margin available with respect to rated flow = (evaluated)
- % Margin available with respect to rated head = (evaluated)

Condenser effectiveness

Table 29: Condenser effectiveness

S. No.	Item reference	Units		Stage-I		
				Design	Unit-1	Unit-2
1.	Load (TPP)	MW				
2.	Back pressure (Condenser)	kg/cm²				
3.	Condenser CW inlet temperature	°C	t_1			

S. No.	Item reference	Units		Stage-I		
				Design	Unit-1	Unit-2
4.	Condenser CW outlet temperature A/B average	°C	t_2			
5.	Saturation temperature of steam	°C	T			
6.	Terminal temperature difference TTD (A/B) average	°C	$(T - t_2)$			
7.	Condenser effectiveness A/B average		$(t_2 - t_1) / (T - t_1)$			

Savings Potential Sheet

Table 30: Savings potential sheet for condenser

S. No.	Activity	Savings (kWh/year)	Savings (BDT/year)
1.	CW flow optimization		
2.	Condenser cleaning option		
3.	Stopping one CW pump		
4.	CT effectiveness improvement • Optimizing L/G ratio • Air and water channelization • Spray nozzle effectiveness • Splash bar cleanliness		
5.	FRP blade conversion option		
6.	Optimization on CT fan operations in multicell CTs		
7.	Optimization/efficiency improvement in CW pumps		
8.	COC improvement option		

Note: This list is merely a sample of energy conservation measures (ECMs). The list can vary and can be further supplemented from case to case.

3.7 Energy audit procedure for LPHs and HPHs

List of contents

1. Objective
2. Instruments required
3. Report preparation format
4. Audit tools for auditors
5. Annexures

1. Objective

To determine the efficiency and energy performance of the equipment.

2. Instruments required

- Power analyzer
- Gas analyzer
- Taco meter
- RPM meter
- Flow meter
- Pitot tube
- Manometer

3. Report preparation format

The audit report will be prepared in the following format:

- Foreword
- Audit team
- Technical specifications
- Present practices: Explain in detail the present status.
- Observation and remarks: Refer to the data and conclusion sheets and note observations and remarks about the energy audit carried out.
- Recommendations: Energy conservation options along with savings potential sheet, including estimated expenditure, payback period, and other related expected benefits.
- Single line diagram
- Data regarding calibration of instruments used, indicating dates of last calibration (calibration more than 12 months old is not acceptable).

4. Audit tools for auditors

LPHs

The LPHs and HPHs in the TPP are used to increase the efficiency of the boiler. The condensate water from the condenser gets heated in the LPH by steam, which is extracted from LP turbines. Design specifications for the LPHs are given in the annexures.

HPHs

The LPHs and HPHs in the steam power plant are used to increase the efficiency of the boiler. The water after boiler feed water pumps (BFPs) gets heated by the HPH by steam that is extracted from the HP and IP turbines.

5. Annexures

LPHs

Table 31: Data collection sheet for LPHs

Particulars	Unit	LP heater #	LP heater #	LP heater #
Heater position (horizontal/vertical)				
LPH ID code & number				
Number of zones (de-superheating, condensing, drain cooling)	Numbers			
Number of tubes	Numbers			
Surface area	m^2			
Tube size (ODx thickness)	Mm			
Feed water inlet temperature	°C			
Feed water outlet temperature	°C			
Extraction steam flow	TPH			
Extraction steam pressure	kg/cm^2			
dP (water side)	mmWC			
TTD	°C			
Drain cooler approach (DCA) temperature	°C			

Temperature rise	°C			

HPHs

Table 32: Data collection sheet for HPHs

Particulars	Unit	HPH#	HPH#	HPH#
Heater position (horizontal/vertical)				
HPH ID code and number				
Number of zones (de-superheating, condensing, drain cooling)	Number			
Number of tubes	Number			
Surface area	m^2			
Tube size (ODx thickness)	Mm			
Feed water inlet temperature	°C			
Feed water outlet temperature	°C			
Extraction steam flow	TPH			
Extraction steam pressure	kg/cm^2			
dP (water side)	mmWC			
TTD	°C			

3.8 Energy audit procedure for fan systems

List of contents

1. Objective
2. Instruments required
3. Audit procedure
4. Report preparation format
5. Audit tools for auditors
6. Annexures

1. Objective

To assess the existing performance of fans. Interunit comparison gives an impression about performance trends between two inspections and permits early interference in case of a fall in the performance.

2. Instruments required

- Online instruments (calibrated at least within the last 12 months).
- Digital manometer of suitable range, pitot tube (S-type and L-type) with appropriate probes for measurement of pressure head and velocity head.
- Additional/pressure gauges with an appropriate range of measurement and calibrated before the audit.
- Power analyzer portable (or) calibrated energy meter connected to respective equipment.

3. Audit procedure

- Compile design, PG test and fan curves, along previous and last energy audit value fans.
- Ensure that all online instruments are calibrated within the last 12 months. Compile the calibration dates/data for all instruments. All instruments must comply with the designed accuracy levels after calibration.
- Observe and fill the data sheet for 4 hours at half-hour intervals, and two sets of readings in a day need to be compiled.
- Two sets of the readings could be compiled during the following period—First set: 0900–1300 hr, second set: 1400–1800 hr.
- Calculate the fan efficiency as per the calculation sheet.
- Compare the results with design, PG test, previous data, and last energy audit data.

Table 33: Comparison of fan efficiencies

Unit	Fan efficiency					
	Rated value	Design value	PG test value	Previous best value	Last energy audit value	Present energy audit actual value
Fan-l						
Fan-2						
Fan-3						

- The investigations for abnormality are to be carried out for problem identification.
- Enlist scope for improvement.
- Enlist recommendations for actions to be taken for improvement.
- Cost-benefit analysis with savings potential for initiating improvement measures.

4. Report preparation format

The audit report will be prepared in the following format:

- Foreword
- Audit team
- Technical specifications
- Present practices: Explain in detail the present status.
- Observation and remarks: Refer to the data and conclusion sheets and note observations and remarks about the energy audit carried out.
- Recommendations: Energy conservation options along with savings potential sheet, including estimated expenditure, payback period, and other related expected benefits.
- Single line diagram
- Data regarding calibration of instruments used, indicating dates of last calibration (calibration more than 12 months old is not acceptable).

5. Audit tools for auditors

- Fan static efficiency, η_{fan}
  = [(Air kW) * 100] / [(Motor operating efficiency, $\eta_{m\text{-}op}$) * (Fan motor input power, kW)]
- Air kW (in kW)
  = [(Measured air flow, F, in m³/second) * (Static differential head, ΔH, in mmWC) * 100] / (102)
- Fan motor input power consumption (P_i) (kW)
  = 1.732 * V * I * P_f (or measured value)
- Motor efficiency – $\eta_{m\text{-}op}$
  = [($P_{r\text{-}o}$) * (Motor load % / 100) * 100] / (P_i)
- Motor load %
  = (I_m / I_r) * (V_m / V_r) * 100

Where:

Motor load % = Output power (operating) as a % of rated nameplate power
I_m = Measured operating current
I_r = Rated current
V_m = Measured voltage

V_r = Rated voltage

- Air flow (F) in tons/hr
  = (Measured air flow in m³/second) * (Density of air at measured temperature, kg/m³) * (3,600 / 1,000)
- SPC [(kW) / (tons/hr)]
  = (Fan motor input power, P_i, kW) / (Air flow (F) in tons/hr)
- SEC [(kWh) / (ton)]
  = (Fan motor input power, P_i, kW) / (Air flow (F) in tons/hr)
- % Margin available with respect to rated motor input power
  = [(Measured motor input power, P_i in kW) * 100] / (Rated motor input power)
- % Margin available with respect to rated pump flow
  = [(Measured air flow, F, in m³/second) * 100] / (Rated fan flow in m³/second)
- % Margin available with respect to rated pump head
  = [(Measured fan head developed, in mmWC) * 100] / (Rated pump head in mmWC).

Note 1: The efficiency of the fan deteriorates with the extent of partial loading and the type of flow control mechanism deployed.

Note 2: The energy consumption increases with an increase in fluid flow; for instance, an increase in excess air quantity and air leakage into the flue gas path.

6. Annexures

The data sheet for fan efficiency assessment

Table 34: Data collection sheet for fan efficiency assessment

Day	Time	Fan motor input kW	Total air flow TPH	Total difference head mmWC	Temperature °C
1	0900				
	0930				
	1000				
	1030				
	1100				
	1130				
	1200				
	1230				
	1300				
2	0900				
	0930				
	1000				
	1030				
	1030				
	1100				
	1130				
	1200				
	1230				
	1300				

Design data

Table 35: Design parameters for fans

Parameter reference	Unit of measurement	Value
Motor rated power	kW	
Fan design duty input power	kW	

Fan rated capacity	m^3/hr	
	Tons/hr	
Fan design duty capacity	m^3/hr	
	Tons/hr	
Fan rated head	mmWC	
Fan design duty head	mmWC	
Fan rated efficiency	%	
Fan design duty efficiency	%	

Calculation sheet fan efficiency assessment

Table 36: Calculation sheet fan efficiency assessment

Average fan power consumption-average	kW
Average gas/air flow at fan inlet	TPH
Average differential head developed across fan (Disc head – Suction head)	mWC
Average temperature (at measurement point)	°C
The density of air at the measured temperature	kg/m^3
Motor efficiency (evaluated)	%
Fan static efficiency	%
(As calculated from section 4.0) Design fan efficiency at base load	%
SPC	kW/(ton/hr)$_{air}$
SEC	kWh/ton$_{air}$
Margin on motor power with respect to rated	%
Margin on flow with respect to rated	%
Margin on head with respect to rated	%

Savings potential sheet

Table 37: Savings potential sheet for fans

S. No.	Activity	Annual energy savings (kWh/year)	Annual monitory savings (BDT/year)
1.	Replacement by high-efficiency fans		
2.	Impeller trimming/retrofit		
3.	Application of variable speed drives		
4.	Optimization of pressure drops		
5.	Duct network size optimization, etc.		

3.9 Energy audit procedure for compressed air systems

List of contents

1. Objective
2. Instruments required
3. Audit procedure
4. Report preparation format

5. Audit tools for auditors
6. Annexures

1. Objective

To evaluate the performance of compressed air generation and distribution system on the following lines:

- **Generation end:**
  - To evaluate the actual capacity of compressors
  - To evaluate SEC (kW/NM^3/m) compressor
  - To evaluate the intercooler and after the cooler performance
  - Stage-wise compressor performance evaluation
  - Drive speed analysis and observing belt tension
- **Transmission end:** To check the pressure drop along the transmission line
- **Utilization end:**
  - To check the air pressure at different pneumatic equipment
  - Leak survey

2. Instruments required

- Energy meter
- Pressure gauge
- Temperature gauges
- Stopwatch
- Tachometer
- Tensiometer

3. Audit procedure

- ***Step 1 (compile the compressor data)***
  - Make/type the rated capacity discharge pressure, cut off the pressure, and cut-in pressure.
  - Observe the drive specification of the compressor, viz. motor-rated kW, volts, amps, and power factor.
  - Observe the receiver volume including interconnecting pipeline up to the outlet isolating valve for each compressor.
  - Get a schematic diagram of the compressed air system along with user points.
  - Get all the online instruments that are pressure gauges, temperature gauges, kW, and kWh meters calibrated.
- ***Step 2 (compressor capacity test)***
  - Isolate the compressor along with its receiver being taken for the test from the main compressed air system by tightly closing the isolation value or blanking, thus closing the receiver outlet.
  - Open the water drain valve and drain out water fully and empty the receiver and the pipeline that the water trap is tightly closed once again to start the test.
  - Start the compressor and activate the stopwatch.
  - Note the time taken to attain the normal generated pressure P_2 (in the receiver) from the initial pressure P_I.
  - Calculate the capacity as per the formula given below:

    Actual free air discharge.

    $$\mathbf{Q = \{(P_2 - P_1) / (P_a)\} * (V / t) * \{(273 + T_a) / (273 + T_r)\}}$$

    Where:

    P_2 = Final pressure after filling (kg/cm$^2{}_a$)

    P_o = Atmospheric pressure (kg/cm$^2{}_a$)

    V_r = Receiver volume in m^3

T_r = Receiver temperature (°C)
T = time taken to build up pressure to P_2 in minutes from P_1
T_a = Ambient temperature

- ***Step 3 (efficiency evaluation)***
  - Calculate the ideal kw as per the formula given below:
    Ideal power kW
    $kW = (NK / K-1) (Q * P_o / 0.612) [(P_2 / P_1)^{[K-1 / K]}]$

    Where:
    N = Number of stages
    K = Ratio of specific heat (1.35 for air)
    P_1 = Suction pressure in $kg/cm^2{}_a$
    P_o = Discharge pressure in $kg/cm^2{}_a$

  - Measure actual kW during steady-state load conditions. Calculate the actual efficiency.

    Compressor efficiency = (Ideal kW/Actual compressor input kW)

  - Compare actual with the design efficiency

- ***Step 4 (leakage quantification)***
  - This test may not be possible in the running plant since this involves isolation of all end-user points individually in the whole system across the power plant, which may not be practically possible. In such a case, an intensive physical leak survey should be undertaken as detailed in step 9.
  - However, whenever the opportunity arises (when the plant is shut down for any reason), the test may be carried out.
    System leakage (Cfm) = (Q * T) / (T + t)

    Where:
    Q = Actual free air discharge (cfm)
    T = Onload time
    t = Offload time

- ***Step 5 (stage-wise compressor performance)***
  - Fill the stage-wise compressor performance sheet regarding suction/discharge pressure and temperature.
  - Observe the difference between actual discharge temperature and design discharge temperature.
  - Calculate the energy loss keeping in view that every 40oC rise in air temperature results in a 1% rise in energy.
- ***Step 6 (intercooler/aftercooler performance)***
  - Note ambient air temperature (Ta).
  - Measure inlet air temperature to cooler (Ti).
  - Measure outlet air temperature of cooler (To).
  - Calculate temperature difference (To - Ta).
  - If (To - Ta) > 5oc, recommend for cooler checking concerning rusting, choking and tube leakage, tube inadequate CW flow rate, and tube material of construction.
  - Repeat the test for the aftercooler. Refer to the annexure formats for recordings.
- ***Step 7 (power consumption analysis)***
  - Measure kW for baseload and unload conditions.
  - Compare the above measurement with respective design values.
  - Compare unload power of all compressors.

  - Compare baseload power for all compressors.
  - In the case of appreciable differences in similar compressors, a detailed analysis should be made.
- ***Step 8 (drive speed analysis and belt tension)***
  - Measure drive speed (N1) with the help of a tachometer.
  - Measure the diameter of drive and a driven pulley that is D1 and D2, respectively.
  - Calculate the theoretical value of driven rpm (N2).

    Governing equation:

    $\mathbf{D_1 * N_1 = D_2 * N_2}$
  - Measure actual driven rpm Na by the tachometer.
  - Calculate slip (N2 - Na).
  - As per the result of slip check look for the possibility for lagging of pulley, filling the grooves, or changing the pulley.
  - Measure belt tension and recommend accordingly.
- ***Step 9 (leak survey)***
  - Survey the compressed air network throughout the plant and note down the leakages.
  - Estimate the leakage based on the diameter of the leak point and pressure of the pipe (refer to the format).
  - Recommend steps to plug different leakages.
- ***Step 10 (pressure survey)***
  - Run the compressors and fill the system.
  - Achieve steady state.
  - Note the pressure at different locations simultaneously.
  - Calculate the ideal pressure at those locations.
    - Pressure drops in the pipeline
    - $dP = \{(7.57 * Q\ (1.85) * L * 10^{(4)}) / (d^{(5)} * p)\}$
    - dp = Pressure drop in the pipeline (kg/cm^2)
    - Q = Air flow quantity (m^3/min)
    - L = Length of the pipeline (mm)
    - P = Initial gauge air pressure (kg/cm^2g)
  - Estimate the loss by subtracting actual from ideal pressure (refer to the pressure drop test format).
- ***Step 11 (suction filter status)***
  - Measure dp at the filter.
  - Compare actual dp with design dp.
  - As per the above recommendations for cleaning or changing filters, ensure the type and quality of a filter as per the requirement—air filter specifications must meet the following:
    - 100% removal efficiency for 10-micron particles.
    - 99.5% removal efficiency for 2-micron particles.
    - 97% removal efficiency for 1-micron particles.
- ***Step 12 (lube oil inspection)***
  - Collect the lube oil sample.
  - Get the sample analyzed.
  - If the metal traces are found excessive, complete change of oil and/or an inspection of compressor bearings is warranted.
- ***Step 13 (drain valve)***
  - Observe the working of the drain valve.
  - If necessary, advise for more alert operation in case of manual values.
  - Also, explore the possibility of providing an electronic timer operated value, if not provided earlier.
  - If an electronic time-operated value is there, ensure proper working after recording nonperforming valves.

4. <u>Report preparation format</u>

The audit report may be prepared in the following format:

- Foreword
- Audit team
- Technical specifications
- Present practices: Explain in detail the present status.
- Observation and remarks: Refer to the data and conclusion sheets annexed and put down your observations and remarks about the energy audit carried out.
- Recommendations: Energy conservation options along with savings potential sheet including estimated expenditure, payback period, and other related expected benefits.
- Single line diagram

5. Audit tools for auditors

- 4°C rise in air temperature results in 1% rise in energy consumption.
- The optimum pressure differential for the pressure switch setting is 0.5–1.0 kg/cm^2.
- For every 25 mbar (10 in Water Alternating Gas (WAG) pressure lost at the inlet, the compressor performance is reduced by 2%.
- 20–30% of the power requirement can be saved by taking clean, cool dry air.
- Surface area for intercooler/aftercooler.
  - Optimum surface area: 0.5 m2/m3/min
  - Minimum surface area 0.35 nl/m3/min
- For three- or four-stage compressors, lube oil consumption of 0.111 liters/kW is typical.
- A worn valve can reduce compressor efficiency by as much as 50%.
- Ensure that air filter specifications meet the requirement of 100% removal efficiency for 10 micron particles, 99.5% for 2 microns, and 97% for I micron.
- Distribution pipe
  - In general, the main should be given a fall of not less than 1 m in 100 min in the direction of air flow.
  - The distance between the drawing points should not exceed 30 m.

6. Annexures

- Intercooler/aftercooler performance (data collection sheet)
- The standard for leakage estimate
- Sizing of air branch pipes

The maximum recommended flow through branch lines of steel pipe, IP liters per second free air + for branch mains not exceeding ***30 m length (ISO 65)***.

Table 38: Applied gauge pressure—Nominal pipe size

	Applied gauge pressure (in the bar)—Nominal pipe size in millimeter (NB)										
	6 mm	8 mm	10 mm	15 mm	20 mm	25 mm	32 mm	40 mm	50 mm	65 mm	80 mm
4 kg/cm^2 (g)	1.7	3.7	8.3	15.4	23	44	89	135	260	410	725
6.3 kg/cm^2 (g)	2.5	5.7	12.6	23.4	35	65	133	200	290	620	2.5
8.0 kg/cm^2 (g)	3.1	7.1	15.8	29.3	44	83	168	255	490	780	3.1

Source: Table I, p. 143, Branch-Lines, Pneumatic Handbook by R.H Warring, Texas, 6th Edition, 1982.

The flow values are based on a pressure drop as follows:

- 10% of applied pressure per 30 meters (100 ft.) of pipe size 6–15 mm Nominal Bore (NB).

- 5% of applied pressure per meter (100 ft.) of pipe 20–80 mm Nominal Bore (NB).

Sizing of air mains (steel pipe)

Table 39: Sizing of air mains

Pipe normal size (mm)	Recommended air flow in liters/second (at applied pressure 7 bar gauge) (Air velocity not to exceed 6 m/second)
6	1
8	3
10	5
15	10
20	17
25	25
32	50
40	65
50	100
65	180
80	240
100	410
125	610
150	900

Source: Table I, Section :2b, p. 136, Pneumatic Handbook by R.H. Warring, Texas, 6th Edition, 1982.

Savings Potential

Table 40: Savings potential for compressor air systems

S. No.	Activity	Savings (kWh/year)	Savings (Rs/year)
1	Improving compressors efficiency		
2	Better intercooler performance		
3	Pressure reduction for cleaning		
4	Meeting future requirements by DM plant compressors instead of the main compressor		

Note: These are merely four examples (there could be many more).

Free air delivery (FAD) test (data collection)

Table 41: Data collection sheet for FAD test

Parameter	Air compressor 1 IAC I	Air compressor 2 IAC II	Air compressor 3 IAC III	Air compressor 4 PAC I	Air compressor 5 PAC II
Trial date					
Trial time					
Final PR (P_1) kg/cm^2					
Initial PR (P_2) kg/cm^2					
Atmosphere pressure (P_o) (kg/cm^2					
Ambient temperature (1)°C					
Receiver volume (v) M^3					
Time (t) minutes					
Capacity at ambient temperature Nm^3/min					
Free air delivery					

(FAD) Nm³/min					
Design FAD Nm³/min					
Actual kW					
Design kW					
Actual kW/Nm³/min					
Design kW/Nm³/min					

Note: IAC = Instrument air compressor; PAC = Plant air compressor.

FAD test (data collection)

Table 42: Data collection sheet

Parameter	IAC I	IAC II	IAC III	PAC I	PAC II
Suction pressure P_S (kg/cm²)					
Discharge pressure P_d (kg/cm-)					
Capacity Q (m³/min)					
Stages					
Actual power (kW)					
Ideal power (kW)					
Actual efficiency					
Power saving potential					
Monitoring savings potential (BDT/year)					

Note: IAC = Instrument air compressor; PAC = Plant air compressor.

Power consumption pattern (data collection)

Table 43: Data collection sheet for power consumption pattern

Drive	Date	Voltage	kV	Current (AMP)			Power factor			kW Consumption		
				No load	Load isolated	Load normal	No load	Load isolated	Load normal	No load	Load isolated	Load normal
IAC -I												
IAC-II												
IAC-III												
PAC-I												
PAC-II												
PAC-III												

Note: IAC = Instrument air compressor; PAC = Plant air compressor.

Intercooler/aftercooler performance (data collection)

Table 44: Data collection for intercooler/aftercooler

Parameter	IAC I	IAC II	IAC III	PAC I	PAC II
Cooler	Intercooler	Intercooler	Intercooler	Intercooler	Intercooler
Date					
Ambient temperature °C					
Inlet temperature °C					
Outlet temperature °C					

(Ti - To) °C					
Effectiveness					
Actual power (kW)					
Ideal power (kW)					
Compressor in service					
Saving potential (kW)					
Saving potential (BDT/year)					

Note: IAC = Instrument air compressor; PAC = Plant air compressor.

Stage-wise compressor performance (data collection)

Table 45: Data collection sheet for stage-wise compressor

Parameter	IAC I		IAC II		IAC III		PAC I		PAC II	
Cooler	LP	HP	LP	HP	LP	HP	LP	HP	LP	HP
Suction pressure P_1 (kg/cm²)										
Suction temperature T_1 °(C)										
Discharge pressure P_2 (kg/cm²)										
Discharge temperature T_2 °(C)										

Pressure drop test (data collection)

Table 46: Data collection sheet for pressure drop test

S. No.	Location	Actual pressure (kg/cm²)	Design pressure (kg/cm²)
	Compressor house		
	Turbine generator bay		
	Ash handling system		
	Electrostatic precipitator (ESP)		
	Silo		
	CW pump house		
	Mills		
	Boiler (firing floor)		
	ID fan		
	FD fan		
	PA fan		

Note: These are examples of locations. They could be different in different facilities.

3.10 Energy audit procedure for CT

List of contents

1. Objective
2. Instruments required
3. Audit procedure
4. Report preparation format
5. Audit tools for auditors
6. Annexures

1. Objective

To assess the existing performance of CTs. Interunit comparison gives an impression about the performance trends between two inspections and permits early interference in case of a fall in performance.

2. Instruments required

- Online instruments (calibrated at least within the last 12 months)
- Whirling psychrometer
- Accurate digital thermometers
- HT/LT load analyzers
- Turbine type or noncontact air/water flow meters

3. Audit procedure

- Compile design, PG test values of CTs, CT fans, and CW pumps, along with previous and last energy audit values of these equipment.
- Collect CT fan and CW pump curves along with technical specifications.
- Ensure that all CW online instruments are calibrated within the last 12 months. Compile the calibration dates/data for all the instruments. All instruments must comply with the designed accuracy levels after calibration.
- Observe and fill the data sheet for 4 hours at half-hour intervals and compile two sets of readings per day. First set: 100–1400 hr; second set: 1800–2200 hr.
- Calculate the CT effectiveness and CW pump efficiency as per the calculation sheet.
- Compare the results with design, PG test, previous data, and last energy audit data.
- The investigations for abnormality are to be carried out for problem identification.
- Identify scope areas for improvement.
- List out recommendations for actions to be taken for improvement.
- Conduct a cost-benefit analysis with savings potential for initiating improvement measures.

4. Report preparation format

The audit report may be prepared in the following format:

- Foreword
- Audit team
- Technical specifications
- Present practices: Explain in detail the present status.
- Observation and remarks: Refer to the data and conclusion sheets annexed and put down your observations and remarks about the energy audit carried out.
- Recommendations: Energy conservation options along with savings potential sheet, including estimated expenditure, payback period, and other related expected benefits.
- Single line diagram

5. Audit tools for auditors

- CT range (°C) = [CW inlet temperature (°C) - CW outlet temperature (°C)]
- CT approach (°C) = [CW outlet temperature (°C) - wet bulb temperature (°C)]
- CT effectiveness (%) = [(CW inlet temperature (°C) - CW outlet temperature (°C)) * 100 / (CW in temperature (°C) - WB temperature (°C))]
- L/G ratio (kg water/kg air) = Total CW water flow in CT (kg/hr) / Total air flow in CT (kg/hr)
- CT heat loading (Kcal/hr) = CW flow (m^3/hr) x CT range (°C) x density of water (kg/m^3)
- CT operating TR = CT heat loading / 3,024
- CT evaporation loss (m^3/hr) = CW circulation (m^3/hr) x CW temperature difference across CT (°C) / 675
- % evaporation loss = Evaporation loss (m^3/hr) x l00 / CT CW circulation rate (m^3/hr)

- Purge or blow down (m^3/hr) = Evaporation loss (m^3/hr) / (COC - 1)
- COC = Cycles of concentration (design data for the facility)
- The efficiency of the fan system is affected by the extent of partial loading and the type of flow control mechanism deployed.

CT specifications

Table 47: CT specifications

S. No.	Item reference	Units	Design value
1.	Tower type	Cross flow or counter flow	
2.	Circulation water flow	m^3/hr	
3.	Hot CW inlet temperature	°C	
4.	Cold CW outlet temperature	°C	
5.	Range	°C	
6.	Wet-bulb temperature	°C	
7.	Approach	°C	
8.	CT pump (input power)	kW	
9.	CT fan motor (input power)	kW	
10.	CT drift loss per tower	kg/hr	
11.	CT evaporation loss per tower	kg/hr	
12.	Number of cells	Numbers	
13.	Fans per cell	Numbers	
14.	Internal cell dimensions	m x m	
15.	Overall tower dimensions	m x m	
16.	Hot water inlets	Numbers	
17.	L/G ratio	kg water/kg air	
18.	Drift eliminators type		
19.	Type/maker of the fan		
20.	Fan kW/per fan	kW	
21.	Diameter of fan	mm	
22.	Blade angle	degrees	
23.	Blade material		
24.	Gear box reduction ratio		

6. <u>Annexures</u>

The data sheet for CT performance

Table 48: Data sheet for CT performance

S. No.	Item reference	Units	CT reference
1	CT inlet air DBT	°C	
2	Inlet air WBT	°C	
3	CT exhaust air DBT	°C	
4	CT exhaust air WBT	°C	
5	CW inlet temperature	°C	
6	CW outlet temperature	°C	
7	Total CW flow	kg/hr	
8	Total air flow through CT (turbine flow meter measured values)	kg/hr	
9	Number of fans in service		
10	Number of CW fans in service		
11	Total fan power	kW	
12	Total CW pump power	kW	

Calculation sheet

CT Ref:

Date:

Table 49: Calculation sheet for CT

Duration of observations	hr
Average CT inlet temperature	°C
Average CT outlet temperature	°C
Average WBT	°C
Average CW flow	kg/hr
Average air flow	kg/hr
Total CW pump power	kW
Total CT fan power	kW

Performance indicators

Table 50: Performance indicators for CT

CT range	°C
CT approach	°C
CT effectiveness	%
L/G ratio	kg water/kg air
Evaporation loss with respect to (w.r.t.) circulation	%
CT heat loading	Kcal/hr
TR of CT (CT heat loading / 3,024)	TR
CT heat loading w.r.t. design	%

Performance results

Table 51: Performance results of CT

Item reference	Units	Cooling tower # 1				
		Design value	PG test value	Previous best value	Last energy audit value	Present energy audit actual value
CT range	°C					
CT approach	°C					
CT effectiveness	%					
L/G ratio	kg (water)/kg(air)					
Evaporation Loss w.r.t. circulation	%					
CT heat loading	Kcal/hr					
	%					

	TR					

Savings potential sheet

Table 52: Savings potential of CT

S. No.	Activity	Annual energy savings (kWh/year)	Annual monetary savings (BDT/year)
1.	CT effectiveness improvement		
	• Optimizing L/G ratio		
	• Air and water channelization		
	• Spray nozzle effectiveness		
	• Splash bar cleanliness		
2.	FRP blade conversion option		
3.	Optimization of CT fan operations in multicell CTs		
4.	Optimization/efficiency improvement in CW pumps		
5.	COC improvement option		

3.11 Energy audit procedure for refrigeration and heating, ventilation, and air conditioning (HVAC) system

List of contents

1. Objective
2. Instruments required
3. Audit procedure
4. Report preparation format
5. Audit tools for auditors
6. Annexures

1. Objective

To assess the existing performance of refrigeration and air conditioning plants, and to identify the scope of improvement, if any.

2. Instruments required

Online pressure gauges and temperature indicators, in-situ flow meters with an appropriate range of measurement, and portable ultrasonic flow meters, all calibrated before the audit.

- Hygrometer
- Load analyzer
- Pitot tube with digital manometer
- Vein type anemometer/hot wire anemometer

3. Audit procedure

- Compile design and PG test data of the refrigeration and air conditioning (RAC) plant, along with previous and last energy audit values.

- Ensure that all online instruments are calibrated within the last 12 months. Compile the calibration dates/data for all the instruments. All instruments must comply with the designed accuracy levels after calibration.
- List out the end users of the RAC plant, along with their temperature and load requirements, running hours, and operation profile.
- Observe and fill the data sheet every 1 hour and take three sets of readings during different load conditions, during the day (forenoon, afternoon) and night.
- Calculate the cooling load (temperature rise [TR]) of the plant during various load conditions. Evaluate the SPC (kW/TR) for each of the conditions, using the formula given in the audit tools, which will serve as an indicator for the health of the RAC plant. Also, calculate the coefficient of performance (COP).
- Compare the kW/TR and COP values with the rated/PG test values and last energy audit values.

Table 53: Comparison of RAC system

RAC plant reference							
Rated value		Previous best value		Last energy audit value		Present energy audit actual value	
SPC	COP	SPC	COP	SPC	COP	SPC	COP

- Evaluate the CT's effectiveness by the procedures mentioned in the audit procedures on CTs.
- The investigations for abnormality are to be carried out for problem identification.
- List out scope for improvement. The checklist presented in the annexure may be referred to as an aid to identify energy conservation opportunities.
- List recommendations for actions to be taken for improvement.
- Conduct cost-benefit analysis with savings potential for initiating improvement measures.

4. Report preparation format

The audit report may be prepared in the following format:

- Foreword
- Audit team
- Technical specifications
- Present practices: Explain in detail the present status.
- Observation and remarks: Refer to the data and conclusion sheets annexed and put down your observations and remarks about the energy audit carried out.
- Recommendations: Energy conservation options along with the savings potential sheet, including estimated expenditure, payback period, and other related expected benefits.
- Single line diagram

5. Audit tools

Cooling load (L) in TR = $m * C_p * (T_i - T_o) / 3{,}024$

Where:

m = mass flow rate of chilled water or secondary coolant in kg/hr
C_p = specific heat of chilled water (or secondary coolant)
T_i = temperature of chilled water (or secondary coolant) at the evaporator inlet
T_o = temperature of chilled water (or secondary coolant) at the evaporator outlet

The mass flow rate of chilled water (m) may be physically measured using an ultrasonic flow meter or calculated based on the actual input motor power, head developed by the chilled water pumps, and available characteristic curves (in the absence of which a pump efficiency would have to be assumed).

COP = (Refrigeration effect) / (Energy input, both the numerator and the denominator to be expressed in the same unit, which is watts or Kcal/hr or kW).

(For instance, if refrigeration effect is 1 TR, then it can be expressed as 3,024 Kcal/hr, and if the energy input is 0.25 kW, then it can be expressed as (0.25 * 860) Kcal/hr. Thus, keeping the units of numerator and denominator the same).

6. Annexures

The data sheet for RAC plants

Table 54: Data collection sheet for RAC system

Parameters (as measured)	Units	Design values	Observed Values at	
			7.00 hrs.	8.00 hrs.
Suction pressure of refrigerant to compressor	Psi			
Discharge pressure of refrigerant from compressor	Psi			
Chilled water temperature at chiller inlet	°C			
Chilled water pressure at chiller inlet	kg/cm²g			
Chilled water temperature at chiller outlet	°C			
Chilled water pressure at chiller outlet	kg/cm²g			
Condenser water temperature at condenser inlet	°C			
Condenser water pressure at condenser outlet	kg/cm²g			
Condenser water temperature at condenser outlet	°C			
Condenser water pressure at condenser outlet	kg/cm²g			
CW inlet temperature to CT	°C			
CW outlet temperature from CT	°C			
CT inlet air DBT	°C			
CT inlet air WBT	°C			
CT outlet air DBT	°C			
CT outlet air WBT	°C			
Number of fans in service				
Air flow through CT (anemometer measured value)	kg/hr			
Electrical measurements				
Compressor motor input power	kW			
Chilled water pump-1 motor input power	kW			
Chilled water pump-2 motor input power	kW			
Condenser water pump-1 motor input power	kW			
Condenser water pump-2 motor input power	kW			
AHU fan-1 motor input power	kW			
AHU fan-2 motor input power	kW			
AHU fan-3 motor input power	kW			
CT fan-1 motor input power	kW			
CT fan-2 motor input power	kW			

Note: This assumes that the RAC plant comprises one compressor, two chilled water pumps, two condenser water pumps, two CT fans, and three air handling units (AHUs). However, some may be modified based on the actual situation. If there is more than one compressor, then the electrical load measurements, as well as the suction and discharge pressure of each compressor are to be recorded separately.

Calculation sheet

Table 55: Calculation sheet for RAC plant

S. No.	Parameters	Units	Design values	Calculated values
1	Total cooling load	TR		
2	Individual SPC	kW/TR		
2a.	SPC for compressor			
2b.	SPC for chilled water pumps			
2c.	SPC for condenser water pumps			
2d.	SPC for CT fans			
3	Total electrical load (*of compressor + chilled water pumps + condenser water pumps + CT fans*)	kW		
4	Overall SPC (item 3 / item 1)	kW/TR		
4a.	CT range	°C		
4b.	CT approach	°C		
4c.	CT effectiveness	%		
4d.	COP	kW/TR		
5	Overall COP			
6	CT range	°C		
7	CT approach	°C		
8	CT effectiveness %	%		
9	CT capacity	TR		

- If there is more than one compressor working in parallel with each other, then the overall SPC for all the compressors needs to be computed.
- For chilled water pumps and condenser water pumps and fans, the overall SPC of pumps and fans is to be computed.
- For calculating CT range, approach, and effectiveness, please refer to the module on CTs.
- The total cooling load is calculated based on the chilled water-cooling effect.
- However, the AHUs can also be evaluated on the secondary loop. The evaluation of the TR load of AHU can be done based on air Dry Bulb Temperature (DBT) and Wet Bulb Temperature (WBT) at inlet and outlet of AHU.
- Air flow measurement. Air flow can be measured by:
  - An anemometer
  - A fan motor power input fan head developed and fan performance curves.

- ***Checklist***
  - Application of inlet vane control in AHU fans.
  - Application of three-way valves in chilled water supply lines to AHU.
  - Regular cleaning of air filters.
  - Scope of CT performance improvement.
  - Scope of stopping one or more chilled water pumps.
  - Scope of stopping chilled water flow through idle chillers.
  - Incorporation of sun films on the glass windowpanes, at end-use locales.
  - Incorporation of air curtains at end-use locales.
  - Checking the condenser effectiveness vis-à-vis design values.
  - Checking the condenser water pump performance vis-à-vis design values.
  - Checking the suction and discharge pressure of the compressor vis-à-vis design values.

Savings potential sheet

Table 56: Savings potential sheet for RAC plant

S. No.	Activity	Annual savings	
		Annual energy savings (kWh/year)	Annual monetary savings (BDT/year)

		.	

3.12 Energy Audit procedure for electric load management and electric motor system

List of contents

1. Objective
2. Instruments required
3. Audit procedure
4. Report preparation format
5. Audit tools for auditors
6. Annexures

1. Objectives

This module will help in:

- Drawing up the demand profile.
- Characterization of energy consumption revealed by the demand profile.
- Identification of savings opportunities in the demand profile.
- Evaluation of the savings opportunities by time of use (TOU) and time of day (TOD) tariffs.
- Identification of power factor correction and related savings opportunities.
- Identification of savings opportunities in electrical motors.

2. Instruments required

- Online instruments (calibrated at least within the last 12 months)
- HT/LT load analyzers
- Electrical demand controller
- Noncontact thermometers

3. Audit procedure

- Collect previous daily or monthly load profile data/curves along with electricity bills.
- Collect electrical load inventory data.
- Record the demand profile for a typical day of operations to bring out useful information such as:
  - Peak demand
  - Night load start-up load
  - Weather effects
  - Loads that cycle
  - Any other interactions like occupancy effects, production effects, etc.
- The load profile could be drawn at a time interval of 15 minutes or 30 minutes using one of the following demand profiling methods:
  - Periodic utility meter readings
  - Recording clip-on ammeter measurements
  - Basic recording power meter
  - Multichannel recording power meters
  - Energy management system or (Supervisory Control and Data Acquisition [SCADA] system)
  - Dedicated monitoring system

Note: For customers billed on kVA demand, there is an opportunity to reduce the peak or minimum kVA demand by increasing the power factor.

- The nonpeak power factor that is of concern from the perspective of demand costs is estimated, and the application of capacitors or variable capacitor banks (one that adjusts itself to the load and the power factor) can be installed.

- Carry out the motor load survey of the identified key electrical motors and investigations for abnormality for problem identification.
- Investigate for abnormalities like unbalanced loading, part loading, etc.; scope for improvements, like soft starters, installation of capacitors at motor terminals, incorporation of variable speed drive possibility of installing small size motors, etc. by assessing the duty of existing motors, etc.
- List out recommendations for actions and prepare cost analysis with savings potential for initiating improvement measures.

4. **Report preparation format**

The audit report may be prepared in the following format:

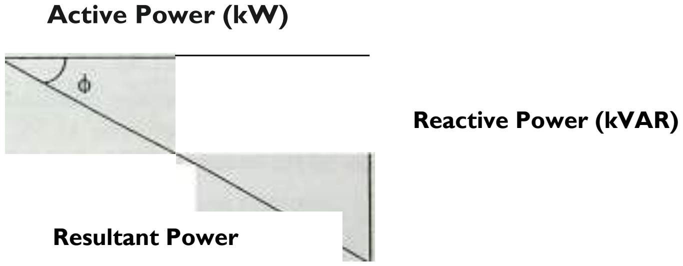
- Foreword
- Audit team
- Technical specifications
- Present practices: Explain in detail the present status.
- Observation and remarks: Refer to the data and conclusion sheets annexed and put down your observations and remarks about the energy audit carried out.
- Recommendations: Energy conservation options along with savings potential sheet, including estimated expenditure, payback period, and other related expected benefits.
- Single line diagram

5. Audit tools for auditors

- It is important that the demand profile be measured at a time when the operation of the facility is typical. Opportunities for savings can be found in the demand profile, and typical examples are:
  - o Short-time peak demand and opportunity for demand reduction by scheduling.
  - o Loads that cycle on/off frequently, during unoccupied periods.
  - o Start-up peak demand scope for interlocking of major loads to avoid simultaneous starts.
  - o Nonessential loads connected during peak periods—possible scope for peak shedding.
  - o Installation of Maximum Demand (MD) controllers for better management of load profile.
  - o Peak clipping by alternative power supply, viz. diesel generator (DG) sets, cogeneration power, etc.
  - o Valley filling (low demand during the night) by load shifting and taking.
  - o Advantage of TOD or TOU tariff structure.
- Power factor = Cos (θ) = kW/kVA.

$$kVA = \sqrt{kW^2+kVAR^2}$$

Figure 3: Power factor



- Capacitor ratings for power factor correction by direct connection to induction motors.

Table 57: Capacitor rating (kVAR) for motor speed (rpm)

Motor rating (HP)	Capacitor rating (kVAR) for motor speed (rpm)					
	3000	1,500	1,000	750	600	500
5	2	2	2	3	3	3
7.5	2	2	3	3	4	4
1	3	3	4	5	5	6
15	3	4	5	7	7	7
20	5	6	7	8	9	10
25	6	7	8	9	9	12
30	7	8	9		10	15
40	9	10	12	15	16	20
50	10	12	15	18	20	22
60	12	14	15	20	22	25
75	15	16	20	22	25	30
100	20	22	25	26	32	35
125	25	26	30	32	35	40
150	30	32	35	·40	45	50
200	40	45	45	50	55	60
250	45	50	50	60	65	70

**The values here are based on average conditions and efficiency to maintain a power factor of 0.95 to 0.97 between 33.3% and 125% of rated load and apply to 50 Hz motors of 220, 400/440, and 3300 V.*

- Motor efficiency is the ratio of mechanical energy delivered at the rotating shaft to the electrical energy input.
    - Motors like other inductive loads are characterized by power factors less than unity.
    - Squirrel cage motors are more efficient than the slip ring motors, and high-speed motors are more efficient than the low-speed motors.
    - Efficiency is also a function of motor temperature. Temperature enclosed, fan-cooled (TEFC) motors are more efficient than screen-protected drip-proof (SPDP) motors.
- Factors affecting motor performance are:
    - Intrinsic losses are independent of motor load.
        - Magnetic core losses (eddy current and hysterics losses)
        - Friction and windage losses
    - Extrinsic factors
        - Quality of power supply
        - Age of motor
        - Maintenance practices
        - Rewinding practices
- The impact of intrinsic factors can be reduced by the design and high-efficiency motors or energy-efficient motors that operate with efficiencies that are typically 3 to 4 percentage points higher than the standard motors.
- For every 10°C increase in motor operating temperature over the recommended peak, the motor life (insulation capability) is estimated to be halved.
- If rewinding is not done properly, the efficiency can be reduced by 5–8%.
- Balanced voltage can save 3–5% of energy consumption.

- Variable speed drives option can help in reducing the energy consumption by 5–15%, and even to the tune of 35% as in the case of fan and pump applications.
- Energy savers/soft starters will not only reduce insulation stress on the motor but more importantly, help reduce power consumption by 5–8% of the starting kW.
- In case of high starting torque and low operating loads (<50%), delta-star starter application will help in reducing energy consumption.

Power consumption (E) (kW) = 1.732 * V * I * P_f (or measured value)

Where:
V = Measured operating voltage at motor input (line to line)
I = Measured operating current at motor input
P_f = Measured power factor at motor input

Motor load % (method - 1) = (I_m / I_r) * (V_m / V_r) * 100

Where:
Motor load % = Output power (operating) as a % of rated name plate power
I_m = Measured operating current
Ir = Rated current (name plate)
V_m = Measured voltage
V_r = Rated voltage (name plate)
(V_m / V_r) = Voltage correction factor

Motor load % (method - 2) = [(S_s - S_m) * 100] / [(S_s - S_r) * (V_r / V_m)^2]

Where:
Motor load % = Output power (operating) as a % of rated name plate power
S_s = Synchronous speed in rpm
S_r = Name plate rated speed in rpm
S_m = Measured speed in rpm
(S_s – S_m) = S_{lip}
V = Measured RMS mean voltage (line to line)
V_r = Name plate rated voltage
(V_m / V_r) = Voltage correction factor

Motor load % (method 3) = [(P_i) * (100)] / [(P_{or} / η_{fl})]

Where:
Motor load % = Output power (operating) as a % of rated name plate power
P_i = Measured 3-ph input power (kW)
P_{or} = Name plate rated output power (kW)
η_{fl} = Name plate efficiency at full rated load

Motor efficiency – ($\eta_{m\text{-}op}$) = [(P_{or}) * (Motor load % / 100) * 100] / (P_i)

Where:
$\eta_{m\text{-}op}$ = Motor efficiency at operating conditions (%)
P_{or} = Nameplate rated output power (kW)
Motor load % = Output power (operating) as a % of rated nameplate power
P_i = Measured 3-ph input power (kW)
Reactive power kVAR = {(kVA)^2 + (kW)^2} 0.5

Capacitance required to improve from P_{f1} to P_{f2} = kW [Tan {Cos^{-1} (P_{f1})} – Tan {Cos^{-1} P_{f2}}]

Where:
kW= Existing active power load of the system
P_{f1} = Existing power factor (low)
P_{f2} = Proposed power factor (high)
P_i = Measured 3-ph input power (kW)
kVAR = The capacitance required to be added to the power system to improve the power factor from a lower level to a higher level.

Reduction in kVA demand by improving power factor from P_{f1} to P_{f2} (Δ kVA) = kVA_1 - kVA_2

or = kW {(1 / P_{f1}) - (1 / P_{f2})}

Where:
kW = Existing active power load of the system (remains same regardless of P_f variation)
P_{f1} = Existing power factor (low)
P_{f2} = Proposed power factor (high)
kVA1 = Resultant power (kVA) demand at prevailing P_{f1} (kVA1 = kW / P_{f1})
kVA2 = Resultant power (kVA) demand at proposed P_{f2} (kVA2 = kW / P_{f2})

Reduction in the distribution loss % in kWh when tail end power factor is raised from P_{F1} to a new power factor P_F, will be proportional to
$[1 - (P_F / P_F)^2$ j x 100

Where transformer loading is known, the actual transformers loss at given load can be computed as:

= No load loss + (kVA load / rated kVA)^2 * (Full load loss)

6. Annexures

The data sheet for demand profile

Table 58: Data sheet for demand profile

Time	kVA	Time	kVA

Note:

- Record the kVA values every 15 minutes/30 minutes, depending on the time interval of MD assessment.
- Plot the kVA values against time for 1 day and repeat the process, to obtain a realistic plot, considering various factors influencing the demand profile.
- Check out for possible kVA reduction options.

The data sheet for the motor load survey

Table 59: Data sheet for motor load survey

S. No	Motor reference	Drive reference	Rated parameters	Measured parameters	% Loading	Remarks
			Volt amp pf kW rpm	Volt amp pf kW rpm		

**Estimate the % kW loading of the motor = (operating kW) * 100 / (Rated kW / Motor efficiency).*

Bring out the options for energy savings by identifying the suitable measures applicable in each case.

Savings potential sheet

Table 60: Savings potential sheet for electric load management and electric motor system

S. No.	Activity	Annual energy savings (kWh/year)	Annual monetary savings (BDT/year)
1.	Improvement of power factor		
2.	Demand control by		
a.	MD controller		
b.	Off-peak load shifting		
3.	Improved motor operating efficiency by		
a.	Speed reduction (by variable speed drive)		
b.	Soft starter/energy saver adoption		
c.	Motor replacement for efficiency margins		
d.	High efficiency motor application		
e.	Delta to start conversion for motors loaded below 50% (starting torque requirements to be checked) or Del-Star starters.		

3.13 Energy Audit procedure for lighting systems

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1. Objectives
2. Instruments required
3. Audit procedure
4. Report preparation format
5. Audit tools for auditors
6. Annexures

1. Objectives

- To measure illumination levels at various locations.
- To compare the illumination levels with standard values.
- Suggest ways and means to optimize the illumination levels and to reduce/optimize the power consumption at different locations.
- To measure the total power consumption of all lighting feeders.
- Compare the consumption with design value. Suggest ways to optimize and reduce power consumption.

2. Instruments required

- Luxmeter
- Tong tester
- Power analyzer
- P_f – Meter

3. Audit procedure

Activity I

- Identify the locations for audit.
- Collect electrical drawings/schematics for lighting circuits.

Activity II

- Measure the lux level with lux meter both for daytime as well as night-time periods.
- Compare existing illumination levels with standard levels.
- Recommend as per conclusion derived for lux level reduction/improvement.

Activity III

- Measure actual power consumption of all lighting feeders for at least 24 hours with the help of an energy meter of 0.5 accuracy, duly calibrated.

- Calculate the total power consumption of each feeder by adding the wattage of lighting systems installed on that feeder including other power loads, if any.
- Compare the actual power of that feeder with the designed power of the feeder (refer to annexure).
- Diagnose the cause for any difference between actual and ideal power. Recommend, as per conclusion derived from the above measurements, for improvement and optimization of power consumption. Suggest ways to improve, such as providing timers, group switching, occupancy sensors, replacement of high-power consuming lamps with efficient and low power consuming lamps of appropriate wattage, and lux level.

4. Report preparation format

The audit report may be prepared in the following format:

- Foreword
- Audit team
- Technical specifications
- Present practices: Explain in detail the present status.
- Observation and remarks: Refer to the data and conclusion sheets annexed and put down your observations and remarks about the energy audit carried out.
- Recommendations: Energy conservation options along with savings potential sheet, including estimated expenditure, payback period, and other related expected benefits.
- Single line diagram

5. Audit tools for auditors

- Derive ways to improve natural light during daytime.
- Incorporating timers and photo sensors in lighting circuits.
- Easy accessibility to on/off switches and incorporation of group switching.
- Modifying electrical circuits for easy operation.
- Switching off alternate lights in late night hours in streetlights.
- Phasing out inefficient lamps with higher efficiency lamps and luminaires. Promoting LED against fluorescent tubular lamps (FTLs), CFLs, HP mercury vapor lamps (HPMVs), and High-Pressure Sodium Vapour Lamps (HPSV) lamps.
  - Replacing inefficient HPMV lamps with HPSV lamps of lower wattage for outdoor applications but with same or better lumen, keeping functional requirement in view.
  - Replacing 1,000-watt Halogen lamps with 250-watt HPSV lamps.
  - Use of electronic or compact low loss ballasts for tube lights (FTLs) and HPSV lamps.
  - Use of better reflectors in lighting.
  - Clean the reflector at regular intervals.
  - Refer to standard illumination values for various areas in power stations as given in the annexure.
  - Install occupancy sensors in office buildings and conference rooms and use of photosensitive controls for streetlighting.

6. Annexures

Recommended illumination values for various areas in power stations

Table 61: Recommended illumination values for various areas in power stations

S. No.	Industrial building and process	Illumination (Lux)
I.	Electricity generating station indoor location	
A	Turbine halls	200
B	Auxiliary equipment, battery rooms, blowers, auxiliary generators, switchgear, and transformer chambers	100
C	Boiler houses (including operating floor), platforms, coal conveyors, pulverizers, feeders, precipitators, soot, and slag blowers	70–100

S. No.	Industrial building and process	Illumination (Lux)
D	Boiler house and turbine house	100
E	Basements	70
F	Conveyor houses, conveyor galleries, junction towers	70–100
G	Control rooms	
I	Vertical control panels	200–300
II	Control desks	300
III	Rear of control panels	150
IV	Switch houses	150
2.	**Electricity generating station's outdoor location**	
A	Coal unloading areas	20
B	Coal storage areas	20
C	Conveyors	50
D	Fuel oil delivery headers	50
E	Oil storage tanks	50
F	Cat walks	50
G	Platforms boiler and turbine decks	50
H	Transformers and outdoor switchgear	100
3	**Canteens**	150
4	**Clock room**	100
5	**Entrance, corridors, stairs**	100
A	Exit roads, car parks, internal factory roads	20
6	**Laboratories and test rooms**	
A	Electrical and instrument laboratories	450
B	Central laboratories balance rooms	300
7	**Machine and fitting shops**	
A	Wrought bench and machine works	150
B	Medium bench and machine work, ordinary automatic machines, rough grinding, medium grinding, fine buffing	300
C	Fine bench and machine work, fine automatic machines, medium grinding, fine buffing, and polishing	700
8	**Office**	
A	Entrance halls and reception areas	150
B	Conference rooms, executive offices	300
C	General offices	300
D	Drawing offices	300
i	General	300
ii	Boards and tracing	450
E	Corridors and cars	70
F	Stairs	100
G	Lift landing	150

Inventory of lighting lamps/Luminaires and replacement recommendations

Table 62: Inventory of lighting lamps/luminaires and replacement recommendations

S. No.	Location reference area (1)	Number of fittings with watt rating (2)	Total kW (including wattage of chokes) (3)	Recommendation (4)	Total kW of recommended system (5)	Power saved (3–5) (A)	Annual illumination hours (B)	Annual energy savings (A) * (B)

Table 63: Illumination level measurement sheet

Illumination Level Measurement Sheet			
S. No.	**Area**	**Existing illumination level**	**Standard illumination level**
1.	GT, ST -HALL		
2.	Machine shop		
3.	Office rooms of plant personnel		
4.	Unit control room		
5.	Boiler (firing floor)		
6.	Mill area		
7.	Conveyors		
8.	Compressor house		
9.	Ash handling plant		
10.	ESP control room		
11.	Battery room		

Energy consumption measurements—Feeder wise

Table 64: Energy consumption measurements—Feeder wise

S. No.	Lighting feeder identification	Designed power (kW)	Actual power (kW)

Energy consumption measurements of lighting transformers

Table 65: Energy consumption measurements of lighting transformers

S. No.	Lighting feeder identification	Daytime transformer input power (kW)	Night-time transformer input power (kW)	Status of tap changer position

Energy conservation options

Table 66: Energy conservation options for lighting systems

S. No.	Energy conservation measure reference	Annual energy savings (kWh/year)	Annual monetary savings (BDT/year)

3.14 Energy audit procedure for electrostatic precipitators (ESPs)

List of contents

1. Objectives
2. Instruments required
3. Audit procedure
4. Report preparation format
5. Audit tools for auditors
6. Annexures

1. Objectives

- To evaluate existing dust collection efficiency of ESPs.
- To evaluate SPC in kWh/Nm³ of gas flow and kWh/kg dust collection.

2. Instruments required

- Stack monitoring kit (for gas flow and dust loading, isokinetic sampler)
- Online instruments (as existing)
- Power analyzer
- Temperature indicators

3. Audit procedure

Activity I

- Select the unit for which the energy audit of the ESP system is to be carried out.
- Collect specifications, design, and PG test data.
- Check availability and working of various online and portable instruments to be used during the trial.
- Observations should be made while running the unit at constant load.

Activity II

- Take an overall view of the system comprising ESPs, ash flushing system, and ESP control room.
- Ensure that all fields of ESPs are in operation and proper ash evacuation is taking place from the hoppers/hopper during the test.
- During the trial run, take inlet dust loading (mg/Nm³) and outlet dust loading simultaneously, using a stack monitoring kit (isokinetic sampler).
- During the trial, carry out flue gas analysis to determine the % O2 or CO_2 in the flue gas by using collection balloons and or sat apparatus (or online gas analyzers) at inlet and outlet duct of ESPs.
- Record ESP control room readings, viz. individual field currents and power consumption as per the table given in the annexure.
- Simultaneously, record source equipment (boiler) control room readings, as per the table given in the annexure.

- The minimum duration of the test could be 3.5 hours per stream of ESP (in case of multiple ESP streams), and all the specified parameters are to be recorded every half hour. These are to be recorded simultaneously, including the pitot-tube measurements.
- Record kWh consumption on primary side of recti-former (AC) and kWh on secondary side of recti-former (DC).
- Record/measure the recti-former CW flow and the CW TR (Δ T, °C).

Activity III

Calculations may be performed to draw following conclusions, per formula given in the section "Audit tools for auditors."

- Calculate the dust collection efficiency.
- Calculate the SPC kWh per Nm^3 of dusty air handled and per kilogram of dust collected.
- Calculate the excess air levels before and after the ESPs.
- Compare the above values with PG test/design values. If the observed values are worse than the PG test/design values, then identify reasons for deterioration.
- Suggest measures for energy saving.

4. Report preparation format

The audit report may be prepared in the following format:

- Foreword
- Audit team
- Technical specifications
- Present practices: Explain in detail the present status.
- Observation and remarks: Refer to the data and conclusion sheets annexed and put down your observations and remarks about the energy audit carried out.
- Recommendations: Energy conservation options along with savings potential sheet, including estimated expenditure, payback period, and other related expected benefits.
- Single line diagram

5. Audit tools for auditors

- ESP efficiency = $(d_i - d_o) * 100 / (d_i)$
- Rectiformer efficiency = [kWh (DC) output] * 100 / [kWh (AC) input]
- Where:
  d_i = inlet dust loading, (mg/Nm^3)
  d_o = outlet dust loading, (mg/ Nm^3)
  - SPC (kWh/Nm^3 gas flow) = (ESP input power, kW) / (Average dusty gas flow through ESP, Nm^3/hr)
  - SPC (kWh/kg dust collected) = (ESP input power, kW) / (Dust collected kg/hr)

6. Annexures

Field data sheet

Table 67: Field data sheet for ESP

Item reference	Time (in hours)			
Source equipment load parameters (e.g., boiler)				
Boiler main steam flow (TPH)				
Boiler coal flow (TPH) or fuel flow				
Flue gas temperature at ESP inlet (°C)				
Flue gas temperature at ESP outlet (°C)				
CO_2 or O_2 at ESP inlet duct (%)				
CO_2 or O_2 at ESP outlet duct (%)				
Dust loading at ESP inlet (mg/Nm^3)				

Dust loading at ESP outlet (mg/Nm^3)				
Gas flow rate (Nm^3/hr)				
Recti-former primary side kW (or kWh) (AC)				
Recti-former primary side kW (or kWh) (DC)				
Drying heater power (kW) (or kWh)				

ESP control room data

Table 68: Data collection sheet for ESP control room

Time	09:30	10:00	10:30	…….	………	16:00	16:30	17:00	17:30
Field-1									
Current (mA)									
Volts (kV)									
Charge ratio									
Field-2									
Current (mA)									
Volts (kV)									
Charge ratio									
Field-3									
Current (mA)									
Volts (kV)									
Charge ratio									
Field-4									
Current (mA)									
Volts (kV)									
Charge ratio									
Field-5									
Current (mA)									
Volts (kV)									
Charge ratio									

Performance assessment

Table 69: Performance assessment for ESP

Gas flow	Units	Actual	Design
Gas flow	Nm^3/hr		
% Dust removed	%		
ESP collection efficiency	%		
Recti-former conversion efficiency	%		
SPC	kWh/Nm^3		
	kWh/kg dust removed		
Specific heater power consumption	kWh/Nm^3		
	kWh/kg dust removed		

3.15 Energy audit procedure for insulation

List of contents

1. Objectives
2. Instruments required
3. Audit procedure
4. Report preparation format
5. Audit tools for auditors
6. Annexures

1. <u>Objectives</u>

- To evaluate the loss of thermal energy at various locations of external hot *surfaces (predominantly, boiler surfaces, turbine surfaces, hot vessel surfaces, steam pipeline surfaces, hot oil pipeline surfaces, etc. which, typically are between 200°C and 250°C max.)*
- To evaluate the loss in terms of fuel and money lost.
- To find out the ways and means of improving the insulation level and reducing surface heat losses.

2. <u>Instruments required</u>

- Noncontact thermometer with laser sighting
- Thermo-vision camera (if available)
- Distance measurement device with laser sighting
- Normal measurement tape (10 m)

3. <u>Audit procedure</u>

Compilation of drawings/sketches/material details

Compile the following:

- Single line diagram of all the hot and cold lines of the plant with their dimensions.
- Dimensional sketches of other hot surfaces of boilers, turbines, vessels, etc., and cold surfaces.
- Details of insulation material and cladding used (emissivity of cladding, etc.).

Data collection

Collect the following data:

- Calorific value of the fuel being fired on the day of the audit.
- Annual hours of operation of each unit.
- Latest "as received" cost of the fuel(s).
- Latest boiler efficiency of each unit.
- Average wind velocity.
- Unit cost of reinsulation, including material, labor, etc.
- Temperature measurements: Measure the temperatures at various locations of different hot and cold surfaces. Temperature readings at various locations and elevations should be taken with the help of a noncontact thermometer or a thermo-vision camera. For pipelines, measure, and record temperatures separately. Make a specific record regarding physically damaged insulation surfaces, damaged claddings, uninsulated/unclad surface details, and places of hot air/steam/hot liquid leakages/chilled water leakages/chilled brine leakages. To arrive at the temperature at a particular elevation, average all the readings at the location to be taken.
- Data analysis: Calculate the heat loss and the money lost.
- Recommend for change or repair of insulation, as per conclusion derived from the above, clearly indicating expenditure involved, payback period, expected annual savings, and other allied benefits.

4. <u>Report preparation format</u>

The audit report may be prepared in the following format:

- Foreword
- Audit team
- Technical specifications
- Present practices: Explain in detail the present status.
- Observation and remarks: Refer to the data and conclusion sheets and note observations and remarks about the energy audit carried out.
- Recommendations: Energy conservation options along with savings potential sheet including estimated expenditure, payback period, and other related expected benefits.
- Single line diagram
- Data regarding calibration of instruments used indicating dates of last calibration (calibration more than 12 months old is not acceptable).

5. Audit tools for auditors

Calculation of insulation thickness

Thermal insulation delivers the following benefits:

- Reduces overall energy consumption.
- Offers better process control by maintaining process temperature.
- Prevents corrosion by keeping the exposed surface of a refrigerated system above dew point.
- Provides fire protection for the equipment.
- Absorbs vibration.

Heat loss from a surface is expressed as

$$\mathbf{H = h * A * (T_h - T_a)}$$

Where:

h = Heat transfer coefficient, W/m^2-K
H = Heat loss, watts
T_a = Average ambient temperature, °C
T_s = Desired/actual insulation surface temperature, °C (20–30°C above ambient temperature)
T_h = Hot surface temperature (for hot fluid piping), °C, and cold surface temperature (for cold fluids piping)

For horizontal pipes, heat transfer coefficient **(h)** can be calculated by:

$$h = (A + 0.005\ (T_h – T_a)) \times 10\ W/m^2\text{-}K$$

For vertical pipes, heat transfer coefficient **(h)** can be calculated by:

$$h = (B + 0.009\ (T_h – T_a)) \times 10\ W/m^2\text{-}K$$

Using the coefficients A and B as given below.

Table 70: Heat transfer coefficients

Surface	€	A	B
Aluminum, bright rolled	0.05	0.25	0.27
Aluminum, oxidized	0.13	0.31	0.33
Steel	0.15	0.32	0.34
Galvanized sheet metal, dusty	0.44	0.53	0.55
Nonmetallic surfaces	0.95	0.85	0.87

$$T_m = (T_h + T_s) / 2$$

Where:

k = Thermal conductivity of insulation at mean temperature of T_m, W/m-C

t_k = Thickness of insulation, mm
r_1 = Actual outer radius of pipe, mm
$r_2 = (r_1 + t_k)$
R_s = Surface thermal resistance
= (1 / h) °C - m²/W
R_1 = Thermal resistance of insulation
= (t_k / k) °C - m²/W
€ = emissivity

The heat flow from the pipe surface and the ambient can be expressed as follows:
H = Heat flow, Watts = $(T_h – T_a) / (R_1 + R_s) = (T_s – T_a) / R_s$

From the above equation, and for a desired T_s, the R_l can be calculated. From R_l and known value of thermal conductivity k, thickness of insulation can be calculated.

Equivalent thickness of insulation for pipe, E_{tk}
$E_{tk} = (r_1 + t_k) * l_n \{(r_1 + t_k) / r_1\}$

Simplified formula for heat loss calculation
Various charts, graphs, and references are available for heat loss computation. The surface heat loss can be computed with the help of a simple relation as given below. This equation can be used up to 200–250°C surface temperature. Factors like wind velocities, conductivity of insulating material, etc. have not been considered in the equation.

Surface heat loss (S) = $[10 + (T_s - T_a) / 20] * (T_s - T_a)$

Where:
S = Surface heat loss in Kcal/hr m²
T_s = Hot surface temperature in °C
T_a = Ambient temperature in °C

Total heat loss (H_s) = S * A

Where:
H_s = Total heat loss in Kcals/hr
A = Surface area in m²

Based on the cost of heat energy, the quantification of heat loss in BDT can be worked out as under:

Equivalent fuel loss (H_f) (kg fuel/year) = [(H_s) * (Annual hours of operation)] / [(GCV of fuel) * (Boiler efficiency (η_b))]

Annual heat loss in monetary terms (BDT/year) = H_f * Fuel cost (BDT/kg)

Where:
GCV = Gross calorific value of fuel Kcal/kg
η_b = Boiler efficiency in %

Case example
A steam pipeline 100 mm diameter is not insulated for 100 meters of length, supplying steam at 10 kg/cm² to the equipment. Find out the fuel savings if it is properly insulated with 65 mm insulating material.

Assumptions:

Boiler efficiency = 80%
Fuel oil cost = BDT 15000/ton
Surface temperature without insulation = 170°C
Surface temperature after insulation = 65°C
Ambient temperature = 25°C

Existing heat loss:

$S = [10 + (T_s - T_a) / 20] \times (T_s - T_a)$
$T_s = 170°C$
$T_a = 25°C$
$S = [10 + (170 - 25) / 20] \times (170 - 25) = 2{,}500$ Kcal/hr m²
$S_l = S =$ Existing heat loss (2,500 Kcal/hr-m²)

Modified system

After insulating with 65 mm glass wool with aluminum cladding, the hot face temperature will be 65°C.

$T_s - 65°C$
$T_a - 25°C$

Substituting these values

$S = [10 + (65 - 25) / 20] \times (65 - 25)$
$= 480$ Kcal/hr m²
$S_2 = S =$ Proposed case heat loss
= (480 Kcal/hr m²)

Properties of insulating material

Table 71: Properties of insulating material

Insulating material	Temperature limit °C	Density kg/m l kg/m l	Thermal conductivity W/m-°K	Water absorbed (¾ by volume)	Comments
Calcium	200–700	80–200	0.05–0.32	75 (high)	High water absorbency but will dry out. Good workability.
Foam glass	200–500	130–140	0.02–0.10	0.2	Deteriorates in alkali solution.
Polyurethane	200–130	20–100	0.01–0.03	1.6	Significant deterioration in acid and various organic but resists water. Excellent workability.
Ceramic	200–1,400	40–200	0.08–0.45		
Mineral workability fiber	50–1,000	100–200	0.07–0.032	70 (high)	Good workability.

Emissivity for different cladding material

Table 72: Emissivity for different cladding material

Aluminum	0.15 - 0.30
Stainless steel	0 20 - 0.40
Oxidized steel	0.80 - 0.90
Fabric	0.70 - 0.80

Thermal conductivities of commonly used hot insulation material (W-m²/m°C or W-m/°C)

Table 73: Thermal conductivities of commonly used hot insulation material

Mean temperature °C	Calcium silicate	Resin bonded mineral wool	Ceramic fiber blankets
100	-	0.04	-
200	0.07	0.06	0.06
300	0.08	0.08	0.07
400	0.08	0.11	0.09
700	-	-	0.17
1000	-	-	0.26
Specific heat (kJ/kg °C)	0.96	0.921	1.07
	At 40°C	At 20°C	At 980°C
Service temperature (°C)	950	700	1,425
Density kg/m3	260	48 to 144	64 to 128

Effect of wind velocity on heat loss

After insulation service

Table 74: Effect of wind velocity on heat loss

Wind velocity km/hr	Vare-pipe heat loss W/m	Temperature °C	Heat loss W/m
0	2,153.7	48.66	103.1
5	3,059.7	46.36	104.4
10	3,620.3	45.51	104.7
15	4,064.2	45.01	105.1
20	4,444.7	44.65	105.2
25	4,782.0	44.38	105.4

Thermal conductivity = 0.082 W-m/°K, Cladding: Oxidized steel
Basis: Pipe diameter = 150 mm. Fluid temperature = 250°C.
Insulation thickness = 130 mm. Ambient temperature = 400°C.

6. <u>Annexures</u>

Fuel savings calculation (Illustration using the above case example is given below.)

Table 75: Fuel savings calculation for insulation

Fuel savings calculation		
Pipe dimension	=	Diameter (mm): Length (m)
Surface area existing (A_1): m²	=	3.14 x diameter (m) before insulation x length (m)
Surface area after insulation (A_2): m²	=	3.14 x diameter (m) after insulation x length (m)
Total heat loss in existing system (S_1 x A_1)	=	2,500 x 31.4 = 78,500 Kcal/hr
Total heat loss in modified system (S_2 x A_2)	=	480 x 72.2 = 34,656 Kcal/hr
Reduction in heat loss	=	78,500 – 34656 = 43,844 Kcal/hr
Number of hours of operation in a year	=	8,400 hrs/year
Total heat loss	=	43,844 x 8,400 = 368,289,600 Kcal/year
Calorific value of fuel oil	=	10,300 Kcal/kg
Boiler efficiency	=	80%
Price of fuel oil	=	BDT 70,000/ton
Yearly fuel oil savings	=	368,289,600 / 10,300 x 0.8
	=	44,695 kg/year

<u>Observation sheets:</u>

- Surface reference name:
- Location details:
- Surface dimensions:
  - Flat surface

Length (m) =
Breadth (m) =
- o Pipe surface
  Outer diameter (m) =
  Inner diameter (m) =
  Length (m) =
- Total exposed surface:
  - o Area (A), m2 =
- Surface temperatures and other data:

Table 76: Data collection sheet for insulation

Parameter reference	UoM	Daytime	Night-time	Comments/ remarks
Ambient temperature	°C			
Hot surface temperature (for hot flat surface)	°C			
Hot surface temperature (for hot fluid pipe)	°C			
Mean temperature	°C			
Boiler efficiency	%			
Average GCV of fuel	Kcal/kg			
Annual hours of operation	hr/year			

Calculation sheet

Table 77: Calculation sheet for insulation

Parameter reference	Symbol	UoM	Value	Comments/ remarks
Heat transfer coefficient	h	W/m2-K		
Thermal conductivity of insulation at mean temperature of T_m	k	W/m-k		
Heat loss	H	Watts		
Surface thermal resistance	R_s	°C-m2/W		
Thermal resistance of insulation	R_l	°C/W		
Insulation thickness	E_{tk}	Mm		
Surface heat loss	S	Kcal/hr-m2		
Total annual heat loss	H_s	Kcal/year		
Equivalent annual fuel loss	H_f	(kg fuel/year)		
Annual heat loss in monetary terms		(BDT/year)		

Energy saving potential sheet

Table 78: Energy savings potential sheet for insulation

Saving measure reference	Annual heat savings (Kcal/year)	Equivalent annual fuel savings (Sm3NG/year) or (tons coal/year) or (kL HSD/year)	Annual monetary savings (BDT/year)

3.16 Energy audit procedure for pumping systems

List of contents

1. Objectives
2. Instruments required
3. Audit procedure
4. Report preparation format
5. Audit tools for auditors
6. Annexures

1. Objectives

- To assess the existing efficiency and performance of the pumps/pumping system.

- Inter pump comparison gives an impression about performance trends between two inspections and permits early interference in case of fall in performance.

2. Instruments required

- Online instruments (calibrated at least once within the last 12 months).
- Noncontact type ultrasonic flow meter.
- Turbine flow meter for open channel flows.
- Pressure gauges with an appropriate range of measurement and calibrated before the audit.
- Power analyzer HT/LT, calibrated energy meter connected to respective equipment.

3. Audit procedure

Activity I

- Select the pump or pumping station for which the Cleaner Production and Energy Efficiency (CP-EE) audit is required to be carried out.
- Collect specifications, design/performance guarantee test data, pump characteristic curves, and schematic diagrams of the pumping system.
- Collect maintenance history, existing problems if any in the system. Ensure that all CW line instruments are calibrated within the last 12 months. Compile the calibration dates/data for all the instruments. All the instruments must comply with the designed accuracy levels after calibration.
- Check availability and working of various online and portable instruments to be used for observations during the trials.
- Observations should be made by running the pumps in different combinations (if the pumps are connected in parallel).

Activity II

- Take an overall view of the pumping system comprising pumps, motors, coupling, suction/discharge valves, piping, flanges, and pump seals/glands for checking the general health of the pumping system, that is, to note noticeable leakages of the process fluid and thermal insulation deterioration if the fluid handled is hot or cold.
- Carry out power measurements of pumps. In the absence of a power analyzer/energy meter, use a tong tester and estimate the power consumption by the formula given in the section, "Audit tools for auditors."
- Measure fluid flow (if available directly) or decide to measure fluid flow by tank filling method. Otherwise, estimate fluid flow by measuring suction pressure, discharge pressure, and power input, and use pump characteristic curves. It would be best, however, to measure fluid flow using an ultrasonic portable flow meter.
- Various parameters observed should be noted on a log sheet shown in the annexure (for 4 hours, at half-hour intervals, and two sets of readings per day).

Activity III

- Calculations may be performed to draw the following conclusions, as per the formula given in the section "Audit tools for auditors."
- Calculate the combined efficiency of pump and motor.
- Estimate fluid flow (if the flow is not available directly).
- Evaluate SPC (kW/m^3/hr) and SEC (kWh/m3).
- Compare the above values with rated values, with PG test/design values.
- If there is a large variation, look for areas for improvement.
- Suggest measures for energy savings.
- The investigations for abnormality are to be carried out for problem identification.
- List out scope for improvement. The checklist presented in Annexure 3 may be referred to as an aid to identify energy conservation opportunities.

- List recommendations for actions to be taken for improvement.
- Conduct a cost-benefit analysis with savings potential for initiating improvement measures.

4. Report preparation format

The audit report may be prepared in the following format:

- Foreword
- Audit team
- Technical specifications
- Present practices: Explain in detail the present status.
- Observation and remarks: Refer to the data and conclusion sheets and note observations and remarks about the energy audit carried out.
- Recommendations: Energy conservation options along with savings potential sheet, including estimated expenditure, payback period, and other related expected benefits.
- Single line diagram
- Data regarding calibration of instruments used indicating dates of last calibration (calibration more than 12 months old is not acceptable).

5. Audit tools for auditors

Pumps

- **Power consumption (E) (kW) = 1.732 * V * I * P_f (or measured value)**
- **Combined pump-motor efficiency – $\eta_{p\text{-}m}$ (%) = [(m) * (TDH) * (9.81) * (100)] / (E)**

  Where:
  E = Pump motor input power (kW)
  m = Fluid flow (m^3/second)
  TDH = Total differential head (mWC)
  9.81 = Gravitational constant
- **Motor load % = (I_m / I_r) * (V_m / V_r) * 100**

  Where:
  Motor load % = Output power (operating) as a % of rated nameplate power
  I_m = Measured operating current
  I_r = Rated current
  V_m = Measured voltage
  V_r = Rated voltage
- **Motor efficiency – $\eta_{m\text{-}op}$= [(P_{ro}) * (Motor load % / 100) * 100] / (P_i)**

  Where:
  $\eta_{m\text{-}op}$ = Motor efficiency at operating conditions (%)
  P_{ro} = Nameplate rated output power (kW)
  Motor load % = Output power (operating) as a % of rated nameplate power
  P_i = Measured input power 3-ph (kW)

- Pump efficiency - η_{pp}
  = (Combined pump-motor efficiency, $\eta_{p\text{-}m}$) * (100) / (motor efficiency, $\eta_{m\text{-}op}$)
- SPC [(kW) / (m^3/hr)]
  = (Power consumption, E in kW) / (Fluid flow, F, in m^3/hr)
- SEC [(kWh) / (m^3)]
  = (Power consumption, E in kW) / (Fluid flow, F, in m^3/hr)
- % Margin available with respect to rated motor input power
  = (Measured motor input power, P_i, in kW) * 100 / (Rated motor input power)

- % Margin available with respect to rated pump flow
  = (Measured fluid flow, F, in m^3/hr) * 100 / (Rated pump flow)
- % Margin available with respect to rated pump head
  = (Measured fluid head, TDH, in mWC) * 100 / (Rated pump head)

6. Annexures

Observations on the pumping system

Table 79: Observations on the pumping system

Time	Units	Design	Actual					Remarks
			Time Ref-1	Time Ref-2	Time Ref-3	Time Ref-4	Average	
Suction pressure	kg/cm²(g)							
Discharge pressure	kg/cm²(g)							
THD	mWC							
Discharge valve position	%							
Fluid flow Motor input power Motor loading	m^3/hr kW %							
Motor efficiency (operating)	%							
% Margin available concerning rated motor power input % Margin available concerning pump rated head % Margin available concerning pump rated flow	% % %							

Pump audit guidelines

Conduct shut-off head trial (maximum 1-minute duration and ensure discharge valve is fully closed and not passing). If head corresponds to less than 90–95% of name plate value, look for pump internal problems like:

- Gland seal leak
- Shaft misalignment
- Impeller pitting, wear out
- Casing wears out
- Bearing wears out, etc.
- Based on existing pump efficiency, evaluate cost benefits for pump replacement with higher efficiency pump.
- Impeller replacement
- Water flow optimization
- Avoidance of by-pass flows

Based on % margins available on flow, head, motor input kW, and process demand variation, evaluate cost benefits for application of:

- Variable speed drives
- Impeller size optimization
- Smaller more efficient multi-pump application
- Pipe size and pumping network optimization both on the suction and discharge side

In addition, identify scope for improving net positive suction head (NPSH) and suction side improvements like high-efficiency foot valves, high-efficiency strainers, and seamless pipelines.

In general, look out for the following possibilities:

Low and no cost measures

- Turn off the pump when it is not needed. This can be done automatically with the incorporation of artificial intelligence and Internet of Things (AI & IoT)/installation controls.
- Inspect pump impeller periodically to remove external debris that will improve flow.

Medium cost measures

- Use pump at best efficiency point by trimming or changing the impeller, especially if the head is higher than necessary. If a pump is continuously throttled to 10% less than its design or rate, trim the impeller to reduce electrical demand by up to 25%.
- Restore internal clearances in the pump if performance has changed significantly.
- Balance the system to minimize flows and reduce pump power requirements.
- Use a small booster pump for small loads requiring HP.
- Avoid frequent on/off cycling of a pump, as it increases power consumption during start-t. A soft starter can be provided if frequent on/off cycling is unavoidable.

Higher cost measures

- Use low friction coatings on the internal surfaces of pumps to improve pump efficiency.
- Replace oversized pumps.
- Apply variable frequency drive (VFD) for wide load variations (VFD changes the speed of the pump for the more efficient match of horsepower requirements with output).
- Use multiple pumps instead of one large pump.
- Replace standard efficiency pump drive motor with premium high-efficiency motor.
- Review and change pipe diameter. A 15% increase in the pipe diameter can reduce pressure drop by 50%. This allows a smaller pump size to be used.

3.17 Energy audit procedure for coal mills

List of contents

1. Objectives
2. Instruments required
3. Audit procedure
4. Report preparation format
5. Audit tools for auditors
6. Annexures

1. Objectives

The major objectives of a coal mill energy audit are:

- To evaluate SEC of the mills (kWh/ton of coal).
- To establish air-to-coal ratio of the mills (ton of air/ton of coal).
- To perform heat balance of the mills.
- To analyze the coal fineness and mill rejects.

2. Instruments used

- Power analyzer
- Online instruments (calibrated at least within the last 12 months)
- Calibrated fuel flow measurement device (online)
- Calibrated mill air fan flow measurement device (online)
- Pitot tube and digital manometer
- Stroboscope
- Taco meter

3. Audit procedure

- Carry out power measurements of mills, primary air (PA) fans, seal air fans, etc. In the absence of energy meters, take readings from online panel instruments for current, voltage, power factor, etc. For LT equipment, portable instruments can be used for power measurements.
- Coal flow to be established by dirty pitot tube test (to be carried out on pulverized coal lines). This also helps in identifying unbalancing/choking occurring in flow in the pulverized coal lines. The online coal flow values, if available, may also be taken, ensuring appropriate coal feeder calibration.
- Air flow to be established per PA fan, by clean air pitot tube method.
- Determine the air-to-coal ratio of the mill; [(kg/hr of air) / (kg/hr of coal)].
- Determine the SEC values; (kWh/ton of coal); of the:
  - Mill,
  - PA fans, and
  - Total mill system (Mill + PA fan).
- Determine moisture % evaporated by the hot PA in the mill by performing mass and heat balance across the mill.
- Record the key as-run, mill operating parameters that have a bearing on the performance and energy consumption of the mill, and compare these average as-run values with design values (pressure drop across mill, exit temperature of ground product from the mill, dryness [or M %] of coal at input and output of the mill, size distribution of coal at inlet and outlet of the mill, velocity of air in the mill, classifier rotor speed, hydraulic grinding pressures, hardness of coal, % mill rejects, and GCV of mill rejects).
- Analyze the coal fineness for over-grinding/under-grinding.
- Analyze for excessive mill rejects and for possible loss of coal (GCV of representative ground sample of mill rejects) and reasons for grinding table overloading.
  - The investigations for abnormality are to be carried out, related to various operating parameters.
  - Enlist scope for improvement, with extensive checks.
  - Enlist recommendations for action to be taken for improvements.
  - Cost analysis with savings potential for the improvement measures.

4. Report preparation format

The audit report may be prepared in the following format:

- Foreword
- Audit team
- Technical specifications
- Present practices: Explain in detail the present status.
- Observation and remarks: Refer to the data and conclusion sheets and note observations and remarks about the energy audit carried out.
- Recommendations: Energy conservation options along with savings potential sheet, including estimated expenditure, payback period, and other related expected benefits.
- Single line diagram
- Data regarding calibration of instruments used, indicating dates of last calibration (calibration more than 12 months old is not acceptable).

5. Audit tools for auditors

- Air-to-coal ratio of the mill; (kg air/kg coal):
  = (Input air flow rate to mill, TPH) / (Input coal flow rate to mill, TPH)
- Mill SEC (kWh/ton):
  = (Average mill motor input power consumption, kW) / (Coal input flow rate to mill, TPH)

- PA fan SEC (kWh/ton):
  = (Average PA fan motor input power consumption, kW) / (Coal input flow rate to mill, TPH)
- Overall SEC of the mill system; (kWh/ton):
  = [(Average mill motor input power, kW) + (Average PAF motor input power, kW)] / (Coal input flow rate to mill, TPH)
- % mill rejects; (%):
  = [(TPH of mill rejects) * 100] / (Coal input flow rate to mill, TPH)
- Loss in generation of power due to coal lost in mill rejects; (kW):
  = [(TPH mill rejects * 1,000) * (Average GCV of mill rejects; Kcal/kg rejects)] / (HR of Turbine Protection System TPS; Kcal/kW)
- Coal loss in mill rejects: Mill rejects are material in coal that cannot be easily ground, like stones, granite, shale, etc. Mills are designed to throw these rejects out from the mill grinding table. Due to any reason, especially when the mill is overloaded with coal, it often happens that coal pieces also fly out of the mill without getting ground. This manifests as a loss for the TPS, as potential power-generating coal is being wasted. This loss can be projected as loss in generation (kWh), as well as in monetary terms, to encourage measures to be taken to stem the loss at the earliest.
- Mill rejects are an indication of mill performance. It is desirable to make an inter-se comparison of mill rejects among the operating mills. The variation in mill rejects (among the mills) could be due to variation in performance of the mill due to mill internal status, fuel handling, etc.
- Analysis of mill fineness and mill rejects: For a typical pulverized (PF) coal-fired boiler, over 80% of "fine coal" should pass through 200 mesh for good combustion efficiency. Mill performance is monitored by fineness of mill output at regular intervals, and when there is a drop, maintenance practices are reviewed. On the other hand, when fineness of mill output is high (>80% through 200 mesh; 75 microns, µm), then it is a case of over grinding and uncalled for mill energy loss.

6. Annexures

Mill key operating performance

Table 80: Key operating performance parameters of coal mills

Mill operating parameters	Units	Design value	As-run value
Generation load	MW		
Condenser vacuum	mbar or kg/cm^2_a		
Cooling water inlet temperature to condenser	°C		
Mill input coal	TPH		
PA input to mill	TPH		
Mill rejects	TPH		
Mill pressure drop (across mill)	mmWC		
Mill exit temperature	°C		
Coal inlet moisture	%		
Coal outlet moisture	%		
Mill inlet coal size	% passing 25 mm		
Mill outlet coal size	% passing 75 microns (or 200 mesh)		
Velocity of air in the mill	m/s		
Classifier rotor speed	rpm		
Hydraulic grinding pressures	N/m^2		
Hardness of coal	HGI		

Mill rejects reporting

Table 81: Data of mill rejects

Mill reference	Coal input	Mill rejects	Mill reject %	GCV of mill rejects (Representative sample)	Remarks
	TPH	TPH	(% of input)	(Kcal/kg mill rejects)	
Mill-1					
Mill-2					
Mill-3					

Mill performance

Table 82: Data collection sheet for mill performance

Mill reference	Air to coal ratio of the mill		Mill SEC		PA fan SEC		Overall SEC of the mill system		Loss in generation of power due to coal lost in mill rejects		Remarks
	kg air/kg coal		kWh/ton		kWh/ton		kWh/ton		kW		
	Design	As-run	Design	As-run	Design	As-run	Design	As-run	Design	As-run	
Mill-1											
Mill-2											
Mill-3											
Mill-4											
Mill-5											
Mill-6											

Mill input feed sieve analysis

Table 83: Mill input feed sieve analysis

Sieve size (mm)	% passing	% cumulative
+150 mm		
+106 mm		
+90 mm		
+75 mm		
+50 mm		
+40 mm		
+25 mm		
+10 mm		

Note: Ideally 97.8% should pass through a 25-mm screen.

Mill output product sieve analysis

Table 84: Mill output product sieve analysis

Sieve size (micron)	% residue
+212 μm	

+150 µm	
+90 µm	
+75 µm	
-75 µm	

Note: Ideally 80% should pass through 75-mm screen. (200 mesh)

% Moisture removed in the mill aided by hot PA—by mass and heat balance method

Mill mass and heat balance

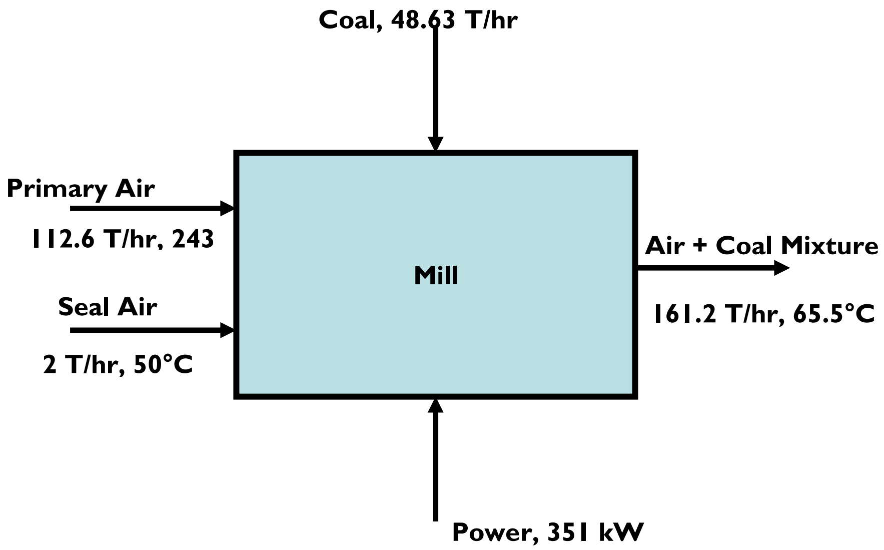

Figure 4: Mill mass and heat balance

PA—used for drying and conveying coal.
Seal air—pressurized air used to seal the motor shaft of coal mill to avoid leakage.

Coal mill heat balance
Total PA flow = 112.6 TPH
Inlet PA temperature = 243°C
Seal air flow = 2.0 TPH
Seal air temperature = 50°C
Coal flow rate = 48.63 TPH
Power consumption = 351 kW
Air and coal mix flow = 161.23 TPH
Air and coal mix temperature = 65.5°C
Ambient temperature = 35°C
Reference temperature = 0°C

Heat input
Sensible heat of PA I/L = Flow x specific heat x (T - t)
= 112,600 x 0.24 x (243 – 0)
= 6,566,832 Kcal/hr
Sensible heat of seal air = Flow x specific heat x (T - t)
= 2,000 x 0.24 x (50 - 0)
= 24,000 Kcal/hr
Heat equivalent of power = Power consumption x 860
= 351 x 860
= 301,860 Kcal/hr

Total heat input	= 6,566,832 + 24,000 + 301,860
	= 6,892,692 Kcal/hr

Heat output

Sensible heat of coal air mix	= Flow x specific heat x (T - t)
	= 161,230 x 0.24 x (65.5 – 0)
	= 2,534,536 Kcal/hr
Heat carried away by moisture (by difference)	= Total heat input – Heat of coal air mix
	= 6,892,692 – 2,534,536
	= 4,358,156 Kcal/hr
Total moisture removed	= 4,358,156 / 540
	= 8,071 kg/hr
% Moisture removed	= 8,071 / 48,630

3.18 Energy audit procedure for economic evaluation of ECMs

List of contents

1. Introduction
2. Modes of analysis
    - Payback period
    - Return on investment (ROI)
    - Total lifecycle cost
    - Net present value (NPV)
    - Internal rate of return
3. Sensitivity analysis of cost parameters

Application procedure:

Any energy conservation measure (ECM), for successful implementation, will need to be put up with the top management who will be advised by the finance department. The top management and the finance personnel will treat ECMs like any other investment related to power generation. So, it must be kept in mind that besides providing impregnable backup rationale for justifying the investment toward ECMs, the cost benefits must also have enough steam to be able to hold their own in comparison with any other power generation enhancement-related investment. Hence, without any solid economic analysis, the implementation of ECMs will never see the light of the day.

Introduction

Investment in EE systems results in a reduction in resource consumption and operating costs, and an increase in savings. Therefore, it is to be treated as any other capital investment. The principle underlying all types of investment is the net return expected from the proposed investment. This net return must be evaluated and compared with the cost of the project.

There are separate methods of analysis for (a) projects which do not involve major capital investment and (b) projects involving major capital investment. In the first case, simple payback period analysis is sufficient, while in the second case, other detailed method analysis is required. These methods are discussed in the following.

Modes of Analysis

There are several different ways of combining the data on cost and savings from a project to evaluate its economic performance. The different measures of economic performance are referred to in the lifecycle cost rules as "modes of analysis." It may be noted that lifecycle costing (LCC) is a method of expenditure evaluation that recognizes the sum of all costs associated with the expenditure during the time an equipment is used.

Analysis

Payback period and ROI are two modes of analysis frequently used by plants, who are not fully consistent with the LCC approach, in that, they do not consider all relevant values over the entire life period and discount them to a common time basis. Despite its disadvantages, these methods can provide a first-level measure of profitability that is relatively speaking—quick, simple, and inexpensive to calculate. Therefore, they may be useful as initial screening devices for eliminating the more obvious investments.

- The additional four modes of analysis that follow are fully consistent with the LCC approach.
- Total lifecycle cost (present value method).
- Savings/investment ratio (SIR; benefit/cost ratio method).
- NPV.
- Internal rate of return.

Each one of the six modes of analysis is presented in detail in the following.

Payback period
The payback (also known as the simple payback period [SPP]) method determines the number of years required for the invested capital to be offset by resulting benefits. The required number of years is termed as the payback, recovery, or break-even period. The measure is popularly calculated on a before-tax basis and without discounting (i.e., neglecting the opportunity cost of capital). Investment costs are usually defined as the first costs, often neglecting salvage value. The benefits are usually defined as the resulting net change in incoming cash flow or—in the case of a cost-reducing investment like waste heat recovery—as the reduction in net outgoing cash flow.
The SPP is usually calculated as follows:

SPP = (First cost) / (Yearly benefits – Yearly costs)

For example, the SPP for a recuperator that costs BDT 4.0 million to purchase and install, BDT 250,000 per year on average to operate and maintain, and that is expected to save by preheating combustion air an average of BDT 1.4 million per year in oil expenses, may be calculated as follows:

SPP = (4,000,000) / (1,400,000 - 250,000) = 3.5 years

The limitations of the SPP method are:

- The method does not consider cash flow beyond the payback period, and thus does not measure the efficiency of an investment over its entire life.
- The neglect of the opportunity cost of capital—that is, failing to discount costs occurring at different times to a common base for comparison—results in the use of inaccurate measures of benefits and costs to calculate the payback period, and hence determination of an incorrect payback period.

Despite its limitations, there are several situations in which the SPP method might be particularly appropriate:

- Rapid payback may be a prime criterion for judging an investment when financial resources are available to the investor for only a short period of time.
- The speculative investor who has a very limited time will usually desire rapid recovery of the initial investment.
- Where the expected life of the assets is highly uncertain, determination of the break-even life (i.e., payback period) is helpful in assessing the likelihood of achieving a successful investment.

Discounted payback is a variation of the SPP. The discounted payback differs from the simple payback in that the returns are discounted. Consequently, the criticism of the simple payback, that it ignores the time value of money, is circumvented.

Example:
Find the discounted payback for an outlay of US$5,000 for EE equipment having a life of (n) 8 years. This equipment will produce constant net annual savings of US$1,500. The discount rate (d) is 10% per year.

Where discounted savings = annual savings / (1+ d)n

Solution:

Table 85: Example of discounted savings

Year	Discounted savings (US$)	Cumulative discounted savings (US$)
1	$1{,}500 / (1 + 0.1)^1 = 1{,}363.64$	1,363.64
2	$1{,}500 / (1 + 0.1)^2 = 1{,}239.67$	2,303.31
3	$1{,}500 / (1 + 0.1)^3 = 1{,}126.97$	3,730.28
4	$1{,}500 / (1 + 0.1)^4 = 1{,}024.52$	4,754.80
5	$1{,}500 / (1 + 0.1)^5 = 931.38$	5,686.00

US$(5000 – 4754.80) – US$245.20 (remaining capital outlay not yet recovered at the end of year 4). Discounted payback period = 4 + (245.2 / 931.38) = 4.26 years.

ROI
The ROI or return on assets method calculates average annual benefits, net of yearly costs such as depreciation, as a percentage of the original book value of the investment. The calculation is as follows:

ROI = (Average annual net benefits) * 100 / (Original book value)

As an example, the calculation of the ROI for an investment in a waste heat economizer, is as follows:

- Original book value = US$8,000
- Executed life = 10-year annual depreciation, using a straight-line method = US$8,000 / 10 = US$800
- Yearly operational and maintenance costs = US$100
- Expected annual oil saving = US$3,000
- ROI = {[3,000 - (800 + 100)] * 100} / (8,000) = (0.2875 * 100) = 28.75%
- The ROI method is subject to the following principal disadvantages, and therefore is not recommended as a sole criterion for investment decisions:
- Like the payback method, this method does not take into consideration the timing of the cash flows, and thereby may incorrectly state the economic efficiency of the projects.

The calculation is based on an accounting concept, original book value, which is subject to the peculiarities of the firm's accounting practice, and which generally does not include all costs. The method, therefore, results in only a rough approximation of an investments' value. The advantages of the ROI method are that it is simple to compute and is a familiar concept in the business community.

Total lifecycle cost (present value)
When the total lifecycle cost (present value) method is used, all expenditures—regardless of when they are incurred—are compared during a common year (i.e., base year). Future expenditures are properly discounted to reflect their time value. Once these future expenditures are discounted, they may properly be compared to expenditures incurred "today" or during the "base year." Once this discounting is accomplished, all expenditures are weighted on a common basis and may be added together to obtain a total present worth value.

Money has time value. If US$1.0 can be invested today at an 8 percent nominal annual rate, it will be worth US$1.08, one year from now. In other words, the present worth of the US$1.08 to be received next year is US$1.0. The present worth of any amount of money due in the future is calculated by a process known as discounting. In the above illustration, the discounting is performed by dividing the US$1.08 by 1.08 (i.e., 1 + rate).

The discounting process is important in LCC analysis because it facilitates the translation of future values to present values, which makes investment decisions simpler. If the total cost of owning an asset is its initial cost and all subsequent costs, the latter must first be discounted to the present value before they are combined with the initial cost to obtain the lifecycle cost. It would be erroneous to ignore the timing of the future costs and merely add them to the initial cost.

All LCC analysis must be performed in terms of compatible US$ (i.e., US$ dated as of a point in time or a period of time). The tools of LCC analysis by which US$ values are shifted in time are as basic interest formula.

I = an interest or discount rate for the period being considered (%/year).
n = number of interest or discount periods (years).
PV = a present sum of money, or the present value of a sum of money occurring at some other time.
FV = a future sum of money, or the future value of a sum of money occurring at some other time.
A = An end-of-period payment (or savings or receipts) in a uniform series over a period, or the uniform time-equivalent of a sum of money occurring at some other time.

Uniform present value (UPV)

$$\mathbf{UPV = [(1 + i)^{n-1} - 1] / i\,(1 + i)^{n} = (1 / UCR)}$$

Where, UCR is the uniform capital recovery

This factor is used to determine the present amount P, which can be paid by equal payments of a (uniform annual payment) at i-percent interest, for n years. If you know A (uniform annual payment) and want to find the present value of all these payments, then:

$$\mathbf{PV = (UPV) * (A)}$$

Example-1
What single sum, deposited today at 8% interest compounded annually, would enable you to withdraw US$7,760.67 at the end of each of the next 3 years? In other words, we are looking for the present value of a future annuity. The present value of a 3-year annuity of US$7,760.67, at interest of 8%, compounded annually, is US$20,000.

Present value = (UPV) * (A) = 2.57709 * US$7,760.67 = US$20,000

An HVAC system is expected to cost US$125,000. A one-time replacement is expected after 15 years at a cost of US$500,000. Annual operating costs are to be US$125,000 per year. The system is expected to have a salvage value of US$250,000 after 30 years.

Using a 10% discount rate, what is the total present value of the system over 30 years? Note that cash outflow expenditures are expressed in parentheses and that cash inflows (e.g., salvage value) are not.

Present value initial cost Present value of one-time replacement	 = = =	(US$1,250,000.00) 500,000 x (Present value / F, 15 years, 10%) 500,000 X (119,695.00) 0.239393
Present value of operating costs	=	125,000 x (Present value / A, 30 years, l0%)
	=	125,000 X 9.42691
	=	(l.178,363.75)
Present value of salvage value	=	250,000 x (Present value / F, = 14,327.50, 30 years, l0%) 250,000 x 0.0573 l
Total present value of system	=	(US$2,533,731.25)

The total lifecycle costs, or present value, can be used to rank projects by showing which has the least total lifecycle cost. This method can be used only if the benefits of the projects being compared are identical.

SIR (for savings/investment ratio) or benefit/cost ratio
The SIR or benefit/cost ratio expresses savings as a proportion of investment or benefits as a portion of cost where all figures are discounted to either a present value or an annual value equivalent. An SIR that is greater than 1.0 indicates that the proposed investment is cost-effective. The savings investment ratio greater than 1.0 indicates that the project in question will return all capital funds at a rate greater than the discount rate. Accordingly, the greater the value of the SIR or benefit/cost ratio, the more cost-effective the investment opportunity.

Example: What is the benefit/cost ratio of an Energy Service Company (ESCO) to install an EE heat pump at a cost of US$175,000? The estimated energy savings is US$50,000 per year. The useful life of the heat pump is 12 years, and the discount rate is 14%.

Solution:

Present value cost	=	US$175,000
Present value benefits	=	50,000 (Present value / A, 15 years, 14%)
	=	50,000 * (5.66028)
	=	US$283,014
Cost-benefit ratio	=	Present value benefits / Present value costs
	=	283,014 / 175,000
	=	1.62

NPV

The NPV method discounts all the cash flows of a project to a base year. These cash flows include, but are not restricted to, equipment costs, maintenance expenses, energy savings, and salvage values. The cash flows are discounted to reflect their time value. Once all the cash flows are discounted to a base year, the cash flows are weighted on a common basis and may be added together to obtain a total NPV. Since the cash flow is both positive (salvage values, energy savings) and negative (equipment and maintenance costs), a NPV indicates an acceptable project if it is positive. A negative NPV indicates that a project should not be considered.

Example:
An engineer in the food industry is considering a heat recovery device—an economizer—in the flu of one of his company's many ovens. The economizer costs US$500,000, installation costs are expected to reach US$250,000, and annual operating and maintenance costs are estimated at US$25,000. The system has an expected operating life of 20 years, with a salvage value of US$50.000. Energy savings resulting from the installation of the economizer are projected at US$125,000 per year. Using a discount rate of 10%, calculate the NPV of the proposed project.

Present value initial equipment cost	=	(US$500,000)
Present value installation cost	=	(US$250,000)
Present value annual O&M expenses (Present value / A, 20 years, 10%)	=	25,000 x (Present value / A, 20 years, 10%)
	=	212,850
Present value salvage value	=	50,000 x (Present value / F, 20 years, 10%)
	=	7,425
Present value energy savings	=	125,000 x (Present Value / A, 20 years, 10%)
	=	1,064,200
NPV	=	US$108,775

The positive NPV indicates that the project should proceed. Since there are many ovens in this company, presumably, it could also benefit from use of an economizer to capture waste heat—the positive NPV for one project can became multiplicative when other similar projects are considered. The NPV method is like the total lifecycle cost method presented earlier but includes the ability to compare projects with varying benefits.

Internal rate of return

This method (not to be confused with ROI method evaluated earlier) calculates the rate of return that an investment is expected to yield. The internal rate of return method expresses each investment alternative in terms of rate of return, being the interest rate for which the total discounted benefits become just equal to total discounted costs (i.e., net present benefits or net annual benefits are equal to zero, or for which the benefits/cost ratio equals one). The criterion for selection among alternatives is to choose the investment with the highest rate of return.

The rate of return is usually calculated by a process of trial and error, whereby the net cash flow is computed for various discount rates until its value is reduced to zero.

Example:
Calculate the internal rate of return for a heat exchanger that will cost US$250,000, will last 10 years, and will result in fuel savings of US$75,000 each year.

Solution:

- Find the "i" that will equate the following:
- US$250,000 = 75,000 x (Present value / A, 10 years, i = ?)
- To do this, calculate the NPV for various i values, selected by visual inspection:
  - = (US$75000) x (3.571) - US$250,000
  - = US$267,825 - US$ 250,000 = US$17,825
  - = (US$75,000) x (3.029) – US$250,000
  - = US$231,900 – US$250,000 = (US$18,000)

For i = 25% NPV is positive; for i = 30% NPV is negative. Thus, for some discount rate between 25% and 30% NPV, the benefits are equated to present value costs. To find the rate more exactly, without the benefit of a complete set of discount tables or an adequate calculator, you may interpolate between the two rates as follows:

i = 0.25 + (0.30 - 0.25) 17,825 / (17,825 + 18,100) = 0.275 or 27.5%. To decide whether to undertake this investment, it would be necessary for the firm to compare the expected rate of return of 27.5% with its minimum required rate of return.

Sensitivity analysis of cost parameters

Sensitivity analysis is a technique for evaluating a project when there is considerable uncertainty about appropriate values to use in performing the evaluation. For example, uncertainty about the life of a project, the quantity of energy it will save, energy costs, and/or its future replacement costs may raise doubts about its cost effectiveness. To assess the likely range of possible outcomes, several evaluations of the project can be made, based on alternative values of the parameters in question. By evaluating the outcome for upper and lower estimated values of the parameters such as the minimum and maximum estimated life and the minimum and maximum estimated energy savings, sensitivity analysis can be used to bracket the range of likely outcomes and give a clearer estimate of a project's potential cost-effectiveness.

4 Annexure 4: Energy Audit Methodology

Detailed energy auditing is carried out in three phases:

4.1 Phase I–Pre-audit phase

During the initial site visit, the energy auditor/engineer should carry out the following activities:

- Tour the site accompanied by the site representative(s).
- Obtain available site drawings—plant/building layout, steam distribution, compressed air distribution, electricity distribution, etc.
- Discuss with the site's senior management the aim of the energy audit.
- Explain the purpose of the audit and indicate the kind of information needed during the energy audit.
- Discuss economic guidelines associated with the recommendations of the energy audit.
- Analyze the major energy consumption data with the relevant personnel.

The outcome of this visit should be:

- To finalize the distribution and deployment of the energy audit team.
- To know the expectations of the management from the audit.
- To identify the main energy-consuming areas/plant end-use equipment to be studied during the energy audit.
- To confirm the proper working condition of the existing instrumentation and additional metering required (in-site or portable), before the energy audit, for example, for measurement of fuel (coal, oil gas) electricity, steam, water, chilled water, and CW, compressed air, etc.
- To plan for an audit time frame and activity-wise timeline sheet.
- To collect macro data on plant energy resources, major energy-consuming equipment.
- To build awareness and support for a detailed energy audit.

4.2 Phase II–Detailed energy audit phase

Data collection
The information collected during the detailed audit includes:

- Sources of energy supplies (e.g., fuel, electricity import from the grid, or self-generation).
- Energy cost and tariff data.
- Generation and distribution of site services (e.g., compressed air, steam, water, chilled water).
- Process and material flow diagrams.
- Material balance data (input materials, use of refuse-derived fuels [RDF], waste products, or by-products for reuse in other industries, etc.).
- Energy consumption by type of energy, by department, by major process equipment, by end use.
- Various correction charts, curves, and formulas provided by the OEM to the TPP.
- Various characteristic curves of key pumps, fans, vacuum pumps, and rated technical, data of other key auxiliary equipment provided by the OEM to the TPP.
- Potential for fuel substitution, process modifications, and the use of cogeneration (combined cycle) system.
- Review of ongoing energy management procedures and energy awareness training programs.

Fuel analysis and costs

Fuel analysis

The fuel mix used in Bangladesh's power plants heavily favors natural gas. As domestic NG fields are depleting, the Government of Bangladesh plans to increase the use of imported liquefied NG and domestic coal.

About 62.9% of electricity generated in Bangladesh is from NG, whereas 10% is from diesel, 5% from coal, 3% from heavy oil, and 3.3% from renewable sources. The balance is covered by hydropower and imported electricity. Coal is the most economical fuel and is used for base-load power generation. Crude oil can be procured with greater flexibility and is used for middle-to-peak load power generation.

The sources and technologies have changed over time, and some are used more than others. The three major categories of energy for electricity generation are fossil fuels (coal, NG, and petroleum), nuclear energy, and renewable energy sources. During the detailed energy audit, it is worth spending time ascertaining the heating value and fuel flow measuring system of the main and support fuels being used. The single most important energy performance parameter of a TPP is the gross unit HR, which is a function of the total heat input to the system (Mass of fuel * GCV of fuel) and total generation. Thus, the unit's HR can be ascertained by the input/output direct measurement method, involving measurement of the fuel consumption and fuel GCV.

There often is confusion about using GCV or NCV in the calculations. The GCV of fuels is used in calculations where (e.g., boilers), the heat of vaporization of the moisture in the fuel, which is lost by the hot furnace sections, is recovered at the colder exit sections, by way of condensation. The NCV is used in the case of a forging furnace; for instance, where the exit flue gases are way above 400°C, even after the air preheater (APH), and the heat lost by the furnace toward vaporizing the moisture in the fuel, is not recovered as vapor condensation at the furnace exit (on account of the high exit temperatures) and the heat of vaporization is permanently lost from the furnace system.

The accuracy of the generation and export meters is usually beyond doubt, as the power plant revenue (kWh sales) is hinged on their accurate performance (0.1 class meters and regularly calibrated). Regarding the total heat input to the power plant, one must rely on the accuracy of the fuel feed (rate) measuring device and the reported GCV of the fuel.

For solid fuel (coal), the fuel feed rate is measured by gravimetric feeders, where a given constant fixed volume of fuel, is collected and discharged intermittently, and based on a counter that records the number of revolutions, the fuel feed rate is ascertained. The audit observations must include the verification/validation of the accuracy of these meters through checking of calibration report results. The same goes for liquid and gas fuel flow measuring devices, though the level of inaccuracies expected is of a relatively lower order. Regardless, the calibration verification audit activity must not be taken lightly.

In most cases, the fuel GCV is obtained from the coal supplier, which they mention in their delivery invoice. However, there is no guarantee of the veracity of the fuel GCV given, nor about an approved standard method followed to determine the same. In such cases, the accuracy of GCV is a grey area and an issue of concern; necessary backup measures need to be taken by the TPP.

In a few other cases, the TPPs follow the practice of collecting fuel samples from each of the arriving truck loads/rail wagon loads/ship loads of fuel receipts and have them analyzed in the in-house laboratory, for Proximate analysis - FC%, VM%, Ash%, M%, and sometimes, GCV (Kcal/kg fuel) estimation, using bomb calorimeters. The energy audit observations must include an in-depth examination of the lab records and possibly also a trial measurement, of both proximate analysis and GCV, for the audit teams' benefit, which is important.

The location and method (where and how) of taking the coal sample can influence the Kcal/kg fuel value reported from the labs. Mine samples are almost always sampled using mechanical coal samplers. Mechanical samplers, and even hand sampling, involve a crushing step that can dry the sample. Some take the coal sample from the receipt areas—from trucks, wagons, barges—as-received basis, some from the coal heaps lying in the open air in the coal yard—an approximation of air-dried basis, and yet some from the feeder to the coal bunker—as-a fired basis.

The audit team must make keen observations of the method and location of sampling and be cautioned that wherever the sample is taken from, they must maintain a consistent practice and not keep changing sampling locations randomly. The ideal location would be a fuel feeder outlet or if that is impractical, at the feeder to the coal bunkers (as-a fired basis). Gas and oil samples are better collected at the discharge of the fuel storage tanks and sent to accredited/approved labs for analysis. This should be done once every 3 months, and the lab should be instructed to report the GCV of fuel, the proximate analysis, and the ultimate analysis.

Almost none of the TPPs have the instruments, facilities, and wherewithal to evaluate the element-wise fuel composition, as obtained in an ultimate analysis. The common practice is to send fuel samples to an external approved or accredited laboratory, at intervals of every 3–4 months. The energy audit practice is to check all these external reports (over the past couple of years) for consistency of reported values with those that were reported by the in-house lab, identify gaps, and recommend improved procedures/practices.

In cases where the TPP has no such facilities and depends entirely on the fuel supplier's values, the audit team must recommend a systematic best-practice procedure that would need to be implemented on a priority basis. Some TPPs follow an alternative methodology to assess the unit HR. This is called the "turbine HR and boiler efficiency" method, which relies on reliable and accurate records of steam flow to the steam turbine (ST), the boiler efficiency assessment records, and electricity generation records. The gross unit HRs are evaluated as under:

- Gross unit HR (Kcal/kWh) = (Turbine HR) / (Boiler efficiency)
- Turbine HR (Kcal/kWh) = [(Total steam flow to the ST, kg steam/day) * (Steam enthalpy at turbine inlet, Kcal/kg steam – Steam enthalpy at turbine outlet, Kcal/kg steam)] / (kWh generated/day)

It is reasonable to assume that the measurement of steam flow to the ST is much more accurate than solid fuel measurement to the boiler, and so is the thermal efficiency evaluation of the power boilers (by an indirect method—the loss evaluation method). If the TPP is adopting the methodology of using the turbine HR and boiler thermal efficiency, then it is important that the steam flow logbooks, steam flow meter calibration records, and boiler efficiency assessment reports, are thoroughly examined for any deficiencies or gaps by the energy audit team.

GCV can be calculated using the well-acknowledged and time-tested "Dulong" formula, and thereafter the NCV, as given below:

- GCV (Kcal/kg) = [(8,080 * C) + ((34,500) * (H - O / 8)) + (2,240 * S] * (1 / 100).
  Where: C, H, S are components in the fuel as % by weight or % moles.
- NCV (Kcal/kg) = [GCV – 587 * ((9 * H_2) + M) / 100)].

  Where: H_2 and M are components in the fuel as % by weight or % moles

When comparing different fuels, the net calorific value is more relevant than the GCV. This is important when the condensation of the combustion product is not practical, or else it is important when heat at a low temperature cannot be put into any use. For coal and oil, the NCV is about 5% less than the GCV.

For most NG and manufactured gas, the NCV is about 10% less.

Fuel costs
A wide variety of fuels are available for thermal energy supply. Some of the fuels are listed below:

- NG
- HFO
- Light Diesel Oil (LDO)
- Coal

Understanding fuel cost is simple, and it is purchased in tons or kiloliters. Availability, cost, and quality are the three main factors that should be considered while purchasing any fuel. The following factors should be considered during the procurement of fuels for EE and economics:

- Price at source, transport charge, type of transport, BDT/Kcal
- Quality of fuel (GCV, contaminations, moisture, etc.)
- Energy content (GCV)

Baselines

- Assessment of current data: Baseline data is information obtained before, or at the onset of a study (say, before the introduction of an intervention), that serves as a basis for comparison, with data collected at a later point in time, to assess the effect of the program, and to compare what happened before and after the program was implemented. The ability to measure actual cost, schedule, or scope against a baseline can help provide insight into where a project has underperformed or overperformed. This knowledge can then be used to improve future project plans and estimates.
- Establishing baselines (or a reference): This is an important aspect of an energy audit. One needs to establish baselines of every important resource, like input energy (purchased and self-generated electricity, fuels: coal, oil, gas), water, and raw materials/chemicals. The baseline conditions can be expressed in quantity, quality, and cost/value. Without baseline data, it is difficult to estimate any changes or demonstrate progress, so it is best to capture baseline whenever possible.
    - Establish an energy baseline considering a minimum of 12 months of data. A baseline, considering the average for the past 2–3 years, is more desirable.
    - Identify energy performance indicators (e.g., Kcal/ton, Kcal/kWh, total energy cost/ton)
    - Publish and share the baselines with managers and other key stakeholders in the organization.

The energy audit team should ensure that the following baseline data are collected:

- Quantity and type of input materials/resources
- Technology, process used, and equipment used
- Capacity utilization
- Availability factor
- Plant load factor
- Start-ups (number/year, hr/year, additional or secondary fuel consumption, due to start-ups, kg or liters/year or kg or liters/hr)
- Impact of start-ups on HRs (% increase)
- Efficiencies/HRs (station and unit), specific fuel consumption
- Consumption of fuel, water, steam, electricity, compressed air, CW, and chilled water
- Quantity and types of wastes

The energy audit team must especially interview the supervisors and equipment operators, as they have direct and firsthand information related to the equipment. The maintenance manager is often the primary person to discuss the different types of energy-consuming equipment and related performance problems.

It is customary for all TPPs to monitor, record, and log the key operating (as-run) plant parameters, continuously. This is usually referred to as the daily log or trend sheet. The energy audit team must obtain this record in the form of daily average, a monthly average over the year, records. Using the trend sheet data, the comprehensive baseline database can be prepared as the reference point for the energy audit. A corresponding set of identical information must be compiled for design/rated/PG test values (a comparison of these values vis-à-vis, which as-run values, would indicate the performance gaps on the key parameters).

The key operational parameters must be collected as per the format below (day-wise data for 4 typical seasonal months of, say, January, April, July, October; month-wise data for all 12 months of the past 2 to 3 years).

- Generation = MU
- Gross power output = MW
- Net power output = MW
- Maximum load (frequency) = MW, (Hz)
- Minimum load = MW, (Hz)
- Availability factor (AF) = -
- PLF (plant load factor) =
- Fuel type = (coal/HFO/NG)
- Fuel GCV = (Kcal/kg or Kcal/Sm^3)
- Fuel consumption = (tons or Sm^3)
- Fuel Specific Gravity = (SG of different fuels)
- Fuel rate or specific fuel consumption (gross) = (kg fuel/kWh gross or Sm^3/kWh gross)
- Fuel rate or specific fuel consumption (net) = (kg fuel/kWh net or Sm^3/kWh net)
- Specific secondary (or auxiliary) fuel consumption in HRSG = (kg fuel/kWh gross or Sm^3/kWh gross)
- Support fuel (HFO/diesel) only on account of start-ups = (kg fuel/kWh gross or Sm^3/kWh gross)
- Condenser vacuum (ideal: 2 to 7 kPa) = kg/cm^2 or mbar or kPa
- APC = (% gross gen)
- Gross HR = (Kcal/kWh gross)
- CW inlet temperature = °C
- Net HR = (Kcal/kWh net)
- Energy utilization factor (%) (combined cycle) = $[(P_e + Q_{th}) * 100] / (Q_f)$
- Thermal efficiency of boiler (conventional) = $[(Q_s) * (H_s - H_{fw})] * 100 / [(Q_f) * (GCV_f)]$
- Thermal efficiency of boiler (HRSG, combined cycle) = $[(Q_s) * (H_s - H_{fw})] / [\{(Q_{fg}) * (H_{fg\text{-}in} - H_{fg\text{-}out})\} + (Q_{sf\text{-}hrsg}) * (GCV_{sf})]$

Where:

- Qs = Steam generation quantity in the period, kg
- Hs = Enthalpy of steam at the Pressure and temperature, Kcal/kg
- Hfw = Enthalpy of feed water at the Pressure and temperature, Kcal/kg
- Qfg = Flue gas quantity in the period, kg
- Hfg-in = Enthalpy of flue gas at HRSG inlet, at the Pressure and temperature, Kcal/kg
- Hfg-out = Enthalpy of flue gas at HRSG outlet, Kcal/kg
- Qsf-hrsg = Quantity of support fuel fired in HRSG in the period, kg

- GCVsf = GCV of support fuel in HRSG, Kcal/kg
- GCVf = GCV of fuel in conventional boiler, Kcal/kg
- Pe = Generated power, Kcal/hr (i.e., kW * 860)
- Qth = Thermal energy generated for use in HRSG boiler, Kcal/hr
- Overall TPP efficiency (Direct method) = (1 * 860 / Gross HR)
- Total Demineralized (DM) water consumption (or make-up water consumption) = m3
- Specific Demineralized (DM) water consumption (or specific make-up water consumption) = m3 / MU (or) m3 / MW
- Total number of start-ups = numbers/day (or) numbers/month (or) numbers/year
- Total duration spent on start-ups = hr
- Total fuel consumption toward start-ups = Sm3 fuel (or) kg fuel (or) kL fuel
- Specific start-up fuel consumption fuel/start-up (SU) = kSm3 fuel/SU (or) kg fuel/SU (or) kL fuel/SU
- Start-up fuel consumption rate = Sm3 fuel/hr (or) kg fuel/hr (or) kL fuel/hr

Preparing process flow diagrams
Preparing the process flow charts/diagrams is an important task of the energy audit team, as it helps in the explicit understanding of the process, equipment performance, clarity about loss and waste streams, and most importantly, clues about controllable loss and waste streams (steam, condensate, fuel leakages, radiation heat, hot outputs, chilled outputs, etc.) that were otherwise being lost, where incorporation of appropriate control actions, could result in energy and monetary savings.

The audit team must collect the OEM's "heat and mass balance" diagrams at different loads.
The purpose of material and energy balance is to:

- Assess the input, conversion efficiency, output, and losses
- Quantify all material, energy, and waste streams in a process or a system

Material and energy balance is a powerful tool for establishing a basis for improvement and potential savings. An overview of unit operations, important process steps, material, and energy use, and waste generation is then assembled in the form of a process flow diagram. Information from existing drawings, records, and shop floor surveys will help in preparing the flow chart.

Simultaneously, the team should identify the various inputs and output streams at each process step. A typical example of a general flow chart along with a specific example of a boiler heat and mass balance depicts how a flow chart and heat and mass balance should be constructed, as shown below.

The audit focus will depend upon consumption of the input resources, EE potential, the impact of process step on the entire process, or intensity of waste generation/energy consumption.

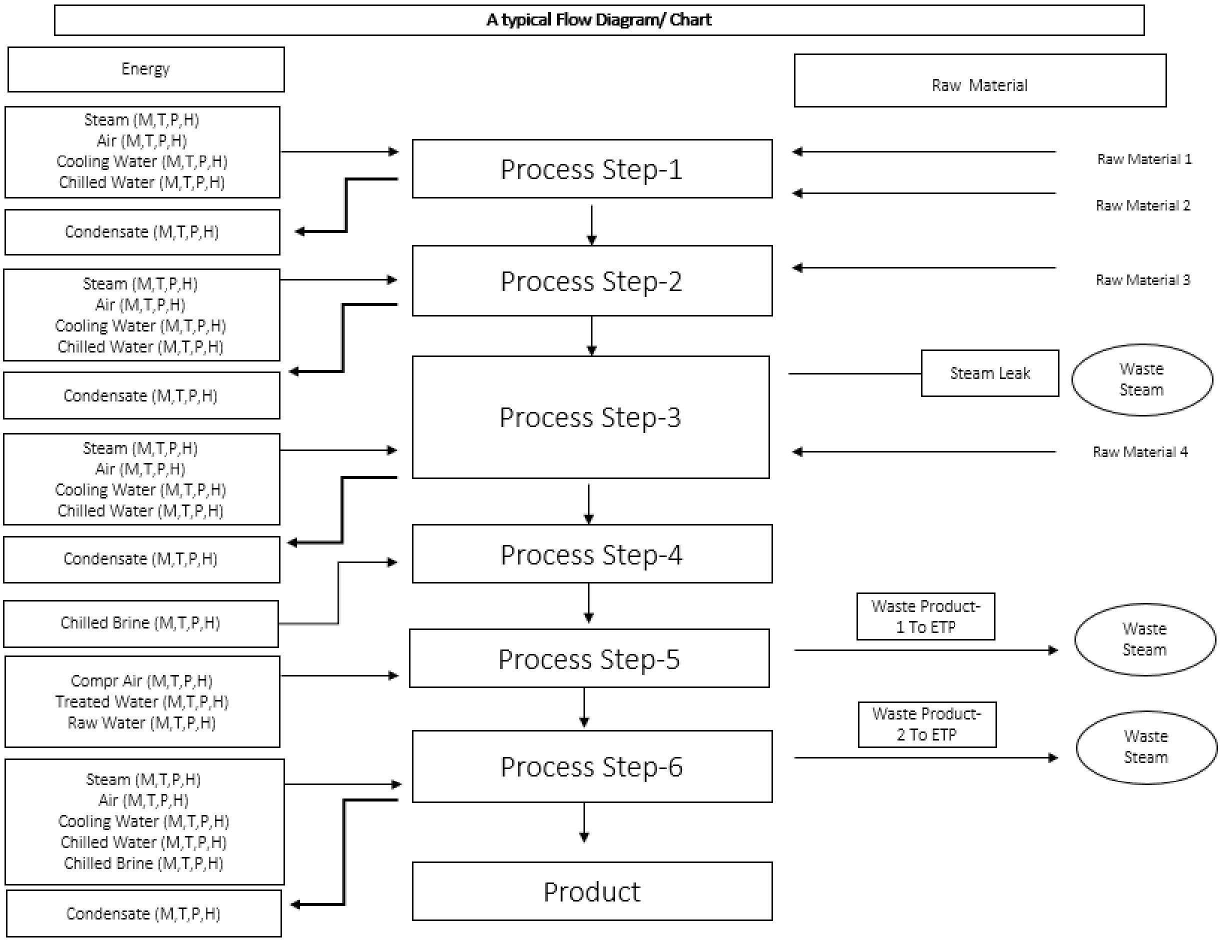

Figure 5: Process flow diagram

Note: Where—M = Flow rate, (mass or volume flow rate), kg/hr or m^3/hr
T = Temperature, °C
P = Pressure, kg/cm^2(g), mbar, P_a, etc.
H = Enthalpy, Kcal/kg

Other characteristics like pH concentration, TDS, etc., can also be included, where required.

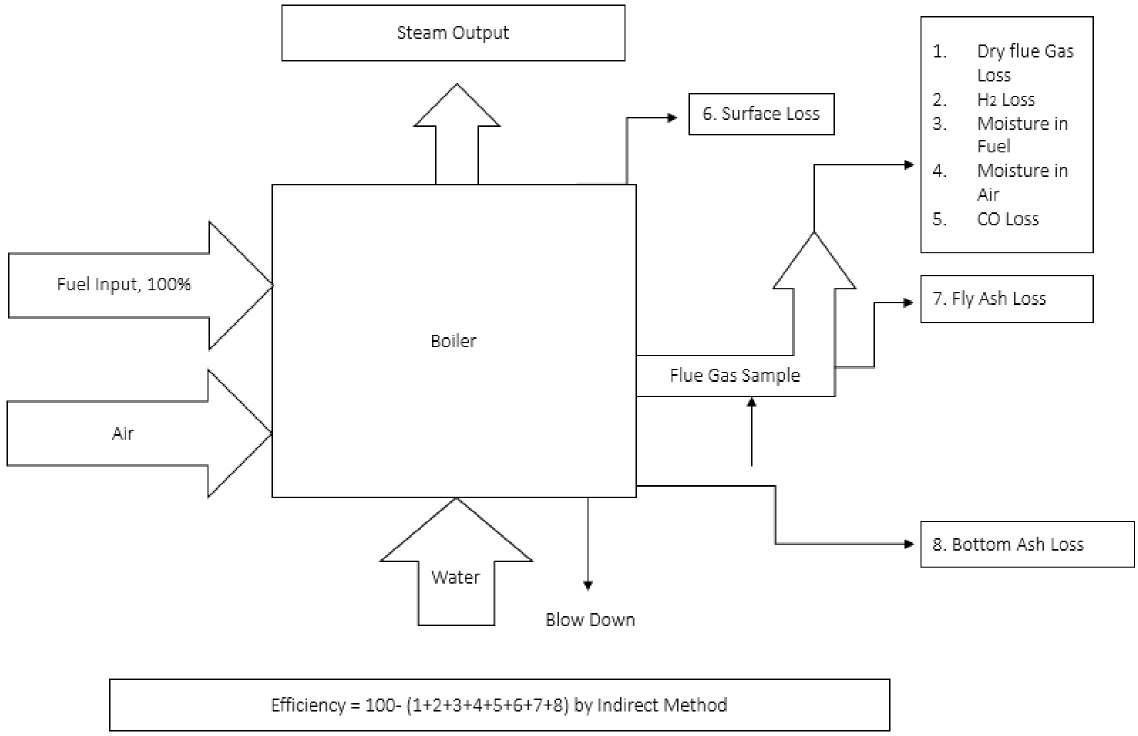

Figure 6: Process flow diagram for boiler

Note: Where—M = Flow rate, (mass or volume flow rate), kg/hr or m^3/hr,
T = Temperature, °C
P = Pressure, kg/cm^2(g), mbar, Pa, etc.
H = Enthalpy, Kcal/kg, and other relevant useful parameters, like O_2 %, will be included for the key items of inputs and outputs to characterize them.

Evaluation of energy performance of equipment

This is by far the most important part of the energy audit of the TPP. It would not be an exaggeration to state that, if a thorough, systematic, and scientific energy performance assessment is conducted on the key energy-use equipment in a TPP, using standardized procedures, called Energy Audit Procedures, then more than half the energy audit task is done. The prime focus of the Energy Audit Procedures is to detect hidden losses and inefficiencies, stemming from these equipment/subsystems, through well-thought-out, diagnostic tools/experiments. These could vary from equipment to equipment and subsystem to subsystem.

The broad structure or outline of each Energy Audit Procedure for the various energy use equipment/subsystems is as under:

- Objectives
- Instruments required
- Audit procedure
- Report preparation format
- Audit tools for auditors
  - Annexures
  - Data sheet/observation sheet
  - Calculation sheet
  - Savings potential sheet

Based on the type of TPP, the relevant energy-use equipment should be shortlisted from the following table, to conduct the energy audit. The equipment that are considered for energy performance evaluation are listed below:

- Main plant:
  - Boiler, ST, condenser, GT (OC) efficiency and HR, GT compressor, and HRSG.
- Auxiliaries:
  - Pumping subsystem covering, BFPs, condensate extraction pumps (CEPs), CW pumps, raw water pumps (RWPs), clarified water pumps (ClWPs), and DM water pumps (DMWPs).
  - Fan subsystem covering, forced draft (FD) fans, induced draft (ID) fans, and PA/secondary air (PA/SA) fans.
  - Regenerative subsystem covering, LPHs and HPHs.
  - Heat exchanger subsystem covering, economizer, and APHs.
  - Fuel handling subsystem covering mills and crushers.
  - General systems covering compressed air, CT, air conditioning and HVAC, electric load management, electric motor load survey, ESPs, thermal insulation, and plant lighting.

As already mentioned earlier in the main manual, the Energy Audit Procedures for each of the main plants subsystems as well as the utility subsystems have been presented as Annexure 3. Here, as mentioned above, the energy consuming equipment auditing procedure is described in detail, which would assist any energy auditor in carrying out the audit for that equipment.

Evaluation of TPP performance

TPP-Energy performance (TPP-EP):
TPP-EP is the measure of whether a plant is currently using more or less energy (APC and other thermal energy) to generate electricity than it did in the past; it is a measure of how well the energy management program is doing. TPP-EP monitoring compares the plant's energy use of a reference year and the subsequent years, considering the quantum of generated electricity output, to determine the improvement (or deterioration) that has been made.

However, since the TPP's electricity generation output varies from year to year, it has a significant impact on TPP's energy use. For a meaningful comparison, it is necessary to determine the energy that would have been required to produce the current year's electricity generation output, had the TPP operated in the same way as it did during the reference year. This calculated value can then be compared with the actual value to determine the improvement or deterioration that has taken place since the reference year.

Generation factor (GF):
The GF is the ratio of generation in the current year to that in the reference year. It is used to determine the energy that would have been required to generate this year's electricity output if the plant had operated in the same way as it did in the reference year.

GF = (Current years' generation) / (Reference year's generation)

Reference year equivalent energy use
The reference year's equivalent energy use (or reference year equivalent) is the energy that would have been used to generate the current year's electricity output. The reference year equivalent is obtained as follows:

Reference year equivalent = (Reference year energy use) x (GF)

TPP-EP is the improvement or deterioration from the reference year. It is a measure of TPP's energy progress.

Plant energy performance =
[(Reference year equivalent – Current years' energy) * 100] / (Reference year equivalent)
Thus, the TPP-EP is the measure of energy saved at the current rate of use, compared to the reference year's rate of use. The greater the improvement, the higher the number.

TPP-EP is the starting point for evaluating energy performance. It does not require detailed calculations of the energy used by every piece of equipment or every process. It utilizes the most effective measure of energy savings, that is, the actual measurement of energy consumption compared to electricity, generation output. The yearly comparisons minimize seasonal effects.

Sometimes, once a plant has started measuring yearly energy performance, management wants more frequent performance information to monitor and control energy use on an ongoing basis. In such cases, TPP-EP can just as easily be used for monthly reporting as yearly reporting.

Overall TPP-EP indicators
Gross unit HR is the heat needed to produce one unit of electricity at the generator. The only power that a TPP can sell is the net load (generation minus auxiliary power) or the amount of electricity that hits the grid. The plant's power requirements for the auxiliary equipment like pumps, fans, mills, air compressors, coal handling plants (CHPs), ash handling plants (AHPs), etc. are subtracted from the generator load, to calculate the grid or net power rating. This load can vary depending on what equipment is in service, the numbers deployed for service, and the operating efficiency of this equipment. There may be some flexibility in what equipment is in service; so, instances like 5 versus 6 mill operation, or 6 versus 7 CW pump operations, improving mill and CW pump efficiency/SEC, will impact the net HR, rather than the gross HR.

To ensure good TPP-EP, the operations/efficiency group executives keep a vigilant watch on both the gross HR as well as the net HR, as being the sentinels that warn of declining performance. An increase in the gross HR is indicative of an efficiency drop in the boiler (increase in one or more of the boiler losses) and/or drop in efficiency of the turbine (increase in one or more of the turbine losses).

Typical controllable boiler system losses are:

- Excess air losses (easily controllable).
- High exit flue gas temperature losses (ensuring effective heat transfer on both water and gas side of water-walls, super heaters, reheaters, economizers, and air preheaters).
- Loss due to unburnt in bottom ash and unburnt carryover losses in flue gases.
- Radiation losses (ensuring effective insulation).
- Turbine losses, which can be reduced with suitable interventions.
- Losses due to steam leakages (much of which can be arrested).
- Radiation losses from the hot surfaces (effective insulation could deal with this).
    - Residual velocity losses (can be reduced using multi-staging turbines).
    - Loss in regulating valves (replace inefficient ones with modern state-of-the-art LP drop regulating valves).
    - Steam leakage losses invariably occur at the main steam valve and regulating valves, seals and glands, spaces between nozzles and moving blades, spaces between diaphragm and shaft of the turbine, and spaces between moving blade rings and turbine casing.
    - The annual running hours of the power plant can be calculated using the following equation:
      Running hours = 24 (hr/day) x 365 (day/year) - FOH (hr/year) - POH (hr/year)

Where:

- FOH (hr/year) is the annual forced outage hours, and POH (hr/year) is the annual planned outage hours.
- The forced outage factor (FOF) can be calculated as follows:
- FOF (%) = FOH (hr/year) x (100) / {24 (hr/day) x 365 (day/year)}
- The planned outage factor (POF) can be calculated as follows:
- POF (%) = POH (hr/year) x (100) / {24 (hr/day) x 365 (day/year)}
- The power output of the plant in MW was obtained as follows:

  Power output = P_{out} [MW] = (Electricity generated, E_g, MWh) / (Annual running hours)

- The availability of the power plant is calculated using the following equation:

  Availability [%] = [(Running hours hr/year) x 100 / 24 hr/day, x 365 days/year]

- PLF:

  PLF = [(Energy generated during the period, MWh) * 100] / [(Total capacity, MW) * (Total hours in the period)]

The TPP-EP and the performance of the main subsystems, viz. the boiler and the turbine, are evaluated using the following Energy Performance Indices. To evaluate them, the empirical relations are presented below.

The energy performance evaluation of all other main and auxiliary subsystems is dealt with in the section, "Evaluation of the Performance of Equipment.

- Overall gross plant (or unit) HR, Kcal/kWh =
  [(Fuel consumed, TPH) * (GCV of fuel, Kcal/kg)] / [Generator output, MW], or
  (Gross turbine HR, Kcal/kWh) / (Boiler thermal efficiency), or
  [(Overall plant fuel rate, kg/kWh) * (GCV of fuel, Kcal/kg)].
- Overall net plant (or unit) HR, Kcal/kWh =
  [Total fuel consumed, tons) * (GCV of fuel, Kcal/kg)] / [(Total electricity generation, MWh) - (Total APC, MWh)], or
  Gross plant HR / [(1 - (APC % / 100)].
- Overall plant efficiency (η plant) % =
  [(Generator output, MW) * 860] * 100 / (Mass flow rate of fuel, TPH) * (GCV of fuel, Kcal/kg), or
  (860) * 100 / (Gross HR, Kcal/kWh).
- THR-G, Kcal/kWh =
  $[Q_1 * (H_1 - h_2)] + [Q_2 * (H_3 - H_2)]$ / (Generator output)

  Where:
  Q_1 = Average main steam flow, kg/hr
  H_1 = Main steam enthalpy at average Pressure and temperature, Kcal/kg
  h_2 = Average feed water enthalpy at average Pressure and temperature, Kcal/kg
  Q_2 = Average reheat steam flow, kg/hr
  H_3 = Average hot reheat enthalpy at average Pressure and temperature, Kcal/kg
  H_2 = Average cold reheat enthalpy at average Pressure and temperature, Kcal/kg
  E_g = Average generator output, kW

- THR-N =
  $[Q_1 * (H_1 – h_2)] + [Q_2 * (H_3 – H_2)]$ / {[Average generator output, MW] * [(1 – (APC % / 100)]}

- Turbine cycle efficiency (thermal efficiency) (η_t) % =
  [860 *100] / [Turbine HR]

Turbine cycle efficiency is defined as the amount of electricity produced by the heat input to the turbine. It is the reciprocal of HR in consistent units.

- Boiler efficiency (η_b) (thermal efficiency) =
  {[(Steam generation, TPH) * (Steam enthalpy, Kcal/kg)] - [(Feed water consumption, TPH) * (Feed water enthalpy, Kcal/kg)]} / [(Fuel consumed, TPH) * (GCV of fuel, Kcal/kg)]
  - This is the evaluation of boiler thermal efficiency by the direct method that is based on steam flow and fuel flow measurements; preferably the boiler thermal efficiency is evaluated by the indirect method.
- Turbine stage (isentropic) efficiency, % =
  [(Actual enthalpy drop across the turbine, Kcal/kg) * 100] / (Stage (isentropic) enthalpy drop across the turbine, Kcal/kg)
- GT and HRSG performance
  - GT, overall plant HR, Kcal/kWh = (Overall plant fuel rate, Sm^3/kWh) * (NCV of gas, Kcal/Sm^3)
  - Efficiency of HRSG boiler, η_{HRSG}: {[(Steam flow rate, kg/hr) * (Enthalpy of steam, Kcal/kg – Enthalpy of feed water, Kcal/kg)] * 100} / {[(GT exhaust gas flow rate, kg/hr) * (Inlet enthalpy of gas, Kcal/kg)] + [(Auxiliary fuel consumption rate, kg/hr) * (GCV of auxiliary fuel, Kcal/kg)]}
  - SSC, kg steam/kWh =

  860 / {(H_1 – H_2) * (η_{mech} * η_{gen} * η_{gear})}

  Where:

  H_1 = Enthalpy of steam at turbine inlet conditions of Pressure and temperature, Kcal/kg

  H_2 = Enthalpy of steam at turbine outlet conditions of Pressure and temperature, Kcal/kg

  η_{mech} = 0.985

  η_{gen} = 0.95

  η_{gear} = 0.98

- Turbine stage (isentropic) efficiency, (%)

  [(Actual enthalpy drop) * 100] / (Isentropic enthalpy drop across the turbine)

  - This procedure is the enthalpy drop efficiency method. It determines the ratio of actual enthalpy drop across the turbine section to the isentropic enthalpy drop. This method provides a good measure for monitoring purposes.
  - Each section of the turbine must be considered as a separate turbine. Each section should be tested, and the results should be trended separately. While conducting the tests, it must be ensured that they are conducted over the normal operating load range.

After evaluating the turbine HR and efficiency, the deviation from the design, if any, should be assessed, and the factors contributing to the deviations must be identified. The major factors to be checked out are:

- Main steam and reheat steam inlet parameters
- Turbine exhaust steam parameters
- Reheater and super heater spray
- Passing of high energy draining
- Loading on the turbine

- Boiler loading and boiler performance
- O&M constraints
- Condenser performance and CW parameters
- Silica deposition and its' impact on the turbine efficiency
- Inter stage sealing, balance drum, and gland sealing
- Nozzle blocks
- Turbine blade erosion
- Functioning of the valves
- Operational status of HPHs
- Performance of reheaters

Forced outage rate analysis[2]
Forced outages of TPPs can be attributed to internal reasons viz. low plant availability on account of various failure problems in TPP equipment, auxiliary systems and also due to external reasons viz., fuel (gas, oil, and coal) restrictions (shortage of fuel or availability of fuel at an affordable price) and grid/transmission system constraints, viz., lower demand/schedules, etc. (on account of reserve shutdown—when units remain out of operation due to lack of schedule/demand/dispatch).

The list below shows the type of fuel in order of start-up time:

- Gas-fired station (shortest start-up time)
- Oil-fired station
- Coal-fired station
- A nuclear power station (longest start-up time).

Table 86: Start-up and shutdown (sample) ramp rates for different power plant types

Start-up and shutdown (sample) ramp rates for different power plant types			
Power plant type	**Ramp rate time (MW/minute)**	**Down time (minute or hour)**	**Up time (minute or hour)**
Solar	200	0.5 minute	0.5 minute
Pump hydro	200	0.5–1 minute	0.5–1 minute
Hydro reservoir	150	1–5 minute	1–5 minute
Wind	30–60	1–2 minute	1–2 minute
GT	20–50	Up to 20 minutes	Up to 20 minutes
GT (CCPP)	20–50	50–60 minutes	50–60 minutes
Nuclear	20	1 hour	1 hour
NG/steam	10–20	1 hour	1 hour
Oil/steam	1–7	2–10 hours	4–12 hours
Coal/steam	2–4	4–48 hours	8–24 hours

The FOF and the POF are used to calculate the annual operating hours of the TPP by subtracting the number of hours of each per year. The term FOF refers to the shutdown of the plant due to unforeseen events, whereas POF refers to the scheduled shutdown for routine maintenance.

- The annual running hours of the power plant can be calculated using the following equation:

  Running hours = 24 (hr/day) x 365 (day/year) – FOH (hr/year) - POH (hr/year)

  Where:
  FOH (hr/year) is the annual FOH, and POH (hr/year) is the annual POH.

- The FOF can be calculated as follows:

[2] Yousef S. H. Najjar & AmerAbu-Shamleh. "Performance evaluation of a large-scale thermal power plant based on the best industrial practices." Scientific Reports. nature.com/articles/s41598-020-77802-8.pdf?proof=t

FOF (%) = FOH (hr/year) x (100) / {24 (hr/day) x 365 (day/year)}

- The POF can be calculated as follows:

POF [%] = POH (hr/year) x (100) / {24 (hr/day) x 365 (day/year)}

- Increase in fuel consumption due to increase in load cycling (ramping down and up).

Large-scale experiments were conducted in an HP pulverized combustion steam generator, with a rated capacity of 300 MWth. The dual-boiler unit load ramping was constrained to 2.5 MWel/minute. The results show that the net total increase in fuel consumption during the ramping cycle was approximately 4% (during ramping down the load to 50% maximum continuous rating, the mean fuel consumption decreased by 10% and during ramp-up back to 100% maximum continuous rating, the mean fuel consumption increased by 14%).

Based on the experiences drawn from Bangladesh TPPs, specific to NG-fired CCPPs, a sample start-up and HR details are mentioned below respectively.

Table 87: Start-up details CCPP (2020–2021)

Start-up details CCPP (2020–2021)		
The average number of start-ups in a year	Number/year	28
The average duration of recovery from cold start to full load	Hours/start-up	10
Average fuel consumption attributable to start-ups	kg/hr, HSD	12,250 (for GT)

Table 88: HR details CCPP (2020–2021)

HR details CCPP (2020–2021)		
	MW	**HR**
Base load	230	1,872.2
Typical operating load	140	2,091.3
Full load	230	1,871.2

With the growing trend of relying on base load, TPPs, as load-following (flexible) ones, are much higher than design levels of cyclic and part-load operations; because of which, they are operated in suboptimal operating parameter regimes, with consequent low operating efficiencies, as also enhanced risk of component failure. The overall outcome being the increased outage as well as increased start-ups. Causes of failure may not only be due to metal fatigue but also due to corrosion, creep, and weld defects (due to repeated thermal shocks).

Failure frequencies are found to be more in coal-based TPPs, a lesser extent in HFO-based TPPs, and the least extent in NG-based TPPs. Most of the forced outages in a TPP are known to be caused by the boiler section (tube leaks—mainly water walls and to a smaller extent second super heater, first reheaters, first super heaters, economizers, and other tube leaks). The boiler failures are followed to a significantly lesser extent by ST system component failures, generator system failures, and balance of plant system (including steam piping) failures.

Commercial material and process repair solutions are available, but the greater challenge is implementing predictive maintenance capabilities and obtaining acceptance of the business case for costly but necessary upgrades. Thus, increased cycling will:

- shorten component life expectancies,
- result in higher plant equivalent forced outage rates (EFORs),
- result in higher capital and maintenance costs to replace components at or near the end of their service lives, and
- result in reduced overall plant life.

The occurrence (how soon or late) of these detrimental effects will depend on the amount of creep damage present and the specific types and frequency of the cycling.

Emissions calculations[3]

- CO_2 emissions from the electricity sector in Bangladesh, accounting for 52.8% of the total country's emissions.
- The CO_2 emission factor for the Bangladesh national grid averages 550 tons CO_2/GWh (range, 530–570 tons CO_2/GWh).
- CO_2 emissions of thermal stations can be calculated using the following formula:
- $AbsCO_2\,(station)_y = \sum Fuel\ con_{i,y} * GCV_{i,y} * EF_i * Oxid_i$

  Where:
  $AbsCO_{2,y}$ = Absolute CO_2 emission of the station in the given fiscal year "y"
  $FuelCon_{i,y}$ = Amount of fuel of type i consumed in the fiscal year "y"
  $GCV_{i,y}$ = GCV of the fuel i in the fiscal year "y"
  EF_i CO_2 = emission factor of the fuel i based on GCV
  $Oxid_i$ = Oxidation factor of the fuel I (normally taken as 0.98)
  1 and 2 refer to the reference periods
  I = fuel, y = year

- Specific CO_2 emissions of stations ($SpecCO_{2(station)y}$) can be computed by dividing the absolute emissions ($AbsCO_{2(station)y}$), estimated above, by the station's net generation ($NetGen_{(station)y}$).

$$Spec\ CO_{2(station)y} = \{AbsCO_{2(station)y}\} / NetGen_{(station)y}$$

Typical CO_2 emission factors for different fuels used in Bangladesh TPPs, based on carbon content in the fuel:

- Coal = 0.97 tons Co_2/MW
- NG = 0.45 tons Co_2/MW
- Furnace HFO = 0.67 kg Co_2 /liter of oil
- Diesel = 0.70 tons Co_2/MW

Table 89: CO_2 emission factors of fuels

CO_2 emission factors of fuels	
Coal	2.42 kg CO_2/kg coal
NG	2.25 kg CO_2/kg NG
Furnace HFO	2.52 kg CO_2/kg HFO
Diesel	2.68 kg CO_2/diesel

Table 90: Density of different fuels

Densities of different fuels		
Fuel	Density (kg/m^3)	
NG	584	(0.68 kg/Sm^3)
Furnace HFO	1,298	
Diesel	850	

Benchmarking and performance analysis

Benchmarking forms the basis for monitoring and target setting. Energy benchmarking for a TPP is a process in which the energy performance of an individual TPP or equipment is compared against a common metric that represents "standard" or "optimal" performance. The most common metric used is *energy intensity,* which measures *"energy use per unit of output."*

[3] Sewa Bhawan, R.K.Puram. "CO2 Baseline Database for the Indian Power Sector User Guide Version 14.0." Government of India Ministry of Power Central Electricity Authority. December 2018. https://cea.nic.in/wp-content/uploads/baseline/2020/07/user_guide_ver14.pdf

External benchmarking: A common approach is external benchmarking wherein comparison is made among individual similar plants within a sector.

A benchmark-type indicator is calculated for all the facilities within a sector so that they can be compared in even terms. This evaluation can answer the following questions: What is the state-of-the-art performance in this given sector? How does my plant compare against the state-of-the-art? How does it compare against most other plants in the sector?

If a TPP would like to choose external benchmarking as the tool of choice for comparison, identifying gaps, and subsequent setting of goals/targets, then they should be able to obtain very detailed information from other TPPs/companies, while in these competitive times, there are issues of sensitivity and confidentiality in sharing and revealing proprietary information.

Since external benchmarking relates to interunit comparison, across a group of similar units, to identify best practices, differences that could complicate comparison on a meaningful and rational basis and which can be grossly misleading are:

- Scale of operation
- Vintage of equipment used
- Type of technology used
- Type of fuel used
- Quality of fuel used
- Other input material quality and specifications
- Product or output quality and specifications

Internal benchmarking: Another approach for energy benchmarking that has been seen widely in recent times is for large companies to set themselves EE goals by using as benchmarks, their own:
- Historical best performance,
- Rated/design performance, and
- PG test values.

Companies use this approach to set targets for reducing energy use by certain percentages over given time frames. In this type of benchmarking, companies do not need to reveal any proprietary information, since the benchmarking is done internally.

Steps in energy conservation benchmarking are summarized below:

- Identify the best available technology for the individual process units.
- Collect information to thoroughly understand the process and identify key/controlling parameters.
- Determine the performance of the processing unit.
- Analyze the gap between the existing and the benchmark for the key controlling parameters.
- Set targets or benchmarks, keep constraints in view, and implement improvements based on the findings
- The benchmark parameters for the TPP sector are given below:
  (1) Gross generation-related:
  - Kcal/kWh power-produced (HR of a power plant)

  (2) Equipment/utility-related:
  - % thermal efficiency in a boiler
  - % turbine efficiency in a turbine
  - % effectiveness in a condenser
  - % effectiveness in an economizer
  - % effectiveness in an APH

- % CT effectiveness in a CT
- kWh/Nm^3 in an air compressor
- kWh/liter in a diesel power generation plant
- kWh/m^3 or kWh/ton in a pump (BFP, CEP, CWP, RWP, AHP, and LP and series pumps)
- kWh/m^3 or kWh/ton in a fan (FD, ID, PA)
- kWh/ton of refrigeration in an air conditioning plant
- % collection efficiency in ESPs
- PUF and kWh/ton coal in a CHP

While referring to such benchmarks, related crucial process parameters need to be stated for a meaningful comparison among similar industries. For instance, in the above case:

- For a power plant/cogeneration plant, plant % loading, condenser vacuum, and inlet CW temperature would be important factors to be mentioned alongside HR (Kcal/kWh).
- For a boiler plant, fuel type and quality, steam pressure, temperature, and flow are useful comparators alongside thermal efficiency, and more importantly, whether thermal efficiency is on GCV basis or net calorific value basis or whether the computation is by direct method or indirect heat loss method. These mean a lot in benchmarking exercises for meaningful comparison.
- For CT effectiveness, ambient air wet/dry bulb temperature, relative humidity, air, and circulating water flows are required to be reported to make meaningful sense.
- For a compressed air system, SPC is to be compared at similar inlet air temperature and pressure of generation.
- For an A/C plant, parity of chilled water temperature level is crucial while comparing kW/ton of refrigeration (TR).
- Diesel power plant performance is to be compared at the similar loading %, steady run condition.

Determining EE measures and potential

- Identification of ECMs

The crux of energy auditing lies in the critical and objective observation skills of the energy auditor. During trials/experiments, the auditor not only needs to remain focused on the task being performed (in order that no parameter or incident is missed) but also be simultaneously aware of deviations of as-run operating conditions/parameters of equipment and associated systems from normal (in order to spot wasteful operations; for instance, dampening/throttling operations in fans/pumps, leakage through open observation ports/measurement points causing avoidable increase in suction fan load, inadequate duct/pipe sizes leading to HP drops and consequent increase in fan/pump power consumption, locations where there is occurrence of excessive surface heat losses taking place, occurrence of frequent tripping, nonoperation of tail-end capacitor banks, inability of equipment to operate at full capacity, overloading equipment to achieve unrealistic targets, avoidable recirculation—a wasteful energy-use practice, inadvertent killing of pressure without complete utilization, blow-offs where there is a significant amount of unused energy in the form of pressure/temperature, etc.).

The energy auditor must discuss with the operating technicians/engineers/managers about such inconsistencies observed or good practice activities being missed out—and get their opinion of how to deal with rectifying/setting right the same. This is the genesis of energy conservation ideas and the process of systematically and scientifically building them up into practically doable ECMs/projects.

Apart from observing and identifying the gaps in existing operations versus best-practice operations, the energy auditor must be capable of identifying potential for incorporation of appropriate "prescriptive" as well as "tailor-made" EE solutions (EE retrofits, technologies and processes, equipment and process modifications, fuel switching, matching usage to requirements, energy cost reduction schemes, house-keeping measures to improve system efficiencies, efficient automation and control systems, and AI & IoT, etc.).

The section on evaluation of energy performance of TPP equipment deals exclusively on the "how to do," of energy audit trials/experiments to evaluate energy performance and identify energy conservation (ENCON) options, among the variety of energy using TPP equipment.
After going through the process of evaluating the energy performance of different energy-using equipment of the TPP, each ECM should be individually assessed for practical feasibility and techno-economic viability.

In addition to auditing the TPP energy-consuming equipment, the audit team must also study the fuel receipt, storage, preparation, and handling practices. Analysis of the records and a physical inspection can reveal several aspects for improvement, leading to energy savings, cost savings, and quality improvement prospects.

- Technical and economic feasibility

The technical feasibility should address the following issues:

- Technology availability, space, skilled labor, etc.
- The impact of EE measures on safety, quality, production, or process.
- Reliability, service issues, maintenance requirements, and spare availability.

Economic viability often becomes the key parameter for management acceptance. The economic analysis can be conducted by using the payback method, the internal rate of return method, the net present value method, etc. For low investment short-duration measures, which have attractive economic viability, the payback method is sufficient. Each ECM should be assessed for its' economic feasibility, keeping the following in mind:

- Investment
  - Equipment
  - Civil works
  - Electricals
  - Instrumentation
  - Auxiliaries
- Annual operating costs
  - Cost of capital
  - Depreciation
  - Workforce
  - Maintenance
  - Energy
- Annual savings
  - Thermal energy
  - Electrical energy
  - Raw material reduction
  - Waste disposal reduction
- Net recurring annual energy savings on account of the ECM = (Annual recurring energy savings due to ECM – energy consumption on account of the ECM), (Kcals or kWh/year).
  - Net annual monetary savings on account of the ECM (BDT/year) = (Annual recurring monetary savings on account of the ECM – Annual operating costs on account of the ECM)
  - Payback period (months) = [(Investment, BDT * 12] / (Net annual monetary savings, BDT /year)
- Classification of ECMs

  The potential ECMs (ENCON options) may be classified into three categories:
  - Low cost-high return
  - Medium cost-medium return

- High cost-high return

Normally, the low cost-high return projects receive priority. Other projects must be analyzed, engineered, and budgeted for implementation in a phased manner. Projects relating to equipment and process changes have high costs coupled with high returns and require scrutiny before funds can be committed. They are complex and need long lead times before they can be implemented. Table 89 presents the broad guidelines and criteria that are generally considered by the management and finance personnel when confronted with the task of approval of any project.

Table 91: Guidelines and criteria for project approval

Priority	A (Good)	B (Maybe)	C (Held)	D (No)
Economic feasibility	Well defined and attractive	Well defined and only marginally acceptable	Poorly defined and marginally unacceptable	Clearly not attractive
Technical feasibility	Existing technology adequate	Existing technology may require to be modified/updated – lack of confirmation	Existing technology is inadequate	No clarity—need major break-through
Risk feasibility	No risk—highly feasible	Minor operating risk—may be feasible	Doubtful	Not feasible

Presentation of ECM

All ECMs must preferably be presented together, in one section, one after another. Each stand-alone ECM should include the following contents:

- Title of the ECM
- Background: Present system description highlighting the deficiencies, preferably with a single line diagram of the current process.
- Recommendation: Statement and a brief description of proposed scheme/measure, preferably with a single line diagram of the proposed process.
- ECM impact:
  - ✓ Annual energy saving—annual quantity of electricity and/or fuel (gas, oil, coal) reduction annual monetary savings (BDT/year)
  - ✓ Investment (BDT)
  - ✓ SPP or internal rate of return or NPV
  - ✓ GHG emission reduction potential (tons CO_2/year)
  - ✓ Rationale (calculation sheets) of the ECM
  - ✓ Other related aspects
  - ✓ Vendor references

Identification of energy efficient technologies and best practices

While carrying out the energy performance assessment on various TPP equipment and other off-site subsections like fuel handling, storage and preparation yards, RWP, CIWP, and DMWP houses, and water treatment plants, several ENCON options/ECMs could be identified. Often the solutions present themselves then and there, sometimes after discussions, and others after detailed analysis. The ENCON options would include better housekeeping practices, better operational practices, incorporation of EE devices, technologies, or processes.

These must be individually listed out, and related manufacturers, vendors, and the suppliers must be contacted for technical and commercial details.

Cost-benefit/financial analysis of energy conservation projects

Energy conservation/EE (EC/EE) projects are very important to the economy and environment. In most instances, in TPPs, the EC/EE projects prove to be the cheapest alternatives, with the fastest returns, if one were to consider "kW" savings vis-à-vis the kW addition. Regardless, it is important to justify any capital investment project to convince top management to release the capital budgets required by carrying out a financial appraisal. The financial tools that can be used to appraise the economic viability of energy-saving projects are discussed below.

In most respects, investment in EE is like any other area of financial management. So, when the organization first decides to invest in increasing its EE, it should apply the same criteria to reduce its energy consumption as it applies to all its other investments. A faster or more attractive rate of ROI in EE should not be demanded.

The basic criteria for financial investment appraisal include:

- Payback period—a financial tool that indicates how long it would take before the investment makes money, and how long the financing term needs to be.

The simplest technique which can be used to appraise a proposal is payback analysis. The payback period can be defined as the time (number of years) required to recover the initial investment (capital cost), considering only the annual net saving (yearly benefits-yearly costs). Once the payback period has ended, all the project capital costs will have been recovered, and any additional cost savings achieved can be seen as a clear profit. The shorter the payback period, the more attractive the project becomes. The length of the maximum permissible payback period generally varies with the management concerned.

The simple payback period can be calculated using the equation:

Payback period (years) = (investment, capital cost) / (net annual monetary savings)
(Annual net monetary saving is the cost saving achieved after all the operational costs have been met.)

- Advantages: It is simple, both in concept and application. A shorter payback generally indicates a more attractive investment. It does not use tedious calculations.
- Limitations: The payback period does not consider savings that are accrued after the payback period has finished. It favors projects that bring substantial cash inflows in earlier years and discriminates against projects that bring substantial cash inflows in later years.

ROI and internal rate of return—financial tools that allow comparison with other investment options.

ROI expresses the annual return expected from a project as a percentage of capital cost or initial investment. ROI is an inverse of the payback period.

ROI (%) = {(Annual net cash flow) * 100} / (investment, capital cost)

In comparing projects, the ROI does not require similar project life or capital cost for comparison. ROI must always be higher than the cost of money (interest rate); the greater the return on investment, the better the investment.

- Advantages: Simple method and easy to calculate. Returns expressed as a percentage makes it easier to evaluate against the borrowing interest.
- Limitations of ROI: It does not consider the time value of the money. The measure will give the same answer whether the economic life is 1 year, 10 years, or 100 years. It also does not account for the variable nature of the annual net cash inflows. The 25% return indicated in

the example would be economically valid only if the investment yields returns of US$25,000/year in perpetuity—not a very realistic condition.

Time value of money

A project usually entails an investment for the initial cost of installation, called the capital cost, and a series of annual costs and/or cost savings (i.e., operating, energy, maintenance, etc.) throughout the life of the project. To assess the project's feasibility, all these present and future cash flows must be equated on a common basis. The problem with equating cash flows, which occur at different times, is that the value of money changes with time. The method by which these various cash flows are related is called "discounting," or the "present value" concept.

Future value (FV) = NPV $(1 + i)^n$ or NPV = FV / $(1 + i)^n$

Where:
FV = Future value of the cash flow
NPV = NPV of the cash flow
i = Interest or discount rate
n = Number of years in the future

The NPV and cash flow measures allow financial planning of the project and provide the company with all the information needed to incorporate EE projects into the corporate financial system. The net present value method considers the time value of money. This is done by equating future cash flow to its current value today; in other words, determining the present value of any future cash flow. The present value is determined by using an assumed interest rate, usually referred to as a discount rate. Discounting is the opposite process to compounding. Compounding determines the future value of present cash flows, whereas discounting determines the present value of future cash flows.

The NPV method calculates the present value of all the yearly cash flows (i.e., capital costs and net savings) incurred or accrued throughout the life of a project and summates them. Costs are represented as a negative value and savings as a positive value. The sum of all the present values is known as the NPV. The higher the NPV, the more attractive is the proposed project.

The NPV of a project is equal to the sum of the present values of all the cash flows associated with it.

$$\mathbf{NPV = [(CF_0) / (1 + d)^0] + [(CF_1) / (1 + d)^1] + [(CF_2) / (1 + d)^2] + \ldots\ldots\ldots + [(CF_n) / (1 + d)^n]}$$

Where:
NPV = Net present value
CF_t = Cash flow occurring at the end of year "t" (t = 0, 1, …., n)
n = life of the project
d = Discount rate

The discount rate (κ) employed for evaluating the present value of the expected future cash flows should reflect the risk of the project.

Hence, the decision rule associated with the NPV criterion is: "Accept the project if the NPV is positive and reject the project if the NPV is negative." A negative NPV indicates that the project is not achieving the return standard and thus will cause an economic loss if implemented. A zero NPV is value neutral. The NPV considers the time value of money, and it considers the cash flow stream in the entire project life.

- Advantages: The NPV criterion has considerable merits. It considers the time value of money. It considers the cash flow stream in its project life.
- Internal rate of return method: By setting the NPV of an investment to zero (the minimum value that would make the investment worthwhile), the discount rate can be computed. The internal rate of return of a project is the discount rate, which makes its NPV equal to zero. It is the discount rate in the equation:

NPV = [(-) (CF_0) / (1 + d)^0] + [(CF_1) / (1 + d)^1] + [(CF_2) / (1 + d)^2] + …… + [(CF_n) / (1 + d)^n]

Where:

CF_t = Cash flow occurring at the end of year "t" (t = 0, 1, …., n)
n = life of the project
d = Discount rate

Note: *CF_t value will be negative if it is expenditure, and positive if it is savings.*

If this discount rate is greater than the current interest rate, the investment is sound.

This procedure, like NPV, can also be used to compare alternatives. The criterion for selection among the alternatives is to choose the investment with the highest rate of return. The calculation procedure for determining internal rate of return is tedious and usually requires a computer spreadsheet. Determining internal rate of return is an iterative process requiring guesses and approximations until a satisfactory answer is derived. The tedium can be averted to some extent by adopting the interpolation method, for instance:

If,
NPV at 13% = (-) 65
NPV at 12% = (+) 495

Then, by interpolation, **internal rate of return = [Lower rate] + {[(NPV at lower rate) * (Higher rate - lower rate)] / [NPV at lower rate – NPV at higher rate]}**

internal rate of return = (12) + {[(495) * (13 - 12)] / [495 - 65]}
= 12.88%

- Advantages: As a popular discounted cash flow method, the internal rate of return criterion has several advantages:
    - It considers the time value of money.
    - It considers the cash flow stream in its entirety.
    - It makes sense to businesspeople who prefer to think in terms of rate of return and find an absolute quantity, like NPV, somewhat difficult to work with.
- Limitations: The internal rate of return figure cannot distinguish between lending and borrowing, and hence a high internal rate of return need not necessarily be a desirable feature.

Comparison between NPV and internal rate of return: Although they look similar, there is an important difference between the two methods. In the NPV calculation, the NPV of the project is determined by assuming that the discount rate (cost of capital) is known. In the internal rate of return calculation, we set the NPV equal to zero and determine the discount rate (internal rate of return), which satisfies this condition. The NPV method is essentially a comparison tool that enables several different projects to be compared while the internal rate of return method is designed to assess whether a single project will achieve a target rate of return.

Financing options: Capital investing requires a source of funds. For large companies, multiple sources may be employed. The process of obtaining funds for capital investment is called financing. The various conventional financing options are:

- Debt financing
- Equity financing
- Retained earnings
- Capital lease
- True lease
- Performance contracting

Debt financing: Debt financing involves borrowing and utilizing the money that is to be repaid at a later point in time. Interest is paid to the lending party for the privilege of using the money. The company owns the equipment, and this arrangement is good for the long-term use of the equipment. The borrower is simply obligated to repay the borrowed funds plus accrued interest according to a repayment schedule. The two primary sources of debt capital are loans and bonds. An added benefit to debt financing under current tax laws is that the depreciation and interest payments on debt capital are tax-deductible.

Equity financing: Under equity financing, the lender acquires an ownership (or equity) position within the borrower's organization. As a result of this ownership position, the lender has the right to participate in the financial success of the organization. The two primary sources of equity financing are stocks and retained earnings. The cost of capital for stocks is higher than the cost of capital for debt financing. This is at least partially attributable to the fact that interest payments are tax-deductible while the stock dividend payments are not.

Retained earnings: Retained earnings are the accumulation of annual earnings surpluses that a company retains within the company's coffers rather than paying out to the stockholders as dividends. Although the company holds these earnings, they truly belong to the stockholders and hence the same cost of capital for a stock is applied. Although the company does not pay external interest charges, it loses tax benefits of interest charges.

Capital lease: A capital lease allows greater flexibility in financing, a lower cost of capital with third-party participation.

True lease: A true lease allows the use of equipment without ownership risks, offers a reduced risk of poor performance, service, equipment obsolescence, etc. and is particularly suitable for short-term use of equipment. The entire lease payment is tax-deductible. However, no ownership is possible at end of the lease contract, and no depreciation tax benefits are available. If the project is to be financed externally, one of the attractive options for many organizations is the use of energy performance contracts delivered by energy service companies (ESCOs).

Energy performance contracting and role of ESCOs: ESCOs are usually companies that provide a complete energy project service, from assessment to design to construction or installation, along with engineering and project management services and financing. Energy performance contracting is a unique arrangement that allows the industry to make necessary improvements in EE while investing very little money up-front. The contractor usually assumes responsibility for purchasing and installing the equipment, as well as maintenance throughout the contract. But the unique aspect of performance contracting is that the contractor is paid based on the performance of the installed equipment. Only after the installed equipment reduces expenses does the contractor get paid. The ESCOs typically serve as contractors within this line of business.

There are a few common types of contracts. The ESCO will usually offer the following options:

- Fixed fee
- Shared savings
- Guaranteed savings

In **fixed fee**, ESCO conducts an audit, designs the project, and either assists the customer to implement the project or simply advises the customer for a fixed lump-sum fee. In the fixed fee contract, the ESCO bears less risk compared to a savings-based fee payment because their fee does not depend directly on the amount of the achieved savings.

In **shared savings**, ESCO designs, finances, and implements the project; verifies energy savings; and shares an agreed percentage of the actual energy savings over a fixed period with the customer.

In **guaranteed savings**, ESCO designs and implements the project but does not finance it, although it may arrange for or facilitate financing. The ESCO guarantees that the energy savings bill is sufficient to cover debt service payments.

Energy managers would prefer the options with "guaranteed savings." However, this extra security (and risk to the ESCO) usually costs more. Percent energy savings contracts are agreements that share energy savings between the host and the ESCO. The more energy saved, the higher the revenues for both the parties.

- Performance contract: Pros and cons
  "Pros"
  - Allows the use of equipment with reduced installation/operational risks and reduced risk of poor performance, service, equipment obsolescence, etc.
  - Allows the host to focus on its core business objectives.

  "Cons"
  - Involves potentially binding contracts, legal expenses, and increased administrative costs.
  - The host must share project savings.

O&M practices

The compulsion to be flexible requires TPPs, in current times, to run their units at the technical minimum load, which can lead to an unstable furnace during low load operation and can increase the secondary HR, the cost of power generation, and increase the secondary oil consumption for frequent reserve shutdowns.

Also, due to growing renewable energy penetration and consequent increase in electricity production from renewable power plants (and other sources), which are extremely variable, TPPs are forced to undergo multiple rounds of load cycling and the forced requirement for quicker-than-design ramp-up and ramp-down times. TPPs are experiencing increased creep-related failures due to higher levels of pressure and temperature cycling.

O&M is one of the most critical factors that drive a power plant to realize projected revenues. Power generation facilities require vigilant, well-organized operations using meticulous maintenance management to stay online, produce energy safely and efficiently, and ensure preservation and longevity of all the TPP assets.

About 50–60% of power plant auxiliary failures take place due to lack of O&M best practices, and it is important to adhere to the standard operating procedures and make maintenance, IT-enabled.

This is especially pertinent in the light of challenges thrown up by the unavailability of fuel and water at acceptable prices, low power selling price, low load operation, frequent shutdowns, unit cycling (cold start-ups, warm start-ups, hot start-ups, load ramp rates [MW/min] and load cycling), etc.

Experience-based best O&M practices include:

- Following well-established operating procedures.

- Maximizing “plant availability,” which is affected by forced or partial outages due to failure of auxiliaries, fuel nonavailability, or grid restrictions.
- Minimizing frequent cold start-ups.
- Reducing the prolonged period of operating the unit at low load and operating the unit beyond design limit.
- Cycling the unit as per OEM recommendations.
- Following condition-based monitoring.
- Introducing an online monitoring system.
- Periodic condition assessment— Non-Destructive Evaluation (NDE).
- Maintaining proper water chemistry.
- Utilizing proper spares.
- Operating controllable parameters as per OEM’s guidelines.
- Implement proper cycle chemistry to prevent boiler tube failures (BTFs).
- Conduct annual plant audits.
- Implement preventive maintenance programs.
- Reduced forced outages.
- Conduct Residual Life Assessment (RLA) and comprehensive cost analysis.

The energy audit team should verify during discussions with the O&M personnel whether any problems/bottlenecks/constraints are occurring that are coming in the way of performing their duties satisfactorily. Having ascertained the gaps, they need to be addressed with suitable recommendations.

Duties of operation wing in a TPP
Key responsibilities are:

- To operate the plant and generate electricity as per the requirement.
- To monitor the process parameters and run the plant optimally and efficiently.
- To start and stop the plant as per requirement.
- To prevent the plant from tripping when problems crop up suddenly in a running plant through diagnosis, understanding, and effective action, as per the situation.

Other responsibilities are:

- Daily review,
- Weekly review,
- Monthly review,
- Tripping analysis review,
- Operation practices to reduce tripping and analysis,
- Overhaul facilitation from an operation,
- Efficiency monitoring and analysis, and
- Unit recommissioning activity and monitoring.

Duties of maintenance wing in a TPP
Key responsibilities are:

- To carry out preventive, breakdown, and planned (shutdown) maintenance of the machinery.
- Outsourcing of work;
- Cost optimization for maintenance activities;
- Procurement of spares;
- Workforce management;
- Inventory management;
- Budget management for maintenance activities;

- Study of the best practices of the industry and its implementation, if found techno-economically suitable; and
- Renovation and modernization activities if the plant is old.

Other responsibilities are:

- Short- and long-term preventive maintenance;
- Predictive maintenance based on condition monitoring;
- Overhaul preparedness;
- Unit-wise overhauling engineering declaration;
- Overhauling scope of work preparedness;
- Execution activity chart preparation;
- Identification of spares, work contract, and other resources for overhauling and its monitoring for ensuring availability before the start of overhauling;
- Five-year rolling plan for unit overhauling;
- Pre-unit overhauling preparedness; and
- Overhauling activity monitoring based on the activity chart.

Techno-managerial responsibilities are:

- Performance improvements plan/quality maintenance;
- Boiler (reduction action plan on short-term and long-term basis;
- Checklist for maintenance activities;
- Checklist for operation activities;
- Protocol for unit overhauling;
- Troubleshooting;
- Best O&M practices for milling system;
- Best O&M practices of boiler, turbine, and balance of plants;
- Weather-specific precautions like summer, monsoon, and winter preparation;
- EE and performance testing;
- EE technology for effective reliability and practices; and
- Pre-overhauling and post-overhauling performance testing.

Identification of vendors and OEMs
A successful energy audit is when the implementation of recommended ECMs takes place. Toward this end, it is important that the energy auditing team provide a list of vendors, suppliers, dealers, and OEMs that have good credentials and reliability to the TPP.

Additionally, the TPP's internal designated energy audit team may be advised to call for official registrations of vendors, suppliers, dealers, and OEMs, so that a comprehensive database of this category of product providers is readily available.

This vendors' record can be regularly updated based on the experiences of TPPs with the vendors.

Report preparation guidelines

- Structure of the energy audit report:
    - The length and detail of the energy audit report will depend upon the facility audit. The report should begin with an executive summary that provides the management of the audited TPP facility with a brief synopsis of the total savings and highlights of each energy-saving measure. An executive summary should be tailored to nontechnical personnel. A reader who understands the report is more likely to implement the recommended ENCON measures.

- The main report should start with a general description of the process or facility. Thereafter, the annual energy consumption and bills should be presented with tables and graphs. This should be followed by a description of energy inputs and outputs by a major department or by a major process and an evaluation of the efficiency of each step in the process. Then the recommended ENCON measures should be presented with calculations for cost and benefits along with the expected payback on any capital investment.
- The audit report should conclude with specific recommendations for detailed engineering studies and feasibility analyses, which must then be performed to justify the implementation of the ECMs that require high investments.
- Regardless of the audience for the audit report, it should be written in a clear, concise, and easy-to-understand format and style.

A sample energy audit report structure is presented below:

Acknowledgments
Acknowledgments from the auditing team to all the concerned personnel and departments who were involved in the detailed energy audit study, those who assisted and helped during the audit, and those who provided support and information and shared their knowledge.

Energy audit team
A list of all the external third-party audit team members, with designation and role.

Executive summary
Company profile, the scope of the energy audit, date, energy consumption, major observations, energy-saving opportunities, prioritization of actions, and recommendations to improve or optimize the system along with a highlight of the impact of energy-saving measures, to be summarized here.

- Energy conservation options with cost-benefits [Measure reference / Annual energy savings (kWh/year and/or Sm3 gas/year and/or tons of fuel oil/year and/or tons coal/year) / Annual monetary savings (BDT/year) / Investment (BDT) / SPP (years/ GHG reduction potential [tons of CO2/year]).
- Prioritized list of energy conservation options [low- or no-cost options with high return; medium cost options with medium return; high-cost options with high return].

Introduction and TPP overview
General TPP overview and history of MW expansion (if any), components of generation cost (including raw materials, energy, chemicals, workforce, overheads, and others), major energy use and areas, experience in energy auditing of the TPP, ECMs already implemented, reasons for instituting the current energy audit and the broad outcomes expected of the energy audit study.

Description of the plant
General information on station capacity, number of units and MW capacity of each, present capacity utilization (part loading), design HR and efficiency, brief description about major equipment, their design, and operational features, any part of load operations, and consequent cold start-ups with reasons, etc.

Scope of the study as per Terms of Reference
Spells out the coverage/extent (the entire power plant and all its' subsystems or only key selected subsystems, or whether it is a diagnostic energy audit addressing only a few troublesome or/and grossly energy-inefficient subsystems).

Energy audit approach/methodology

- To briefly introduce the need for energy audit in the TPP and explain the type of energy audit and audit methodology to be followed during the study.

- To initiate information gathering through interviews with various plant personnel, logbook data collection, historical data gathering, and technical literature.
- To obtain reliable and consistent current operating data of key parameters influencing EE from control panels and through random site measurements.
- To hold discussions with concerned personnel to critically observe and take note of operating practices and to identify specific problem areas and bottlenecks, if any, with respect to energy consumption.
- To conduct representative trials on energy-intensive equipment to evaluate prevalent efficiency and energy performance, and to identify precisely the ENCON options, both operational and otherwise, to affect the cost and energy savings. Portable instruments may be required to be used during these trials, as and when required, in addition to control panel data.
- To identify energy wastage areas and quantification the energy losses.
- To identify suitable measures which will reduce energy losses and avoidable wastages.
- To prepare a cost-benefit analysis for recommended measures.
- To work out ENCON options with detailed techno-economic feasibility analysis.
- To prepare a brief overview of the findings and recommendations, covering different scope areas (after field study) to the management of the TPP.
- To affect any mid-course corrections, where deemed necessary based on feedback from the plant operating group and to finalize acceptable energy conservation proposals.
- In a separate sitting with the top management, to firm up the implementation action plan.

TPP process description

- Brief description of the power generation process.
- Process flow diagram and major unit operations.
- Process flow chart with input energy streams, input raw material streams, output intermediate, and final product streams, output waste product streams, recycle streams, and waste streams that can be sent to another subsystem or another industry as an input. Each stream will be characterized in terms of quantity (throughput rate) and quality parameters (temperature, pressure, concentration, TDS, pH, enthalpy pressure, % O2), etc. This would greatly help during the analysis stage. Heat and mass balance diagrams provided by the OEM for different TPP loads, for steam and feed-water circuits, would be very helpful.

Energy scenario and baselines

- Major energy use (thermal- and electrical-driven) equipment and auxiliaries.
- Fuels used their annual consumption and trends of GCV, ultimate, and proximate analysis.
- Energy generation annual trends.
- Availability factor trends, PLF trends.
- APC trends and support fuel oil consumption trends.
- Forced shutdown and start-up trends (number, duration, and fuel consumption).
- Break-up of APC, unit-wise (Boiler Feed Pump (BFP) %, Condensate Extraction Pump (CEP) %, Cooling Water pump %, Induced Draft Fan (ID) fan %, Forced Draft Fan %, Primary Air Fan System (PA fan) %, Coal Mining System (CoM) %, Contribution of Station Lighting (STN-LGT) %, compressed air %, air conditioning %, Coal Handling Plant (CHP) %, Ash Handling Plant (AHP) %.
- Specific fuel/support fuel consumption trends.
- Gross station HR, unit HR, turbine HR, and efficiencies trend.
- Landed cost and GCV of fuel trends.
- Water consumption trends and cost.
- Station and unit-wise HR and efficiency trends.

Energy system description

- Main plant systems and details of each:
  - Make, number of, number on standby, and technical specifications of boilers, GTs, HRSGs, GT compressors, and STs and condensers.
- Main plant auxiliaries and details of each:
  - Make, number of, number on standby, and technical specifications of BFPs, CEPs, ID fans, FD fans, PA fans, coal mills, and CW pumps.
- Other plant auxiliaries and details of each:
  - Make, number of, number on standby, and technical specifications of CHPs, AHPs, compressed air systems, air conditioning systems, ESPs, and station lighting.

Energy audit and energy performance assessment

- Introduction, total number installed, total number in stand-by mode, technical specifications, as-run trial measurements, observations, and comments, and recommendations/ECMs for each of the following main plant energy-use equipment and auxiliaries:
  - Boilers, HRSG, GT, GT compressor, ST and condenser, steam system, BFP condensate extraction pump, ID fan, FD fan, PA fan, coal mills, CW pumps, CHP, ASP, compressed air system, air conditioning system, ESP, and station lighting.

Prevailing energy management system

- Narration about the status of the prevailing energy management system, the importance given to energy management/conservation, the level of awareness about EE, and the degree to which EE and conservation are enmeshed with the day-to-day, as-run O&M of the TPP.
- The report should contain a brief about the strengths and weaknesses of the designated consumer in the management of energy and energy resources and recommend necessary action to improve upon the method of reporting data, energy management system, improving EE, and reducing energy consumption.

Water balance of TPP (optional)

- Total input water quantity and break-up of sources (quantified and characterized).
- Break-up of in-plant water users (quantified and characterized).
- Wastewater streams (quantified and characterized).

ECMs and recommendations

- List of options in terms of no-cost/low-cost, medium-cost, and high-cost, annual energy and monetary savings, and payback.
- Each stand-alone ECM identified should feature: Title of the ECM/background or description of the ECM with single line diagram of the current process/recommendation statement/annual energy and monetary savings impact, investment, and payback period, and GHG emission reduction potential/rationale (calculation sheets) of the ECMs' other related, expected benefits.
- List of technology providers/vendors.
- Here, a list of vendors/technology providers will be provided for each of the proposed ECMs.
- Implementation plan for ECMs/projects.
- After joint discussions by the third party/accredited energy auditor team and the management team, headed by the plant head, the following lists would be prepared and jointly signed:
  - List-A: ECMs that have been agreed to be implemented immediately, with the commitment of resources like workforce and financial budgets. Also, the top management would identify the persons and teams who will be responsible for (1) the finalization of specifications, (2) selection of vendors, (3) deal finalization, (4) procurement, (5) commissioning, and (6) performance demonstration trials (PG tests) before takeover.
  - List-B: ECMs that have been agreed to be implemented but later.
  - List-C: ECMs that have been rejected, for one reason or another, by the top management.

Annexures

- Historical data, annual consumption, and generation data (last 2–3 years).
- List of tables
- List of figures
- List of software(s) used (if any).

4.3 Phase III–Post audit phase

Presentation of energy audit findings of field study
A presentation of the findings of the energy audit study during the field study to be made to the entire TPP team in the presence of the head of the TPP. All the key observations and each ECM will be presented and discussed prima-facie. Since all the department representatives will be in attendance along with the TPP head, feedback will be taken, in the case of those ECMs, where hesitation is shown to accept the ECM, and concurrence will be taken for those of the ECMs that are acceptable, with the approval of the plant head.

General recommendations
General management recommendations to be made to the TPP's internal energy audit team. These could include:

- Advice on where instrumentation is lacking and needs to be provided.
- Where instruments are malfunctioning and need to be rectified.
- Environmental control good practices that are found lacking.
- Energy management practices that need to be strengthened, and improvements in the existing energy management information systems and reporting structure.

Preparation of action plan
On completion of the energy audit study and the field audit findings presentation, an energy action plan should be prepared based on discussions with the plant head, finance department, purchase department, and all the department heads. After obtaining their concurrence, a list needs to be prepared of the ECMs/ENCON options that should be implemented first, and suggestions for an overall implementation schedule should be considered. At this stage, the third-party energy auditor team will put a closure to its involvement in the energy audit study in the TPP, as per the terms of the contract.

4.4 Implementation and follow-up

This is the stage when the energy audit baton will be taken over by the TPP management designated energy audit implementation team. However, if the energy audit study happened to be undertaken by an ESCO entity, then they will remain until all the agreed implementation activities have been installed and commissioned. An energy audit is incomplete without monitoring and its associated feedback. Monitoring consists of collecting and interpreting data. The data to be collected depends upon the goals chosen in the energy action plan. Electrical power consumption and fuel consumption must be evaluated and monitored. The monitoring data should provide direct feedback to those ablest to implement the changes. Often additional instruments should be installed in various departments in addition to the main metering. Monitoring should result in more action. Good practices should be replicated. If the gap between planned objectives and actual achievements is large, reasons should be analyzed. New objectives and new actions should be initiated, and results should be monitored. In this way, analysis, action, and monitoring are cyclic processes.

Action plan for implementation by the TPP team.

- Based on the discussions with the plant head, finance department, and purchase department, all the department heads will sit together and finalize the action plan for implementation of

ECMs, which will include a selection of responsible person(s), commitment from involved departments, resources requirements (workforce, finance), and time frame for implementation (including preparation of equipment specifications, evaluation of vendors, placement of the order, and commissioning).

- Schemes like ESCO, performance guarantee, lease-based financing, and shared savings financing, could be considered.

5 Annexure 5: Sample Energy Audit Report

Report

on

Detailed Energy Audit Study

of

XXXX
(Name of the TPP)
Thermal Power Plant

By

XXXX
(Name of the Energy Auditing Firm)

5.1 Acknowledgement

xxxxxxx wishes to place on record its deep gratitude to the progressive management of xxxxxxx, for vesting its confidence in xxxxxxx to carry out the detailed **Energy Audit Study of Thermal Power Plant** xxxxxxx,

The study team is especially thankful and appreciative of the keen interest and commitment of ***Mr.*** xxxxxxx

Our special thanks are due to ***Mr./Ms.*** Xxxxxxx, ***Chief Engineer*** and to ***Mr. Ms.*** xxxxxxx***, Addn Chief Engineer*** for their excellent coordination and support during field studies.

Our thanks are also due to the following plant officials for their help and cooperation extended to the xxxxxxx study team during field study period:

Mr./Ms. xxxxxxx***, Superintending Engineer (Mechanical)***
Mr./Ms. xxxxxxx, ***Executive Engineer (Efficiency)***
Mr./Ms. xxxxxxx, ***Deputy Engineer, Energy Conservation Cell***
Mr./Ms. xxxxxxx, ***Deputy Engineer and Energy Manager***

We are thankful to all executives, non-executives, and other staff who have rendered cooperation and assistance to xxxxxxx team during the entire period of the audit at TPS Sikka.

xxxxxxx
Energy Audit Team

5.2 Study Team

Mr./Ms. xxxxxxx, Audit Team Head
Mr./Ms. xxxxxxx, Audit Team Lead, Certified Energy Auditor
Mr./Ms. xxxxxxx, Audit Team Member, Certified Energy Auditor
Mr./Ms. xxxxxxx, Audit Team Member, Certified Energy Auditor
Mr./Ms. xxxxxxx, Audit Team Member, Certified Energy Auditor
Mr./Ms. xxxxxxx, Audit Team Engineer
Mr./Ms. xxxxxxx, Audit Team Engineer
Mr./Ms. xxxxxxx, Audit Team Engineer

5.3 Table of Contents

5.4 Executive Summary

S. No.	ENCON Option	Annual electricity saving (Lakh kWh/year)	Annual monetary saving (Rs. Lakh/year)	Investment (Rs. Lakh)	Simple payback period (years)
	UNIT-2				
1	Improvement in boiler feed water temperature through repair of HPH	4,372 (MT of coal/year)	219.00	Marginal	Immediate
2	Energy saving by stopping one primary air fan	39.99	139.96	Marginal	Immediate
3	Energy saving by reducing number of stages in BFP-2C	34.42	120.46	Marginal	Immediate
4	Energy saving by reducing number of stages in BFP-2B	27.65	96.77	Marginal	Immediate
5	Energy saving by maintaining the ash water ratio as per designed value	22.16	77.56	Marginal	Immediate
6	Energy savings by reducing compressed air pressure from existing 7.8 kg/cm^2 to 6.5 kg/cm^2	4.58	16.03	Marginal	Immediate
7	Energy saving by avoiding recirculation flow in CEP pump	3.90	13.65	Marginal	Immediate
8	Energy saving by installing energy efficient pumps in ash water pump	15.62	54.67	12.93	0.24
9	Energy saving by installation of new energy efficient pumps of BACW	1.85	6.46	2.00	0.31
10	Energy saving by installing energy efficient pumps in ash slurry pump	6.83	23.91	7.67	0.32
11	Energy saving by installation of new energy efficient pumps of TACW	6.45	22.57	9.00	0.40
12	Energy saving by installing new energy efficient pump in BFP-2C	37.61	131.62	120.00	0.90
13	Energy saving by installing variable frequency drive (VFD) in BFP-2C	34.42	120.46	160.00	1.30
14	Energy saving by installing new energy efficient pump in BFP-2B	25.66	89.80	120.00	1.30
15	Energy savings by replacing existing tube type coal mill to modern energy efficient bowl type coal mill	122.15	427.51	600.00	1.40
16	Energy saving by installing VFD in BFP-2B	27.65	96.77	160.00	1.70
17	Energy savings by installing VFD in ID fan: B	8.03	28.11	64.00	2.27
18	Energy savings by installing VFD in ID fan: A	6.94	24.31	64.00	2.63
19	Energy savings by installing VFD in forced draft (FD) fan: A	3.18	11.11	32.00	2.87

20	Energy savings by installing VFD in FD fan: B	3.18	11.11	32.00	2.87
	UNIT-1				
21	Energy saving by stopping one primary air fan	41.37	144.79	Marginal	Immediate
22	Energy saving by reducing number of stages in BFP-2C	28.40	99.41	marginal	Immediate
23	Energy saving by reducing number of stages in BFP-2B	28.37	99.29	marginal	Immediate
24	Energy savings by operating only one FD fan	12.69	44.40	Marginal	Immediate
25	Energy saving through reduction of compressed air leakage	6.95	24.36	15.00	0.62
26	Energy saving by maintaining the ash water ratio as per designed value	19.20	67.21	Marginal	Immediate
27	Energy savings by reducing compressed air pressure	3.24	11.35	Marginal	Immediate
28	Energy saving by installation of new energy efficient pumps of TACW C	6.15	21.53	0.70	0.03
29	Energy saving by installation of new energy efficient pumps of TACW B	4.98	17.41	0.69	0.04
30	Energy saving by installation of new energy efficient pumps of TACW A	4.91	17.19	0.71	0.04
31	Energy saving by installing energy efficient pumps in ash slurry pump	4.21	14.72	2.11	0.14
32	Energy saving by installing energy efficient pumps in ash water pump	8.43	29.49	10.57	0.36
33	Energy savings by installing VFD in ID fan: 1B	25.93	90.77	72.00	0.79
34	Energy savings by installing VFD in ID fan: 1A	19.58	68.51	72.00	1.05
35	Energy saving by installing VFD in BFP-1C	28.40	99.41	144.00	1.40
36	Energy saving by installing VFD in BFP-1B	28.37	99.29	144.00	1.50
	TOTAL	**555.73**	**1,945.09**	**1,157.38**	**0.60**

The energy audit study at this TPP, xxxxxxx, reveals that there is electricity savings potential of 555.73 Lakh kWh/annum and coal savings potential of 4372 MT of coal/annum. The estimated auxiliary power consumption (APC) reduction of 38.96% exists, which would impact since overall percentage of APC reduction from the existing is 12.14% to 7.41%.

5.5 Introduction

Background

xxxxxxx Name of the TPP, as part of their energy efficiency and conservation endeavors, had initiated the process of energy auditing of significant systems/subsystems on a regular basis, with a view of achieving energy consumption optimization and continuous improvement.

xxxxxx Name of the energy audit firm conducting the energy audit study at xxxxxxx Name of the TPP, during the xxxxx month, year. The scope of work is to carry out a detailed energy audit of the electrical, thermal, and insulation system of both the units of the TPP, along with their associated auxiliaries and to quantify the energy conservation potential in the units.

All the major equipment was studied with a site visit, process measurement, operation observation, and collecting all relevant data of the plant. This is to be done by stages ensuring an optimized system is achieved, taking consideration of its fuel and power consumption with minimum investment. The benefits on account of improved efficiency are also projected along with the investment required to achieve the same.

About the unit

xxxxxxx Name of the TPP consists of two water tube boilers of xxxx of capacity 383 TPH, 137 bar (Unit-1) and 391 TPH and 134.5 bar (Unit-2) with a turbine (xxxx make) nominal rating of 120 MW each. The date of commercial operation of Unit-1 was dd.mm.yyyy and for Unit-2 was dd.mm.yyyy.

Electricity generation

The electricity generated by the plant from April 2010 until March 2012 is illustrated in the chart below. The maximum electricity generated in the above stated period was in the month of May 2010 (136.69 MU), and minimum generation was observed in the month of September (50.70 MU).

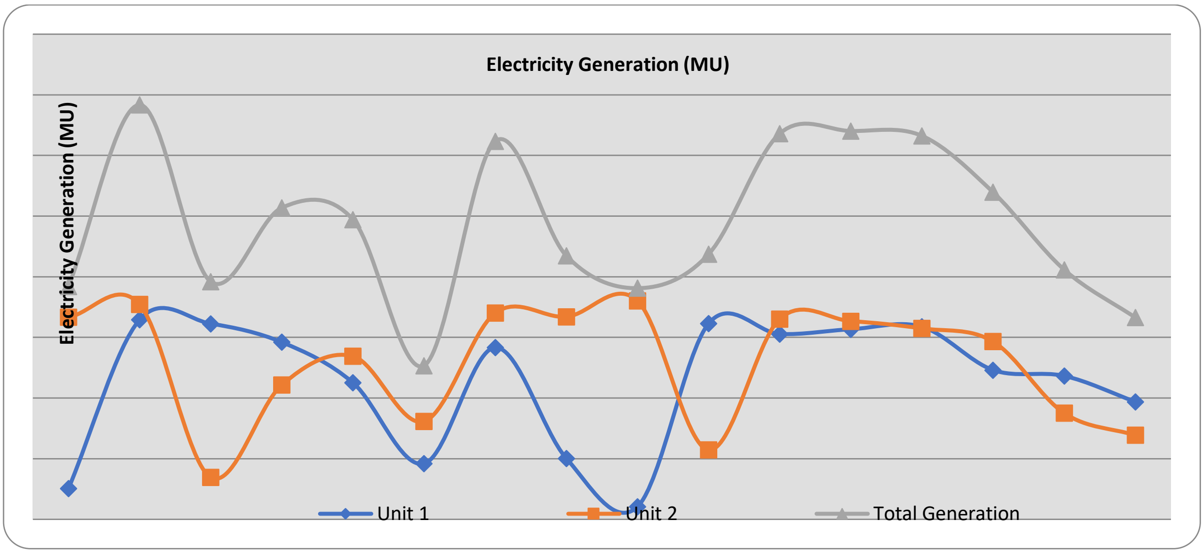

Figure A5-1: Electricity generation by the plant

The electricity generated during the period (April 2010 until July 2011) from Unit-2 constitutes around 54.74% while the generation from Unit-1 is around 45.26%.

The same is depicted in the bar chart below.

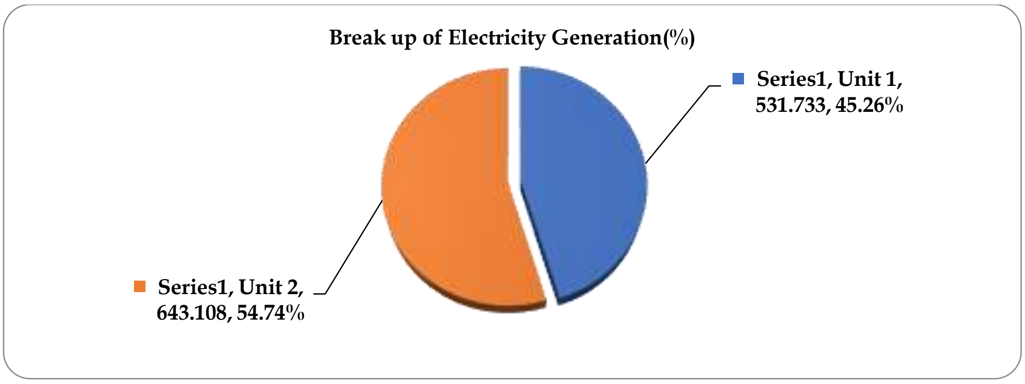

Figure A5-2: Breakup of electricity generation

Coal Consumption

The minimum consumption of coal is observed in the month of September 2010 (41,446.92 MT), and maximum consumption is in the month of March 2011 (107,449.40 MT). The quantity of coal consumed month-wise for the period of April 2021 until July 2011 is illustrated in the chart below.

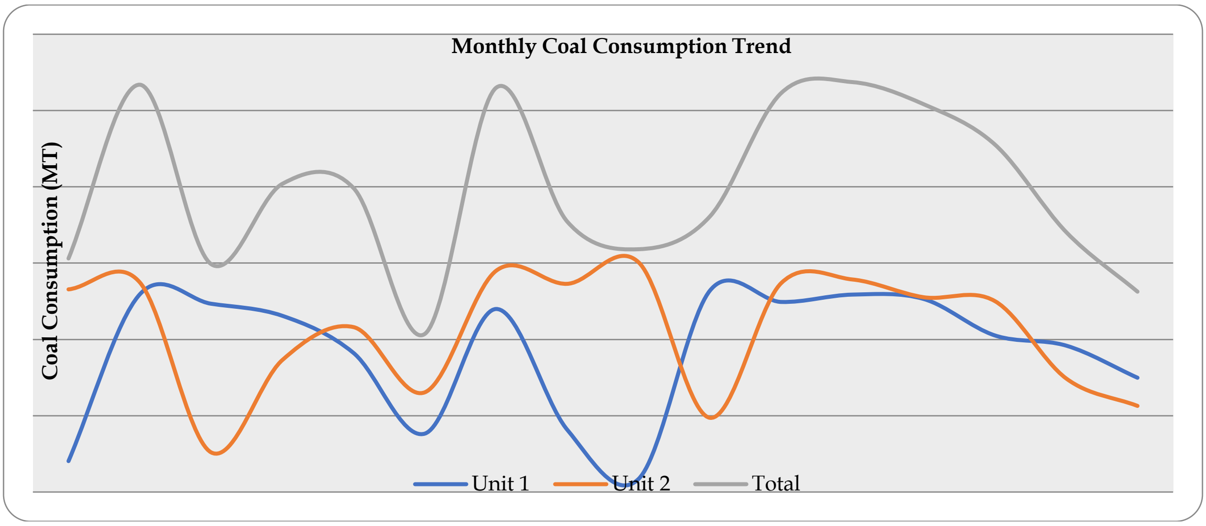

Figure A5-3: Monthly coal consumption

The coal consumption for the period of April 2010 until July 2011 for Unit-2 constitutes around 53.52%, whereas for Unit-1, it is around 46.48%. The same is depicted in the bar chart below.

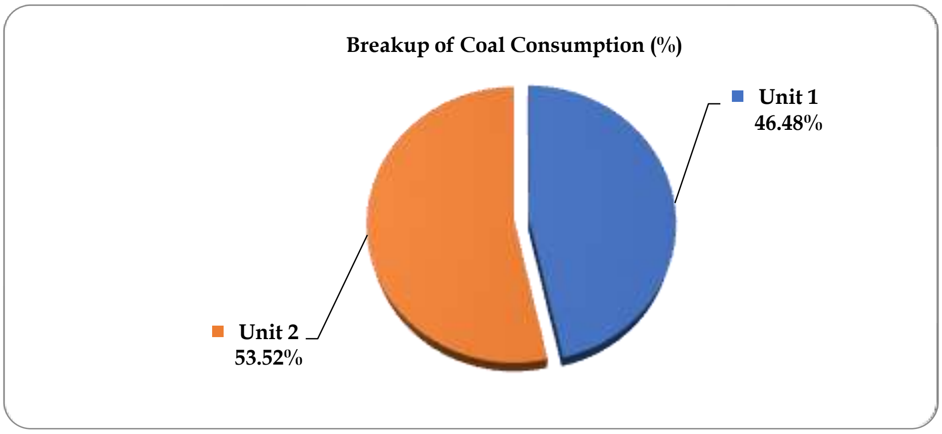

Figure A5-4: Breakup of coal consumption

Fuel rate and plant heat rate

The overall fuel rate for the plant varies from 0.762 kg/kWh (June 2010) to 0.850 kg/kWh (October 2011). Corresponding heat rate varies from 2,658.6 Kcal/kWh to 2,965.6 Kcal/kWh (Calorific value of coal = 3,489 Kcal/kg).

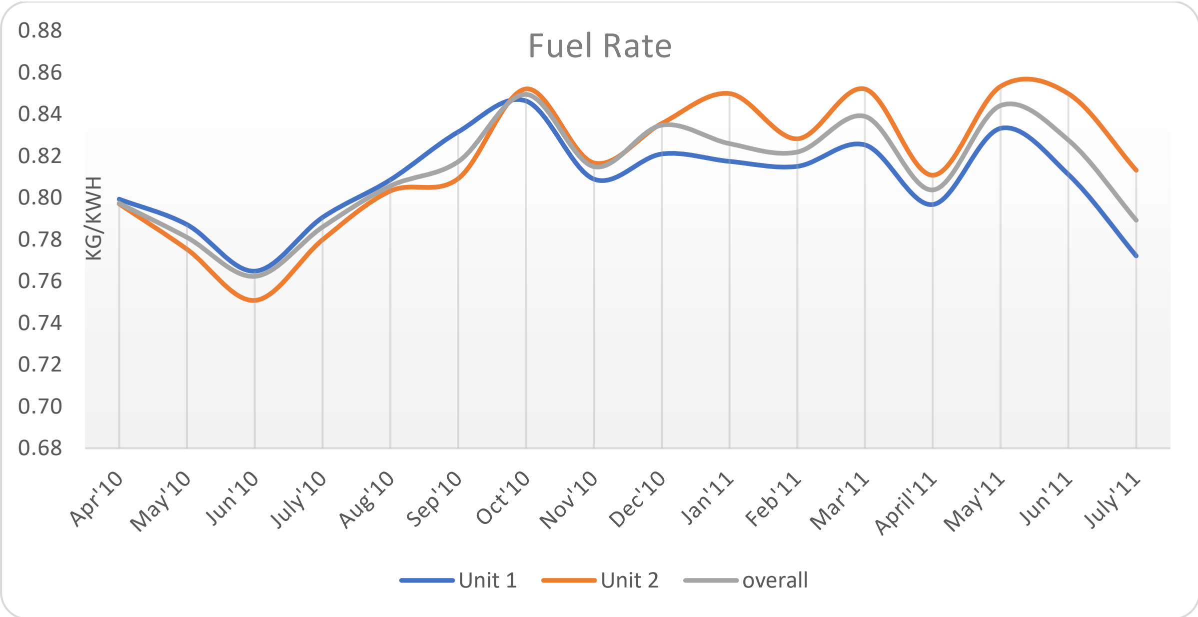

Figure A5-5: Fuel rate and plant heat rate

Plant load factor (PLF)

The minimum plant load factor (PLF) is observed in the month of September 2010, and the maximum PLF is observed in the month of February 2011.

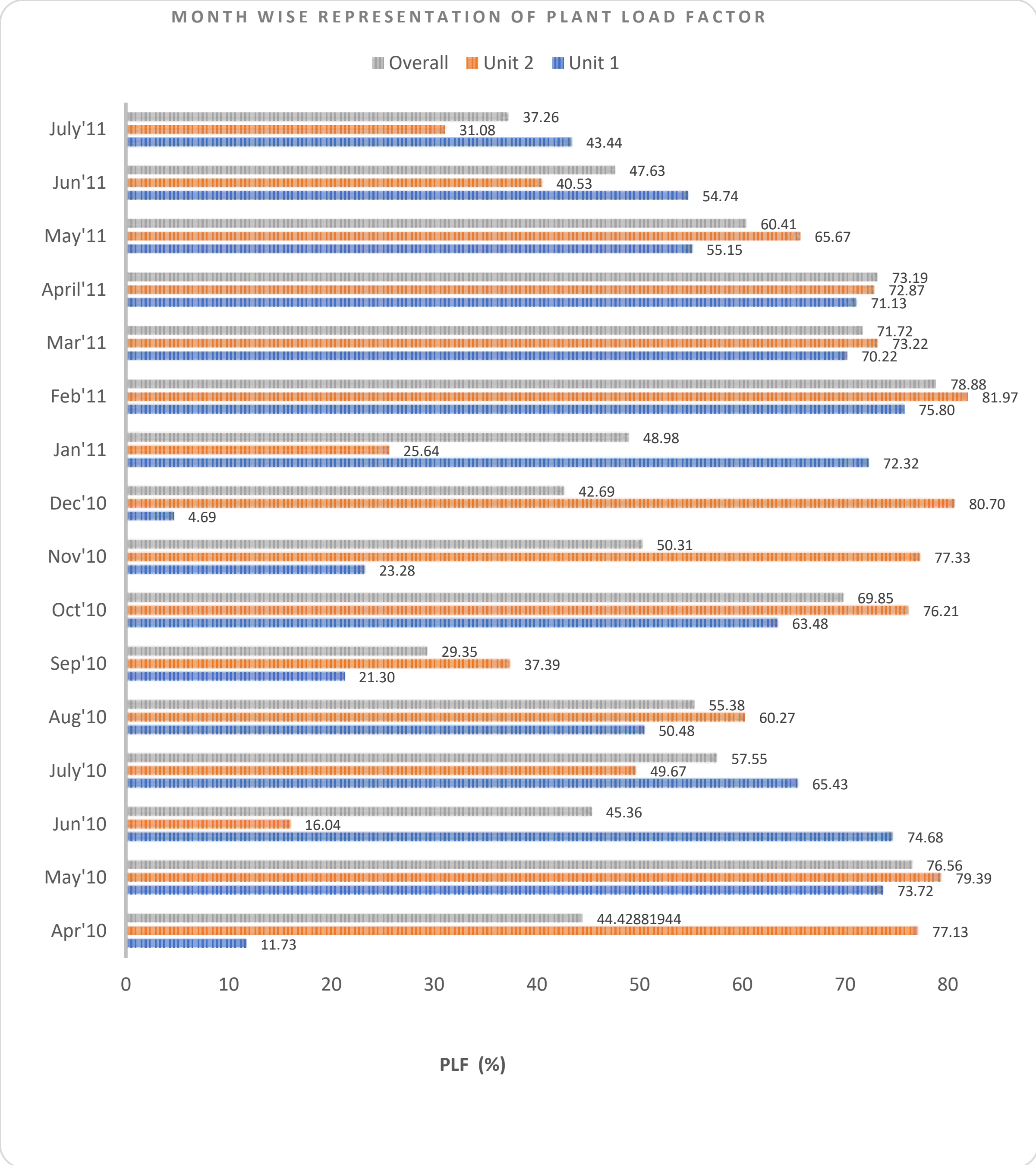

Figure A5-6: Plant load factor

Plant availability

The minimum overall plant availability is observed in the month of September 2010, and the maximum overall plant availability is observed in the month of February 2011.

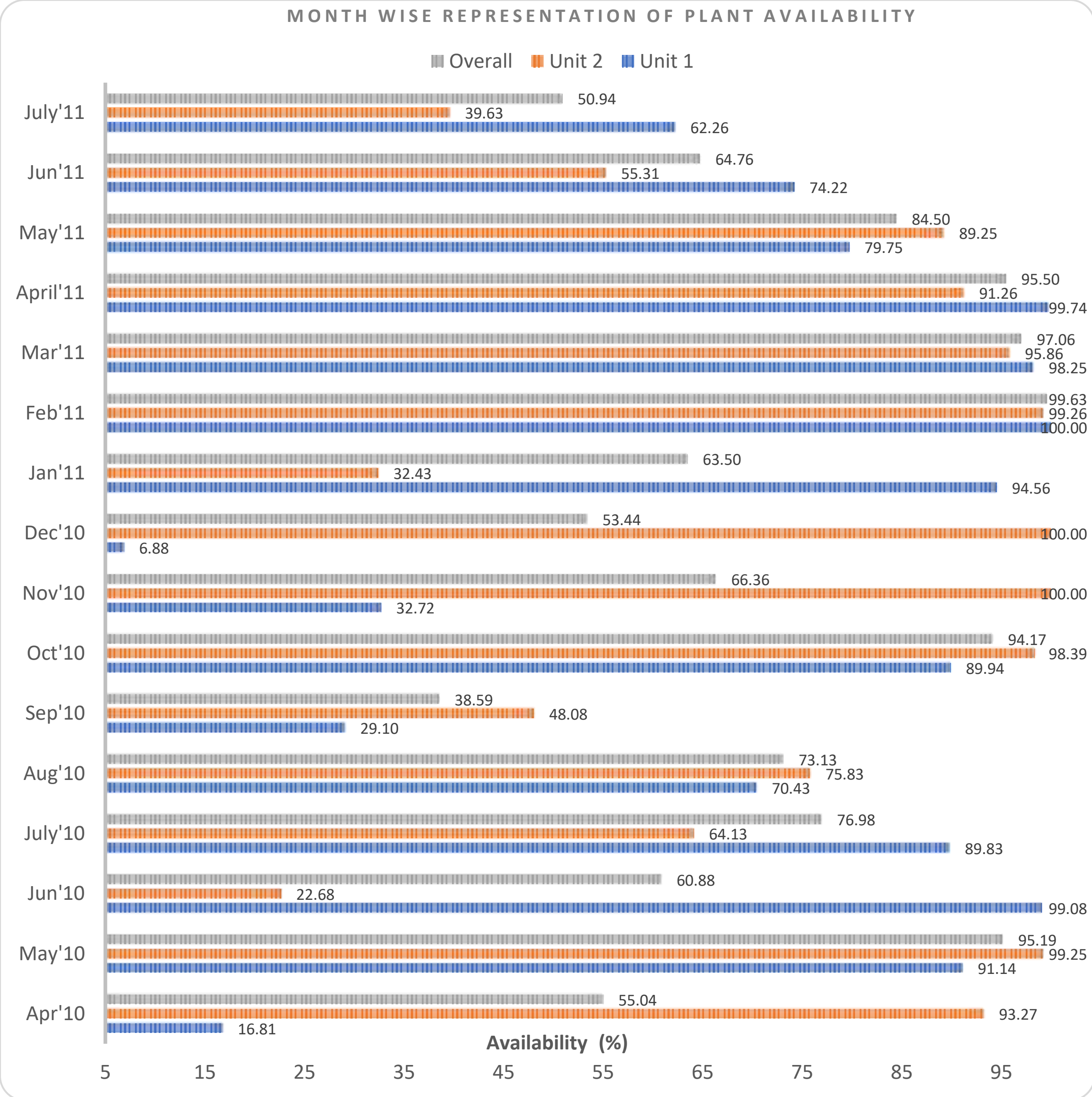

Figure A5-7: Overall plant availability

Auxiliary power consumption (APC)

The overall plant APC varies from 11.13% (February 2011) to 14.43% (September 2010) as against the design APC of 11%.

The maximum APC for Unit-1 and Unit-2 is in the month of December 2010 (26.49%) and June 2010 (15.94%), respectively; similarly, the month of minimum APC for Unit-1 and Unit-2 was January 2011 (10.87%) and February 2011 (11.36%), respectively. The reason for higher APC is due to low availability of the plant and reserve shutdown, etc.

The monthly APC for the period (April 2010 to March 2011) for both Unit-1, Unit-2, and overall plant is depicted as follows.

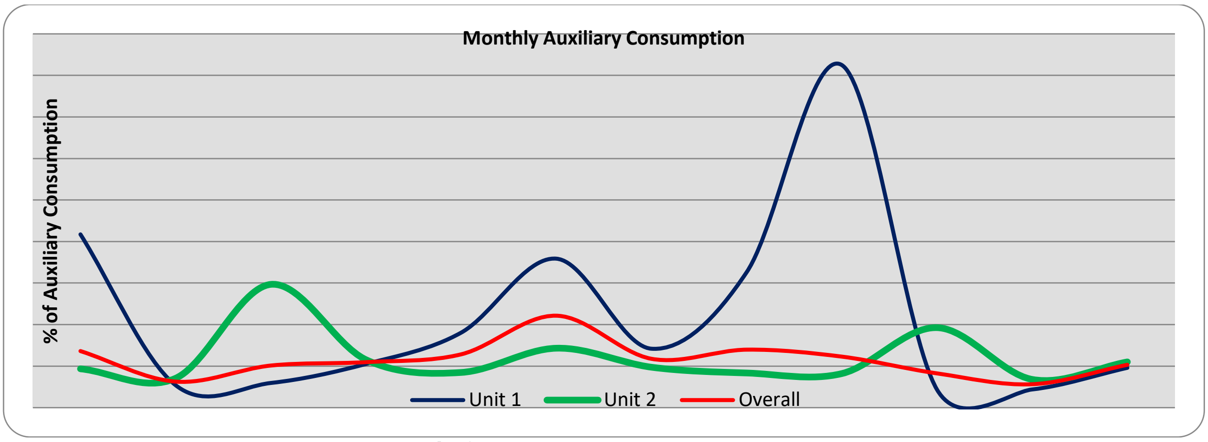

Figure A5-8: Monthly auxiliary power consumption

Furnace oil consumption

The furnace oil is used as support fuel during start-up. The total consumption of furnace oil for the period (April 2010–March 2011) is around 2,234.19 kL. The maximum specific furnace oil consumption is observed in the month of July 2010 (3,130.5 L/MU), and the minimum specific furnace oil consumption is observed in the month of May 2010 (573.6 L/MU).

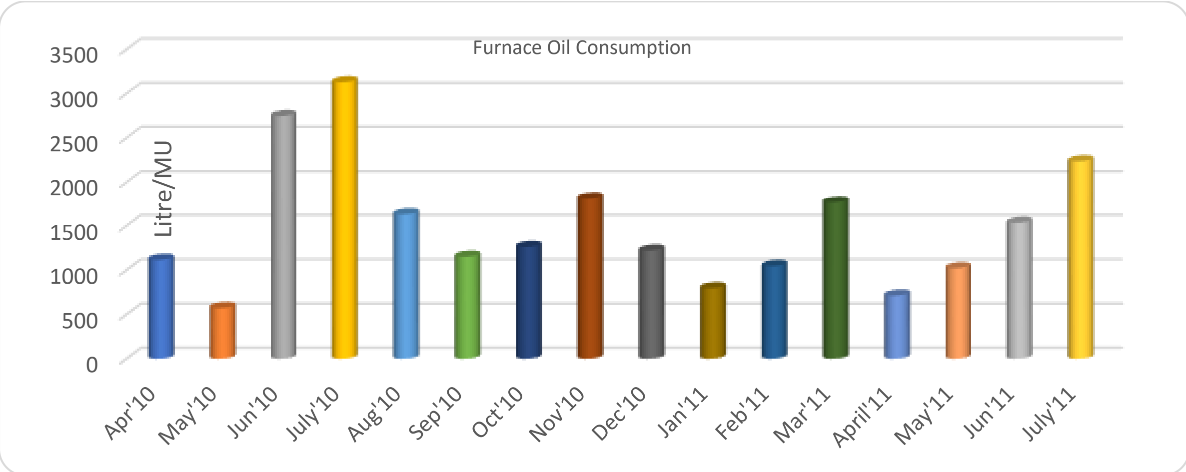

Figure A5-9: Furnace oil consumption

5.6 Scope of work

The scope of work for the energy audit study of xxxx Name of TPP is as follows:

- Historical data collection and analysis to bring out the present specific energy consumption (SEC) indices and to identify the variations of highs and lows.
- Determination of SEC norms (electrical and thermal energy) for the unit.
- To analyze energy consumption data and carry out the heat, mass balances, and prepare energy balance diagram.
- To study the performance of the coal handling system, milling system, draft system, etc., and to suggest energy conservation measures.
- To study the performance of boilers and turbines, air preheaters (APHs), condensers, and their auxiliaries.
- To study the ash handling system and to identify the possible energy conservation measures.
- To study the performance of motors that have major connected load.
- To study the existing process of the plant to minimize various energy losses and to suggest for efficient utilization of process energy and electrical energy.

- To study the lighting energy consumption (illumination study) and to suggest improvement in the lighting system for energy conservation.
- To study the compressed air system and to identify the possible energy conservation measures.
- To study the water pumping system and to identify the possible energy conservation measures.
- To study the performance of chillers and air handling units (AHUs), and to suggest possible energy-saving measures.

5.7 Methodology

The methodology adopted for carrying out the energy audit study is as follows:

- It should comprehensively cover all the energy sources and utility services utilized.
- It should evolve a satisfactory and acceptable method of "measurement" of energy consumption and establishing savings, vis-à-vis measures adopted.
- It should identify the potential areas of savings as well as to offer technically feasible and implementable solutions for energy saving.
- It should link plant production and energy consumption for correctly determining savings.
- It should establish proper "benchmarks" for energy consumption per unit of production in various areas and by major equipment.
- To prepare an energy balance diagram.
- To compare best practices with similar plants elsewhere.
- To develop energy use indices to compare performance and productivity.
- To formulate specific recommendations with cost estimates.
- To formulate a time schedule for implementation.
- To educate, train, and develop plant personnel.
- To analyze energy consumption data, and to carry out heat and mass balances.
- To categorize energy conservation measures as under:

  Energy audit means the verification, monitoring, and analysis of use of energy, including submission of a technical report containing recommendations for improving energy efficiency with cost-benefit analysis and an action plan to reduce energy consumption. The report shall be prepared in the same manner.

5.8 Instruments used

Apart from on-site instruments, portable instruments used in the study include:

- Power analyzer
- Ultrasonic water flow meter
- Flue gas analyzer
- IR thermometer (noncontact type)
- Pitot tubes
- Mano meters
- Digital thermocouples
- Digital lux meter
- Digital thermo-anemometer
- Digital hygrometer

5.9 Unit auxiliaries (Unit-2)

Background

Performance assessment of key plant auxiliaries of Unit-2, based on as-run trials was conducted during the field visit in August 2011, with the objective of energy performance validation against design value, to identify under performance, if any, during the as-run trials. Findings are envisaged to help in assessing the performance, vis-à-vis design/rated values, factors, and parameters affecting performance, key result areas for improvement and attention, leading to reduction in auxiliary energy consumption.

The power consumption of the key auxiliaries was measured by using an online power analyzer to access the as-run performance of the equipment. It was observed during the study period that the feed-water system consumes the maximum power (28%) of the total APC followed by the draught system (23.90%) and milling system (20.43%), etc. Refer to Annexure I for details.

Feed-water system

Boiler feed water pump (BFP)
The feed-water system analysis includes motor loading pattern, efficiency evaluation, and performance assessment of boiler feed water pumps (BFPs) and condensate extraction pumps, and identification of applicable energy conservation (ENCON) options, where possible.

BFPs constitute a key auxiliary, in terms of connected load as well as consumption. All the three BFPs of Unit-2 have identical design specification, and the as-run observation data on BFP are presented as under:

As-run conditions:

- Number of pumps operated: 2
- Deaerator at 70% level
- Type of discharge control: Throttle control
- Drum pressure: 114 kg/cm^2

Table A5-1: Details of boiler feed pump

Item reference	Units	Design	Actual	
			BFP-2B	BFP-2C
Unit load	MW	120	88	
Frequency	Hz	50	50	
BFP flow	TPH	225	150	160
Discharge pressure	kg/cm^2		180	179.4
Suction pressure	kg/cm^2		3.46	3.6
Net positive suction head required	mWC	7.5		
Total differential head	mWC	1,950	1,765	1,758
Power consumption				
Motor input	kW	2,222	1,554.7	1,731
Motor output	kW	2,000	1,399	1,558
Combined efficiency	%	66.4	51.6	49.2
% Margin on power	%		30.04	22.11
% Margin on flow	%		33.3	28.89
% Margin on head	%		9.47	9.85
Specific energy consumption (SEC)	kWh/T	9.9	10.4	10.8

The inter-se comparison of the operating BFPs indicates BFP-2B as having the lowest SEC of 10.4 kWh/T, whereas BFP-2C with SEC of 10.8 kWh/T, as against design SEC of 9.9 kWh/T.

The as-run BFP operational combined efficiencies are ranging from 49.2% to 51.6%; with respect to rated combined efficiency of 66.4%. The key operational factors influencing efficiency variation are felt to be partial loading on flow (67–71%), head (90–91%), drive motor loading (69–73%), throttling and apart from the intrinsic efficiency levels of the pumps, and the drive motor.

BFP loading and reserve margins: Scope for variable frequency drive (VFD) incorporation or stage reduction or replacement with energy efficient pump. As BFP consumes the maximum percentage of APC, therefore any of the options implemented as a measure of energy conservation in boiler feeding pumping system can accrue substantial benefits. In the present context, the loading of BFPs in terms of flow and head developed and the operating pump reserves on flow and head are assessed and presented below.

(Reference: unit loading 88 MW, i.e., 70%)

Table A5-2: Reference of BFP

Reference	Pump loading %		Pump reserve margins %	
	Flow	Head	Flow	Head
BFP-2B	66.7	90.5	33.3	9.47
BFP-2C	71.1	90.2	28.89	9.85

Energy saving by installing VFD

Table A5-3: Energy saving by installing VFD

Item reference	Units		Actual	
		Design	BFP-2B	BFP-2C
Present condition				
Unit load	MW	120	88	
Frequency	Hz	50	50	
BFP flow	TPH	225	150	160
Discharge pressure	kg/cm2		180	179.4
Suction pressure	kg/cm2		3.46	3.6
Total differential head	mWC	1,950	1,765	1,758
Power consumption				
Motor input	kW	2,222	1,554.7	1,731
Motor output	kW	2,000	1,399	1,558
SEC	kWh/T	9.9	10.4	10.8
Future condition				
Unit load	MW	120	88	
Frequency	Hz	50	50	
BFP flow	TPH	225	150	160
Discharge pressure	kg/cm2		155	155
Suction pressure	kg/cm2		3.5	3.5
Total differential head	mWC	1,950	1,515	1,515
Power consumption				
Liquid	kW		619.26	660.54
Motor output	kW	2,000	1,032.1	1,100.9
Motor input	kW	2,222	1,146.8	1,223.2
SEC	kWh/T	9.9	7.6	7.6
Reduction in power	kW		407.9	507.8
% reduction	%		26.2	29.3
Annual energy savings	kWh		2,764,943.9	3,441,717.8
Envisaged annual monetary savings	Rs/year		9,677,303.6	12,046,012.2
Investment	Rs		16,000,000.0	16,000,000.0
Simple payback period (SPP)	Year		1.7	1.3

The envisaged annual monetary savings for BFP-2B and BFP-2C are Rs 96.7 lakh/annum and Rs 120 lakhs/annum, respectively. The total investment required for VFD installation is around Rs. 320 lakhs. The simple payback period (SPP) will be 1.7 years and 1.3 years for BFP-2B and BFP-2C, respectively.

Energy saving by reducing number of stages

The percentage reserve on flow varies from 29% to 33%, and the head margin varies from 9.4% to 9.8%, which indicates that the pump is operating under throttled condition. The discharge pressure generated by the BFP is about 175 kg/cm^2, as against the boiler pressure (drum pressure) requirement of about 115 kg/cm^2, which shows that there is a tremendous scope of pressure reduction in the BFP by reducing the number of stages of the pump.

Table A5-4: Energy saving by reducing number of stages

Item reference	Units		Actual	
		Design	BFP-2B	BFP-2C
Present condition				
Unit load	MW	120	88	
Frequency	Hz	50	50	
BFP flow	TPH	225	150	160
Discharge pressure	kg/cm^2		180	179.4
Suction pressure	kg/cm^2		3.46	3.6
Total dev head	mWC	1,950	1,765	1,758
Power consumption				
Motor input	kW	2,222	1,554.7	1,731
Motor output	kW	2,000	1,399	1,558
SEC	kWh/T	9.9	10.4	10.8
Future condition				
Unit load	MW	120	88	
Frequency	Hz	50	50	
BFP flow	TPH	225	150	160
Discharge pressure	kg/cm^2		155	155
Suction pressure	kg/cm^2		3.5	3.5
Total dev head	mWC	1,950	1,515	1,515
Power consumption				
Liquid	kW		619.26	660.54
Motor output	kW	2,000	1,032.1	1,100.9
Motor input	kW	2,222	1,146.8	1,223.2
SEC	kWh/T	9.9	7.6	7.6
Reduction in power	kW		407.9	507.8
% reduction	%		26.2	29.3
Annual energy savings	kWh/year		2,764,943.9	3,441,717.8
Envisaged annual monetary savings	Rs/year		9,677,303.6	12,046,012.2
Investment	Rs		Marginal	Marginal

The envisaged annual monetary savings for BFP-2B and BFP-2C by reducing two pump stages is around Rs 96.7 lakh/year and Rs 120 lakh/year, respectively.

Energy saving by installing new energy efficient pump

The combined efficiency level of the pump and the drive motor is around 66.4% (designed), and the operating combined efficiencies are around 51.6% and 49.2%, which give a way for replacing them with the new state-of-the-art energy efficient pumps of efficiency around 78%.

Table A5-5: Energy saving by installing new energy efficient pump

Item reference	Units		Actual	
		Design	BFP-2B	BFP-2C
Present condition				
Unit load	MW	120	88	
Frequency	Hz	50	50	
BFP flow	TPH	225	150	160
Discharge pressure	kg/cm^2		180	179.4
Suction pressure	kg/cm^2		3.46	3.6
Total dev head	mWC	1,950	1,765	1,758
Power consumption				
Motor input	kW	2,222	1,554.7	1,731
Motor output	kW	2,000	1,399	1,558
Combined efficiency	%	66.4	51.6	49.2
SEC	kWh/T	9.9	10.4	10.8
Future condition				
Unit load	MW	120	88	
Frequency	Hz	50	50	
BFP flow	TPH	225	200	200
Discharge pressure	kg/cm^2		155	155
Suction pressure	kg/cm^2		3.5	3.5
Total dev head	mWC	1,950	1,515	1,515
Power consumption				
Liquid	kW		825.68	825.68
Motor output	kW	2,000	1,058.6	1,058.6
Motor input	kW	2,222	1,176.2	1,176.2
SEC	kWh/T	9.9	5.9	5.9
Reduction in power	kW		378.5	554.8
% Reduction	%		24.3	32.1
Annual energy savings	kWh		2,565,641	3,760,602
Envisaged annual monetary savings	Rs/year		8,979,744	13,162,108
Investment	Rs		12,000,000	12,000,000
SPP	Year		1.3	0.9

The envisaged annual monetary savings for BFP-2B and BFP-2C, by replacing them with a new energy efficient pump, is around Rs 89.7 lakh/annum and Rs 131.6 lakh/annum, respectively. The total investment required is around Rs 240 lakhs. The SPP will be 1.3 years and 0.9 years for BFP-2B and BFP-2C, respectively.

It is further advised that periodic as-run efficiency assessment along similar lines as in the present case is recommended (at monthly intervals) to enable identification of any gaps in performance and optimization of APC in BFPs.

Condensate extraction pump

To assess the performance of the condensate extraction pump, the electrical as well as flow characteristics have been analyzed. The as-run performance indicators are presented below.

Table A5-6: Performance indicators of condensate extraction pump

Item reference	Units	Design	Actual	
			CEP-2B	CEP-2A
Unit load	MW	120	88	
Frequency	Hz	50	50	
CEP flow	TPH	375.00	370.00	STANDBY
Discharge pressure	kg/cm2		15.00	
Suction pressure	kg/cm2		0.51	
Total dev head	mWC	170.00	144.90	
Power consumption				
Motor input	kW	277.78	229.00	
Motor output	kW	250.00	206.1	
Combined efficiency	%	69.49	70.89	
% Margin on power	%		17.56	
% Margin on flow	%		1.33	
% Margin on head	%		14.76	
SEC	kWh/T	0.74	0.62	

Energy saving by avoiding recirculation flow

To avoid the dry run operation of the pump, the recirculation flow is maintained in the condensate extraction pump. The as-run conditions indicate that the flow maintained for recirculation is about 93 tonnes per hour (TPH), which is consuming an additional power of 25.1%; therefore, it is suggested to avoid/stop the recirculation flow. The rationale for energy savings is tabulated below.

Table A5-7: Energy saving by avoiding recirculation flow

Item reference	Units	Design	Actual	
			CEP-2B	CEP-2C
Present condition				
Unit load	MW	120	88	
Frequency	Hz	50	50	
CEP flow	TPH	375.00	370.00	STANDBY
Discharge pressure	kg/cm2		15.00	
Suction pressure	kg/cm2		0.51	
Total dev head	mWC	170.00	144.90	
Power consumption				
Motor input	kW	277.78	229.00	
Motor output	kW	250.00	206.1	
Combined efficiency	%	69.49	70.89	
% Margin on power	%		17.56	
% Margin on flow	%		1.33	
% Margin on head	%		14.76	
SEC	kWh/T	0.74	0.62	

Future condition				
Unit load	MW	120	88	
Frequency	Hz	50	50	
CEP flow	TPH	375.00	277.00	STANDBY
Discharge pressure	kg/cm^2		15.00	
Suction pressure	kg/cm^2		0.51	
Total dev head	mWC	170.00	144.90	
Power consumption				
Motor input	kW	277.78	171.44	
Motor output	kW	250.00	154.30	
SEC	kWh/T	0.74	0.62	
Reduction in power	kW		57.6	
% Reduction	%		25.1	
Annual energy savings	kWh		390,138	
Envisaged annual monetary savings	Rs/year		1,365,483	
Investment	Rs		Marginal	

Condenser performance

The assessment of condenser performance is to determine performance status and degradation effects. The as-run performance tests can be used as the baseline for evaluating the performance improvement activities, as well as maintenance efficiency. The as-run performance indicator as observed during trial and the design data (key technical specification) of condenser is summarized as follows.

Table A5-8: Condenser performance

Particulars	Units	Design value	Actual
Unit load	**MW**	**120**	**88**
Turbine heat rate	Kcal/kWh	2,007	2,276
Type		Twin shell design	
Number of passes	Number	2	2
Number of passes of circulating water	Number	2	2
Tube length	mm	6,250	6,250
Tube material	—	Cupronickel 90/10	Cupronickel 90/11
Total number of tubes	Number	15,030	15,030
OD of condenser tube	mm	22	22
Tube thickness	mm	1	1
Cooling surface area	m^2	6,400	6,400
Cooling water (CW) flow rate	m^3/hr	17,000	13,674
Inlet water temperature	°C	33.00	27.91

CW temperature rise	°C	8.30	9.11
CW outlet temperature	°C	41.30	37.02
Steam quantity	TPH	264.83	229.97
Condenser back pressure	$kg/cm^2(a)$	0.11	0.13
Saturation temperature	°C	46.95	49.42
TTD at design CW flow and inlet temperature	°C	5.65	12.40
Heat gained by CW	MKcal/hr	141.10	124.63
Heat supplied	MKcal/hr	143.87	124.63
LMTD		9.18	16.54
Effectiveness	%	59.50	42.37

Condenser thermal load

The condenser thermal load works out to 124.63 MKcals/hr at a unit load of 88 MW, whereas the design thermal load is 143.9 MKcals/hr at 120 MW, indicating that thermal load is about 86.63% as against the turbine loading of 73.33%. The higher thermal load is impacted by loss of HPH-5 from the turbine cycle since the extraction steam will manifest as additional load on condenser. Rectification and reintroduction of HPH-5 can help to raise unit generation capability close to the rated value.

Condenser effectiveness

The as-run effectiveness of the condenser is 42.37%, which is lower than rated effectiveness of 59.50%, indicating scope for improvement. This performance drop is likely to be on account of silt deposit on the tube side.

Terminal temperature difference (TTD)

The as-run terminal temperature difference (TTD) value of 12.40°C as against the rated value of 5.65°C indicates significant scope for improvement. Higher TTD is normally due to unclean tubes and/or less water velocity.

LMTD

The as-run value of log mean temperature difference (LMTD) is 16.54°C with respect to design value of 9.18°C.

CW flow adequacy

Based on thermal load, the as-run cooling water (CW) flow has been assessed to be around 13,674 m^3/hr as against the design flow of 17,000 m^3/hr.

Condenser vacuum

The condenser back pressure is well above the design condition despite the CW inlet temperature being less than the rated value. Following analysis substantiates the observation:

- The design back pressure with clean tubes at 33°C CW inlet temperature = 0.11 $kg/cm^2(a)$ (with respect to 120 MW load).
- Saturation temperature predicted = 33°C + Design CW temperature drop + Design TTD = 33 + 8.3 + 5.65 = 46.95°C.
- Actual saturation temperature is 49.42°C, and corresponding back pressure 0.13 $kg/cm^2(a)$.

As against design vacuum of 0.11 $kg/cm^2(a)$ at 120 MW unit load, the as-run value of 0.13 $kg/cm^2(a)$

indicates the satisfactory performance of the condenser at the present loading condition.
State-of-the-art measures for condenser performance upkeep, like chlorination (for bio fouling), online cleaning of condenser tubes, and opportunity-based backwash of the condenser may be taken up.

CW pump
The CW system consumes around 14.44% of APC. There are five CW pumps in the plant performing the duty of water circulation in condenser heat rejection and other cooling duties. Two CW pumps are continuously in operation and are dedicated for Unit-2, and the other two pumps are for Unit-1, whereas one CW pump is kept as standby, which has the flexibility of pumping water to both the units. The schematic diagram of the CW pumps is presented below.

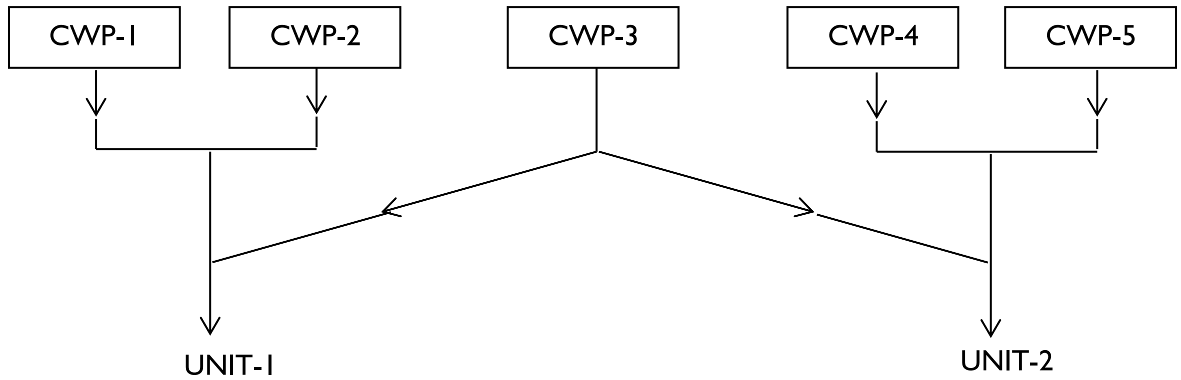

Figure A5-10: Schematic diagram of the CW pumps

The as-run performance as observed during trial and the design data specification of CW pumps are summarized as follows.

Table A5-9: Performance of CW pump

Item reference	Units		Actual	
		Design	CWP-2A	CWP-2B
Unit load	MW	120	88	
Frequency	Hz	50	50	
CWP flow	TPH	10,300	8,060	8,086
Discharge pressure	kg/cm^2		0.8	0.8
Suction pressure	kg/cm^2		0.5	0.5
Total dev head	mWC	17.75	13	13
Power consumption				
Motor input	kW	714.44	681.70	739.90
Motor output	kW	643.00	613.53	665.91
Combined efficiency	%	77.48	46.54	43.02
% Margin on power	%		4.58	-3.56
% Margin on flow	%		21.75	44.48
% Margin on head	%		26.76	26.76
SEC	kWh/T		0.08	0.09

From the above table, it can be observed that the efficiency of the pump is low due to low head developed by the pump as compared to the design value, and the same will affect the performance of the condenser. The reason for low head development is low seawater level at the suction during low-tide period. Desilting activities need to be performed for improving the pump suction.

Boiler auxiliary CW and turbine auxiliary CW system

Boiler auxiliary CW (BACW) systems and turbine auxiliary CW (TACW) systems constitute a key auxiliary, in terms of connected load as well as consumption, as these pumps are in continuous operation even when the plant is in reserve shutdown condition. To evaluate the as-run performance of auxiliary cooling water systems, the flow measurement of the BACW and TACW pumps were carried out with the help of an ultrasonic flow metering device, and the power consumption was monitored with the help of an online power analyzer.

The design specification and as-run observation data of BACW and TACW pumps are presented as under:

As-run conditions:

- Number of pumps operated: Two, A and C/B and C (parallel pumping)
- Type of discharge control: throttle control
- Observations done when standby coolers were in operation.

Table A5-10: Observations on BACW

Particulars	Unit	Design	Actual		Design	Actual
			TACW–A & C	TACW–B & C		BACW–A
Unit load	MW	120	88			
Frequency	Hz	50	50			
TACW flow	m^3/hr	2,100	2,495	2,547	450	523
Suction pressure	m		3.5	2		23
Discharge pressure	m		25.5	25		44
Total dev head	mWC	35	22	23	33	21
Power consumption						
Motor input	kW	289	270	270	62.2	63
Motor output	kW	260	243	243	56	56.7
Combined efficiency	%	77.03	61.55	65.69	72.26	52.78
% Margin on power	%		6.54	6.54		-1.25
% Margin on flow	%		-18.81	-21.29		-16.22
% Margin on head	%		37.14	34.29		36.36
SEC	kWh/m^3	0.14	0.11	0.11	0.14	0.12

Energy saving by installation of new energy efficient pumps

The combined SEC is about 0.11 kWh/m^3, as against the design value of 0.14 kWh/m^3, for TACW pumps. Similarly, the SEC for BACW pump is 0.12 kWh/m^3, as against the design value of 0.14 kWh/m^3. The combined efficiency of the pumps is observed to be lower (61.55%) as compared to the design value of 77.03% for TACW (A and C). The margin on head was observed to be very high (37.14%), and the flow handled by the pumps is more than (18.18%). The margin in power is in the order of 6.54%.

Similarly, the combined efficiency of the TACW (B and C) pump was observed to be lower (65.69%) as compared to the design value of 77.03%. The margin on head was observed to be very high (34.29%), and the flow handled by the pumps is more than (21.29%). Here again, the margin in power is 6.54%. Hence, it is suggested to replace the existing pumps with new properly sized energy efficient pumps.

Rationale

Table A5-11: Energy saving by installation of new energy efficient pumps

Particulars	Unit	Design	Actual		Design	Actual
			TACW–A & C	TACW–B & C		BACW–A
Unit load	MW	120	88			
Frequency	Hz	50	50			
Present condition						
TACW flow	m^3/hr	2,100	2,495	2,547	450	523
Suction pressure	m		3.5	2		23
Discharge pressure	m		25.5	25		44
Total dev head	mWC	35	22	23	33	21
Power consumption						
Motor input	kW	289	270	270	62.2	63
Motor output	kW	260	243	243	56	56.7
Combined efficiency	%	77.03	61.55	65.69	72.26	52.78
% Margin on power	%		6.54	6.54		-1.25
% Margin on flow	%		-18.81	-21.29		-16.22
% Margin on head	%		37.14	34.29		36.36
SEC	kWh/m^3	0.14	0.11	0.11	0.14	0.12
Future condition						
TACW flow	m^3/hr	2,100	2,100		450	450
Suction pressure	m		3.5			23
Discharge pressure	m		25.5			44
Total dev head	mWC	35	22		33	21
Power consumption						
Motor input	kW	289	174.85		62.20	35.77
Motor output	kW	260	157.37		56.00	32.19
Combined efficiency	%	77.03	80.00		72.26	80.00
SEC	kWh/m^3	0.14	0.08		0.14	0.08
Reduction in power consumption	kW		95.15			27.23
% Reduction in power consumption	%		35.24			43.23
Envisaged annual energy savings	kWh/annum		644,898			184,594
Envisaged annual monetary savings	Rs/year		2,257,144			646,081
Investment	Rs		900,000.00			200,000.00
SPP	Year		0.40			0.31

Draught system

ID fan

Induced draft (ID) fans, evacuating the boiler flue gases, constitute a key HT auxiliary, both from a functional point of view, as well as energy intensity. Unit-2 ID fans account for 9.2 Million Unit consumption per annum, constitute 11.11% of the APC, and stand as the fourth largest APC equipment. A schematic figure indicating the flue gas flow path is as follows.

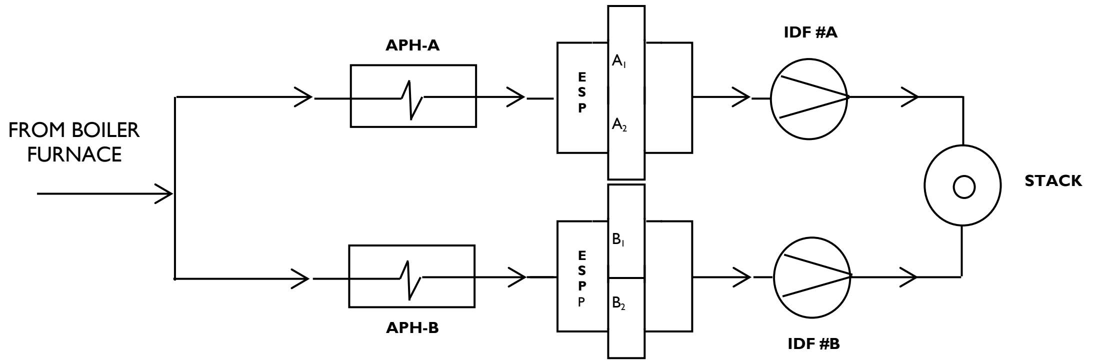

Figure A5-11: Schematic diagram of ID fan
Unit-2: ID fan system (Flue gas path)

Energy savings by installing VFD on ID fan

The performance assessment of ID was conducted, and the operating parameters were recorded, which are given below.

Unit generation status = 88 MW

Table A5-12: Energy savings by installing VFD on ID fan

Particulars	Design	Actual	
		2A	2B
Flow rate, TPH	405.35	254.85	254.85
Flow, m^3/hr	490,680	280,054	285,160
Flue gas temperature, °C	150	109	118
Density, kg/m^3	0.82	0.91	0.89
Suction pressure, mmWC		-230	-243
Total pressure, mmWC	373	233.6	243.7
Power consumption, kW	889	650.3	668.3
Motor output, kW	800	574.3	590.2
Overall efficiency, %	62.3	31	32.1
SEC, kWh/ton of flue gas	2.19	2.55	2.62
Scoop control, %		45	45
Flow margin, %		42.9	41.9
Head margin, %		37.4	34.7
Power margin, %		28.2	26.2

From the above table, it is observed that the flow and head margin of forced draft (FD) fan 2A and 2B is about 42% and 35%, respectively, resulting in a higher SEC of 2.5 kWh/ton of flue gas, compared to the design value of 2.19 kWh/ton of flue gas. Considering the fluctuation in load, it is recommended to install a VFD for efficient capacity control.

Fan (A)

Envisaged annual energy savings = 6.94 Lakh kWh
(6,778 hr x 650 kW x 0.16)
Envisaged annual monetary savings = 24.31 Rs Lakh/annum
(6.95 Lakh kWh x 3.5 Rs/unit)
Investment = Rs 64 Lakh

SPP = 2.63 years

Fan (B)
Envisaged annual energy savings = 8.03 Lakhs kWh
(6,778 hr x 668 kW x 0.18)
Envisaged annual monetary savings = 28.11 Rs Lakh/annum
(8.03 Lakh kWh x 3.5 Rs/unit)
Investment = Rs 64 Lakh
SPP = 2.27 years

Cost-benefit analysis

As HT VFDs involve huge capital costs, the plant may consider LT VFDs with back-to-back transformers (first step down 6.6 kV/0.415 kV and then step up from 0.415 kV/6.6 kV) as shown below.

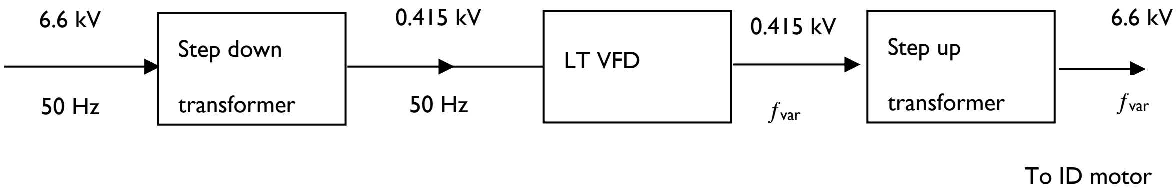

Figure A5-12: Cost-benefit analysis of ID fan

General recommendations

The following are general recommendations toward instrumentation monitoring needs in flue gas path:

- Provision of flue gas flow measurement in all ID fans should be made. This will help in monitoring air ingress.
- Provision for sample collection for O_2 should be made in all the places. This will help in monitoring of air ingress at various places in the flue gas duct.
- Provision of flue gas temperature measurement at all ID fans inlets should be made. This will also help in monitoring of air ingress and exit temperature of flue gas.

Forced draft (FD) fan

To assess the performance of FD fans, the following parameters were observed in the control room, and the power measurements were measured using portable online power analyzers. The performance parameters are tabulated below.

Unit generation status = 88 MW

Table A5-13: Performance of FD fan

Particulars	Design	Actual	
		2A	2B
Flow rate, TPH	227.83	127.95	127.95
Flow, m³/hr	210,600	145,244	144,353
Ambient temperature, °C	50	36.9	35
Density, kg/m³	1.08	1.13	1.13
Suction pressure, mmWC	atm	atm	atm
Total pressure, mmWC	466	150.9	150
Power consumption, kW	444	188	188
Motor output, kW	400	173	173
Overall efficiency, %	66.8	34.5	34.1
SEC, kWh/ton of air	1.94	1.47	1.47
Vane opening, %		60	56
Flow margin, %		31	31.5
Head margin, %		67.6	67.8
Power margin, %		56.8	56.8

It is observed that the efficiency of fans 2A and 2B were found to be 34.5% and 34.1%, respectively, which is much below the design efficiency of 66.8%. It is also observed that enough flow, head, and power margin exist. The SEC was found to be 1.47 kW/ton of air, vis-a-vis design value of 1.94 kW/ton. This is due to very high head margins. It is suggested to install VFD on both the fans to improve efficiency and thereby power savings.

Fan (A)
Envisaged annual energy savings = 3.18 Lakh kWh
(6,778 hr x 188 kW x 0.25)
Envisaged annual monetary savings = Rs 11.11 Lakh/annum
(3.18 Lakh kWh x Rs 3.5/unit)
Investment = Rs 32 Lakh
SPP = 2.87 years

Fan (B)
Envisaged annual energy savings = 3.18 Lakhs kWh
(6,778 hr x 188 kW x 0.25)
Envisaged annual monetary savings = Rs 11.11 Lakh/annum
(3.18 Lakh kWh x Rs 3.5/kWh)
Investment = Rs 32 Lakh
SPP = 2.87 years

Primary air (PA) fan
The major auxiliary for the mill is the primary air (PA) fan, and its motor drive, which constitutes the single largest electricity-consuming subsystem. The PA fan is a critical part of the milling system, and any increase or decrease in air flow directly affects the combustion characteristics in the boiler, resulting in undesirable effects like clinkerization, increase in secondary oil support, and unit load reduction, etc. apart from the heat loss in the boiler. The energy performance features of PA fans were analyzed, and the key indices governing efficiency of fans were worked out as given.

Unit generation status = 88 MW

Table A5-14: Performance of PA fan

Particulars	Design	Actual	
		2A	2B
Flow rate, TPH	165.52	54.05	54.05
Flow, m³/hr	153,000	47,640	47,640
Ambient temperature, °C	50	32.3	32.3
Density, kg/m³	1.13	1.13	1.13
Suction pressure, mmWC	atm	atm	atm
Total pressure, mmWC	1,260	903	915
Power consumption, kW	815	590.6	590.6
Motor output, kW	750	543.3	543.3
Overall efficiency, %	70	21.4	21.7
SEC, kWh/ton of air	4.92	10.92	10.92
Vane opening, %		24.4	46
Flow margin, %		69.1	69.1
Head margin, %		28.3	27.4
Power margin, %		29.1	27.6

From the above table, it is observed that the flow margin of the PA fan 2A and 2B is about 69.1%, which is comparatively higher, indicating that the fan is operating at part load condition of 30% due to damper operation, resulting in higher SEC of 10.92 kWh/ton of air, compared to the design value of 4.92 kWh/ton of air. It is strongly recommended to operate only one fan for efficient capacity control.

Envisaged annual energy savings = 39.99 Lakh kW (6,778 hr x 590 kW)
Envisaged annual monetary savings = R_s 139.96 Lakh/year (3,999,020 x R_s 3.5 / kWh)

Coal mill

The coal milling system is a critical area as regards plant operation, and utmost care is accorded to their upkeep and operation. So much so, the reliability of boiler operation is so dependent on mills that an extra mill operation is often justified as a normal practice. The existing coal mill system constitutes four mills installed with a total of three mills in operation.

The total power consumption in the milling system constitutes around 20.43% of the APC. Toward the energy audit of the milling system, various observations were made, and measurements were undertaken to assess performance of the mills and associated subsystem; these included electrical measurements (kW, PF, amps, V) of operating mills and PA fans. The other key performance features are dictated by mill loading (capacity utilization), and air-to-coal ratios are also tabulated. The as-run performance of the mills is presented below.

Table A5-15: Performance of coal mills

Mill reference	Unit	Mill A		Mill B		Mill C		Mill D	
		A1	A2	B1	B2	C1	C2	D1	D2
Average unit load	MW	89.71						Not in Operation	
Average frequency	Hz	49.96							
Generation voltage	kV	11.00							
Average PF		0.99							
PA flow	TPH	14.96	15.09	18.04	18.08	16.44	17.48		
PA inlet pressure	mmWC	403.35	385.68	368.42	373.30	327.52	327.32		
Average PA mill inlet temperature	(°C)	216.35	213.57	205.52	214.71	200.68	218.24		
Average PA mill outlet temperature	(°C)	68.21	67.68	65.71	67.87	68.52	68.19		
% through 200 mesh	%	55.00		72.00		60.00			
Average power consumption	kW	779.62		761.92		779.62			
Motor rating	kW	770.00		770.00		770.00			
Coal flow									
Design	TPH	38.40		38.40		38.40			
Actual	TPH	13.03	12.52	12.75	11.62	12.90	11.33		
Capacity utilization	%	66.54		63.46		63.09			
Air-to-coal ratio		330.00							
Design									
Actual		1.18		1.48		1.40			
% Load on motor rating	%	91.12		89.06		91.12			
SEC									
Design	kWh/T	22.28		22.28		22.28			
Actual	kWh/T	30.51		31.26		32.18			

Energy savings by replacing an existing tube-type coal mill with a modern energy efficient bowl type coal mill

Table A5-16: Energy savings in energy efficient mills

Mill reference	Unit	Mill A		Mill B		Mill C	
		A1	A2	B1	B2	C1	C2
Present condition							
Average unit load	MW	89.71					
Average frequency	Hz	49.96					
Generation voltage	kV	11.00					
Average PF		0.99					
PA flow	TPH	14.96	15.09	18.04	18.08	16.44	17.48
Average PA mill inlet temperature	°C	216.35	213.57	205.52	214.71	200.68	218.24
Average PA mill outlet temperature °C	°C	68.21	67.68	65.71	67.87	68.52	68.19
% through 200 mesh	%	55.00		72.00		60.00	
Average power consumption	kW	779.62		761.92		779.62	
Motor rating	kW	770.00		770.00		770.00	
Coal flow							
Design	TPH	38.40		38.40		38.40	
Actual	TPH	13.03	12.52	12.75	11.62	12.90	11.33
Capacity utilization	%	66.54		63.46		63.09	
SEC							
Design	kWh/ton	22.28		22.28		22.28	
Actual	kWh/ton	30.51		31.26		32.18	
Future condition							
Type of mill		Bowl mill		Bowl mill		Bowl mill	
Number of mills to be operated		Any three at a time					
SEC	kWh/T	7		7		7	
Reduction in power consumption	kWh/T	23.51		24.26		25.18	
Envisaged annual energy savings	kWh/year	4,071,933		4,008,035		4,134,743	
Envisaged annual monetary savings	Rs	14,251,765		14,028,122		14,471,599	
Investment	Rs	20,000,000		20,000,000		20,000,000	
SPP	Years	1.40		1.43		1.38	

Ash handling plant (AHP)

As part of the ash handling plant (AHP) study, electrical measurements were carried out on ash water pumps and ash disposal pumps by a power analyzer. Historical data analysis was also carried out to study the influence of PLF, partial loading, etc. on the ash generation profile. The AHP study includes energy audit quantification of power consumption of AHP and identifies potential energy conservation options. The monthly ash generation trend is depicted below.

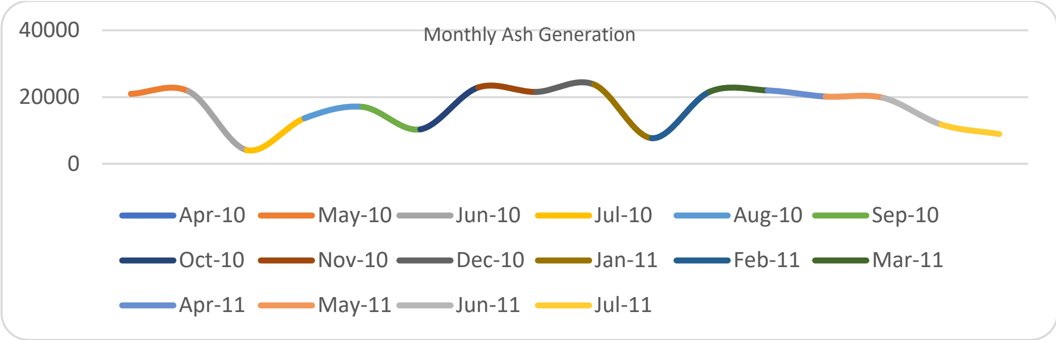

Figure A5-13: Monthly ash generation

*Ash generation is calculated from coal consumption based on 39.45% (ash content) of coal analysis report.

The average ash generation of Unit-2 is 948 MT/day (average for year 2010–2011). It is observed that the maximum ash is handled in the month of December 2010, while the minimum ash handling is in June 2010.

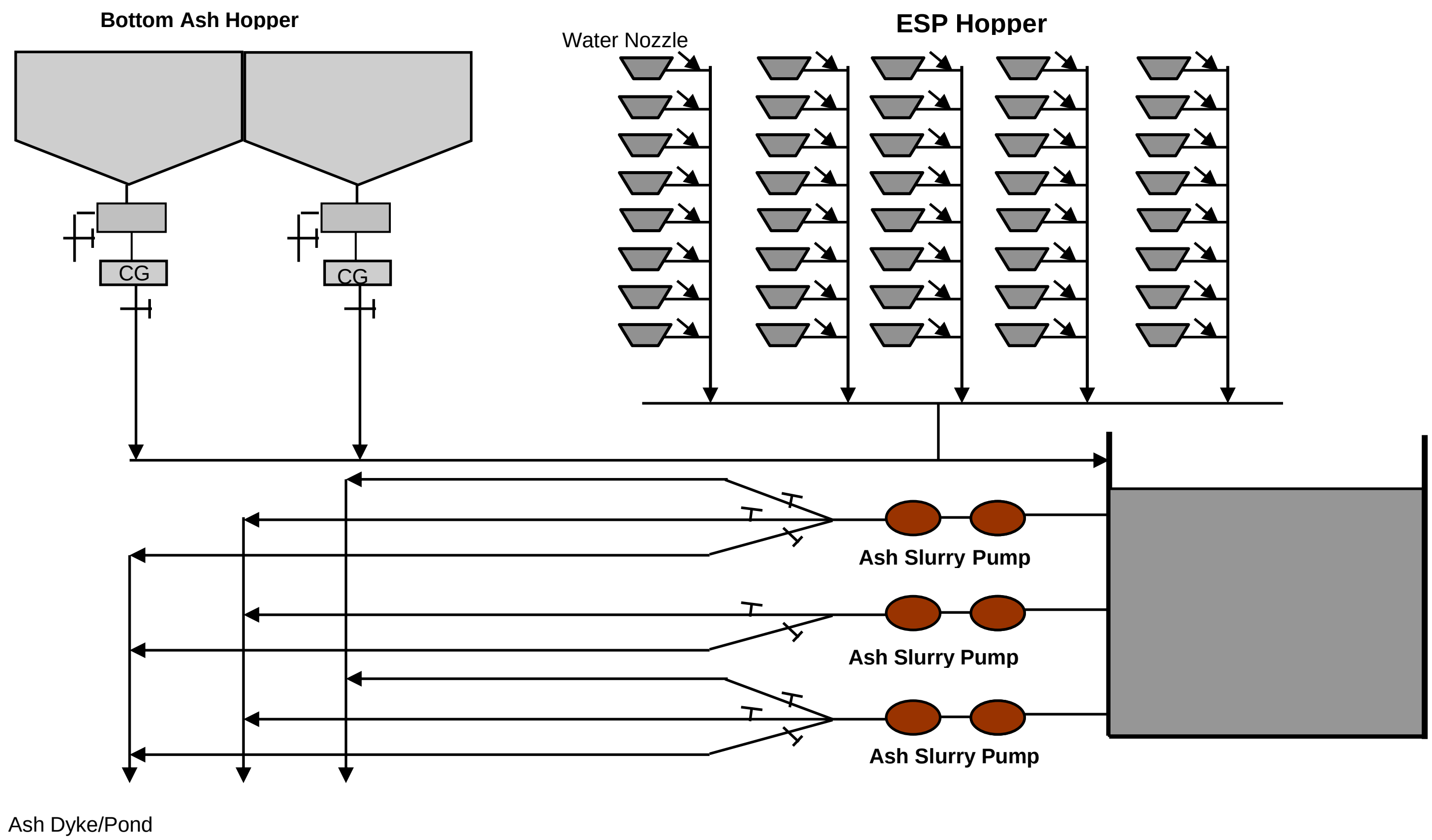

Figure A5-10: Schematic diagram of ash handling system

During the trial period, two ash water pumps, namely pump 2A and 2B, and one ash slurry pump were in operation. The water flow measurement is calculated by keeping the pump efficiency the same as design efficiency. The as-run trial results in comparison to the design values are tabulated below.

Table A5-17: Performance of ash water pumps

Particulars	Unit	Ash water pump		Ash slurry pump	
		Design (2A & 2C)	Actual (2A & 2C)	Design (2A)	Actual (2A)
Pump capacity	m^3/hr	640	643	900	1,155
Suction pressure	mWC		7		6
Discharge pressure	mWC		125		45
Head	mWC	140	118	41	39
Motor input	kW	611.1	517.7	222.2	271.3
Motor output	kW	550.0	465.9	200	244.17
Combined efficiency	%	44.39	44.39	50.28	50.28
SEC	kWh/m^3	0.95	0.22	0.21	0.21
Ash generation	MT/hr		39.5		
Ash water ratio		1:6	1:16.3		

The online power measurement is presented below.

Table A5-18: Online power measurement of ash water pumps

Parameters	Ash water pump-1	Ash water pump-2	Ash slurry pump-1
Voltage	6,868	6,878	6,872
Ampere	21.0	28.6	23.3
kW	224.9	292.8	271.3
Power factor	0.90	0.86	0.98
Motor rating (kW)	275.0	275	200
Motor loading (%)	73.59	95.83	122.1

Energy saving by maintaining the ash water ratio as per designed value

The study findings reveal that the ash water ratio maintained is around 1:16.3, which is very high as compared to the design ash water ratio of 1:6. Hence, it is suggested to minimize the water flow as per the designed condition. The water flow required to maintain the designed ash water ratio of 1:6 for the ash generation of 39.5 TPH is around 237 m^3/hr. This can be achieved by operating only one ash water pump instead of the present operation of two pumps.

The rationale of energy saving by operating one pump is presented as follows.

Table A5-19: Energy saving by maintaining the ash water ratio

Particulars	Unit	Ash water pump (2A & 2C)
Present condition		
Number of pumps in operation	Number	2
Pump capacity	m^3/hr	643
Suction pressure	mWC	7
Discharge pressure	mWC	125
Head	mWC	118

Motor input	kW	517.7
Motor output	kW	465.9
Combined efficiency	%	44.39
SEC	kWh/m3	0.22
Ash generation	MT/hr	39.5
Ash water ratio		16.28
Proposed condition		
Number of pumps	Number	1
Pump capacity	m3/hr	237
Suction pressure	mWC	7
Discharge pressure	mWC	125
Head	mWC	118
Motor input	kW	190.8
Motor output	kW	171.7
Combined efficiency	%	44.39
SEC	kWh/m3	0.80
Ash generation	MT/hr	39.5
Ash water ratio		6.00
Envisaged power reduction	kW	326.9
% Reduction in power	%	63
Envisaged annual electricity savings	kWh/year	2,216,053
Envisaged annual monetary savings	Rs/year	7,756,186
Investment	Rs	NIL

Energy saving by installing energy efficient pumps

The ash slurry pump and ash water pump design efficiency are found to be very low as compared to the state-of-the-art new energy efficient pumps, which operate at 80% of the efficiency. Hence, it is recommended to install new pumps. The envisaged energy savings potential is presented in detail below.

Table A5-20: Energy saving by installing energy efficient ash water pumps

Particulars	Unit	Ash water pump (2A & 2C)	Ash slurry pump (2A)
Present condition			
Number of pumps in operation	Number	2	
Pump capacity	m3/hr	643.21	1,155.19
Suction pressure	mWC	7	6
Discharge pressure	mWC	125	45
Head	mWC	118	39
Motor input	kW	517.7	271.3
Motor output	kW	465.93	244.17
Combined efficiency	%	44.39	50.28
Proposed condition			

Number of pumps	Numbers	2	1
Pump capacity	m^3/hr	643.2	1,155.2
Suction pressure	mWC	**7.0**	6.0
Discharge pressure	mWC	125.0	45.0
Head	mWC	118.0	39.0
Motor input	kW	287.3	170.5
Motor output	kW	258.5	153.5
Combined efficiency	%	80	80
SEC	kWh/m^3	0.45	0.13
Envisaged power reduction	kW	230.4	100.8
% Reduction in power	%	44.5	37.2
Envisaged annual electricity savings	kWh/annum	1,561,930	683,140
Envisaged annual monetary savings	Rs/annum	5,466,756	2,390,992
Investment	Rs	1,292,664	767,304
SPP	Rs	0.24	0.32

Compressed air system

The compressed air system, energy consumption as percentage of total auxiliary consumption, is about 2.39 (the average APC being 13.86% of the total generation). The study of the compressed air system was carried out when the units were operating at 70–80% (88 MW) of their full load capacity (120 MW). The various areas covered during the study are given below:

- Evaluation of performance of compressed air system.
- Survey of compressed air distribution network.
- Review of existing compressed air utilization practices in the station.

There are four reciprocating compressors that are connected to a common header. The compressed air tapping from a common header is passed through the air dryer for instrument air requirements of the plant, whereas the other tapping is used directly for service air requirements of the plant.
The user points of the service air are as below.

➢ Turbine maintenance area
➢ Mills area
➢ RC feeders area
➢ Fire doors area
➢ Igniter cooling area
➢ Any other cleaning requirement
➢ Fuel atomization

The user points of the instrument air are as below.

➢ Solenoid valve operation
➢ Ash slurry pump house
➢ All pneumatic valve operation

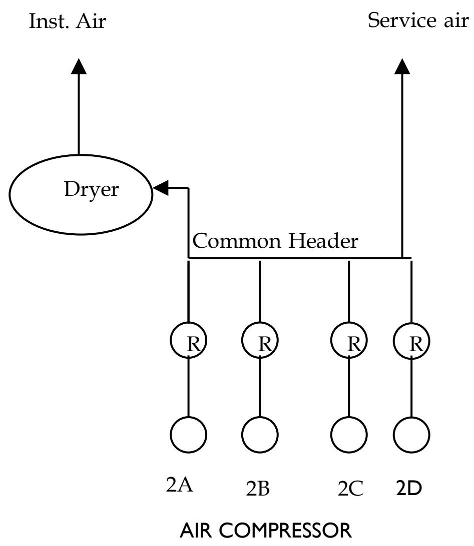

Figure A5-15: Compressed air system

The plant and instrument air pressure are the same, that is, 6.5–6.8 kg/cm^2 for flexibility of operation/emergency requirements. The simplified schematic of the compressor as arranged is presented above. Design specifications are given below.

Table A5-21: Design specifications of compressor air systems

Parameter	Design specifications
Type	Reciprocating
Number of stages	Two
Discharge pressure	8 kg/cm^3 (g)
Capacity	21.18 Nm^3/hr
Motor rating	135 kW
Operating voltage	415 V (+/-10%)

Capacity test result

To know the performance of each compressor, the pump-up test was conducted for all the compressors separately by isolating receivers from distribution headers. Simultaneously, the power drawn by compressors was measured by on-load power analyzers. The equation for calculating the FAD is discussed below.

Actual free air discharge

$$Q = \frac{(\mathbf{P2} - \mathbf{P1})}{Po} \times \frac{\mathbf{V}}{\mathbf{T}}$$

Where:

P_2 = Final pressure after (kg/cm^2 a)

P_1 = Initial pressure after filling

P_0 = Atmospheric pressure (kg/cm^2 a)

V = Storage volume in m^3 include receiver after cooler and delivery piping

T = Time taken to build up pressure in minute.

The findings of the capacity trial are presented as under the with respect to rating.

Table A5-22: Capacity test result of compressor

Parameters	Unit	2A	2B	2C
Initial pressure	kg/cm^2 (g)	4	4	5
	kg/cm^2 (a)	5	5	6
Final pressure	kg/cm^2 (g)	6.0	6.0	7
	kg/cm^2 (a)	7	7	8

Atmospheric pressure	kg/cm^2 (a)	1	1	1
Storage volume	m^3	7.30	7.3	7.3
Receiver temperature	°C	45	45	45
Time	min	0.65	0.58	0.58
Actual FAD				
	Nm^3/min	*19.28*	*21.49*	*21.49*
	Nm^3/hr	1157	*758.00*	*758.90*
	CFM	680	1,289	1,289
Design FAD				
	Nm^3/min	21.18	21.18	21.18
	CFM (@30°C)	748	693	748
Power consumption	kW	127.4	127	116
Motor rating	kW	135.0	135.0	135.0
SEC	$kW/(Nm^3/min)$	6.61	5.91	5.40
	kWh/Nm^3	0.110	0.099	0.090
Iso-thermal power	kW	53.04	59.10	60.63
Iso-thermal efficiency	%	48.41	54.11	60.78

The SEC of the compressors varies from 0.09 kWh/Nm^3 to 0.11 kWh/Nm^3. The performance of the compressors with respect to SEC is found to be satisfactory. Based on normal operation of three compressors for 24 hours a day, it is estimated that the daily total air requirement of the plant is around 89,640 Nm^3/day at 7.8 $kg/cm.^2$

Energy savings by reducing compressed air pressure from existing 7.8 kg/cm^2 to 6.5 kg/cm^2

The plant air pressure requirement at the farthest point is about 4.5 to 5 kg/cm^2, while the compressor is operated at a pressure of 7.8 kg/cm^2. Considering the pressure drop in the distribution line, there is a possibility of pressure reduction of 1.2 kg/cm^2 (7.8–6.5 kg/cm^2). Hence, it is suggested to reduce the compressed air pressure from the existing 7.8 kg/cm^2 to 6.5 kg/cm^2. Based on the trial-and-error method, it can be further reduced to 5.5 $kg/cm.^2$

Rationale

Table A5-23: Energy savings by reducing compressed air pressure

Parameters	Unit	2A	2B	2C
Actual FAD				
	Nm^3/min	*19.28*	*21.49*	*21.49*
	Nm^3/hr	1157	*758*	*758.9*
	CFM	680	1,289	1,289
Final pressure	kg/cm^2 (g)	7.8	7.8	8.3
Design FAD				
	Nm^3/min	21.18	21.18	21.18
	CFM (@30°C)	748	693	748
Power consumption	kW	127.4	127	116
Motor rating	kW	135	135	135
SEC	$kW/(Nm^3/min)$	6.61	5.91	5.4
	kWh/Nm^3	0.11	0.099	0.09
New pressure to be set	kg/cm2 (g)	6.5	6.5	6.5
Reduction in pressure	kg/cm2 (g)	1.3	1.3	1.8
% Reduction in pressure	%	16.7	16.7	21.7
Envisaged power savings	kW	21.2	21.2	25.2

Envisaged annual power savings	kWh/annum	143,919.5	143,467.7	170,511.6
Envisaged annual monetary savings	Rs/annum	503,718.4	502,136.8	596,790.7
Investment	Rs/annum	Marginal	Marginal	Marginal

Checklist for energy efficiency in compressed air system

- Ensure air intake to compressor is not warm and humid by locating compressors in a well-ventilated area or by drawing cold air from inside. Every 4°C rise in air inlet temperature will increase power consumption by 1%.
- Clean air filter regularly.
- Install manometer across filter.
- Fouled intercoolers reduce the compressor efficiency and cause more water condensation in air receivers and distribution lines resulting in increased corrosion.
- If pressure requirements for processes are widely different, it is advisable to have two separate compressors.
- Compressed air leakages of 40–50% is common—carry out periodic leak tests.
- Misuse of compressed air like body cleaning, floor cleaning, and cycle pumping must be discouraged.
- Because of pressure drops, ball and ping gate valves are preferable over globe valves in compressor lines.

Air conditioning system: Performance assessment of chillers

There are three chillers of capacity 30 TR, with motor rating of 30 kW, provided to maintain the conditioned atmosphere in the control room of Unit-2. These chillers are direct expansion, reciprocating type, and double cylinder arrangement with a water-cooled condenser. Generally, two chiller compressors are in operation. The chillers' as-run trials were conducted with the objective to validate the performance against the design value and to assess the SEC and coefficient of performance. The design and trial values are presented below.

Table A5-24: Performance assessment of chillers

Reference	2A	2B
Flow (m³/hr)	15,569.88	19,686.24
Air inlet condition		
DBT	28.00	28.00
WBT	23.40	23.30
Enthalpy	16.72	16.55
Air outlet condition		
DBT	25.90	24.20
WBT	21.10	23.10
Enthalpy	14.58	14.63
Reference delivered (TR)	12.8	14.4
Power consumption (kW)	16.4	20.10
Actual		
SEC (kW/TR)	1.28	1.39
COP	2.74	2.53
Design		
SEC (kW/TR)	1.23	1.23
COP	2.85	2.85

From the above observation, it can be inferred that the SEC by the chillers has grown slightly higher by 4% as against the designed SEC of 1.23 kW/TR. During the performance assessment of chillers, it was observed that the cooling tower (CT) cleanliness and AHU filters were not proper and would require regular maintenance to improve the performance of chillers.

Insulation effectiveness

As a part of the energy conservation measure, thermal insulation condition is an indicative parameter for considering the potential thermal energy saving. The thermal insulation survey was carried out to know the status of the present insulation condition of both the units (Unit-1 and Unit-2).

The observation is tabulated below for boiler's outer surface temperatures.

Boiler-2: Outer surface wall temperatures

Table A5-25: Boiler outer surface temperatures

Area identified	Ambient temperature (°C)	Observed average surface temperature (°C)			
		Front	Left	Rear	Right
Operating floor	32	47	46	55	48
AB tier	32	55	54*	55	60*
Work floor-1	32	54	58	53	62
Work floor-2	32	56	46	52	65
Work floor-3	32	43	52	55	62
LRSB	32	52	41	-	53
Average	32	51	49.5	54	58.3

* Wind box joint leakage

The thermal insulation survey was carried out for major steam lines in the plant, and average outer surface temperatures are shown below. In some cases, the temperatures are high due to bare pipes.

Table A5-26: Thermal insulation survey

Area identified	Ambient temperature (°C)	Average surface temperature (°C)
LP turbine surface	32	52
IP turbine surface	32	110*
HP turbine surface	32	47, 52, 73
LP crossover pipe	32	48
IP crossover pipe to LP	32	210, 90, 50*
HP crossover pipe	32	53
Hot reheat line (HRH) near turbine	32	47
Cold reheat line (CRH) near turbine	32	38
MS line near turbine	32	43
HPH-6 outlet to economizer	32	3(8
Pressure reducing and de-superheating system (PRDS) heater	32	100, 120
MS line near PRDS	32	51
CRH near PRDS	32	44
HRH near PRDS	32	50
PRDS station	32	207, 60, 68
LPH-2 surface	32	38, 39
LPH-3 surface	32	43, 38

Area identified	Ambient temperature (°C)	Average surface temperature (°C)
Deaerator pipes	32	60*
Gland sealing header	32	35
MS line to IP control valve	32	59, 66, 46, 50, 35
HP control valve 1	32	51,62
HP control valve 2	32	59, 57, 75, 80
IP control valve 1	32	78
IP control valve 2	32	80
HP stub	32	33, 35
CRH stub	32	38, 36
BFP	32	105
HRH stub drain to atm	32	108
PA inlet to mill 2D1	32	44.5, 43
PA inlet to mill 2D2	32	40, 35
PA inlet to mill 2B1	32	41, 47
PA inlet to mill 2B2	32	47, 49
PA inlet to mill 2A1	32	42, 45
PA inlet to mill 2A2	32	36, 38

(* = Insulated surface wall temperatures)

The major damage area that needs immediate attention is listed below along with the photographs taken at the site. Periodic evaluation of insulation condition is suggested to arrest any loss that may occur due to poor/inadequate insulation.

Table A5-27: Evaluation of insulation condition

Reference	Observation	Image number	Remarks
HRH stub drain to atm	Insulation damage	1	Bare pipe visible
CRH stub	Insulation damage	2	Cladding damage
FD air duct	Insulation damage	3	1 m x 1 m surface area
IP turbine wall	Insulation damage	4	2 m x 1 m surface area damage
IP crossover turbine pipe to LP	Insulation damage	5	Cladding damage
PRDS station insulation location-1	Insulation damage	6	Bare pipe visible
PRDS station insulation location-2	Insulation damage	7	Insulation needed
PRDS station insulation location-3	Insulation damage	8	Insulation needed
PRDS header insulation damage	Insulation damage	9	Insulation needed
PA hot air bypass line	Insulation damage	10	Insulation needed
Side wall of PA duct to mill	Insulation damage	11	1 m x 1 m surface area damage

	
HRH stub drain to atm	CRH stub
	
FD air duct	IP turbine wall
	
IP crossover turbine pipe to LP	PRDS station insulation location-1

PRDS station insulation location-2

PRDS station insulation location-3

PRDS header insulation damage

PA hot air bypass line

Side wall of PA duct to mill

Figure A5-11: Images of evaluation of insulation condition

5.10 Boiler system (Unit-2)

Background

TPP, Sikka consists of two water tube boilers of Bharat Heavy Electricals Limited (BHEL) make of capacity 383 TPH, 137 bar (Unit-I), and 391 TPH, 134.5 bar (Unit-2) with turbine (BHEL make) nominal rating of 120 MW each. The date of commercial operation of Unit-1 was 26.03.1988 and for Unit-2 was 31.3.1933. The design parameters of the Unit-2 boiler are as follows.

Table A5-28: Design parameters of the Unit-2 boiler

Parameters	Unit	Design		
		MCR (100%)	NCR	MCR (60%)
Boiler type		Tangentially fired; balanced draught; natural circulation; radiant reheat outdoor type; and direct fired pulverized coal with tube mills.		
Main steam				
Pressure	kg/cm² (g)	134.5	132.6	128.4
Temperature	°C	540	540	540
Flow (instant)	TPH	391	357.2	220.7
CRH				
Pressure	kg/cm² (g)	31.47	30.33	17.7
Temperature	°C	340	340	324
Flow (instant)	TPH	351	319.9	191.1
HRH				
Pressure	kg/cm² (g)	29.97	28.96	16.9
Temperature	°C	540	540	540
Flow (instant)	TPH			
Feed water temperature	°C	235	234	210
Ambient air temperature	°C	45	45	45
Combustion air temperature (secondary)	°C	312	307	268
Coal quantity	TPH	81.4	74.1	47.7
Air quantity (total)	TPH	533.6	485.8	311.6
Exit flue gas temperature	°C	145	143	125
Efficiency of boiler	%	85.9	85.9	86.6

Coal

Fuel analysis	Unit	Design
Fuel type	Coal	
Fixed carbon	%	32
Volatile matter	%	23
Moisture	%	10
Ash	%	35
Grindability index	HGI	50
GCV	Kcal/kg	3,800
Size of coal to mill	mm	25

Particulars	Unit	BMCR	TMCR	CL 60%
Oxygen in gas at economizer outlet	%	3.5	3.5	3.5
Carbon dioxide	%	15.53	15.53	15.53
Excess air in gas at economizer outlet	%	20	20	20

Feed water parameters	Unit	Design
Description		
Hardness		Nil
PH at 25°C (Copper alloy boiler system)		8.8–9.2
PH at 25°C (Copper-free preboiler system)		9.0–9.4
Oxygen (max)	ppm	0.007
Total iron	ppm	0.01
Total copper (max)	ppm	0.005
Total CO_2	ppm	Nil
Total silica (max)	ppm	0.02
Specific electrical conductivity at 25°C measured after cation exchanger in the H+ form and after CO removal (max)	s/cm	0.3
Hydrazine residual	ppm	0.01–0.02
Permanganate consumption	ppm	Nil
Oil		Not allowed

Boiler water parameters	Unit	Design
TDS (max)	ppm	50
PH at 25°C		9.4–9.7
SiO_2	ppm	0.4
Phosphate residual	ppm	May 10
Specific electrical conductivity at 25°C	s/cm	100

Steam purity parameters	Unit	Design
TDS	ppm	0.1
Silica (max)	ppm	0.02

5.11 Performance evaluation of boiler

As part of the combustion study, boiler efficiency trials were conducted during normal load. During the trial, the key parameters namely, unit load, coal flow, coal analysis total air flow, mill rejects, combustibles in bottom ash and fly ash, and flue gas analysis were monitored and are presented in the following table. During the as-run trials, all relevant parameters, namely, coal, air, flue gas, water, and steam were collected, and efficiency assessment was carried out. The key findings are as follows.

Boiler performance as-run data:

Table A5-29: Performance evaluation of boiler

Boiler reference: 391 TPH (Unit 2)							
Operating parameters	**Hr**	**9:00 am**	**10:00 am**	**11:00 am**	**12:00 pm**	**1:00 pm**	**Average**
Main steam:							
Pressure	kg/cm² (g)	114	105	110	102	105	107.2
Temperature	°C	535	534	530	535	535	533.8
Enthalpy of steam	Kcal/kg	825.12	826.79	823.21	828.47	827.51	826.2
Flow (Instant)	TPH	277	282	283	280	283	281.0
Hot reheat steam pressure	kg/cm² (g)	24	24	24	24	24	24.0
Hot reheat steam temperature		521	526	522	520	525	522.8
Enthalpy of steam	Kcal/kg	839.47	842.34	840.19	839.00	841.63	840.5

Cold reheat steam pressure	kg/cm² (g)	25.50	25.40	25.60	25.50	25.50	25.5
Cold reheat steam temperature		355	349	345	352	351	350.2
Enthalpy of steam	Kcal/kg	750.24	750.24	744.26	748.33	748.09	748.2
Reheat steam flow (calculated)	TPH						265.0
Flue gas:							
Oxygen	%	4.55	4.16	4.3	4.4	4.2	4.3
Temperature (ECO I/L)	°C	521.5	543	516	515.5	499	519.0
Temperature (ECO O/L)	°C	280	277	277.5	278.5	277.5	278.1
Temperature (AH O/L)	°C	126	125.5	127	125	125.5	125.8
Atmospheric air:							
Air temperature (APH O/L)	°C	229	228	228.5	228.5	228	228.4
DBT	°C	30	31	32	32	30	31.0
Relative humidity	%	78	76.0	75.0	77.0	76.0	76.4
Absolute humidity	kg water/kg air	0.021	0.0217	0.0227	0.0233	0.0204	0.022
Feed water:							
Temperature (before economizer)	°C	192	192	193	193	193	192.6
Temperature (after economizer)	°C	300	296.5	297.5	297.5	297	297.7
Drum pressure	kg/cm² (g)	118	112	125	113	113	116.2
Condenser:							
Cooling water inlet temperature	°C	26.5	27.4	27.5	27.75	27.65	27.4
Cooling water outlet temperature	°C	36.5	35.55	35.5	35.65	35.55	35.8
Coal:							
Mill A-1	TPH	12.4	13.4	13	13.2	13.2	13.04
Mill A-2	TPH	11.62	14.13	13.12	13.12	14.93	13.38
Mill B-1	TPH	11.9	13.54	13.81	13.81	12.76	13.16
Mill B-2	TPH	14.34	11.2	12.2	12.2	12.5	12.49
Mill C-1	TPH	13.44	13.49	14.45	14.45	14.45	14.06
Mill C-2	TPH	10.3	12.2	13.2	13.2	13.2	12.42
Total	TPH	74.0	77.96	79.78	79.98	81.04	78.55
Turbine parameters:							
Generator load	MW	88	88	88	88	88	88.00
Voltage	kV	10.545	10.545	10.545	10.545	10.545	10.55
Condenser vacuum	mmHg	640	640	640	640	640	640.0

5.12 Boiler—Heat loss profile

The heat loss profile covering losses through unburnts in ash, sensible heat loss in dry flue gases, moisture in combustion air, loss due to presence of hydrogen and moisture in coal, radiation, and unaccounted loss, are as follows. Refer to Annexure 2 for details.

Table A5-30: Boiler—Heat loss profile

Description	Unit	TMCR	Actual
Dry flue gas loss	%	4.13	4.24
Loss due to hydrogen and moisture in fuel	%	5.83	8.13
Loss due to moisture in air	%	0.5	0.15

Loss due to unburnt carbon	%	1.84	0.0678
Loss due to radiation	%	0.25	1.5
Unaccounted loss	%	0.5	
Manufacturer's margin	%	1	
Total losses	%	14.05	14.0878
Efficiency	%	**85.95**	**85.91**

The thermal efficiency of the boiler at unit load of 88 MW based on the heat loss method during the trial period was found to be 85.91% against the Turbine Maximum Continuous Rating (TMCR) value of 85.95%.

Coal quality features have a major influence on boiler performance as well as APC and outages. The trend of coal quality being used in respect of proximate and ultimate analysis is presented as follows.

Table A5-31: Proximate and ultimate analysis of coal

Fuel analysis	Unit	Design	Actual
Fuel type	Coal		
Fixed carbon	%	32	27.37
Volatile matter	%	23	21.79
Moisture	%	10	11.39
Ash	%	35	39.45
Grindability index	HGI	50	
GCV	Kcal/kg	3,800	3,489
Size of coal to mill	mm	25	

The lower GCV values, higher percentage ash in coal and lower volatile matter (VM) have a derating effect in boiler output and performance and would also affect APC in milling/fan power. Due diligence and care need to be initiated for assuring coal quality improvement at receipt and handling, etc. Some of the measures like shale removal, crusher performance, sieve analysis, and undersize segregation for butter crushing and milling efficiency are separately addressed in the section.

Recommended good practices

- Measurement of flue gas flow in all ID fans should be done at least once a month, toward monitoring air ingress in the boiler.
- Flue gas analysis should be made at least once a day at the APH inlet, APH outlet, and ID fan inlet to keep control on air ingress and air leakage, in the APH, and in the flue gas duct.
- Check flue gas duct from APH to ID fan inlet by pressurizing the furnace before each annual overhaul at each opportune moment (repair of duct, hangers, supports, expansion joints, duct wall, utility access hole, packing rope, gasket, dampers, and gates, etc. may be taken up as needed).
- Regular checking and repairing of pressure gauges, draft gauges, and temperature gauges both on the air side and flue gas side, need to be carried out at regular intervals. This will help in performance monitoring/upkeep.
- Checking FD fan flow gauges and the provision of individual flow measurements of PA fans may be made toward monitoring air flow for combustion, coal air mixture, and fan performance.
- Coal fineness of 70% through 200 mesh should be maintained. Also, input coal size distribution should be 20–25 mm size, to get quality and quantity output.
- The rotary regenerative APH baskets need to be cleaned during each scheduled maintenance and checked for choking and fouling.

5.13 Performance evaluation of APHs and economizer

Based on the trials, performance analysis of the APHs was carried out to evaluate the deviation from design values. The results presented below correspond to the as-run trial observations. Performance analysis of APHs and economizers is presented below.

Table A5-32: Performance evaluation of APHs and economizers

Operating parameters	Unit	Design	Unit-2
Generation	MW	120	88
Total coal flow	TPH	81.4	78.55
Primary air flow through APH	TPH	221.6	108.1
Secondary air flow	TPH	312	289.5
Total air flow	TPH	533.6	397.6
Total FW flow to economizer	TPH	391	277
Total steam flow	TPH	391	277
Economizer			
Gas temperature at economizer in left	°C	546	519
Gas temperature at economizer in-right	°C	546	519
Gas temperature at economizer out-left	°C	331	279
Gas temperature at economizer out-right	°C	331	282
FW temperature at economizer in	°C	234	192.6
FW temperature at economizer out-left	°C	309	297.7
F W temperature at economizer out-right	°C	309	297.7
* Effectiveness—left	%	24.0385	32.1998
* Effectiveness—right	%	24.0385	32.1998
Heat pickup	MKcal/hr	29.325	29.1127
LMTD	°C	156.71	143.43
APH			
Gas temperature at Ah - A Out	°C	145	124
Gas temperature at Ah - A In	°C	331	279
Gas temperature at Ah - B Out	°C	145	128
Gas temperature at Ah - B In	°C	331	282
O_2 at Ah - A In	%	3.55	4.3
Secondary air temperature at Ah - A In	°C	45	35
Secondary air temperature at Ah - B In	°C	45	35
Primary air temperature at Ah - In	°C	45	35
Primary air temperature at Ah - B Out	°C	302	225
Secondary air temperature at Ah - A Out	°C	307	226
Secondary air temperature at Ah - B Out	°C	307	227
Gas press differential after APH-A	mmWC	-108	-117
Gas press differential after APH-B	mmWC	-108	-127

Primary air press differential across Ah - A	mmWC	26	46
Primary air press differential across Ah - B	mmWC	26	40
Secondary air press differential across Ah - A	mmWC	88	70
Secondary air press differential across Ah - B	mmWC	88	74
Effectiveness: Ah - A	%	91.6084	78.2787
Effectiveness: Ah - B	%	89.8601	76.9231
Heat pickup–Primary air side	MKcal/hr	56.9512	20.539
Heat pickup–Secondary air side	MKcal/hr	81.744	55.584
Total heat pickup	MKcal/hr	138.695	76.123

The pressure drop of flue gas across APH-A and APH-B is of the order of 117 mmWC and 127 mmWC, respectively, against a design value of 108 mmWC. However, there is a slight difference of 10 mmWC to 20 mmWC, which is under controlled limits considering the system. The temperature drop in flue gas in APH-A and APH-B is 155°C and 154°C, respectively, against a design value of 186°C. The lower temperature drop is indicative of deterioration in APH effectiveness. The performance is satisfactory, considering the temperature drop across APH.

On the air side, the rise in air temperature across APH is about 190°C for both APH-A and APH-B against the design value of 257°C. The increase in differential pressure of air across APH (46 mmWC and 40 mmWC for APH-A and APH-B, respectively) against the design value of 26 mmWC, further corroborates the fact that the flue gas side is overloaded with respect to (w.r.t.) design values.

Based on the study findings, the following opportunities are identified for energy savings.
- Repair of HPHs-5 in feed water circuit. (Discussed in turbine and auxiliary section.)
- Insulation improvements for optimizing surface heat loss. (Discussed in insulation section.)

5.14 Turbine and auxiliaries (Unit-2)

Background
Performance assessment of the turbine system of Unit-2, based on as-run trials was conducted, with the objective of validation against design value to identify inefficiencies, if any. Findings are envisaged to help in assessing the performance, vis-à-vis design/rated values, factors, and parameters affecting performance, and key result areas for improvement and attention.

The scope of the energy audit study in turbines is to carry out as-run turbine cycle heat rate and impact parameters affecting heat rate. The as-run performance test determines the turbine performance regarding performance indices as follows:

- HP cylinder efficiency
- Turbine heat rate

The following table highlights the technical features of the steam turbine and its auxiliaries.

Table A5-33: Technical features of the steam turbine

Parameters	Unit	Values
Make		BHEL
Turbine type		Reaction type, condensing, three-cylinder, horizontal, regenerating system of feed water heating, and coupled to a driven AC generator.

Number of stages ➢ HP ➢ IP ➢ LP	Number	➢ 30 ➢ 2 x 20 ➢ 2 x 10
Number of cylinders	Number	3
Number of extractions	Number	6
Steam parameters		
Pressure before stop valve	kg/cm² (a)	125.85
Temperature before stop valve	°C	530
Pressure at inlet to reheat stop valve	kg/cm² (a)	28.8
Temperature at inlet to reheat stop valve	°C	535
Exhaust pressure	kg/cm² (a)	0.1033
Cooling water temperature	°C	33
Speed	rpm	3,000
Frequency	HZ	47.5–51.5
Turbo generator		
Minimum continuous output at generator terminals	MW	120
Maximum continuous rating	kVA	150
Rated power factor		0.8 (lagging)
Rated terminal voltage	kV	10.5
Rated speed	rpm	3,000
Rated frequency	HZ	50
Rated operating hydrogen pressure	kg/cm² (g)	3

5.15 Performance assessment of HP turbine

Evaluation procedure (methodology)

The as-run performance test is conducted by the enthalpy drop efficiency method. Enthalpy drop test is used as a method of trending the performance of high pressure (HP) and intermediate pressure (IP) sections of the steam turbine. This method determines the ratio of actual enthalpy drop across the turbine section to the isentropic enthalpy drop.

While it is very difficult to make immediate corrections to turbine performance degradation, the information can be used as part of cost-benefit analysis to determine the optimum point at which the losses due to decreased performance are greater than the costs associated with turbine maintenance. The enthalpy drop test is performed at the valve wide-open condition. The test at valve wide open provides a base line and the test at similar pre- and postcondition is used to evaluate the improvements made during turbine overhaul.

HP cylinder efficiency

In connection with the requirements of the as-run performance test, six turbine trials each of 1-hour duration were conducted on the same date. The requisite number of readings taken for the relevant operating parameters during the trial period were averaged out for computing HP cylinder efficiency. The as-run parameters were obtained during the trial and compared against the corresponding design data. Based on the respective inlet and outlet steam condition at HP cylinder, the HP cylinder efficiency has been computed as 80.77% against the design value of 80.19%, which is presented in the table below. Comparison of as-run trial values of HP turbine cylinder efficiency w.r.t. design values:

Table A5-34: Trial values of HP turbine cylinder efficiency

	Load: 88 MW		
Parameters	**Units**	**Design**	**Actual**
Main steam			
Steam pressure	kg/cm² (a)	125.85	107.4

Steam temperature	°C	530	532.9
Enthalpy	Kcal/kg	819.1	825.8
CRH steam			
Steam pressure	kg/cm² (a)	30.3	26.56
Steam temperature	°C	340	346.3
Enthalpy	Kcal/kg	739.7	745.5
Isentropic enthalpy	Kcal/kg	720.1	726.3
Actual enthalpy drop	Kcal/kg	79.4	80.4
Isentropic enthalpy drop	Kcal/kg	99.0	99.5
Isentropic efficiency	%	80.19	80.77

Comments on HP turbine efficiency and improvement options

The performance parameters show that the performance of the HP turbine is close to design value. It is recommended to investigate the following HPT internals during the overhaul for possible heat rate improvements.

- Nozzle block erosion
- Turbine blade erosion
- Deposits on nozzles and blades
- Gland packing leakages
- Strip seal leakages
- Malfunctioning of control valve

Also, the instruments need to be calibrated regularly.

Comments on IP turbine efficiency and improvement options

The IP turbine efficiency could not be evaluated due to lack of on-site instrumentation and nonavailability of IP turbine **exhaust temperature and pressure.** However, it is recommended to investigate IP turbine internals during overhaul for actual conditions of damage (and apply need-based repairs): given the fact that silica content in steam is higher than the norm.

The areas of concern may include:

- Erosion/deposits of turbine blades
- Reheater bypass valve leakage
- Excess gland seal leakage
- Strip seal leakages

5.16 Turbine cycle heat rate and thermal efficiency

Based on the as-run steam parameters, the turbine cycle heat rate is given as:

$$= \frac{MS\ Flow, \frac{kg}{hr} \times (MS\ enthalpy - FW\ enthalpy), \frac{kCal}{kg} + \ RH\ Flow, \frac{kg}{hr} \times (HRH\ enthalpy - CRH\ enthalpy) kcal/kg}{Generator\ output\ (kW)}$$

$$= \frac{277000\ \times (825.8 - 193) + \ (277000 - 13350(840.43 - 745.5)}{88000}$$

= 2,276.3 Kcal/kWh

Thermal efficiency of turbine:

$$= \frac{860\ \times 100}{Turbine\ Heat\ Rate, \frac{kCal}{kWh}}$$

= 860 / 2,276.3
= 37.78%

Thermal efficiency of station:

$$= \text{Thermal Efficiency of Turbine, \%} \times \text{Efficiency of Boiler, \%}$$

= 37.78 x 85.93 = 32.46%

It may be noted that the guaranteed heat rate is 2,007 Kcal/kWh as per the following, indicating a deviation of about 11–12% on turbine heat rate.

The thermal efficiency of the turbine as assessed during the audit study was found to be 37.78% as against the design value of 42.85%. The thermal efficiency of the station was 32.46% as against the design value of 36.82%.

Table A5-35: Evaluation of turbine performance

Particulars	Steam flow, TPH	FW temperature after heater, °C	Reheat pressure drop, %	Condenser pressure, kg/cm2 (abs)	Heat rate, Kcal/kWh
Guaranteed	357.2	233.8	1.37	0.109	2,007
Actual	277	205.4	7.05	0.13	2,276.3
Deviation, %	22.45	12.14	80	16.15	11.83

The following measures are suggested for the heat rate improvement.
HPH-5 not being in service.

It was observed that the HPH-5 was not in service, and the feed water from the BFP passed through HPH-6 and went to the economizer. The total loss due to HPH-5 not being in service manifests as:

- Increased thermal load on economizer and water walls, affecting boiler capacity and unit generation.
- Increased load on the condenser since the condenser needs to handle additional quantity, equivalent to extraction steam of HPHs.

It is felt that repair/rectification/reinduction of HPHs into turbine cycle is a key result area that world benefit in terms of:

- Raising boiler capacity
- Release in condenser thermal load, enabling higher generation
- Heat rate improvement

It may be seen that against a design feed water temperature of 233.8°C after the last heater (at unit load of around 120 MW), the actual FW temperature at economizer inlet is about 193°C (i.e., lower by 40°C); due to the HPH-5 being out of service, the effect of heat rate is about 27.02 Kcal/kwh (every one degree reduction in feed water temperature results in heat rate reduction of 0.67 Kcal/kWh).

5.17 Performance of heaters

HPHs and LPHs performance were evaluated, and the key parameters were recorded. The performance of LPHs assessment is done based on:

TTD = t_{sat} - $t_{fw\ out}$ = Terminal temperature difference (should be as less as possible),
DCA = t_{drain} - $t_{fw\ in}$ = Drain cooler approach (should be as less as possible), and
TR = $t_{fw\ out}$ - $t_{fw\ in}$ = Temperature rise (should be as high as possible).

The results are given below.

It can be observed that the performance of LPH-1 and HPH-6 is not satisfactory in terms of TR with respect to design. The analysis reveals that in LPH-2 and HPH-6, TTD was observed to be high. This calls for inspections of tube and shell side internals.

However, the following are suggested for improving TTD, DCA, and TR:

- Prevention of tube leaks
- Removal of noncondensable gases/air venting in the shell side
- Removal of plugging in tubes
- Repair of fouled tubes
- Reduction of feed water heater drain bypass and leaks/blocks
- Water and steam side contamination of tubes

5.18 Comparison of design and actual values of HPHs and LPHs

Table A5-36: Performance evaluation of heaters

Performance evaluation of heaters										
Description	LPH-1		LPH-2		LPH-3		HPH-5		HPH-6	
Steam inlet	**Design**	**Actual**	**Design**	**Actual**	**Design**	**Actual**	**Design**	**Actual**	**Design**	**Actual**
Pressure, kg/cm²(a)	0.38	0.11	0.83	0.83	2.38	1.6	13.02	Not in service	32.85	25.8
Temperature, °C	75	79.6	114	138.8	212.6	200	413.9		341.2	345
Enthalpy, Kcal/kg	630.6	594.7	647.4	659.3	692.3	651.9	786.8		739.0	745.0
Flow (TPH)	11.53	3.25	10.08	4.82	16.022	17.86	19.88		34.74	13.35
Saturation temperature, °C	74.66	47.38	94.21	96.15	125.2	121.4	190.75		240.78	223
Drain inlet										
Temperature, °C	76.7	80	96.3	118.4			195.4			
Flow (TPH)	26.09	22.67	16.02	17.86			34.74			
Drain outlet										
Temperature, °C	54.3	60.4	76.7	80	96.3	118.4	160		195.4	155.8
Flow (TPH)	37.62	30.74	26.10	22.677	16.02	17.86	54.63		34.74	13.35
Feed water inlet										
Temperature, °C	47	52	70.4	66	90.2	90.4	153.9		189.3	177
Pressure, kg/cm²(a)	19.63	16	18	6.9	17	6.8	172.03		171.03	175
Flow (TPH)	305.21	277	305.21	277	305.21	277	375.08		375.08	277
Feed water outlet										
Pressure, kg/cm²(a)	18.8	7.22	17.2	6.5	16.2	5	171.2		169.2	125
Temperature, °C	70.4	64.6	90.2	88	121.2	124.8	189.3		236	205.4
Flow (TPH)	305.21	277	305.21	277	305.21	277	375.08		375.08	277
TTD, °C	4.26	-17.22	4.01	8.15	4.08	-3.4	1.45		4.78	17.6

DCA, °C	7.3	8.4	6.3	14	6.1	28	6.1		6.1	-21.2
Feed water TR	23.40	12.60	19.80	22.00	31.00	34.40	35.40		46.7	28.4

Overall improvement margins

As enumerated above, towards achieving the overall HR improvement, it is felt that key result areas are:

- Reintroduction of HPHs-5 into turbine cycle
- Control of main steam pressure and temperature
- Control of reheat steam temperature
- Improvement and rectification based on inspection of internal conditions of damage, during turbine overhaul.

It is our considered opinion that further to benefits of HPH introduction, discussed separately, the other areas listed above can lead to heat rate savings of 27 Kcal/kWh, on a conservative basis.

Cost-benefit analysis of ENCON options are as follows:

⇒ Recommissioning of HPHs-5.

⇒ Need-based rectification to turbine elements based on inspection and achieving steam-rated parameters.

Improvement in boiler feed water temperature through repair of HPH

Estimated annual generation	643.11 MU (April 2010–March 2011)
Actual feed water temperature at ECO in	193°C
Design feed water temperature at ECO in	233.8°C
Expected feed water temperature rise	(233.8–193)°C
	40.8°C
Heat rate reduction norms on installation of HPH	*0.67 Kcal/kWh for each 1°C rise in feed water temperature.*
Heat rate reduction for 40.8°C rise in feed water temperature	0.67 x 40.8 Kcal/kWh
	27.336 Kcal/kWh
The savings potential toward heat rate reduction (considering 75% of heat rate reduction for conservative estimate)	27.336 x 0.75 Kcal/kWh
	20.50 Kcal/kWh
Therefore, annual heat rate reduction	20.50 Kcal/kWh x 643.11 x 10^6 kWh
	13,185 million Kcal
Equivalent annual coal savings (considering, boiler efficiency 86.43% and GCV of coal 3,489 Kcal/kg)	13,185 x 10^6 / (3,489 x 0.8643) MT
	4,372 MT/year
	R_s 219 Lacs/year *(R_s 5,027/MT of landed cost of coal)*
Equivalent investment toward repairing work of HPH-5.	Marginal

5.19 Unit auxiliaries (Unit-I)

Background

Performance assessment of key plant auxiliaries of Unit-1, based on as-run trials was conducted during the field visit, with the objective of energy performance validation against design value to identify under-performance, if any, during the as-run trials. Findings are envisaged to help in assessing the performance, vis-à-vis design/rated values, factors, and parameters affecting performance, and key result areas for improvement and attention, leading to reduction in auxiliary energy consumption.

The power consumption of the key auxiliaries was measured by using an online power analyzer to access the as run performance of the equipment. It was observed during the study period that the feed water system consumed the maximum power (38.28%) of the total APC followed by the draught system (29.48%) and CW system (12.76%), etc. Refer to Annexure 3 for details.

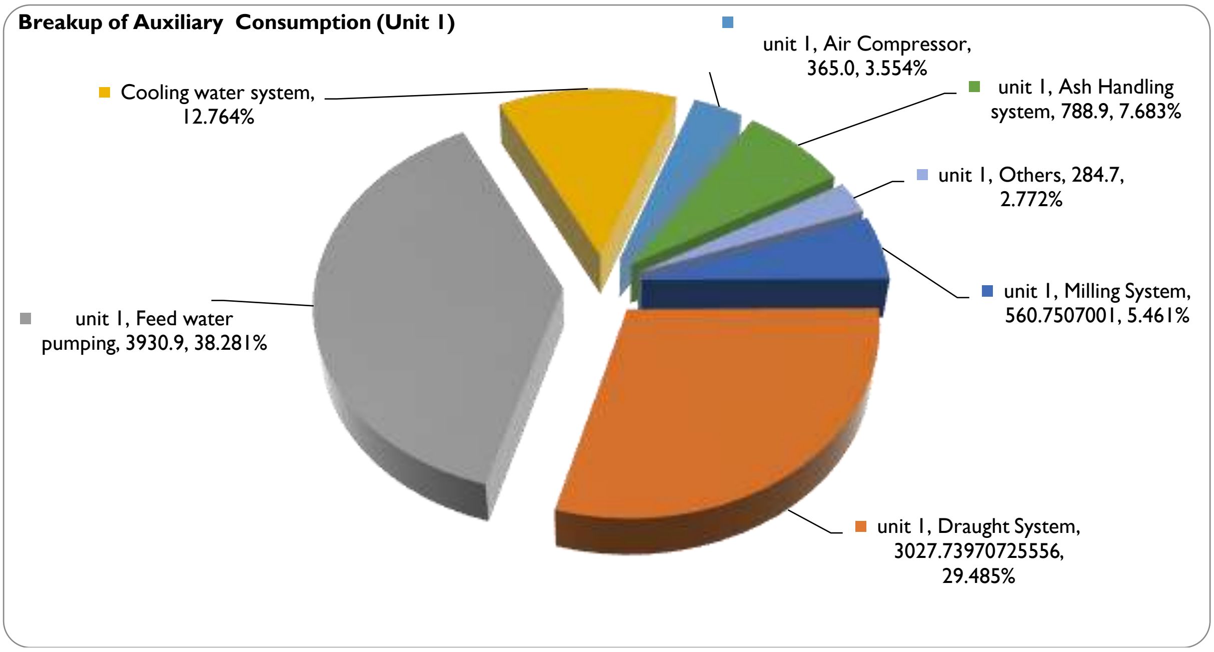

Figure A5-12: Breakup of auxiliary consumption (Unit 1)

BFP

The feed-water system analysis includes motor loading pattern, efficiency evaluation, and performance assessment of BFPs and condensate extraction pumps, and identification of applicable ENCON options, where possible. The BFPs constitute a key auxiliary in terms of connected load as well as consumption. All the three BFPs of Unit-1 have identical design specification, and the as-run observation data on BFPs are presented as under:

As-run conditions:

- Number of pumps operated: 2
- Type of discharge control: Throttle control

Table A5-37: Details of BFP

Item reference	Units	Design	Actual	
			BFP-1B	BFP-1C
Unit load	MW	120	82	
Frequency	Hz	50	50	
Flow	TPH	240.00	173.78	137.63
Discharge pressure	kg/cm²		156.60	165.2
Suction pressure	kg/cm²		4.40	4.40
Total dev head	mWC	1,950.00	1,522.00	1,608.00
Power consumption				
Motor input	kW	2,000.00	1,605.00	1,421
Motor output	kW	1,800.00	1,444.5	1,278.9
Combined efficiency	%	70.85	49.90	47.15
% Margin on power	%		19.75	28.95
% Margin on flow	%		27.59	42.66
% Margin on head	%		21.95	17.54
SEC	kWh/T	8.33	9.24	10.33

The inter-se comparison of the operating BFPs indicates BFP-1B as having the lowest SEC of 9.24 kWh/T, whereas BFP-2C with SEC of 10.33 kWh/T, as against design SEC of 8.33 KWh/T.

The as-run BFP operational combined efficiencies range from 47.15% to 49.90%, with respect to rated combined efficiency of 70.85%. The key operational factors influencing efficiency variation are felt to be partial loading on flow (27.59% to 42.66%), head (21.95% to 17.54%), drive motor loading (19.75% to 28.95%), throttling and apart from the intrinsic efficiency levels of the pumps, and the drive motor. As the loading factor influences the efficiency variations, BF pump loading and reserve margins contain scope for VFD incorporation or stage reduction of existing pump. The BFP consumes the maximum percentage of APC, therefore any of the options of implementation as a measure of energy conservation in the boiler feeding pumping system can accrue substantial benefits.

Energy saving by installing VFD

Table A5-38: Energy saving by installing VFD

Item reference	Units		Actual	
		Design	BFP-1B	BFP-1C
Present condition				
Unit load	MW	120	82	
Frequency	Hz	50	50	
Flow	TPH	240.00	173.78	137.63
Discharge pressure	kg/cm²		156.60	165.2
Suction pressure	kg/cm²		4.40	4.40
Total dev head	mWC	1,950.00	1,522.00	1,608.00
Power consumption				
Motor input	kW	2,000.00	1,605.00	1,421
Motor output	kW	1,800.00	1,444.5	1,278.9
Combined efficiency	%	70.85	49.90	47.15
% Margin on power	%		19.75	28.95
% Margin on flow	%		27.59	42.66
% Margin on head	%		21.95	17.54
SEC	kWh/T	8.33	9.24	10.33
Future condition				
Unit load	MW	120	82	
Frequency	Hz	50	50	
BFP flow	TPH	240.00	173.78	137.63
Discharge pressure	kg/cm²		156.60	165.2
Suction pressure	kg/cm²		4.40	4.40
Total dev head	mWC	1,950.00	1,522.00	1,608.00
Power consumption				
Motor input	kW	2,000.00	1,130.30	945.73
Motor output	kW	1,800.00	1,017.27	851.16
SEC	kWh/T	8.33	6.50	6.87
Reduction in power	kW		474.7	475.3
% Reduction	%		29.6	33.4
Annual energy savings	kWh		2,836,818	2,840,209
Envisaged annual monetary savings	Rs/annum		9,928,863	9,940,731
Investment	Rs		14,400,000	14,400,000
SPP	Year		1.5	1.4

The envisaged annual monetary savings for BFP-1B and BFP-1C is Rs 99.2 lakh/annum and Rs 99.4 lakhs/annum, respectively. The total investment required for VFD installation is around Rs 288 lakhs. The SPP will be 1.5 years and 1.4 years.

Energy saving by reducing number of stages

The percentage reserve on flow varies from 27.59% to 42.66%, and the head margin varies from 21.95% to 17.54%, which indicates that the pump is operating under throttled condition. The discharge pressure generated by the BFP is about 156 kg/cm² and 165.2 kg/cm² as against the boiler pressure (drum pressure) requirement of about 130 kg/cm², which shows that there is a tremendous scope of pressure reduction in the BFP by reducing the number of stages of the pump.

Table A5-39: Energy saving by reducing number of stages

Item reference	Units		Actual	
		Design	BFP-1B	BFP-1C
Present condition				
Unit load	MW	120	82	
Frequency	Hz	50	50	
Flow	TPH	240.00	173.78	137.63
Discharge pressure	kg/cm²		156.60	165.2
Suction pressure	kg/cm²		4.40	4.40
Total dev head	mWC	1,950.00	1,522.00	1,608.00
Power consumption				
Motor input	kW	2,000.00	1,605.00	1,421
Motor output	kW	1,800.00	1,444.5	1,278.9
Combined efficiency	%	70.85	49.90	47.15
% Margin on power	%		19.75	28.95
% Margin on flow	%		27.59	42.66
% Margin on head	%		21.95	17.54
SEC	kWh/T	8.33	9.24	10.33
Future condition				
Unit load	MW	120	82	
Frequency	Hz	50	50	
BFP flow	TPH	240.00	173.78	137.63
Discharge pressure	kg/cm²		156.60	165.2
Suction pressure	kg/cm²		4.40	4.40
Total dev head	mWC	1950.00	1522.00	1608.00
Power consumption				
Motor input	kW	2,000.00	1,130.30	945.73
Motor output	kW	1,800.00	1,017.27	851.16
SEC	kWh/T	8.33	6.50	6.87
Reduction in power	kW		474.7	475.3
% Reduction	%		29.6	33.4
Annual energy savings	kWh		2,836,818	2,840,209
Envisaged annual monetary savings	Rs/annum		9,928,863	9,940,731
Investment	Rs		Marginal	Marginal

The envisaged annual monetary savings for BFP-1B and BFP-1C, by reducing two pump stages, are around Rs 99.2 lakh/annum and Rs 99.4 lakh/annum, respectively.

Condenser performance

The assessment of condenser performance is to determine performance status and degradation effects. The as-run performance tests can be used as the baseline for evaluating the performance improvement activities, as well as maintenance efficiency. The as-run performance indicator as observed during trial and the design data (key technical specification) of condenser is summarized as follows.

Table A5-40: Condenser performance evaluation

Particulars	Units	Design value	Actual
Unit load	MW	120	82
Turbine heat rate	Kcal/kWh	2,088	2,177
Type		Twin shell design	
Number of passes	Number	2	2
Number of passes of circulating water	Number	2	2
Tube length	mm	6,250	6,250
Tube material	—	Cupronickel 90/10	
Total number of tubes	Number	15,030	15,030
OD of condenser tube	mm	22	22
Tube thickness	mm	1	1
Cooling surface area	m^2	6,400	6,400
CW flow rate	m^3/hr	17416	11848
Inlet water temperature	°C	33.00	27.91
CW temperature rise	°C	8.30	9.11
CW outlet temperature	°C	41.30	37.02
Steam quantity	TPH	265.96	198.62
Condenser back pressure	kg/cm^2(a)	0.11	0.103
Saturation temperature	°C	46.95	46.00
TTD at design CW flow and inlet temperature	°C	5.65	8.98
Heat gained by CW	MKcal/hr	144.55	107.99
Heat supplied	MKcal/hr	144.48	107.99
LMTD		9.18	13.01
Effectiveness	%	59.50	50.38

Condenser thermal load

The condenser thermal load works out to 107.99 MKcals/hr at a unit load of 82 MW, whereas the design thermal load is 144.48 MKcals/hr at 120 MW, indicating that thermal load is about 74.84% as against the turbine loading of 68.33%.

Condenser effectiveness

The as-run effectiveness of the condenser is 50.38%, which is lower than rated effectiveness of 59.50%, indicating scope for improvement. This performance drop is likely to be on account of silt deposit on the tube side.

TTD

The as-run TTD value of 8.68°C as against the rated value of 5.65°C indicates significant scope for improvement. Higher TTD is normally due to unclean tubes and/or less water velocity.

LMTD

The as-run value of LMTD is 13.01°C with respect to design value of 9.18°C.

CW flow adequacy
Based on thermal load, the as-run CW flow has been assessed to be around 11,848 m^3/hr as against the design flow of 17,416 m^3/hr.

Condenser vacuum
The condenser back pressure is well above the design condition despite the CW inlet temperature being less than the rated value. Following analysis substantiates the observation:

- The design back pressure with clean tubes at 33°C CW inlet temperature = 0.11 kg/cm2(a) (with respect to 120 MW load).
- Saturation temperature predicted = 33°C + Design CW temperature drop + Design TTD = 33 + 8.3 + 5.65 = 46.95°C.
- The actual saturation temperature is 46.00°C and corresponding back pressure 0.103 kg/cm2(a).

As against the design vacuum of 0.11 kg/cm^2(a) at 120 MW unit load, the as-run value of 0.103 kg/cm^2(a) indicates the satisfactory performance of the condenser at the present loading condition. State-of-the-art measures for condenser performance upkeep, like chlorination (for bio fouling), online cleaning of condenser tubes, and opportunity-based backwash of the condenser, may be taken up.

CW pump
The CW system consumes around 12.76% of APC. Two CW pumps are continuously operated and are dedicated for Unit-1, and one CW pump is kept on standby, which has the flexibility of pumping water to both the units.

The as-run performance as observed during trial and the design data specification of CW pumps is summarized as follows.

Table A5-41: Specification of CW pumps

Item reference	Units		Actual	
		Design	CWP-1A	CWP-1B
Unit load	MW	120	82	
Frequency	Hz	50	50	
CWP flow	TPH	10,000	5,924	5,924
Discharge pressure	kg/cm^2		0.85	0.9
Suction pressure	kg/cm^2		0.55	0.55
Total dev head	mWC	17.75	14	14.5
Power consumption				
Motor input	kW	693.33	652.00	645.00
Motor output	kW	624.00	586.80	580.50
Combined efficiency	%	77.51	38.51	40.32
% Margin on power	%		5.96	6.97
% Margin on flow	%		40.76	47.98
% Margin on head	%		21.13	18.31
SEC	kWh/T		0.11	0.11

From the above table, it can be observed that the efficiency of the pump is low due to low head and high flow margin developed by the pump as compared to the design value, and the same will affect the performance of the condenser. The reason for low head development is low seawater level at the suction during low tide period. Desilting activities need to be performed for improving the pump suction.

BACW and TACW system

BACW and TACW constitute a key auxiliary, in terms of connected load as well as consumption because these pumps are in continuous operation even when the plant is in reserve shutdown condition. To evaluate the as-run performance of the auxiliary cooling water system, the flow measurement of the BACW and TACW pumps were done with the help of an ultrasonic flow metering device, and the power consumption was monitored with the help of an online power analyzer.

The design specification and as-run observation data of BACW and TACW pumps are presented below.

Table A5-42: Design specification of BACW and TACW pumps

Particulars	Unit	Design	Actual			Design	Actual	
			TACW -A	TACW -B	TACW -C		BACW -A	BACW -B
Unit load	MW	120	82					
Frequency	Hz	50	50					
Flow	m^3/hr	850	830	807	827	350	408	435
Suction pressure	m		3.5	3.5	3.5		18	15
Discharge pressure	m		8	8	8		47	45
Total dev head	mWC	35	4.5	4.5	4.5	33	29	30
Power consumption								
Motor input	kW	139	96.3	97	117	61.1	52.3	52.3
Motor output	kW	125	86.67	87.3	105.3	55	47.07	47.07
Efficiency	%	64.86	11.74	11.34	9.63	57.23	68.50	75.55
% Margin on power	%		30.66	30.16	15.76		14.42	14.42
% Margin on flow	%		2.35	5.06	2.71		-16.57	-24.29
% Margin on head	%		87.14	87.14	87.14		12.12	9.09
SEC	kWh/m^3	0.16	0.12	0.12	0.14	0.17	0.13	0.12

Energy saving by installing properly sized energy efficient pumps

The SECs for TACW-A, TACW-B and TACW-C pumps are about 0.12 kWh/m^3, 0.12 kWh/m^3, and 0.14 kWh/m^3, respectively, as against the design value of 0.16 kWh/m^3. Similarly, the SEC for BACW-A and BACW-B pump are 0.13 kWh/m^3 and 0.12 kWh/m^3 as against the design value of 0.17 kWh/m^3. The efficiencies of the above pumps were observed to be lower (11.74%, 11.34%, and 9.63%) as compared to the design value of 64.86% for TACW pumps.

The margin on head was observed to be very high (87.14%), and the flow handled by the pumps was satisfactory. The margin in power was of the order of 30.66%, 30.16%, and 15.76%. Similarly, the efficiency of the BACW-A and BACW-B pumps was observed to be satisfactory. The margin on head was observed to be high (12.12% and 9.09%), and the flow handled by the pumps was more than (16.57% and 24.29%). Here again, the margin in power was 14.42%. Hence, it is suggested to replace the existing pumps with new properly sized energy efficient pumps.

Rationale

Table A5-43: Energy saving by installing properly sized energy efficient pumps

Particulars	Unit	Design	Actual		
			TACW-A	TACW-B	TACW-C
Present condition					
Unit load	MW	120	82		
Frequency	Hz	50	50		

Flow	m^3/hr	850	830	807	827
Suction pressure	m		3.5	3.5	3.5
Discharge pressure	m		8	8	8
Total dev head	mWC	35	4.5	4.5	4.5
Power consumption					
Motor input	kW	139	96.3	97	117
Motor output	kW	125	86.67	87.3	105.3
Combined efficiency	%	64.86	11.74	11.34	9.63
% Margin on power	%		30.66	30.16	15.76
% Margin on flow	%		2.35	5.06	2.71
% Margin on Head	%		87.14	87.14	87.14
SEC	kWh/m^3	0.16	0.12	0.12	0.14
Future condition					
Flow	m^3/hr	850	830	807	827
Suction pressure	m		3.5	3.5	3.5
Discharge pressure	m		8	8	8
Total dev head	mWC	35	4.5	4.5	4.5
Power consumption					
Motor input	kW	139	14.14	13.74	14.08
Motor output	kW	125	12.72	12.37	12.68
Combined efficiency	%	64.86	80.00	80.00	80.00
Reduction in power	kW		82.2	83.3	102.9
% Reduction	%		85.3	85.8	88.0
Annual energy savings	kWh		491,012	497,537	615,021
Envisaged annual monetary savings	Rs/annum		1,718,544	1,741,378	2,152,573
Investment	Rs		70,680	68,721	70,424
SPP	Year		0.0411	0.0395	0.0327

Draught system

ID fan

ID fans, evacuating the boiler flue gases, constitute a key HT auxiliary from a functional point of view as well as energy intensity. Unit-1 ID fans constitute 13.3% of APC and stand as the second largest APC equipment. A schematic figure indicating the flue gas flow path is as follows.

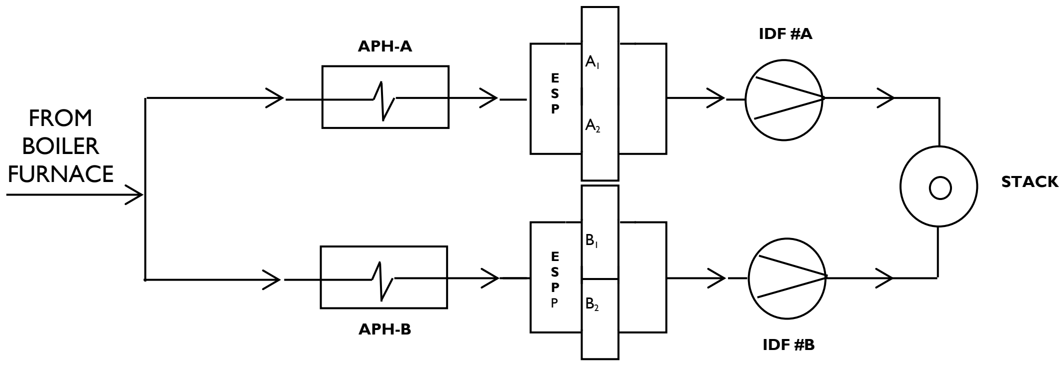

Figure A5-13: Schematic diagram of ID fan

Unit-1: ID fan system (flue gas path)

The performance assessment of the ID fan has been conducted, and the operating parameters are recorded, which are given below.

Table A5-44: Performance assessment of ID fan

Particulars	Design	Actual	
		1A	1B
Unit load		82	
Frequency		50	
Flow rate, TPH	408.5	215.635	215.635
Flow, m³/hr	496,800	245,724	245,724
Flue gas temperature, °C	152	125.2	125.2
Density, kg/m³	0.82	0.88	0.88
Suction pressure, mmWC		-181.94	-181.94
Discharge pressure, mmWC		33.13	10.00
Total pressure, mmWC	332	215.07	191.94
Power consumption, kW	1,000	647.96	719.92
Overall efficiency, %	49.91	24.68	19.82
SEC, kWh/ton of flue gas	2.45	3.00	3.34
Scoop control, %		78.3	62.4
Flow margin, %		50.54	50.54
Head margin, %		35.22	42.19
Power margin, %		35.21	28.01

From the above table, it is observed that the flow and head margin of both FD fans 1A and 1B is about 50.54%, resulting in a higher SEC of 3.09 kWh/ton and 3.75 kWh/ton of flue gas compared to the design value of 2.45 kWh/ton of flue gas. Considering the fluctuation in load, it is recommended to install VFD for efficient capacity control.

Energy savings by installing VFD in an ID fan

Table A5-45: Energy savings by installing VFD in an ID fan

Particulars	Design	Actual	
		1A	1B
Present condition			
Unit load		82	
Frequency		50	
Flow rate, TPH	408.5	215.635	215.635
Flow, m³/hr	496,800	245,724	245,724
Flue gas temperature, °C	152	125.2	125.2
Density, kg/m³	0.82	0.88	0.88
Suction pressure, mmWC		-181.94	-181.94
Discharge pressure, mmWC		33.13	10.00
Total pressure, mmWC	332	215.07	191.94
Power consumption, kW	1,000	647.96	719.92
Motor output, kW	900	583.17	647.93

Overall efficiency, %	49.91	24.68	19.82
SEC, kWh/ton of flue gas	2.45	3.00	3.34
Scoop control, %		78.3	62.4
Flow margin, %		50.54	50.54
Head margin, %		35.22	42.19
Power margin, %		35.20	28.01
Future condition			
Flow rate, TPH	408.5	215.635	215.635
Flow, m^3/hr	496,800	245,724	245,724
Flue gas temperature, °C	152	125.2	125.2
Density, kg/m^3	0.82	0.88	0.88
Suction pressure, mmWC		-181.94	-181.94
Discharge pressure, mmWC		33.13	10.00
Total pressure, mmWC	332	215.07	191.94
Power consumption, kW	1,000	320.40	285.95
Motor output, kW	900	288.36	257.35
Overall efficiency, %	49.91	49.91	49.91
SEC, kWh/ton of flue gas	2.45	1.49	1.33
Reduction in power	kW	327.6	434.0
% Reduction	%	50.6	60.3
Annual energy savings	kWh	1,957,530	2,593,439
Envisaged annual monetary savings	Rs/annum	6,851,354	9,077,037
Investment	Rs	7,200,000	7,200,000
SPP	Years	1.05	0.79

FD fan

To assess the performance of the FD fan, the following parameters were observed in the control room, and the power measurements were done using a portable online power analyzer. The performance parameters are tabulated below.

Table A5-46: Performance parameters of FD fan

Particulars	Design	Actual	
		IA	IB
Unit load		82	
Frequency		50	
Flow rate, TPH	240.30	125.08	130.73
Flow, m^3/hr	222,120	111,753	119,868
Ambient temperature, °C	50	39.2	39.2
Density, kg/m^3	1.08	1.1	1.1
Suction pressure, mmWC	atm	atm	atm
Total pressure, mmWC	452	138.3	145.6
Power consumption, kW	444.4	122.7	231.4
Motor output, kW	400	110.4	208.3

Particulars	Design	Actual	
		1A	1B
Overall efficiency, %	68.35	38.12	22.82
SEC, kWh/ton of air	1.85	1.89	1.77
Vane opening, %		17	19.9
Flow margin, %		47.9	44.2
Head margin, %		69.4	67.8
Power margin, %		72.4	47.9

It is observed that the efficiencies of the FD fan 1A and 1B were found to be 19.73% and 22.29%, respectively, which is much below the design efficiency of 68.35%. It is also observed that enough flow, head, and power margin exist.

The SEC was found to be 1.89 kW/ton and 1.77 kWh/ton of air, vis-a-vis design value of 1.85 kW/ton. This is due to very high head margins. It is suggested to operate one fan as a measure to conserve the energy as enough margin exists. The rationale for savings is as given below.

Table A5-47: Energy savings in FD fan

Particulars	Design	Actual	
		1A	1B
Present condition			
Unit load		82	
Frequency		50	
Flow rate, TPH	240.30	125.08	134.17
Flow, m^3/hr	222,120	111,753	119,868
Ambient temperature, °C	50	39.2	39.2
Density, kg/m^3	1.08	1.1	1.1
Suction pressure, mmWC	atm	atm	atm
Total pressure, mmWC	452	138.3	145.6
Power consumption, kW	444.4	122.70	231.42
Motor output, kW	400	110.43	208.28
Overall efficiency, %	68.35	38.12	22.82
SEC, kWh/ton of air	1.85	0.98	1.72
Vane opening, %		17	19.9
Flow margin, %		47.9	44.2
Head margin, %		69.4	67.8
Power margin, %		72.4	47.9
Future condition			
Unit load		82	
Frequency		50	
Flow rate, TPH	240.30	259.25	
Flow, m^3/hr	222,120	231,621.59	
Ambient temperature, °C	50	39.20	
Density, kg/m^3	1.08	1.12	

Particulars	Design	Actual	
		IA	IB
Suction pressure, mmWC	atm	atm	
Total pressure, mmWC	452	138.31	
Power consumption, kW	444.4	141.83	
Motor output, kW	400	127.64	
Overall efficiency, %	68.35	68.35	
SEC, kWh/ton of air	1.85	0.55	
Reduction in power	kW	212.3	
% Reduction	%	60.0	
Annual energy savings	kWh	1,268,705	
Envisaged annual monetary savings	Rs/annum	4,440,468	
Investment	Rs	Nil	

PA fan

The major auxiliary for the mill is the PA fan and its motor drive, which constitutes the single largest electricity consuming subsystem. The PA fan is a critical part of the milling system, and any increase or decrease in air flow directly affects the combustion characteristics in the boiler, resulting in undesirable effects like clinkerization, increase in secondary oil support, and unit load reduction, etc., apart from heat loss in the boiler. The energy performance features of PA fans were analyzed, and the key indices governing efficiency of fans were worked out as given.

Table A5-48: Energy performance of PA fan

Particulars	Design	Actual	
		IA	IB
Unit load		82	
Frequency		50	
Flow rate, TPH	156.18	73.25	73.25
Flow, m^3/hr	144,360	65,444	65,444
Ambient temperature, °C	50	39.2	39.2
Density, kg/m^3	1.08	1.1	1.1
Suction pressure, mmWC	atm	atm	atm
Total pressure, mmWC	1,308	833.65	1,227.08
Power consumption, kW	944.4	527.80	710.18
Motor output, kW	850	475.02	639.16
Overall efficiency, %	60.50	31.28	34.22
SEC, kWh/ton of air	6.05	7.21	9.70
Vane opening, %		52.7	39
Flow margin, %		53.10	53.10
Head margin, %		36.27	6.19
Power margin, %		44.12	24.80

Based on the existing margin in flow head and power, it is suggested to operate one fan as a measure to conserve the energy. The rationale for savings is as given below.

Table A5-49: Energy savings in PA fan

Particulars	Design	Actual	
		1A	1B
Present condition			
Unit load		82	
Frequency		50	
Flow rate, TPH	156.18	73.25	73.25
Flow, m³/hr	144,360	65,444	65,444
Ambient temperature, °C	50	39.2	39.2
Density, kg/m³	1.08	1.1	1.1
Suction pressure, mmWC	atm	atm	atm
Total pressure, mmWC	1,308	833.65	1,227.08
Power consumption, kW	944.4	527.8	710.2
Motor output, kW	850	475.0	639.2
Overall efficiency, %	60.50	31.28	34.22
SEC, kWh/ton of air	6.05	7.21	9.70
Vane opening, %		52.7	39
Flow margin, %		53.10	53.10
Head margin, %		36.27	6.19
Power margin, %		44.12	24.80
Future condition			
Unit load		82	
Frequency		50	
Flow rate, TPH	156.18	146.5	
Flow, m³/hr	144,360	130,887	
Ambient temperature, °C	50	39.2	
Density, kg/m³	1.08	1.1	
Suction pressure, mmWC	atm	atm	
Total pressure, mmWC	1,308	833.65	
Power consumption, kW	944.4	545.7	
Motor output, kW	850	491.2	
Overall efficiency, %	60.50	60.50	
SEC, kWh/ton of air	6.05	3.73	
Reduction in power	kW	692.2	
% Reduction	%	55.9	
Annual energy savings	kWh	4,136,850	
Envisaged annual monetary savings	Rs/annum	14,478,974	
Investment	Rs	Nil	

Coal mill

The coal milling system is a critical area regarding plant operation, and utmost care is accorded to their upkeep and operation. So much so, the reliability of boiler operation is so dependent on mills that an extra mill operation is often justified as a normal practice. The existing coal mill system constitutes six mills installed with a total of five mills in operation.

The total power consumption in the milling system constitutes around 5.5% of the APC. In the energy audit of the milling system, various observations were made, and measurements were undertaken to assess performance of the mills and associated subsystem; these included electrical measurements (kW, PF, amps, V) of operating mills and PA fans. The other key performance features are dictated by mill loading (capacity utilization), and the air-to-coal ratio are also tabulated. The as-run performance of the mills is presented below.

Table A5-50: As-run performance of the coal mills

Mill reference	Unit	Mill A	Mill B	Mill C	Mill D	Mill E	Mill F
		A1	B1	C1			
Average unit load	MW	82.00					
Average frequency	Hz	50.00					
Generation voltage	kV	13.46					
Average PF		0.99					
PA flow	TPH	25.23	STANDBY	34.36	24.50	32.93	29.83
Differential pressure across mill	mmWC	N/A		356.80	338.50	N/A	N/A
Average PA mill inlet temperature	(°C)	236.00		236.00	236.00	236.00	236.00
Average PA mill outlet temperature, °C	(°C)	73.13		73.00	73.50	73.78	75.10
Average power consumption	kW	168.11		127.37	138.95	122.52	152.74
Motor rating	kW	200.00		200.00	200.00	200.00	200.00
Coal flow							
Design	TPH	17.10		17.10	17.10	17.10	17.10
Actual	TPH	13.48		14.55	12.35	12.30	12.21
Capacity utilization	%	78.86		85.07	72.25	71.93	71.39
Air-to-coal ratio							
Design		1.07		1.07	1.07	1.07	1.07
Actual		1.87		2.36	1.98	2.68	2.44
% Load on motor rating	%	75.65		57.32	62.53	55.13	68.73
SEC							
Design	kWh/T	13.00		13.00	13.00	13.00	13.00
Actual	kWh/T	12.47		8.76	11.25	9.96	12.51

Compressed air system

In the compressed air system, the energy consumption as a percentage of total auxiliary consumption is about 3.9% (the average APC being 12.52% of the total generation). The study of the compressed air system was carried out when the units were operated at 70–80% (82 MW) of their full load capacity (120 MW). The various areas covered during the study are given below:

- Evaluation of performance of compressed air system.
- Survey of compressed air distribution network.
- Review of existing compressed air utilization practices in the station.

There are four reciprocating compressors that are connected to a common header. The compressed air tapping from a common header is passed through an air dryer for instrument air requirement of the plant, whereas the other tapping is used directly for service air requirement of the plant.

The user points of the service air are:

➢ Turbine maintenance area
➢ Mills area
➢ RC feeder belts area
➢ Fire doors area
➢ Igniter cooling area
➢ Any other cleaning requirement
➢ Fuel atomization

The user points of the instrument air are:

➢ Solenoid valve operation
➢ Ash slurry pump house
➢ All pneumatic valve operation

The plant and instrument air pressure are the same; that is, 6.5–6.8 kg/cm^2 for flexibility of the operation/emergency requirement. The simplified schematic of the compressor as arranged is presented as under:

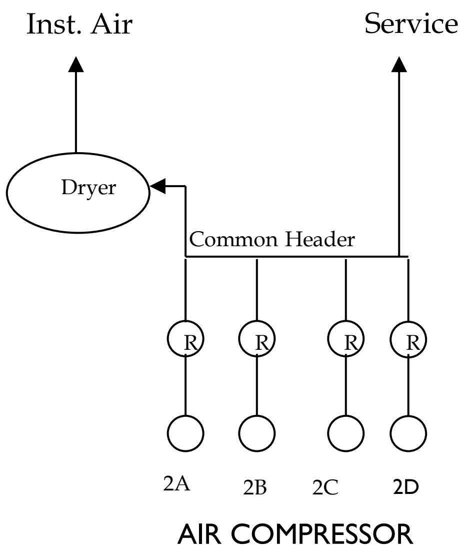

Figure A5-14: Schematic diagram of compressor air system

Design specifications are given below.

Table A5-51: Design specification of compressor

Parameter	Design specifications
Type:	Reciprocating
Number of stages	Two
Discharge pressure	8 kg/cm^3 (g)
Capacity	18.10 Nm^3/min
Motor rating	100 kW
Operating voltage	415 V (+/-10%)

Capacity test result

To know the performance of each compressor, the pump-up test was conducted for all the compressors separately by isolating the receiver from the distribution header, and simultaneously, the power drawn by the compressors was measured by an on-load power analyzer. The equation for calculating the FAD is discussed below.

Actual free air discharge

$$Q = \frac{(P2 - P1)}{Po} \times \frac{V}{T}$$

Where:

P_2 = final pressure after (kg/cm² a)
P_1 = Initial pressure after filling
P_0 = Atmospheric pressure (kg/cm² a)
V = Storage volume in m³, includes receiver after cooler and delivery piping
T = Time taken to build up pressure (in minutes).

The findings of the capacity trial are presented as under w.r.t. rating.

Table A5-52: Findings of the capacity trial

SAC-1A			
Initial pressure	=	5.5	kg/cm² (g)
	=	6.5	kg/cm² (a)
Final pressure	=	7.5	kg/cm² (g)
	=	8.5	kg/cm² (a)
Atmospheric pressure	=	1	kg/cm² (a)
Storage volume	=	6.7	m³
Receiver temperature	=	45	°C
Time	=	1.1	min
FAD (actual)			
	=	*10.46*	*Nm³/min*
	=	*369.00*	*CFM*
	=	627	Nm³/hr
FAD (design)	=		m³/min
	=	18.10	*Nm³/min*
	=	640	CFM (@30°C)
Power consumption	=	95	kW
Motor rating	=	100.0	kW
SEC	=	9.08	*kW/(Nm³/min)*
	=	0.151	*kWh/Nm³*
Iso-thermal power	=	29.81	*kW*
Iso-thermal efficiency	=	36.92	%
SAC-1B			
Initial pressure	=	4.9	kg/cm² (g)
	=	5.9	kg/cm² (a)
Final pressure	=	8	kg/cm² (g)
	=	9	kg/cm² (a)
Atmospheric pressure	=	1	kg/cm² (a)
Storage volume	=	6.7	m³
Receiver temperature	=	45	°C
Time	=	1.36	min
FAD (actual)			
	=	*13.11*	*Nm³/min*

		462.00	*CFM*
	=	787	Nm³/hr
FAD (design)			
	=	18.10	*Nm³/min*
	=	640	CFM (@30°C)
Power consumption	=	94	*kW*
Motor rating	=	100.0	kW
SEC	=	7.17	*kW/(Nm³/min)*
	=	0.119	*kWh/Nm³*
Iso-thermal power	=	53.40	*kW*
Iso-thermal efficiency	=	66.06	%
IAC-1A			
Initial pressure	=	5	kg/cm^2 (g)
	=	6	kg/ cm^2 (a)
Final pressure	=	7.5	kg/ cm^2 (g)
	=	8.5	kg/cm^2 (a)
Atmospheric pressure	=	1	kg/cm^2 (a)
Storage volume	=	6.7	m^3
Receiver temperature	=	45	°C
Time	=	1.08	min
FAD (actual)			
	=	*13.31*	*Nm³/min*
	=	*470.00*	*CFM*
	=	799	Nm³/hr
FAD (design)			
Design	=		
	=	18.10	*Nm³/min*
	=	640	CFM (@30°C)
Power consumption	=	90	kW
Motor rating	=	100.0	kW
SEC	=	6.76	*kW/(Nm³/min)*
	=	0.113	*kWh/Nm³*
Iso-thermal power	=	45.49	*kW*
Iso-thermal efficiency	=	58.77	%
Compressor	**IAC-1B**		
Initial pressure	=	5.3	kg/cm^2 (g)
	=	6.3	kg/cm^2 (a)
Final pressure	=	7.5	kg/cm^2 (g)
	=	8.5	kg/cm^2 (a)
Atmospheric pressure	=	1	kg/cm^2 (a)
Storage volume	=	6.7	m^3
Receiver temperature	=	45	°C

Time	=	1.35	min
FAD (actual)			
	=	*9.37*	*Nm^3/min*
	=	*330.80*	*CFM*
	=	562	Nm^3/hr
FAD (design)			
Design	=		
	=	18.12	*Nm^3/min*
	=	640	CFM (@30°C)
Power consumption	=	89.8	kW
Motor rating	=	100.0	kW
SEC	=	9.58	*kW/(Nm^3/min)*
	=	0.160	*kWh/Nm^3*
Iso-thermal power	=	28.92	*kW*
Iso-thermal efficiency	=	37.44	%

The SEC of the compressors varies from 0.113 kWh/Nm^3 to 0.160 kWh/Nm^3. The performance of the compressors with respect to SEC is found to be satisfactory. Based on normal operation of three compressors for 24 hours a day, it is estimated that the daily service air requirement of the plant is around 33,939 Nm^3/day, and the instrument air requirement is around 27,112 Nm^3/day.

Energy saving through reduction of compressed air leakage

Air leak test

Table A5-53: Air leak test for compressor system

SAC-1B			
Average load time (when no end users were on)	=	200	Seconds
Average unload time (when no end users were on)	=	75	Seconds
% Loading (when no end users were on)	=	72.73	%
Compressor capacity actual FAD	=	13.11	Nm^3/min
Present SPC	=	7.17	kW/(Nm^3/min)
Present leakage rate	=	9.54	Nm^3/min
Present equivalent power loss due to leakage	=	68.36	kW
Practical acceptable limit for CA leakage	=	15	%
Reduction in leakage rate (from 72% to 15%)	=	7.57	Nm^3/min
Envisaged reduction in power loss	=	54.26	kW
Envisaged annual energy savings by reducing leakage (from 72% to 15%)	=	239,845	kWh/annum
Envisaged annual monetary savings	=	*839,458*	*Rs/annum*
Investment toward repair and maintenance of leaky CA line and replacement of leaking fittings	=	50,000	Rs
SPP	=	0.71	Months
IAC-1B			
Operating pressure	=	8.1	$kg/cm^2(a)$

Free air delivery (design)	=	640	CFM
Free air delivery (actual)	=	330.80	CFM
Power consumption	=	89.8	kW
SEC	=	9.58	kW/Nm³/min
		9.37	Nm³/min
% Loading (when no end users were on)	=	100.00	%
Present leakage rate	=	9.37	Nm³/min
Present equivalent power loss due to leakage	=	90	kW
Practical acceptable limit for CA leakage	=	15	%
Reduction in leakage rate (from 100% to 15%)	=	7.97	Nm³/min
Envisaged reduction in power loss	=	76.33	kW
Envisaged annual energy savings by reducing leakage (from 100% to 15%)	=	456,148	kWh/annum
Envisaged annual monetary savings	=	*1,596,518*	*Rs/annum*
Investment toward repair and maintenance of leaky CA line and replacement of leaking fittings	=	100,000	Rs
SPP	=	0.75	Months

Leak test for SAC-1B

Table A5-54: Leak test for SAC-1B

S. No.	Compressor condition	Trial time (minutes)	Time (seconds)
1	Load	0	200.00
2	Unload	200	75.00
3	Load	275	
Average load time		200	72.73
Average unload time		75	27.27
Total time		275	

Energy saving through reduction in compressed air pressure

The plant's air pressure requirement at the farthest point is about 4.5–5 kg/cm², whereas the compressor is operated at the pressure of 7.5–8.0 kg/cm². Considering the pressure drop in the distribution line, there is a possibility of pressure reduction of 1.0 kg/cm² (7.5–6.5 kg/cm²). Hence, it is suggested to reduce the compressed air pressure from the existing 7.5 kg/cm² to 6.5 kg/cm². Based on the trial-and-error method, it can be further reduced to 5.5 kg/cm².

Table A5-55: Energy saving through reduction in compressed air pressure

Parameters	Unit	SAC-1A	SAC-1B	IAC-1A	IAC-1B
Actual FAD					
	Nm³/min	10.5	13.1	13.3	9.4
	Nm³/hr	627.5	786.7	798.9	330.8
	CFM	369.0	462.0	470.0	330.8
Final pressure	kg/cm² (g)	7.5	8.0	7.5	7.5
Design FAD					
	Nm³/min	18.1	18.1	18.1	18.1
	CFM (@30°C)	640.0	640.0	640.0	640.0
Power consumption	kW	95.0	94.0	90.0	89.8
Motor rating	kW	100.0	100.0	100.0	100.0
SEC	kW/(Nm³/min)	9.1	7.2	6.8	9.6

	kWh/Nm³	0.2	0.1	0.1	0.2
New pressure to be set	kg/cm² (g)	6.5	6.5	6.5	6.5
Reduction in pressure	kg/cm² (g)	1.0	1.5	1.0	1.0
% Reduction in pressure	%	13.3	18.8	13.3	13.3
Envisaged power savings	kW	12.7	17.6	12.0	12.0
Envisaged annual power savings	kWh/annum	75,696.0	105,327.0	71,712.0	71,552.6
Envisaged annual monetary savings	Rs/annum	264,936.0	368,644.5	250,992.0	250,434.2
Investment	Rs/annum	Marginal	Marginal	Marginal	Marginal

Performance assessment of chillers

There are three chillers of capacity 30 TR with motor rating of 30 kW to maintain the conditioned atmosphere in the control room of Unit-1. These chillers are direct expansion, reciprocating type, and double cylinder arrangement with water cooled condenser. Generally, two chiller compressors are in operation. The chillers' as-run trials were conducted with the objective of validating the performance against the design value and to assess the SEC and coefficient of performance.

The design and trial values are presented below.

Table A5-56: Performance assessment of chillers

Reference	1A
Flow (m³/hr)	20,645.28
Air Inlet condition	
DBT	24.00
WBT	21.20
Enthalpy	14.72
Air outlet condition	
DBT	18.80
WBT	17.90
Enthalpy	12.17
Reference delivered (TR)	20.5
Power consumption (kW)	26.3
Actual	
SEC (kW/TR)	1.28
COP	2.74
Design	
SEC (kW/TR)	1.23
COP	2.85

From the above observation, it can be inferred that the SEC by the chillers has grown slightly higher by 4% (1.28 kW/TR) as against the design SEC of 1.23 kW/TR. During the performance assessment of chillers, it was observed that the CT cleanliness and AHU filters were not proper and would require regular maintenance to improve the performance of the chillers.

AHP

As part of the AHP study, electrical measurements were carried out on ash water pumps and ash disposal pumps by an on-load power analyzer. Historical data analysis was also carried out to study the influence of PLF, partial loading, etc. on the ash generation profile. The study of AHPs includes energy audit quantification of power consumption of AHP, as well as identifies potential energy conservation options.

The monthly ash generation trend is depicted below.

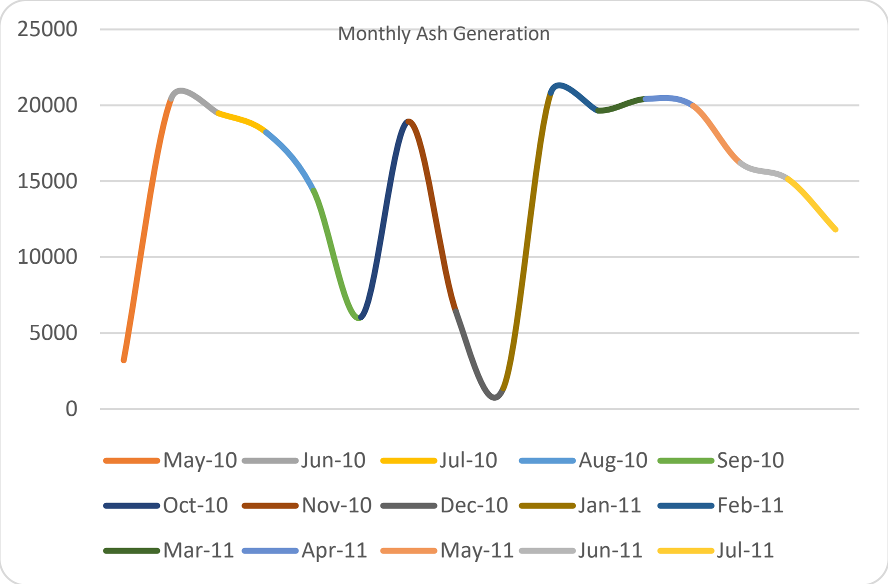

Figure A5-15: Monthly ash generation

*Ash generation is calculated from coal consumption based on 39.45% (ash content) of a coal analysis report.

The average ash generation of Unit-1 is 933 MT/day (average for year 2010–2011). It was observed that the maximum ash was handled in the month of January 2011 while the minimum ash handling was in December 2010.

Schematic diagram of ash handling system

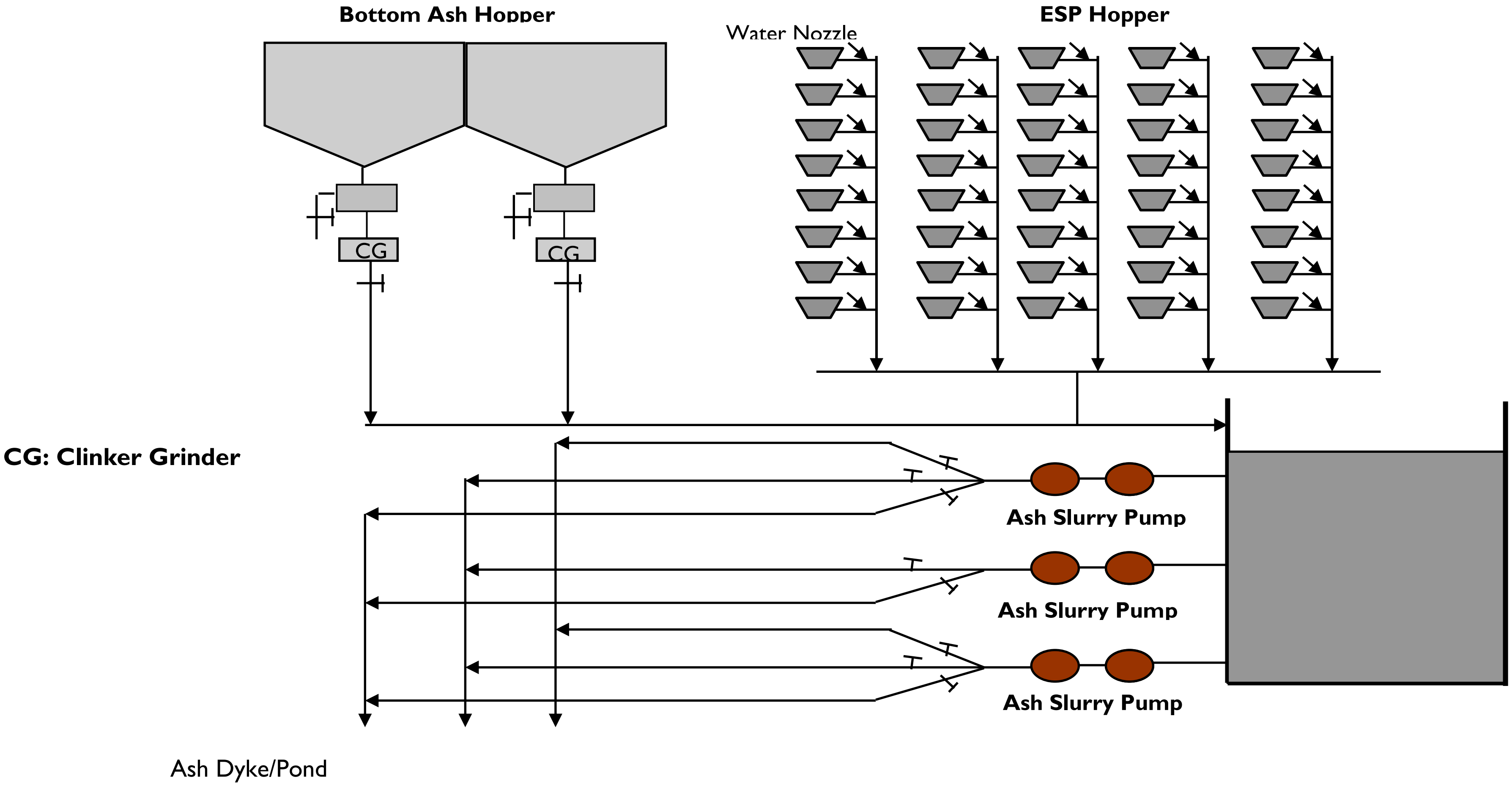

Figure A5-16: Schematic diagram of ash handling system

During the trial period, two ash water pumps, namely pump 1A and 1B, and one ash slurry pump were in operation. The water flow measurement is calculated by keeping the pump efficiency the same as the design efficiency. The as-run trial results in comparison with the design values are tabulated below.

Table A5-57: As-run trial results for ash water pumps

Particulars	Unit	Ash water pump		Ash slurry pump	
		Design	1B & 1C	Design	Actual (1A)
Number of pumps in operation	Number	2	2	1	1
Pump capacity	m^3/hr	640	575	618	318
Suction pressure	mWC		7		6
Discharge pressure	mWC		115		45
Head	mWC	125	108	31	39
Motor input	kW	388.9	376.0	194.4	117.28
Motor output	kW	350	338.4	175	105.552
Combined efficiency	%	62.29	50.00	29.83	32.00
SEC	kWh/m^3	0.55	0.65	0.28	0.33
Ash generation	MT/hr		28.34		
Ash water ratio			20.29		
% Margin on flow	%		10.17		48.57
% Margin on head	%		13.60		-25.81
% Margin on power	%		3.32		39.68

Energy saving by maintaining the ash water ratio as per designed value

The study finding reveals that the ash water ratio maintained is around 1:20.29, which is very high as compared to the design ash water ratio of 1:6. Hence, it is suggested to minimize the water flow as per the designed condition. The water flow required to maintain the designed ash water ratio of 1:6 for the ash generation of 28.34 TPH is around 170 m^3/hr. This can be achieved by operating only one ash water pump instead of the present operation of two pumps. The rationale of energy saving by operating one pump is presented below.

Table A5-58: Energy saving by maintaining the ash water ratio

Particulars	Unit	Ash water pump	
		Design	1B & 1C
Present condition			
Number of pumps in operation	Number	2	2
Pump capacity	m^3/hr	640	575
Suction pressure	mWC		7
Discharge pressure	mWC		115
Head	mWC	125	108
Motor input	kW	388.9	376.0
Motor output	kW	350	338.4
Combined efficiency	%	62.29	50.00
SEC	kWh/m^3	0.55	0.65
Ash generation	MT/hr		28.34
Ash water ratio			20.29
Proposed condition			
Number of pumps	Nos	2	1
Pump capacity	m^3/hr	640	170
Suction pressure	mWC		7

Discharge pressure	mWC		115
Head	mWC	125	108
Motor input	kW	388.9	92.7
Motor output	kW	350	83.4
Combined efficiency	%	62.29	60.00
SEC	kWh/m³	0.55	0.55
Ash generation	MT/hr		28.34
Ash water ratio			6.00
Envisaged power reduction	kW		283.3
% Reduction in power	%		75
Envisaged annual electricity savings	kWh/annum		1,920,411
Envisaged annual monetary savings	Rs/annum		6,721,438
Investment	Rs		NIL

Energy saving by installing energy efficient pumps

The design efficiencies of the ash slurry pump and ash water pump were found to be very low as compared to the state-of-the-art new energy efficient pumps, which will operate at 80% efficiency. Hence, it is recommended to install new pumps. The envisaged energy savings potential is presented in detail below.

Table A5-59: Energy saving by installing energy efficient pumps

Particulars	Unit	Ash water pump (1B & 1C)	Ash slurry pump (1A)
Present condition			
Number of pumps in operation	Number	2	1
Pump capacity	m³/hr	575	318
Suction pressure	mWC	7	6
Discharge pressure	mWC	115	45
Head	mWC	108	39
Motor input	kW	376.0	117.28
Motor output	kW	338.4	105.552
Combined efficiency	%	50.00	32.00
Proposed condition			
Number of pumps	Number	2	
Pump capacity	m³/hr	574.9	317.8
Suction pressure	mWC	7.0	6.0
Discharge pressure	mWC	115.0	45.0
Head	mWC	108.0	39.0
Motor input	kW	235.0	46.9
Motor output	kW	211.5	42.2
Combined efficiency	%	80	80
SEC	kWh/m³	0.41	0.13
Envisaged power reduction	kW	141.0	70.4
% Reduction in power	%	37.5	60.0
Envisaged annual electricity savings	kWh/annum	842,571.2	420,519.2
Envisaged annual monetary savings	Rs/annum	2,948,999.1	1,471,817.1
Investment	Rs	1,057,443.75	211,104
SPP	Rs	0.36	0.14

Insulation effectiveness

As a part of the energy conservation measure, the thermal insulation condition is an indicative parameter for considering the potential thermal energy saving. The thermal insulation survey was carried out to know the status of the present insulation condition of Unit-1. The observation is tabulated below for boiler outer surface temperatures. The thermal insulation survey was carried out for major steam lines in the plant, and the average outer surface temperatures are shown below. In some cases, the temperatures are high due to bare pipes.

Table A5-60: Insulation effectiveness

Area identified	Ambient temperature (°C)	Average surface temperature (°C)
LP turbine surface	32	52
IP turbine surface	32	60
HP turbine surface	32	47, 52, 73
LP crossover pipe	32	48
IP crossover pipe to LP	32	55, 90, 50
HP crossover pipe	32	53
HRH near turbine	32	47
CRH near turbine	32	38
MS line near turbine	32	43
HPH-6 outlet to economizer	32	38
PRDS header	32	100, 120
MS line near PRDS	32	51
CRH near PRDS	32	44
HRH near PRDS	32	50
PRDS station	32	150*, 60, 68
LPH-2 surface	32	38, 39
LPH-3 surface	32	43, 38
Deaerator pipes	32	60*
Gland sealing header	32	35
MS line to IP control valve	32	59, 66, 46, 50, 35
HP control valve 1	32	51, 62
HP control valve 2	32	59, 57, 75, 80
IP control valve 1	32	78
IP control valve 2	32	80
HP stub	32	33, 35
CRH stub	32	38, 36
BFP-1	32	90
HR heater stub drain to atm	32	108
HPH-5	32	80
HPH-6	32	85

(* = Insulated surface wall temperatures)

The major damage area that needs immediate attention has been listed below along with the photographs taken at the site. Periodic evaluation of insulation condition is suggested to arrest any loss that may occur due to poor/inadequate insulation.

Table A5-61: Evaluation of insulation condition

Reference	Observation	Image number
1	CRH entering turbine floor	Insulation damage
2	HRH near boiler drum	Insulation damage
3	FD damper	Insulation damage
4	PRDS station	Insulation damage
5	ESP inlet	Insulation damage
6	Deaerator pipes	Insulation damage
7	FCV Station	Insulation damage
8	HPH-5	Insulation damage
9	Near HPH-6 steam line	Insulation damage
10	Near CEP area steam line	Insulation damage

CRH entering

HRH near boiler drum floor

FD damper

PRDS station

ESP inlet

Deaerator pipes

FCV station

HPH-5

Near HPH-6 steam line

Near CEP area steam line

Figure A5-17: Images of evaluation of insulation condition

5.20 Boiler system (Unit-I)

Background

Thermal power plant, name of the TPP, consists of one water tube boiler of BHEL make, of capacity 383 TPH, 137 bar with turbine (BHEL make) nominal rating of 120 MW. The design parameters of the Unit-1 boiler are as follows.

Table A5-62: Design parameters of the Unit-1 boiler

Parameters		Design		
	Unit	MCR (100%)	NCR	MCR (70%)
Boiler type		Tangentially fired; balanced draught; natural circulation; radiant reheat outdoor type; and direct fired pulverized coal with tube mills.		
Main steam:				
Pressure	kg/cm² (g)	137		131.7
Temperature	°C	540	540	540
Flow (instant)	TPH	383	372	268
CRH				
Pressure	kg/cm² (g)	28.24		20.5
Temperature	°C	339	345	337
Flow (instant)	TPH	343	343	250
HRH				
Pressure	kg/cm² (g)	26.84		19.5
Temperature	°C	540	540	540
Flow (instant)	TPH	343		250
Feed water				
FW flow	TPH	383	367.4	261.9
Economizer inlet temperature		228	229	213
Economizer outlet temperature		298	299	285
Air				
Ambient air temperature	°C	45	45	40
Primary air flow	TPH	65.4	63.9	53.2
APH outlet temperature	°C	308	308	284
Secondary air flow	TPH	381.2	365	256.8
Secondary air outlet temperature		300	300	280
Tempering air flow	TPH	78.9	80.4	62.2
Total combustion air	TPH	525.5	509.3	372.2
Coal quantity	TPH	69.5	67.4	49.8
Exit flue gas temperature	°C	152	153	136
Efficiency of boiler	%	85.9		86.1

Coal

Fuel analysis	Unit	Design
Fuel type	Coal	
Fixed carbon	%	39
Volatile matter	%	25

Moisture	%	8
Ash	%	28
Grindability index	HGI	50
GCV	Kcal/kg	4,400

Feed water parameters	Unit	Design
Description		
Hardness		Nil
PH at 25°C (Copper alloy boiler system)		8.8–9.2
PH at 25°C (Copper-free preboiler system)		9.0–9.4
Oxygen (maximum)	ppm	0.007
Total iron	ppm	0.01
Total copper (maximum)	ppm	0.005
Total CO_2	ppm	Nil
Total silica (maximum)	ppm	0.02

Boiler water parameters	Unit	Design
TDS (max)	ppm	50
PH at 25°C		9.1–10.1
SiO_2	ppm	0.4
Phosphate residual	ppm	5–10
Specific electrical conductivity at 25°C	s/cm	100

Steam purity parameters	Unit	Design
TDS	ppm	0.1
Silica (max)	ppm	0.02

5.21 Performance evaluation of boiler

As part of combustion study, the boiler efficiency trials were conducted during normal load. During the trial, the key parameters namely, unit load, coal flow, coal analysis total air flow, mill rejects, combustibles in bottom ash and fly ash, and flue gas analysis were monitored and are presented in the following table. During the as-run trials, all relevant parameters, namely, coal, air, flue gas, water, and steam, were collected, and efficiency assessment was carried out. The key findings are as follows.

Boiler performance as-run data

Table A5-63: Performance evaluation of boiler

Boiler Reference: 383 TPH (Unit-1)							
Operating parameters	**Hr**	**9:00 AM**	**10:00 AM**	**11:00 AM**	**12:00 PM**	**1:00 PM**	**Averag e**
<u>Main steam:</u>							
Pressure	kg/cm² (g)	102	104	104	103	102	103.0
Temperature	°C	535	537	536	534	534	535.2
Enthalpy of steam	Kcal/kg	828.47	829.19	828.71	827.75	827.99	828.4
Flow (instant)	TPH	243	245	244	245	244	244.2
Hot reheat steam pressure	kg/cm² (g)	20	18	20	18	20	19.2
Hot reheat steam temperature	°C	536	538	536	534	535	535.8
Enthalpy of steam	Kcal/kg	848.80	850.24	848.80	848.09	848.09	848.8
Cold reheat steam pressure	Kg/cm² (g)	25.80	25.80	25.80	25.80	25.80	25.8

Cold reheat steam temperature		347	345	345	344	344	345.0
Enthalpy of steam	Kcal/kg	746.17	744.98	744.98	742.82	737.79	743.3
Reheat steam flow (calculated)	TPH						230.0
Flue gas:							
Oxygen	%	6.4	5.8	6	6.3	6.2	6.1
Temperature (ECO I/L)	°C	377	379	380	382	384	380.4
Temperature (ECO O/L)	°C	275	273	274	274	274	274.0
Temperature (AH O/L)	°C	126	122	122	128	128	125.2
Air temperature:							
Primary air	°C	247	244	249	250	249	247.8
Secondary air	°C	234	230	235	236	234	233.8
Atmospheric air:							
DBT	°C	37	39	39	40	41	39.2
Relative humidity	%	80	82.0	81.8	82.2	81.0	81.4
Absolute humidity	kg water/kg air	0.032	0.03734	0.03724	0.0396	0.041	0.037
Feed water:							
Temperature (before economizer)	°C	210	211	212	211	211	211.0
Temperature (after economizer)	°C	295	294	295	293	294	294.2
Drum pressure	Kg/cm^2 (g)	112	113	115	112	110	112.4
Condenser:							
CW inlet temperature	°C	29	29	28	28	28	28.4
CW outlet temperature	°C	39	39	39	39	39	39.0
Coal:							
Mill A	TPH	13.4	13.4	14.3	14.4	14.4	13.98
Mill B	TPH	0	0	0	0	0	0.00
Mill C	TPH	13	15	13.4	14	16	14.28
Mill D	TPH	12.1	12.7	12	12	12.3	12.22
Mill E	TPH	11.8	11.5	12	12.6	12.6	12.10
Mill F	TPH	12.2	14.2	12	12.5	11	12.38
Total	TPH	62.5	66.8	63.7	65.5	66.3	64.96
Turbine parameters:							
Generator load	MW	81	83	75	82	81	80.40
Voltage	kV	13.6	13.4	13.4	13.4	13.5	13.46
Condenser vacuum	mmHg	665	664	661	662	662	662.80

5.22 Boiler—Heat loss profile

The heat-loss profile covering losses through unburnts in ash, sensible heat loss in dry flue gases, moisture in combustion air, loss due to presence of hydrogen, and moisture in coal, radiation, and unaccounted loss, are as follows. Refer to Annexure 4 for details.

Table A5-64: Boiler—Heat loss profile

Description	Unit	MCR	Actual
Dry flue gas loss	%	4.4	4.24
Loss due to hydrogen and moisture in fuel	%	5.42	8.06
Loss due to moisture in air	%	0.55	0.27
Loss due to unburnt carbon	%	2	0.07

Description	Unit	MCR	Actual
Loss due to radiation	%	0.23	1.5
Unaccounted loss	%	1.5	
Manufacturer's margin	%	0	
Total losses	%	14.1	14.14
Efficiency	%	85.9	85.86

The thermal efficiency of the boiler at unit load of 82 MW based on the heat loss method during the trial period was found to be 85.8% against the MCR value of 85.9%. Coal quality features have a major influence on boiler performance as well as APC and outages. The trend of coal quality being used, in respect of proximate and ultimate analysis, is presented as follows.

Table A5-65: Proximate and ultimate analysis of coal

Fuel analysis	Unit	Design	Actual
Fuel type	**Coal**		
Fixed carbon	%	39	27.37
Volatile matter	%	25	21.79
Moisture	%	8	11.39
Ash	%	28	39.45
Grindability index	HGI	50	
GCV	Kcal/kg	4,400	3,489
Size of coal to mill	mm	25	

The lower GCV values, higher percentage ash in coal, and lower VM have a derating effect in boiler output and performance and would also affect APC in milling/fan power. Due diligence and care need to be initiated for assuring coal quality improvement at receipt and handling, etc. Some of the measures like shale removal, crusher performance, sieve analysis, and undersized segregation for butter crushing and milling efficiency, are separately addressed in the section.

5.23 Performance evaluation of APHs and economizer

Based on the trials, performance analysis of the APHs was carried out to evaluate the deviation from design values. The results presented below correspond to the as-run trial observations. Performance analysis of APHs and economizers is presented in the following.

Table A5-66: Performance analysis of APHs and economizers

Operating parameters	Unit	Design	Unit-I
Date 6/9/2011			(Average of 1 day)
Generation	MW	120	82.12
Total coal flow	TPH	67.4	52.67
Primary air flow through APH	TPH	63.9	146.85
Secondary air flow	TPH	365	85.57
Total air flow	TPH	509.3	431.27
Total FW flow to economizer	TPH	391	283.57
Total steam flow	TPH	391	244.20
Economizer			
Gas temperature at economizer in-B	°C	536	380.44
Gas temperature at economizer in-A	°C	536	380.44
Gas temperature at economizer out-B	°C	344	273.44
Gas temperature at economizer out-A	°C	344	273.44
FW temperature at economizer in	°C	229	210.82
FW temperature at economizer out-B	°C	299	292.93
FW temperature at economizer out-A	°C	299	296.64
Effectiveness-B	%	22.8013	48.41
Effectiveness-A	%	22.8013	48.41

Heat pickup	MKcal/hr	27.37	23.28
LMTD	°C	168.71	72.70
Air preheater			
Gas temperature at Ah Out -A	°C	153	127.00
Gas temperature at Ah A In-A	°C	344	273.44
Gas temperature at Ah Out-B	°C	153	138.11
Gas temperature at Ah In-B	°C	344	273.44
O_2 at Ah In-A	%	3.55	6.14
SA temperature at Ah In-A	°C	45	40.56
SA temperature at Ah In-B	°C	45	32.89
PA temperature at Ah In-A	°C	45	39.20
PA temperature at Ah In-B	°C	45	39.20
PA temperature at Ah Out-A	°C	308	247.50
PA temperature at Ah Out-B	°C	308	246.00
SA temperature at Ah Out-A	°C	300	233.11
SA temperature at Ah Out-B	°C	300	217.63
Gas press differential after APH-A	mmWC	-101	-136.71
Gas press differential after APH-B	mmWC	-101	-134.76
PA press differential across Ah - A	mmWC	34	198.87
PA press differential across Ah - B	mmWC	34	210.06
SA press differential across Ah - A	mmWC	52	22.00
SA press differential across Ah - B	mmWC	52	20.38
Effectiveness: Ah - A	%	85.28	82.78
Effectiveness: Ah – B	%	87.95	88.28
Heat pickup—PA side	MKcal/hr	16.80	30.37
Heat pickup—SA side	MKcal/hr	93.0	15.81
Total heat pickup	MKcal/hr	109.88	46.18

The pressure drop of flue gas across APH-A and APH-B was of the order of (-)136 mmWC and (-) 134 mmWC, respectively, against a design value of (-) 101 mmWC. There is a slight difference of 10 mmWC to 20 mmWC, which is under controlled limits considering the system. The temperature drop in flue gas in APH-A and APH-B is 146°C and 135.33°C, respectively, against a design value of 191°C. The lower temperature drop is indicative of deterioration in APH effectiveness. The performance is satisfactory, considering the temperature drop across APH.

Based on study findings, the following opportunity is identified for energy savings.

- Insulation improvements for optimizing surface heat loss (discussed in insulation section).

5.24 Turbine and auxiliaries (Unit-1)

Background

Performance assessment of the turbine system of Unit-1, based on as-run trials was conducted during the first week of Month, year, with the objective of validation against design value, to identify inefficiencies, if any, during the as-run trials. Findings are envisaged to help in assessing the performance, vis-à-vis design/rated values, factors and parameters affecting performance, and key result areas for improvement and attention.

The scope of the energy audit study in turbines is to carry out as-run turbine cycle heat rate and impact parameters affecting heat rate. The as-run performance test determines the turbine performance regarding performance indices as follows.

- HP cylinder efficiency.
- Turbine heat rate.

5.25 Performance assessment of HP turbine

Evaluation procedure (methodology)

The as-run performance test is conducted by the enthalpy drop efficiency method. Enthalpy drop test is used as a method of trending the performance of HP and IP sections of the steam turbine. This method determines the ratio of actual enthalpy drop across turbine sections to the isentropic enthalpy drop.

While it is very difficult to make immediate corrections to turbine performance degradation, the information can be used as part of the cost-benefit analysis to determine the optimum point at which the losses due to decreased performance are greater than the costs associated with turbine maintenance. The enthalpy drop test is performed at the valve wide-open condition. The test at valve wide-open provides a baseline, and the test at similar pre- and postcondition is used to evaluate the improvements made during turbine overhaul.

HP cylinder efficiency

In connection with the requirements of the as-run performance test, the average 1-day values for turbine trials (each of 1 hour duration) were taken from the control room on the same date. The requisite numbers of readings taken for the relevant operating parameters during the trial period were averaged out for computing HP cylinder efficiency.

The as-run parameters were obtained during trial and compared against the corresponding design data. Based on the respective inlet and outlet steam condition at HP cylinder, the HP cylinder efficiency has been computed as 86.2% against the design value of 77.7%, which is presented in the table below.

Comparison of as-run trial values of HP turbine cylinder efficiency w.r.t. design values

Table A5-67: As-run trial values of HP turbine cylinder efficiency

Parameters	Units	Design	Actual
Main steam			
Steam pressure	kg/cm^2 (a)	127.61	104.0
Steam temperature	°C	537.78	535.2
Enthalpy	Kcal/kg	822.0	828.4
CRH steam			
Steam pressure	kg/cm^2 (a)	27.96	26.80
Steam temperature	°C	340.378	345.0
Enthalpy	Kcal/kg	740.3	744.5
Isentropic enthalpy	Kcal/kg	716.9	731.1
Actual enthalpy drop	Kcal/kg	81.7	83.9
Isentropic enthalpy drop	Kcal/kg	105.1	97.3
Isentropic efficiency	%	77.7	86.2

Comments on HP turbine efficiency and improvement options

The performance parameters show that the performance of the HP turbine is close to the design value.

Turbine cycle heat rate and thermal efficiency

Based on the as-run steam parameters, the turbine cycle heat rate is given as:

$$= \frac{MS\ Flow, \frac{kg}{hr} \times (MS\ enthalpy - FW\ enthalpy), \frac{kCal}{kg} + \ RH\ Flow, \frac{kg}{hr} \times (HRH\ enthalpy - CRH\ enthalpy) kcal/kg}{Generator\ output\ (kW)}$$

= (244.2 x (828.4 – 211) + (230 x (848 – 743)) / (80,400)

= 2,176.98 Kcal/kWh

Thermal efficiency of turbine:

$$= \frac{860 \times 100}{Turbine\ Heat\ Rate, \frac{kCal}{kWh}}$$

= 860 / 2,176.98
= 39.50%

Thermal efficiency of station

$$= \text{Thermal Efficiency of Turbine, \%} \times \text{Efficiency of Boiler, \%}$$

= 39.50 x 85.86 = 33.91%

It may be noted that the guaranteed heat rate at NCR is 2,087 Kcal/kWh, as per the following indicating a deviation of about 4–5% on turbine heat rate. The thermal efficiency of the turbine as assessed during the audit study was found to be 39.50% as against the design value of 41.20%. The thermal efficiency of the station was 32.46% as against the design value of 35.39%.

Performance of heaters

HPH and LPH performance was evaluated, and the key parameters were recorded. The performance assessment of LPHs is done based on:

TTD = t_{sat} - $t_{fw\ out}$ = Terminal temperature difference (should be as less as possible)
DCA = t_{drain} - $t_{fw\ in}$ = Drain cooler approach (should be as less as possible)
TR = $t_{fw\ out}$ - $t_{fw\ in}$ = Temperature rise (should be as high as possible)

And the results are given below.

It can be observed that the performance of LPH-1 is not satisfactory in terms of temperature rise with respect to design. The analysis reveals that in LPH-1 and LPH-2, TTD is observed to be high. This calls for inspections of tube and shell side internals.

However, the following are suggested for improving TTD, DCA, and TR:

- Prevention of tube leaks
- Removal of incondensable gases/air venting in the shell side
- Removal of plugging in tubes
- Repair of fouled tubes
- Reduction of feed water heater drain bypass and leaks/blocks
- Water and steam side contamination of tubes

Comparison of design and actual values of HPHs and LPHs

Table A5-68: Comparison of design and actual values of HPHs and LPHs

Performance evaluation of heaters										
Description	**LPH-1**		**LPH-2**		**LPH-3**		**HPH-5**		**HPH-6**	
Steam inlet	**Design**	**Actual**	**Design**	**Actual**	**Design**	**Actual**	**Design**	**Actual**	**Design**	**Actual**
Pressure, kg/cm²(a)	0.44	0.3	1.24	0.935	2	1.9	14.63	13.6	27.96	22
Temperature, °C	77.62	78	169.1	138.8	222	215	461.13	420	341.86	330
Enthalpy, Kcal/kg	631.0	632.3	673.1	659.1	696.5	694.3	809.5	790.0	740.2	739.0
Flow (TPH)	12.673	2.56	16.2	7.46	7.76	5.68	14.868	3.75	23.411	14.20

Saturation temperature, °C	76.39	68.33	105.17	97.01	118.6	118	196.16	192.7	228.9	216.3
Drain inlet										
Temperature, °C	79.17	62	107.95	86			200.63	189		
Flow (TPH)	22.092	13.14	7.76	5.68			23.747	14.20		
Drain outlet										
Temperature, °C	53	52	79.17	62	108	86	174.02	143	200.63	189
Flow (TPH)	34.765	23.16	22.092	13.14	7.76	5.68	38.615	17.95	23.411	14.20
Feed water inlet										
Temperature, °C	47.4	52	73.61	66	102.39	92	165.46	158	195.07	178
Pressure, kg/cm²(a)		16		7.9	17	8.5	160	161	160	161
Flow (TPH)	302.21	287.89	302.21	287.89	302.21	287.89	365.065	244	365.065	244
Feed water outlet										
Pressure, kg/cm²(a)		7.22	17.2	6.5	16.2	8.2		158		125
Temperature, °C	73.61	59	102.39	85	117.35	104	195.07	178	221.79	210
Flow (TPH)	302.21	287.89	302.21	287.89	302.21	287.89	365.06	244	365.06	244
Terminal temperature difference (TTD), °C	2.78	9.33	2.78	12.01	1.25	14	1.09	14.7	7.11	6.3
Drain cooler approach (DCA), °C	5.6	0	5.56	-4	5.61	-6	8.56	-15	5.56	11
Feed water temperature rise	26.21	7.00	28.78	19.00	14.96	12.00	29.61	20	26.72	32
Effectiveness, %	86.73	26.92	30.14	26.10	12.51	9.76	10.01	7.63	18.20	21.05
% Deviation in effectiveness	68.96		13.41		22.00		23.77		-15.66	

5.26 Station auxiliaries

5.26.1 Coal handling plant

The coal handling plant (CHP) primarily serves the function of transporting coal from the wagon tipplers to the bunkers. Average coal consumption by the plant for both the units is around 9.54 lakh tons/annum (April 10–March 2011).

Contribution of CHP in APC is around 2.47%, and the percentage of current generation (88 MW) is 0.34%. The mode of coal unloading is through wagon tripling where it passes through an apron feeder, single roll crusher, and then to belt conveyors 1 and 2.

The output size from the single roll crusher is 200 mm, whereas the product size out from the crusher house is around (-20 mm). There are in total 9 streams of belt conveyors, each having normal capacities of 500 MTPH with a greater flexibility of operation between lines.

The salient feature of CHP is that it contains crusher (ring granulators) of 500 MTPH each. Blending of Indian coal and washery-coal is being practiced. The design specifications of major equipment in CHPs are listed below.

Table A5-69: Design specifications of major equipment in CHPs

Wagon tipplers	
Number	2
Make	Elecon
Type	Rotaside
Angle of tilting	150° (maximum)
Capacity	12 boxes per hour
Motor rating	95 hp
Speed	1,500 rpm
Apron feeders	
Number	2
Pan width	1,800 mm
Type	
Angle of tilting	
Capacity	500 MTPH
Motor rating	60 hp
Motor speed	1,500 rpm
Speed	14.9 m/min to 2.9 m/min
Single roll crusher	
Number	2
Make	Elecon
Rotor speed	62 rpm
Weight of crusher	12.3 tons
Drive motor	150 hp
Drive motor speed	1,500 rpm
Feed size	70% of lumps below 300 mm, 30% of lumps above 300 mm
Product size	200 mm
Capacity	500 MTPH
Roller screen	
Number	2
Feed size	200 mm
Make	Elecon
Product size	20 mm
Capacity	500 MTPH
Motor rating	2 x 30 hp
Speed	1,500 rpm
Ring granulator	

Number	2
Make	Elecon
Capacity	500 MTPH
Feed size	200 mm
Product size	20 mm
Motor rating	560 hp
Speed	1,480 rpm

Table A5-70: Capacity of conveyor

Conveyor reference	Capacity (MTPH)	Lift (m)	Belt speed (m/second)	Motor rating (kW)	Motor rpm
1	500	9.365	2.63	37.3	1,500
2	500	9.365	2.63	37.3	1,500
3	500	7.735	2.63	37.3	1,500
4A–4B	500	20.735	2.63	62.664	1,500
5A–5B	500	22.3	2.63	74.6	1,500
6A–6B	500	43.5	2.63	131.296	1,500
7A–7B	500	3.5	2.63	34.316	1,500
8A–8B	500	13.5	2.63	55.95	1,500
9A–9B	500	27.15	2.63	74.6	1,500

Motor loading

Table A5-71: Motor loading of conveyor

Reference	Phase	Voltage	Ampere	kW	PF	Motor rating (in kW)	Motor loading (%)
Apron feeder 2		412.1	108.5	59.7	0.80	45	119.40
Conveyor 2		410.3	24.0	16.8	0.99	37	40.86
Conveyor 4B		413.7	105.0	62.7	0.84	63	89.57
Conveyor 5A		413.4	79.5	45.8	0.79	75	54.96
Conveyor 7A		411.4	41.0	28.1	0.94	45	56.20
Conveyor 6A		PANEL LOCKED (INACCESSIBLE)					
Single roll crusher 2		415.0	54.5	28.8	0.7	110	23.56
Crusher 1		STANDBY					
Crusher 2	R	6,810.0	11.1	127.0	0.97		
	Y	6,822.0	14.4	168.4	0.99		
	B	6,828.0	13.5	143.7	0.90		
Average		**6,820.0**	**13.0**	**146.4**	**0.95**	**420.0**	31.37

During the motor load survey, it was observed that the motor loading varies from 23.56% to 119.40%.

The apron feeder is loaded 119.4% (instant reading) and needs further observation and monitoring toward replacement of the motor with a suitably sized motor of adequate rating.

General recommendations:

- Efforts are to be made to maximize conveyor loading to achieve lower SEC figures.
- Alternative day cleaning of the vibrating screen is recommended to optimize crusher loading.
- Reschedule/avoid short-time belt running/short-time crusher running. This will reduce consumption because of stabilizing of system start-up/stop losses of the CHP system; improve SEC apart from system breakdown due to hot start-up restrictions on HT equipment.
- To have control on belt and crusher idle running hours.
- Follow direct bunkering routes as far as possible and avoid stacking and reclaiming the route to reduce SEC.

5.26.2 Water treatment plant

Reverse osmosis plant

The source of water for the seawater reverse osmosis plant is seawater taken from the existing circulating water system. To reduce the TDS and make it suitable to meet the water requirements of the power station's service water, steam generator makeup water treatment, BACW system, seawater pretreatment plant, and seawater reverse osmosis plant are provided. The seawater pretreatment plant is designed for flow of 750 m^3/hr, and the seawater reverse osmosis plant can produce permeation of 4,400 m^3/day on a continuous basis.

The reverse osmosis plant has two stages to treat seawater. One stage consists of a clarifier and gravity filtration process. After clarification, the treated water is supplied to the second stage for further processing and then the obtained sweet or potable water is supplied to the reservoir of the raw water system.

The reverse osmosis plant can produce output flow of 1 m^3/hr permeating water with raw water inlet flow of 204 m^3/hr @ 30% recovery when feed water TDS is less than 35,000 ppm for one stream. There are four HP water pumps of capacity 215 m^3/hr, head 643.5 mWC, and motor rating of 600 kW. Out of the four pumps, one is put into operation, and the plant is run for an hour a day. There are 3 filter seawater pumps, out of which one is put into operation. The power measurements for the above two pumps are given below.

Table A5-72: Power measurement of pumps

Reference	Voltage kV	Ampere	kW	PF	Motor rating (in kW)	Motor loading (%)
HP pump	6.6	34.91	359.225	0.9	600	53.88
Filter seawater pump	410	42.8	27.3538	0.9	33.5	73.49

The total energy consumption in the reverse osmosis plant and permeate flow for the month of August 2011 is given in the following table. It is observed that the total power consumption is 8,760 kWh and permeated flow is 1,168 m^3. The operation of the reverse osmosis plant is also a reason for increase in the APC.

Table A5-73: Energy consumption in reverse osmosis plant

Energy consumption in reverse osmosis plant during the month of August 2011			
S. No.	Period	Power consumption (kwh)	Permeate flow m^3
1	August 1–6, 2011	1,920	294
2	August 8–11, 2012	1,440	192
3	August 16–20, 2013	2,040	240

4	August 22–27, 2014	2,040	298
5	August 29–31, 2015	1,320	144
	Total	**8,760**	**1,168**

5.26.3 Transformer

As part of the energy audit, the HT and LT transformers were studied. The unit has a well-conceived primary and secondary distribution network with emphasis on reliability of operations. Most of the transformers are provided with tap-changing provisions.

The unit has the following important transformers catering to various requirements:

- 2 Generator transformers
- 2 Unit auxiliary transformers (UATs)
- 2 Station transformers
- 2 ESP transformers
- 2 AH transformers
- 2 Unit service transformers (USTs)
- 5 Distribution transformers
- 8 Other transformers

While the generator transformers cater to the power export requirements, the UATs of each unit explicitly supply the auxiliary power requirements of the respective units. All the secondary distribution load requirements are met through these LT transformers.

Specifications of transformers

Table A5-74: Specifications of transformers

Reference	Capacity		Make
GT-I	75/110/150 MVA	138 kV, 627.6 A–13.8 kV, 6,276 A	Crompton Greaves Ltd
GT-II	75/105/150 MVA	138 kV, 314/440/628 A–10.5 kV, 4,129/5,780/8,258 A	Transformers & Elect. Ltd
ST-I	15/25 MVA	132 kV, 65.6/109.3–7 kV, 1,237.1 A, 2,061.9 A	Voltamp transformers
ST-II	15/25 MVA	132 kV, 65.6/109.3–7 kV, 1,237.1 A, 2,061.9 A	Voltamp transformers
ICT	37.5/50 MVA	132 kV, 164/218.7–66 kV, 328/437.4 A	Apex transformers
UAT-I	15 MVA	13.8 kV, 627.5 A–7 kV, 1,237.2 A	Emco transformers ltd
UAT-II	15 MVA	10.5 kV, 824.7 A–7 kV, 1,237.2 A	Voltamp transformers
SST-1A/1B	1.6 MVA	6.6 kV, 140 A–433 V, 2,133 A	Ashok transformers
UST-1A/1B/1C	1.25 MVA	6.6 kV, 109 A–433 V, 1,666 A	Ashok transformers
UST-2A1/2A2/ 2B1	1.6 MVA	6.6 kV, 140 A–433 V, 2,133 A	Amod transformers
CHP tr. I/II	1.6 MVA	6.6 kV, 140 A–433 V, 2,133 A	Ashok transformers
ESP tr. IA/IB	1.25 MVA	6.6 kV, 109 A–433 V, 1,666 A	Ashok transformers
AHP tr. 1A/1B	1.25 MVA	6.6 kV, 109 A–433 V, 1,666 A	Ashok transformers
WTP I/II	1.25 MVA	6.6 kV, 109 A–433 V, 1,666 A	Ashok transformers
ESP tr. 2A/2B	1 MVA	6.6 kV, 87.5 A–433 V, 1,333 A	Amod transformers
AHP tr. 2A/2B	1 MVA	6.6 kV, 87.5 A–433 V, 1,333 A	Amod transformers

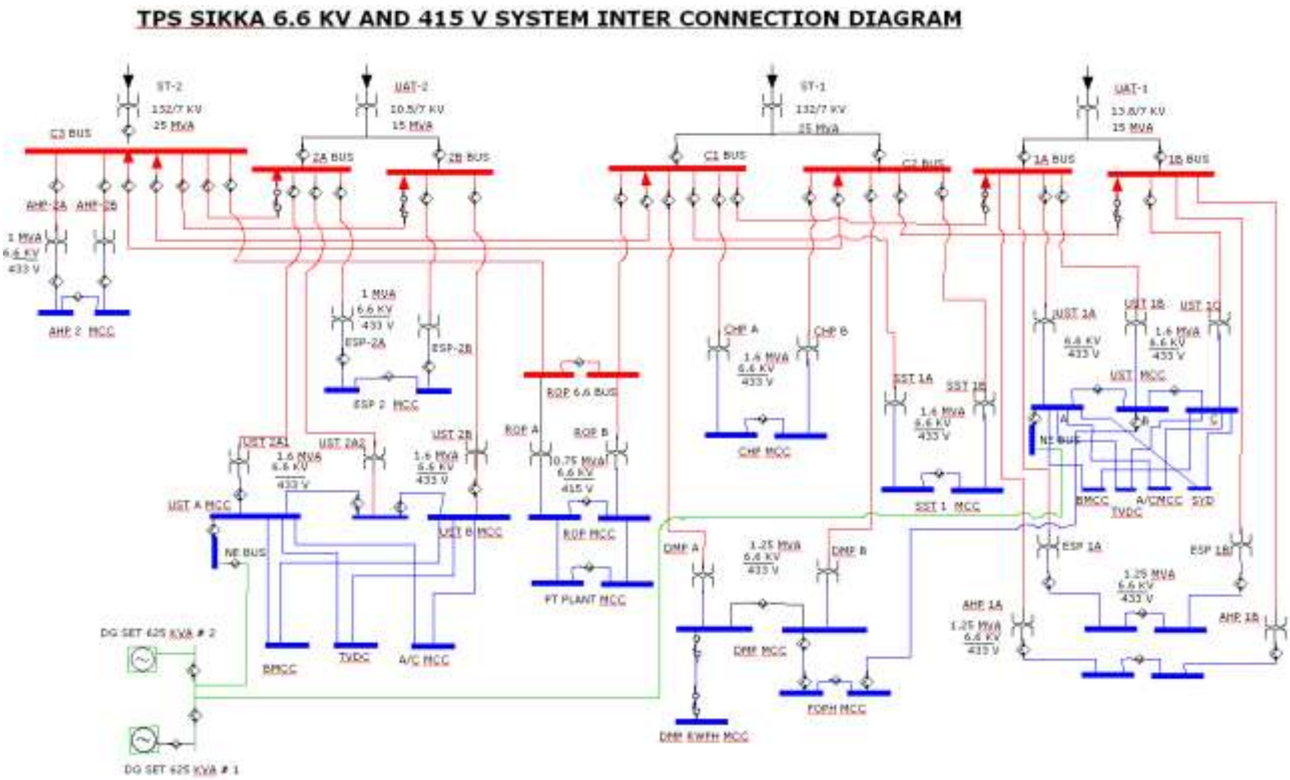

Figure A5-18: 415 V system interconnection diagram

UATs

As part of the audit, on APC, the load measurements on the two-unit auxiliary transformers as well as two USTs were carried out. The percentage loading of the reference transformers is given below. (Refer to the annexure for details.)

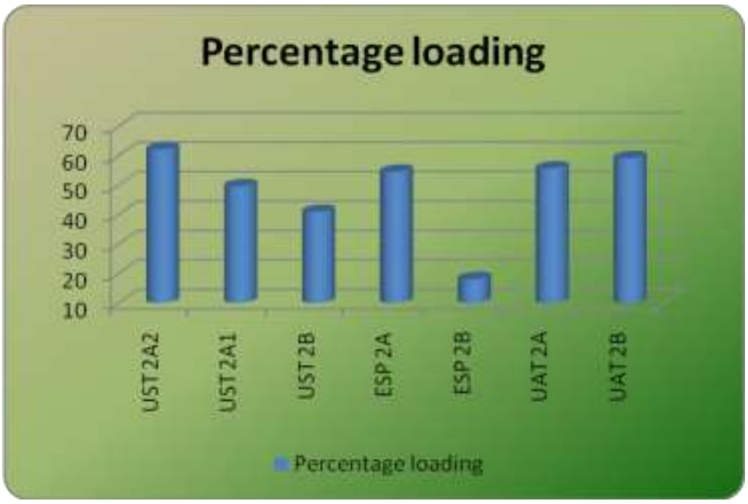

Figure A5-19: Percentage loading of UATs

Table A5-75: Percentage loading of transformer

Transformer reference	Percentage loading
UST 2A2	62.1
UST 2A1	49.6
UST 2B	40.9
ESP 2A	54.5
ESP 2B	18.06
UAT 2A	55.6

UAT 2B	59.1
Average	**48.55**

The capacity utilization of the HT transformers based on the as-run load measurements indicate loading percentage varying from 18.06% to 62.1%. However, the maximum demand profile for each of the transformers needs to be recorded for optimization. The main contributing factor for less capacity utilization is that the standby transformers are being kept in either charged condition or very low load operations to meet any exigencies and maintain reliability of operations. Following are the calculated transformer losses for the reference transformers.

Table A5-76: Transformer losses for the reference transformers

Transformer reference	kWh/day
UST 2A2	234.5
UST 2A1	140
UST 2B	148.32
ESP 2A	112
ESP 2B	155.9
UAT 2A	942.2
UAT 2B	1,019.2
Total	2,752
Electricity generated	2,112,000
% Generation	0.13%

Transformer losses

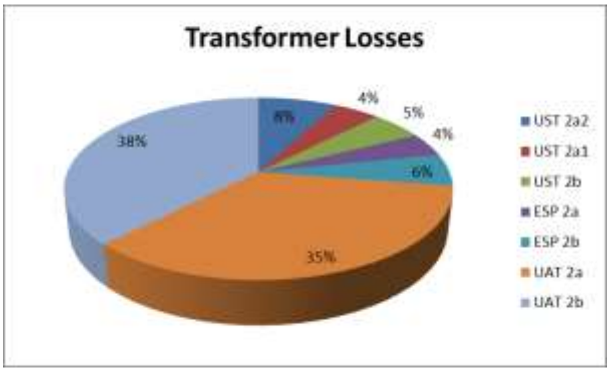

Figure A5-20: Transformer losses

The estimated energy requirement of the reference transformers is 2,752 kWh/day. This accounts for 0.13% of daily electricity generation and is marginal.

5.26.4 Plant lighting system

The plant consists of different types of lamps for lighting in different areas inside and outside the generating unit. The types of lamps are tabulated below.

Table A5-77: Plant lighting system

Type	Number	Connected load (kW)
70 WATT HPSV	3	0.210
80 WATT HPMV	20	1.600
125 WATT HPMV	1,401	175.125
250 W HPMV	67	16.750
400 W HPMV	98	39.200
Total	**1,589**	**232.88**

The lux levels measured at various locations during night-time are as follows.

Table A5-78: Lux level measured at various locations

Reference	Average lux level range
Office room (service building)	239
Office corridor (service building)	185–350
Office staircase (service building)	70
BFP 1	100–230
CEP 1A	50
Control room (Unit-2)	100–211
Compressor 2A	100
Transformer	50
Condenser	185
LPH-1	50
Condenser 4.8 m	120
Turbine hood	40
LPH-2	58
LPH-3	58
Panel room	60
Control room (Unit-1)	164–202
CT room	40
Control valve	40
FO section	38
Mill	38

There are 8 lighting voltage controllers located at various places of the plant that help in power saving.
CHP lighting LDB-7, 73.13 kW, 175.8 A
Lighting LDB-8, 94.22 kW, 225.4 A

Replacement of HPMV lamps with HPSV lamps

In the plant areas, which do not require a high color rendering index, the quality of light provided by HPSV lamps would be more than adequate.

HPMV lamps offer themselves as a replacement with HPSV lamps with sizable scope for reduction in lighting load.

Recommendation

The existing low-efficiency HPMV luminaires can be replaced by high efficiency HPSV lamps, with corresponding 35–55% reduced wattage. The replacement option for various wattage of lamps is as follows.

Table A5-79: Replacement option for various wattage of lamps

Existing	Replace with	% Reduction in lighting load
HPMV 80/125 Watt	HPSV 70 Watt	55
HPMV 250 Watt	HPSV 150 Watt	40
HPMV 400 Watt	HPSV 250 Watt	37

By installing the HPSV lamps, an average of about 42% reduction in connected load can be achieved, which is equivalent to 98.6 kW. Taking into consideration the requirement of necessary lighting quality and envisaging 50% replacement of HPMV lamps in a phased manner, lighting load reduction of 50 kW could be achieved.

Annual energy savings potential (370 kW x 0.55 x 12 hrs x 365 days)	50 kW

Annual monitory savings potential (@ Rs 3.5 per kWh)	Rs 5.11 Lakh
Investment (for each replacement of luminaire is given below)	Can be taken up on failure replacement basis

Rationale

Potential for reduction in connected load	50 kW
Average operating hours	8 hours
Annual energy savings potential (50 kW x 8 hrs x 365 days)	146,000 kWh
Annual monitory savings potential (@ Rs 3.5 per kWh)	Rs 5.11 Lakh
Investment (for each replacement of luminaire is given below)	Can be taken up on failure replacement basis

HPSV 70 Watt	3,500
HPSV 150 Watt	4,250
HPSV 250 Watt	5,000

Appendix 1: Online power measurement details and APC details (Unit-2)

Reference	Phase	Voltage	Ampere	kW	PF	Voltage	Ampere	kW	PF	Motor rating (in kW)	Motor loading (%)	CT ratio
Incomer 2A1		430.5	7.9	5.30	0.90	430.5	1,185.0	795.2	0.9			
		431.0	7.9	5.40	0.92	431.0	1,185.0	813.8	0.9			3,000
		430.7	7.6	4.70	0.81	430.7	1,140.0	688.8	0.8			
Average		430.7	7.8	5.13	0.88	430.7	1,170.0	765.2	0.9			
Incomer 2B1		431.1	5.2	3.49	0.90	431.1	26.0	17.5	0.9			3,000
		431.4	5.3	3.68	0.92	431.4	26.5	18.2	0.9			
		430.0	5.2	3.59	0.92	430.0	26.0	17.8	0.9			
Average		430.8	5.2	3.59	0.91	430.8	26.2	17.8	0.9			
Incomer from UAT 2A	R	112.1	113.4	20.35	0.9	6,726	567	5,944.71	0.9			1,000/1A
	Y	112.2	114	20.3	0.9	6,732	570	5,981.49	0.9			
	B	113	113.7	17.94	0.8	6,780	568.5	5,340.70	0.8			
	Average	112.4	113.7	19.5	0.9	6,746.0	568.5	5,755.63	0.9			
UAT 2B	R	113.9	10.1	1.70	0.89	6,834.0	10.1	106.4				1,000
	Y	114.7	10.3	1.83	0.90	6,882.0	10.3	110.8				
	B	114.4	10.2	1.80	0.90	6,864.0	10.2	109.1				
Average		114.3	10.2	1.78	0.90	6,860.0	10.2	108.8				
UST 2A1	R	113.9	8.7	1.6	0.9	6,834	87	957.69	0.9			200/1A
	Y	114.4	8.7	1.6	0.9	6,864	87	961.89	0.9			
	B	114.3	8.7	1.5	0.9	6,858	87	930.05	0.9			
	Average	114.2	8.7	1.6	0.9	6,852.0	87.0	949.88	0.9	1,250	68.39	
UST 2A2	R	113.8	0.3	0.56	0.9	6,828	3	32.64	0.9			
UST 2B		113.9	6.6	1.20	0.94	6,834.0	49.5	550.8				150
		114.8	13.6	2.50	0.93	6,888.0	68.0	754.5				100
		114.4	13.4	2.50	0.94	6,864.0	67.0	748.7				
Average		114.6	13.5	2.50	0.94	6,876.0	67.5	751.6		643.0	105.20	
ESP transformer 2A	R	114	1.1	1.96	0.9	6,840	8.25	86.01	0.9			150/1A
	Y	114.5	0.6	1.07	0.9	6,870	4.5	47.12	0.9			
	B	114.5	0.9	1.26	0.7	6,870	6.75	58.63	0.7			
	Average	114.3	0.9	1.4	0.8	6,860.0	6.5	63.92	0.8	1,250	4.60	
Station service transformer 2		114.3	0.5	0.09	0.92	6,858.0	5.0	54.6	0.9			
		114.4	0.4	0.06	0.86	6,864.0	4.0	40.9	0.9			
		114.0	0.4	0.07	0.94	6,840.0	4.0	44.5	0.9			200

Average		114.2	0.4	0.07	0.91	6,854.0	4.3	46.7	0.9	1,600.0	2.6	
Tube mill 2A	R	114.1	136.1	25.6	1	6,846	68.05	766.54	1			100/1A
	Y	114.8	141.2	26.75	1	6,888	70.6	800.15	1			
	B	114.6	136.5	25.8	1	6,876	68.25	772.16	1			
	Average	114.5	137.9	26.1	1.0	6,870.0	69.0	779.62	1.0	770	91.12	
Tube mill 2B	R	114	13.6	2.5	0.9	6,840	68	757.25	0.9			
	Y	114.5	13.7	2.5	0.9	6,870	68.5	766.17	0.9			
	B	114.4	13.5	2.5	1	6,864	67.5	762.35	1			
	Average	114.3	13.6	2.5	0.9	6,858.0	68.0	761.92	0.9	770	89.06	
Tube mill 2C									Standby			
Tube mill 2D		113.9	13.1	2.45	0.95	6,834.0	65.5	736.5				100
		114.7	13.6	2.50	0.95	6,882.0	68.0	770.0				
		114.4	13.5	2.50	0.90	6,864.0	67.5	722.2				
Average		114.3	13.4	2.48	0.93	6,860.0	67.0	743.0		770.0	86.84	
Mill seal air fan A1									Standby			
Mill seal air fan A2		118.8	9.2	1.58	0.83	448.2	69.0	44.5	0.8	55	72.75	150
Mill seal air fan B1		119.5	10.6	1.85	0.84	450.8	79.5	52.1	0.8	55	85.33	150
Seal air fan B2									Standby			
Seal air fan C1		120.2	10.8	1.95	0.86	453.5	81.0	54.7	0.9	55	89.53	150
Seal air fan C2									Standby			
Seal air fan D2		119.4	9.5	1.67	0.86	450.5	71.3	47.8	0.9	55	78.23	150
PA fan 2A	R	114	11.9	1.98	0.8	6,840	59.5	592.11	0.8			0.2
	Y	114.4	11.8	1.97	0.8	6,864	59	589.19	0.8			0.1
Average		114.2	11.9	2.0	0.8	6,852.0	59.3	590.6	0.8	750	70.88	
PA fan 2B		113.9	11.7	1.95	0.84	6834.0	58.5	581.6				100
		114.7	11.9	2.00	0.85	6,882.0	59.5	602.8				
		114.4	11.8	1.90	0.85	6,864.0	59.0	596.2				
Average		114.3	11.8	1.95	0.85	6,860.0	59.0	593.5				
FD fan 2A	R	114	6.3	1.23	1	6,840	15.75	184.72	1			0.1
	Y	114.5	6.58	1.28	1	6,870	16.45	193.78	1			0.2
	B	114.4	6.3	1.25	1	6,864	15.75	185.37	1			0.1
Average		114.3	6.4	1.25	0.99	6,858.0	16.0	188.0				
FD fan 2B		113.9	5.7	1.10	0.99	6,834.0	14.3	167.0				50
		114.8	6.1	1.20	0.99	6,888.0	15.3	180.1				
		114.4	6.0	1.17	1.00	6,864.0	15.0	178.3				
Average		114.4	5.9	1.16	0.99	6,862.0	14.8	175.1				
ID fan 2A	R	114	11.4	2.16	1	6,840	57	648.26	1			0.2
	Y	114.4	11.3	2.18	1	6,864	56.5	651.55	1			0.2
	B	114.5	11.4	2.19	1	6,870	57	651.10	1			0.1
	Average	114.3	11.4	2.2	1.0	6,858.0	56.8	650.3	1.0	800	73.16	

ID fan 2B		113.9	12.2	2.30	0.95	6,834.0	61.0	685.9				100
		114.8	12.5	2.30	0.95	6,888.0	62.5	708.3				
		114.4	12.3	2.30	1.00	6,864.0	61.5	731.1				
Average		114.4	12.3	2.30	0.97	6,862.0	61.7	708.5		800.0	79.70	
BFP 2A	R	114.1	13.5	2.09	0.8	6,846	168.75	1,560.71	0.8			250/1A
	Y	114.6	13.2	1.94	0.8	6,876	165	1,572.02	0.8			
	B	114.5	13.2	2.03	0.8	6,870	165	1,531.38	0.8			
	Average	114.4	13.3	2.0	0.8	6,864.0	166.3	1,554.7	0.8	2000	69.96	
BFP 2B	R	114.1	13.5	2.09	0.8	6,834	172.5	1,592.60	0.8			
	Y	114.6	13.2	1.94	0.8	6,882	173.75	1636.12	0.8			
	B	114.5	13.2	2.03	0.8	6,864	173.75	1631.84	0.8			
	Average	114.4	13.3	2.0	0.8	6,860.0	173.3	1620.2	0.8	2000	72.91	
BFP 2C									Not Loaded			
Condensate Ext pump 2A							Standby					
Condensate Ext pump 2B		113.9	9.0	1.50	0.86	6,834.0	22.5	229.0	0.86			
CW pump 2A	R	113.8	11.8	2.2	1	6,828	59	669.83	1			100/1A
	Y	114.4	12.1	2.3	1	6,864	60.5	690.48	1			
	B	114.4	12	2.2	1	6,864	60	684.77	1			
	Average	114.2	12.0	2.2	1.0	6,852.0	59.8	681.70	1.0	643	95.42	
CW pump 2B		113.9	13.3	2.47	0.94	6,834.0	66.5	739.9				
Vacuum pump 2B		115.5	11.5	1.40	0.60	479.3	115.0	57.3	0.6	93	55.44	200
DW pump 2B		116.0	7.3	1.18	0.81	437.6	73.0	44.8	0.8	75	53.78	200
BACW 2A		422.2	97.8	63.08	0.88	422.2	97.8	62.9	0.9	56	101.14	
BACW 2B									Standby			
TACW 2A		113.7	17.5	2.96	0.87	429.0	218.8	141.4	0.9	130	97.89	250
TACW 2B									Standby			
TACW 2C		431.6	16.0	10.46	0.87	431.6	200.0	130.1	0.9	130	89.95	250
Compressor 2A		113.8	15.4	2.70	0.89	429.3	192.5	127.4	0.9	135	84.93	250
Compressor 2B		STANDBY										
Compressor 2C		431.5	15.0	9.46	0.84	431.5	75.0	47.1	0.8	135	31.39	250
Compressor 2C	On 100% loading	431.4	188.6	115.80	0.82	431.4	188.6	115.8	0.8	135	77.20	
	On 50% loading	432.5	121.5	79.33	0.86	432.5	121.5	79.3	0.86	135	52.89	
Compressor 2D									Standby			
AC compressor 2A		424.0	30.1	16.35	0.74	424.0	30.1	16.4	0.74	30	49.07	
AC compressor 2B		429.1	34.4	20.50	0.80	429.1	34.4	20.5	0.80	30	61.36	
FO pump 2B		432.0	11.8	6.00	0.70	432.0	11.8	6.2	0.70	15	37.08	
Degassed air blower 2		441.0	1.4	0.55	0.52	441.0	1.4	0.6	0.52			

Degassed water pump 2		430.0	8.7	5.11	0.77	430.0	8.7	5.0	0.77			
Alum dosing pump 2		440.0	1.2	0.87	0.92	440.0	1.2	0.8	0.92			
Ash water pump 1	R	114.0	8.2	1.40	0.89	6,840.0	20.5	216.1	0.89			50
	Y	115.1	8.8	1.58	0.90	6,906.0	22.0	236.8	0.90			
	B	114.3	8.2	1.47	0.91	6,858.0	20.5	221.6	0.91			
Average		114.5	8.4	1.5	0.9	6,868.0	21.0	224.9	0.90	275.0	73.59	
Ash water pump 2								Standby				
Ash water pump 3	R	114.1	11.5	2.00	0.85	6,846.0	28.8	289.8	0.85			50
	Y	115.3	11.5	2.20	0.86	6,918.0	28.8	296.3	0.86			
	B	114.5	11.3	1.90	0.87	6,870.0	28.3	292.4	0.87			
Average		114.6	11.4	2.0	0.9	6,878.0	28.6	292.8	0.86	275	95.83	
Ash slurry pump 1	R	114.0	8.9	1.70	0.97	6,840.0	22.3	255.7	0.97			50
	Y	115.2	9.8	1.90	0.98	6,912.0	24.5	287.4	0.98			
	B	114.4	9.2	1.80	0.99	6,864.0	23.0	270.7	0.99			
Average		114.5	9.3	1.8	1.0	6,872.0	23.3	271.3	0.98	200	122.1	

Appendix 2: Performance evaluation of boilers (Unit-2)

Coal analysis		
Carbon content	32.21	%
Hydrogen content	3.75	%
Nitrogen content	1.84	%
Oxygen content	10.87	%
Sulphur content	0.49	%
Ash content	39.45	%
Moisture content	11.39	%
GCV of coal	3,489	Kcal/kg
Ash analysis		
Unburnts in fly ash	1.16	%
Unburnts in bottom ash	3.98	%
GCV of fly zone ash	40	Kcal/kg
GCV of bottom ash	138.86	Kcal/kg
Efficiency by indirect method:		
Theoretical air requirement for	$((11.6 \times C) + (34.8 \times (H_2 - O_2 / 8)) + 4.35 \times S)$	kg/kg of coal
Complete combustion	100	
	4.59	kg/kg of coal
Excess air (EA) supplied	$O_2\% \times 100$	
	$21 - O_2\%$	
	25.91	%
AAS	(1 + EA / 100) X Theoretical air	
	5.78	kg/kg of coal
Mass of dry flue gas	AAS + 1	
	6.78	kg/kg of coal
% Heat loss in dry flue gas (L1)	$m \times C_p \times (T_f - T_a) \times 100$	
	GCV of fuel	
	4.24	%
% Heat loss due to H_2 in fuel (L2)	$9 \times H_2 \times (584 + C_p (T_f - T_a)) \times 100$	
	GCV of fuel	
	6.06	%
% Heat loss due to moisture in	$M \times (584 + C_p (T_f - T_a)) \times 100$	
Fuel (L3)	GCV of fuel	
	2.05	%
% Heat loss due to moisture in	$AAS \times Humidity \times (T_f - T_a)) \times 100$	
Air (L4)	GCV of fuel	
	0.15	%
% Heat loss due radiation and	1.5	%
unaccounted loss (L5)		
% Heat loss due to unburnts in	Total ash collected / kg of fuel burnt X GCV of convective zone ash X 100	
Bottom zone ash (L6)	GCV of fuel	
	0.06249	%
% Heat loss due to unburnts in	Total ash collected / kg of fuel burnt X GCV of economizer ash X 100	
Fly ash (L7)	GCV of fuel	
	0.01	%
Boiler efficiency by indirect method	100 - (L1 + L2 + L3 + L4 + L5 + L6 + L7)	
	85.93	%

Appendix 3: (Online power measurement Unit-1)

Reference	Phase	Voltage	Ampere	kW	PF	Motor rating (kW)	Motor loading (%)	CT ratio
Incomer from ST		6,852	136	1,130	0.70			
		6,813	136	1,123	0.70			
		6,780	136	1,086	0.68			1,600
Average		6,815	136	1,113	0.69			
Incomer from ST		6,864	80	932	0.98			1,600
		6,876	80	934	0.98			
		6,846	80	939	0.99			
Average		6,862	80	935	0.98			
Incomer ST2		6,828	75	798	0.90			2,500
		6,900	63	695	0.93			
		6,852	63	653	0.88			
Average		6,860	67	715	0.90			
Tie to Unit-1A bus		6,780	90	1,015	0.96			
		6,870	95	1,074	0.95			
		6,792	90	1,016	0.96			1,000
Average		6,814	92	1,035	0.96			
Tie to Unit-1B bus		6,876	20	188	0.79			1,000
		6,876	20	226	0.95			
		6,840	20	225	0.95			
Average		6,864	20	213	0.90			
Tie to C_1 to C_3							No load	
C_3 - C_2 Tie							No load	
C_3 - C_1 Tie							No load	
Station service transformer 1		6,780	6	69	0.98			
		6,864	6	70	0.98			
		6,828	5	57	0.96			200
Average		6,824	6	65	0.97			
UAT-1A		6,750	305		0.95			1,000
		6,774	315		0.75			
		6,756	310		0.90			
		6,760	310	3,630	0.87	12,000	27.22	
UAT-1B		6,750	450					1,000
		6,750	475					
		6,780	455					
		6,760	460	5,386		12,000	40.39	
ESP-1A		6,780	6					150

		6,756	3					
		6,780	5					
		6,772	5	25		800	2.77	
			0					
UST-1B		6,702	42					150
		6,714	42					
		6,708	42	488		1,280	34.31	
UST-1C		6,750	40					150
		6,780	42					
		6,750	38					
		6,760	40	468		1,000	42.15	
ST-1		6,906	168					1,600
		6,822	176					
		6,912	176					
		6,880	173	2,065		12,000	15.49	
UST-1B		6,732	18	204	0.97			
		6,720	18	153	0.73			
		6,822	17	143	0.71			150
Average		6,758	18	166	0.80	1600.0	7.5	
UST-1C		6,768	16	144	0.78			
		6,822	17	185	0.91			
		6,816	16	156	0.84			150
Average		6,802	16	161	0.84	1,250.0	9.8	
AH transformer 01		6,840	2	25		1,250	20.69	150
AH transformer 02		6,840	2	25		1,000	24.36	
		6,918	2	20				
Average		6,879	2	23	0.85			
Water treatment plant transformer		6,864	5	62	0.99			
		6,882	5	53	0.98			
		6,852	5	61	0.98			150
Average		6,866	5	57	0.98	1,250.0	4.1	
Coal handling transformer 1		6,774	39	430	0.94			
		6,864	40	437	0.92			
		6,816	40	444	0.94			200
Average		6,818	40	437	0.93	1,600.0	23.0	
Water treatment Plant transformer 1		6,774	6	68	0.97			
		6,870	6	70	0.98			

		6,828	6	69	0.97			150
Average		6,824	6	69	0.97			
CW pump 1A		6,756	56	655	0.96			
		6,804	60	673	0.96			
		6,750	57	628	0.95			100
Average		6,770	57	652	0.96	624.0	94.0	
CW pump 1B						Standby		
CW pump 1C						Standby		
FO pump 1B		439	12	6	0.65	15		
Overhead pump 3		450	15	11	0.92	9.3	102.2	
Raw water pump 1		444	18	9	0.65	15	54.6	
Raw water pump 3						In maintenance		
Raw water pump 2		430	21	12	0.75	15	68.8	
Overhead pump 1		445	16	11	0.88	9.3	99.6	
Overhead pump 2		445	16	11	0.88	9.3	102.7	
Ash water pump 1		6,840	21	216				50
		6,906	22	237				
		6,858	21	222				
Average		6,868	21	225	0.90	175.0	115.6	
Ash water pump 2						Not in operation		
Ash water pump 3		6,846	29	290				50
		6,918	29	296				
		6,870	28	292				
Average		6,878	29	293	0.86	175	150.6	
Ash slurry pump 1		6,840	22	256				50
		6,912	25	287				
		6,864	23	271				
Average		6,872	23	271	0.98	175	131.50	
Nash vacuum pump 1A					Standby			
TACW 1A		438	146	96	0.87	125	69.34	
BACW 1B		444	77	52	0.89	55	85.58	
BFP 1C						Standby		
Reverse osmosis plant								
HP pump	R	6,600	33	340	0.90			
	Y	6,600	35	360	0.90			
	B	6,600	37	378	0.90			
		6,600	35	359	0.90	600	53.88	
Filter seawater pump	R	410	44	28	0.90			

	B	410	41	26	0.90			
		410	43	27	0.90			
		410	43	27	0.90	33.5	73.49	
CW pump 1A		6,762	42	339	0.69			100
		6,786	58	654	0.96			
		6,756	57	635	0.96			
		6,768	52	532	0.87	624	76.73	
CW pump 1B		6,762	56	501	0.77			100
		6,786	55	583	0.91			
		6,762	55	515	0.80			
		6,770	55	533	0.83	624	76.89	
Coal mill 1B		6,744	13	139	0.90			25
		6,774	14	149	0.93			
		6,732	9	102	0.99			
		6,750	12	131	0.94	200	58.93	
Coal mill 1C		6,750	11	89	0.70			25
		6,756	12	98	0.73			
		6,780	10	88	0.73			
		6,762	11	92	0.72	200	41.26	
Coal mill 1D		6,756	8	71	0.78			25
		6,756	14	131	0.78			
		6,756	14	123	0.78			
		6,756	12	108	0.78	200	48.77	
Coal mill 1E		6,756	10	103	0.86			25
		6,780	11	115	0.90			
		6,756	10	103	0.86			
		6,764	10	107	0.87	200	48.15	
Coal mill 1F		6,756	12	96	0.70			25
		6,780	14	148	0.91			
		6,750	14	126	0.80			
		6,762	13	123	0.80	200	55.21	
FD fan 1A		6,750	20	229	0.98			50
		6,780	21	242	0.98			
		6,738	20	224	0.97			
		6,756	20	231	0.98	400	52.07	
FD fan 1B		6,720	20	198	0.85			50
		6,696	21	190	0.78			
		6,780	20	183	0.78			
		6,732	20	190	0.80	400	42.85	
ID fan 1A		6,750	56	644	0.98			125
		6,780	59	669	0.97			
		6,744	56	630	0.97			

		6,758	57	648	0.97	1200	48.59	
ID fan 1B		6,732	69	720	0.89	900	71.99	
PA fan 1A		6,756	34	282	0.71			100
		6,792	67	673	0.86			
		6,750	67	666	0.85			
		6,766	56	528	0.81	850	55.88	
Pa fan 1B		6,750	71	701	0.85			100
		6,756	74	688	0.80			
		6,786	73	741	0.87			
		6,764	72	710	0.84	850	75.19	
					0.00			125
Coal mill 1A		6,732	15	169	0.70			25
		6,774	14	167	0.90			
		6,750	14	168	0.10			
		6,752	14	168	0.57	200	75.64	
CEP 1A		6,756	24	229	0.82			30
		6,780	29	283	0.82			25
		6,744	24	228	0.81			30
		6,760	26	247	0.82	250	88.80	
BFP 1B		6,780	165	1,938	0.80			200
		6,756	165	1,931	0.83			
		6,732	172	2,005	0.83			
		6,756	167	1,958	0.82	1,800	97.90	
BFP 1C		6,816	146	1,724	0.10			200
		6,918	150	1,797	0.80			
		6,792	141	1,659	0.87			
		6,842	146	1,726	0.59	1,800	86.31	
TACW C pump		419	200	115	0.79	125	82.8	
TACW A pump		420	196	117	0.82	125	84.18	
IAC 1A		420	144	88	0.84	100	79.19	
IAC B		419	198	46	0.30	100	41.58	
Nash B		412	138	80	0.82	95	76.22	
SAC 1A		420	132	85	0.89	100	76.91	
Ash water pump 1A		Standby						
Ash water pump 1B		416	287	188	0.91	175	96.78	
Ash water pump 1C		415	284	188	0.92	175	96.58	
Ash slurry pump 1B		418	180	117	0.90	175	60.32	
Ash slurry pump 1A		Standby						

Appendix 4: Boiler performance evaluation (Unit-1)

Coal analysis		
Carbon content	32.21	%
Hydrogen content	3.75	%
Nitrogen content	1.84	%
Oxygen content	10.87	%
Sulphur content	0.49	%
Ash content	39.45	%
Moisture content	11.39	%
GCV of coal	3,489	Kcal/kg
Ash analysis		
Unburnts in fly ash	1.16	%
Unburnts in bottom ash	3.98	%
GCV of fly zone ash	40	Kcal/kg
GCV of bottom ash	138.86	Kcal/kg
Efficiency by indirect method:		
Theoretical air requirement for	$((11.6 \times C) + (34.8 \times (H_2 - O_2 / 8)) + 4.35 \times S))$	kg/kg of coal
Complete combustion	100	
	4.59	kg/kg of coal
Excess air (EA) supplied	$O_2\% \times 100$	
	$21 - O_2\%$	
	41.32	%
AAS	$(1 + EA / 100) \times$ Theoretical air	
	6.49	kg/kg of coal
Mass of dry flue gas	AAS + 1	
	7.49	kg/kg of coal
% Heat loss in dry flue gas (L1)	$m \times C_p \times (T_f - T_a) \times 100$	
	GCV of fuel	
	4.24	%
% Heat loss due to H_2 in fuel (L2)	$9 \times H_2 \times (584 + C_p (T_f - T_a)) \times 100$	
	GCV of fuel	

	6.02	%
% Heat loss due to moisture in	M X (584 + C_p (T_f - T_a)) X 100	
Fuel (L3)	GCV of fuel	
	2.03	%
% Heat loss due to moisture in	AAS X Humidity X (T_f - T_a) X 100	
Air (L4)	GCV of fuel	
	0.27	%
% Heat loss due radiation and	1.5	%
Unaccounted loss (L5)		
% Heat loss due to unburnts in	Total ash collected / kg of fuel burnt X GCV of convective zone ash X 100	
Bottom zone ash (L6)	GCV of fuel	
	0.06249	%
% Heat loss due to unburnts in	Total ash collected / kg of fuel burnt X GCV of economizer ash X 100	
Fly ash (L7)	GCV of fuel	
	0.01	%
Boiler efficiency by indirect method	100 - (L1 + L2 + L3 + L4 + L5 + L6 + L7)	
	85.86	%

Appendix 5: Load profile of transformer

Load profile of UST-2a$_2$
Assumed load loss = 16 kW
Assumed no-load loss = 3.2 kW
Full load amps = 140 A

Time	A	kWh	NLL (kWh)	FLL (kWh)
0:00	87	20,061	3.2	6.18
1:00	87	20,061	3.2	6.18
2:00	87	20,061	3.2	6.18
3:00	87	20,061	3.2	6.18
4:00	87	20,061	3.2	6.18
5:00	87	20,061	3.2	6.18
6:00	87	20,061	3.2	6.18
7:00	87	20,061	3.2	6.18
8:00	87	20,061	3.2	6.18
9:00	87	20,061	3.2	6.18
10:00	87	20,061	3.2	6.18
11:00	87	20,061	3.2	6.18
12:00	87	20,061	3.2	6.18
13:00	87	20,061	3.2	6.18
14:00	87	20,061	3.2	6.18
15:00	87	20,061	3.2	6.18
16:00	87	20,062	3.2	6.18
17:00	87	20,062	3.2	6.18
18:00	87	20,062	3.2	6.18
19:00	87	20,062	3.2	6.18
20:00	87	20,062	3.2	6.18
21:00	87	20,062	3.2	6.18
22:00	87	20,062	3.2	6.18
23:00	87	20,062	3.2	6.18
24:00	87	20,062	3.2	6.18
Total			**80**	**154.5**

Total no-load loss = 80 kW
Total full load loss = 154.5 kW
Total consumption = 234.5 kWh/day

Load profile of UST-2a$_1$
Assumed load loss = 12.5 kW
Assumed no-load loss = 2.5 kW
Full load amps = 140.0 A

Time	A	MW	kWh	NLL (kWh)	FLL (kWh)
0:00	65	0.55	334.454	2.5	2.70
1:00	65	0.55	334.456	2.5	2.70
2:00	65	0.55	334.458	2.5	2.70
3:00	66	0.55	334.461	2.5	2.78
4:00	66	0.55	334.462	2.5	2.78
5:00	66	0.55	334.464	2.5	2.78
6:00	66	0.55	334.466	2.5	2.78
7:00	66	0.55	334.468	2.5	2.78
8:00	66	0.55	334.47	2.5	2.78
9:00	66	0.55	334.472	2.5	2.78
10:00	66	0.55	334.474	2.5	2.78
11:00	90	0.55	334.477	2.5	5.17
12:00	73	0.66	334.479	2.5	3.40
13:00	70	0.63	334.481	2.5	3.13
14:00	71	0.65	334.484	2.5	3.22
15:00	71	0.65	334.486	2.5	3.22
16:00	70	0.64	334.489	2.5	3.13
17:00	70	0.64	334.491	2.5	3.13
18:00	70	0.65	334.494	2.5	3.13
19:00	70	0.65	334.496	2.5	3.13
20:00	75	0.67	334.498	2.5	3.59
21:00	75	0.67	334.5	2.5	3.59
22:00	70	0.62	334.503	2.5	3.13
23:00	70	0.62	334.505	2.5	3.13
24:00	70	0.62	334.508	2.5	3.13
Total				**62.5**	77.5

Total no-load loss = 62.5 kW
Total full load loss = 77.5 kW
Total consumption = 140 kWh/day

Load profile of ESP transformer-2b
Assumed load loss = 10 kW
Assumed no-load loss = 2 kW
Full load amps = 87.48 A

Time	A	NLL (kWh)	FLL (kWh)
0:00	6	2	2.65
1:00	6	2	2.65
2:00	6	2	2.65
3:00	6	2	2.65
4:00	6	2	2.65
5:00	6	2	2.65
6:00	6	2	2.65
7:00	6	2	2.65

8:00	6	2	2.65
9:00	7	2	3.60
10:00	7	2	3.60
11:00	7	2	3.60
12:00	7	2	3.60
13:00	7	2	3.60
14:00	7	2	3.60
15:00	6	2	2.65
16:00	6	2	2.65
17:00	5	2	1.84
18:00	5	2	1.84
19:00	5	2	1.84
20:00	5	2	1.84
21:00	5	2	1.84
22:00	5	2	1.84
23:00	5	2	1.84
24:00	5	2	1.84
Total		48	65.47

Total no-load loss = 48 kW
Total full load loss = 65.47 kW
Total consumption = 113.47 kWh/day

Load profile of ESP transformer-2a
Assumed load loss = 12.5 kW
Assumed no-load loss = 2.5 kW
Full load amps = 87.48 A

Time	A	kWh	NLL (kWh)	FLL (kWh)
0:00	6	40,728	2.5	3.31
1:00	6	40,728	2.5	3.31
2:00	6	40,728	2.5	3.31
3:00	6	40,728	2.5	3.31
4:00	6	40,728	2.5	3.31
5:00	6	40,728	2.5	3.31
6:00	6	40,729	2.5	3.31
7:00	6	40,729	2.5	3.31
8:00	6	40,729	2.5	3.31
9:00	7	40,729	2.5	4.50
10:00	7	40,729	2.5	4.50
11:00	7	40,729	2.5	4.50
12:00	7	40,730	2.5	4.50
13:00	7	40,730	2.5	4.50
14:00	7	40,730	2.5	4.50
15:00	6	40,730	2.5	3.31
16:00	7	40,731	2.5	4.50

17:00	7	40,731	2.5	4.50
18:00	7	40,731	2.5	4.50
19:00	6	40,731	2.5	3.31
20:00	6	40,732	2.5	3.31
21:00	6	40,732	2.5	3.31
22:00	6	40,732	2.5	3.31
23:00	6	40,732	2.5	3.31
24:00	6	40,732	2.5	3.31
Total			62.5	93.44

Total no-load loss = 62.5 kW
Total full load loss = 93.44 kW
Total consumption = 155.94 kWh/day

Load profile of UST-2b
Assumed load loss = 16 kW
Assumed no-load loss = 3.2 kW
Full load amps = 140 A

Time	A	MW	kWh	NLL (kWh)	FLL (kWh)
0:00	66	0.65	412.086	3.2	3.56
1:00	66	0.65	412.089	3.2	3.56
2:00	66	0.65	412.092	3.2	3.56
3:00	66	0.65	412.095	3.2	3.56
4:00	66	0.65	412.098	3.2	3.56
5:00	66	0.65	412.101	3.2	3.56
6:00	66	0.65	412.104	3.2	3.56
7:00	66	0.65	412.107	3.2	3.56
8:00	56	0.57	412.11	3.2	2.56
9:00	56	0.57	412.113	3.2	2.56
10:00	56	0.57	412.115	3.2	2.56
11:00	30	0.33	412.117	3.2	0.74
12:00	51	0.53	412.119	3.2	2.12
13:00	51	0.52	412.121	3.2	2.12
14:00	50	0.52	412.124	3.2	2.04
15:00	50	0.52	412.126	3.2	2.04
16:00	51	0.54	412.129	3.2	2.12
17:00	51	0.54	412.131	3.2	2.12
18:00	56	0.58	412.134	3.2	2.56
19:00	56	0.58	412.137	3.2	2.56
20:00	58	0.59	412.14	3.2	2.75
21:00	58	0.59	412.143	3.2	2.75
22:00	58	0.58	412.145	3.2	2.75
23:00	58	0.58	412.148	3.2	2.75
24:00	58	0.58	412.15	3.2	2.75
Total				80.00	68.32

Total no-load loss = 80 kW

Total full load loss = 68.32 kW
Total consumption = 148.32 kWh/day

Load profile of UAT-2b
Assumed load loss = 75 kW
Assumed no-load loss = 15 kW
Full load amps = 824.8 A

A	MW	kWh	NLL (kWh)	FLL (kWh)
470	4.5	772.6	15	24.35
470	4.5	772.68	15	24.35
470	4.5	772.761	15	24.35
470	4.5	772.843	15	24.35
470	4.5	772.925	15	24.35
470	4.5	773.006	15	24.35
470	4.5	773.088	15	24.35
470	4.5	773.17	15	24.35
470	4.5	773.25	15	24.35
470	4.5	773.33	15	24.35
470	4.5	773.415	15	24.35
450	4.3	773.445	15	22.32
460	4.5	773.57	15	23.33
460	4.5	773.645	15	23.33
470	4.5	773.733	15	24.35
470	4.5	773.821	15	24.35
470	4.5	773.893	15	24.35
470	4.5	773.966	15	24.35
540	5	774.064	15	32.15
540	5	774.155	15	32.15
540	5	774.247	15	32.15
540	5	774.339	15	32.15
540	5	774.43	15	32.15
540	5	774.515	15	32.15
540	5	774.6	15	32.15
			360	659.28

Total no-load loss = 360 kW
Total full load loss = 659.28 kW
Total consumption = 1,019.2 kWh/day

Load profile of UAT-2a
Assumed load loss = 75 kW
Assumed no-load loss = 15 kW
Full load amps = 824.8 A

A	kWh	NLL (kWh)	FLL (kWh)
600	798.8	15	39.68866
440	798.8	15	21.34368
440	798.8	15	21.34368
440	798.8	15	21.34368
440	798.8	15	21.34368
440	798.8	15	21.34368
440	798.8	15	21.34368
440	798.8	15	21.34368
440	798.8	15	21.34368
450	798.8	15	22.32487
450	798.8	15	22.32487
470	798.8	15	24.3534
460	798.8	15	23.32811
450	798.8	15	22.32487
460	798.8	15	23.32811

460	798.8	15	23.32811
460	798.8	15	23.32811
460	798.8	15	23.32811
465	798.8	15	23.838
460	798.8	15	23.32811
460	798.8	15	23.32811
460	798.8	15	23.32811
460	798.8	15	23.32811
460	798.8	15	23.32811
460	798.8	15	23.32811
Total		360	582.21

Total no-load loss = 360 kW
Total full load loss = 582.2 kW
Total consumption = 942.2 kWh/day

Checklist for performance improvement in TPPs

- ✓ Impact of parameter deviation on heat rate
  - PARTIAL LOADING, MW 210, 24.7, PER 20 MW, 1.235 Kcal/kWh
  - MS PRESS KG/CM^2,150, 25.5, PER 20 KG/CM^2, 1.275 Kcal/kWh
  - MS TEMP AT HPT INLET DEG C, 535 7.5, PER 10 DEG C, 0.75 Kcal/kWh
  - HRH TEMP AT IPT INLET DEG, 535 6.6 PER 10 DEG C, 0.66 Kcal/kWh
  - CONDENSER VACUUM mmHg, 660 23.4 PER 10 mm Hg, 2.34 Kcal/kWh
  - FEED WATER TEMP DEG C, 241 16 PER 20 DEG C, 0.8 Kcal/kWh
  - RH ATTEMP FLOW T/HR 0 6.4 PER 10 T/HR, 0.64 Kcal/kWh
  - OXYGEN % IN FLUE GASES 3 % to 8 %

From above, to achieve minimum heat rate, keep the operating parameters as close to the design parameters.

- ✓ Normative station heat rate. Existing coal-based stations.
  - 210 MW – 2,500 Kcal/kWh
  - 500 MW – 2,425 Kcal/kWh
  - In respect of 500 MW and above units where the boiler feed pumps are electrically operated, the station heat rate will be 40 Kcal/kWh lower than the station heat rate indicated above.
  - New coal-based stations – 1.065 x Design heat rate.

- ✓ Heat rate of turbine cycle unit, Kcal/kWh
  - 210 MW turbine (LMZ) - 2,063
  - 210 MW turbine (KWU) - ν 210 MW - 1,952 ν 168 MW - 2,001
  - 500 MW turbine (KWU) -
  - 500 MW - 1,945
  - 400 MW - 1,988
  - 300 MW - 2,063.2
  - 250 MW - 2,134.3

- ✓ Example of 210 MW
  - Operating efficiency of unit is 37.5%.
  - Unit heat rate is 2,305 Kcal/kWh.
  - That is, to produce 860 Kcal (heat equivalent to one kWh), 2,305 Kcal heat must be supplied to the boiler.
  - Losses in the boiler - 266 Kcal
  - Losses in turbine generator - 1,179 Kcal
  - Total losses - (266 + 1,179) = 1,445 Kcal

- Total heat input to boiler = (1,445 + 860) Kcal, produces 1 kWh

✓ Power plant efficiency
- Subcritical, 34%
- Super critical, 37%
- Ultra-super critical, 41%

✓ Major reasons for higher gross heat rate
- Low combustion efficiency leads to high carbon loss.
- High-force outages due to failure of boiler tubes.
- Poor performance of milling system.
- Lack of maintenance planning and spares planning.
- Low turbine cylinder efficiency.
- High dry gas losses due to high unwanted excess air.
- Poor sealing and heat transfer in air preheaters.
- Low condenser vacuum.
- High air ingress in the boiler and high heat loss due to poor insulation.
- Poor performance of ESP leading to failure of ID fan and low availability.
- High CW inlet temperature due to poor performance of CT.
- Nonavailability of quantity and quality coal.
- High APC.
- Obsolete control and instrumentation (C&I) system.
- Poor quality critical valves lead to passing and poor control.

✓ Conclusion
- Only improvements in the station heat rate,
- Specific fuel oil consumption, and
- Auxiliary energy consumption.

✓ Can make generating units competitive.
- Less emissions
- As the heat rate decreases (heat rate improves), the amount of fuel for the same generation also goes down.
- With less fuel burned, emissions (greenhouse gases) are lowered.

Heat rate audit in TPP
The new scenario is the new competitive scenario that power stations must face.

- To reduce the generating costs.
- To maintain high availability, efficiency, and operational flexibility.
- To meet strict environmental conditions.
- To manage and extend the equipment's life, including systems modernization.

The generation cost
The variable overall cost is a function of:

- The plant availability factor
- Station heat rate
- Specific fuel oil consumption
- Auxiliary energy consumption

The variable cost decides the competitiveness of the electric units in a generating pool.

The generation cost reduction

- The kWh fuel cost = 70% approximately the variable overall cost.
- The fuel cost components: The station heat rate (Kcal/kWh).
- To reduce the variable cost through the heat rate improvement.

Losses in TPP

- Boiler losses
- Turbine losses
- Condensate/feed water system losses
- Circulating water system losses
- Steam conditions
- Electrical auxiliary losses
- Steam auxiliary losses
- Fuel handing
- Heat losses
- Cycle isolation
- Impact of parameter deviation on heat rate
- DM water makeup.

Boiler losses

- Symptoms
    - o Boiler efficiency
    - o Exit gas temperature high
    - o Excess air
- Causes
    - o Moisture losses
    - o Dry gas losses
    - o Incomplete combustion
    - o Radiation losses
    - o Moisture losses
        - a. High moisture in air
        - b. Tube leaks
        - c. Coal quality
    - o Dry losses
        - a. Boiler casing air leakage
        - b. Air preheater leakage
        - c. Incorrect fuel air ratio
        - d. Fouled heat transfer surfaces
    - o Incomplete combustion
        - a. Coal quality
            - I. Increase in ash content
            - II. Increase in carbon content
            - III. Decreased coal mill fineness
            - IV. Classifier vanes improperly adjusted
            - V. Ring/roller wear
            - VI. Classifier vane wear
            - VII. Burner tips plugged/eroded
            - VIII. Burner damper settings
            - IX. Incorrect fuel air ratio
            - X. High oxygen at boiler out

Turbine losses

- Symptoms
  - HP/IP/LP section efficiency
- Causes
  - Mechanical damage
  - Metallurgical defects
  - Maintenance practices
  - Flow area decrease
  - Mechanical blockage
  - Blade deposits
  - Flow area bypass
  - Flow area increase
  - Flow area bypass
    - HP turbine inlet bushing leakage
    - Main steam valve leakage
    - HP gland seal leakage
    - IP steam/intercept valve leakage
    - IP turbine inlet bushing leakage
  - Flow area increase
    - Spill strip or packing leakage
    - Rubbing
    - Thermal stress
    - Erosion of turbine stages
    - Solid particle erosion of nozzle block
    - Condenser leaks
    - Poor water chemistry
    - Blade mechanism damage

Leaking steam in the turbine does not contribute to power generation.

Condensate/feed water system losses

- Symptoms
  - Low feed water temperature
- Causes
  - HPHs/LPHs out of service
  - CEP/BFP efficiency
  - Shaft rub
  - Impeller wear
  - Flow resistance path increase
  - LPHs/HPHs (high TTD/DCA)
    - Excessive tube plugged
    - Feed water heater out/bypass
    - Feed water heater level low/high

Circulating water losses

- Symptoms
  - High back pressure
- Causes
  - Number of CW pump in operation
  - Air binding of condenser tubes
    - Excessive air in leakage
    - Inadequate air removal capacity
  - Fouled condenser tubes

        - Microfouling
        - Plugged condenser tubes
        - Air binding water box
    - Low circulating water flow
        - Increased CW system resistance
        - Decreased CW pump performance
        - Excessive condenser tube plugged
    - Steam condition
        - Firing conditions
        - High super heater spray flow
        - High reheater spray flow
        - Inadequate heat transfer surface

Electrical auxiliary losses

- Symptoms
    - Station load
- Causes
    - Precipitator (ESP) performance
        a. Ash deposit
        b. Excessive rapping
        c. High ash in coal
    - Fan (ID, FD, PA)
    - Change in fan efficiency
    - AHP chocking
    - Pump (BFP, CEP, CW)
        a. Change in pump efficiency
    - LP/HP feed water heater tube plugged
    - Coal mill performance
        a. Classifier setting incorrect ν coal quality

Steam auxiliary losses

- Excessive soot blowing
- Decrease in BFP turbine efficiency
- Low inlet steam temperature
- Excessive steam flow through vacuum pump/ejector
- Steam trap/vent leaking
- Excessive usage of steam coil

Fuel handling

- Spillage from the belt/transport
- Measurement inaccuracies
- Coal pile erosion
- Wind erosion
- Water erosion
- Coal pile fire

Heat losses

- Insulation on duct, pipe, turbine, etc.
- No insulation
- Insulation damages
- Poor insulation
- Cladding missing/loose
- Steam leakage

- Leakage to blow down tank
- Leakage through vents and drains

Cycle isolation

- Leakage from recirculation valves of BFP/CEP
- Leakage through bypass valves
- Leakage to condenser through high energy drains
- Leakage to condenser through emergency control valves of feed water heaters
- Check high energy drains after every startup
  - Provide thermocouple in high energy drains
  - To detect passing of drain valve

500 MW turbine controllable losses

- DM water makeup
  - Boiler tube leaks
  - Excess deaerator venting to atmosphere
  - Excess continuous blowdown
  - Excess steam lost through condenser venting
  - Valve packing leaks
  - Pump seal leaks
  - Steam leaks to atmosphere

Heat rate monitoring

- Daily heat rate calculation by deviation method and identification of heat rate losses
- Monthly performance test (as per ASME PTC/BS/DIN PG test method)
- Boiler efficiency
- Air preheater performance
- Economizer performance
- Turbine heat rate
- HP-LP-IP cylinder efficiency
- Heaters and condenser
- Turbine cycle rate

6 Annexure 6: Energy Audit Tips, Checklist, and Best Practices in a TPP

6.1 Tips, checklist, and best practices for EE in thermal and electrical subsystems

Thermal and electrical subsystems

Boilers[4]

- Preheat combustion air with waste heat (22°C reduction in flue gas temperature increases boiler efficiency by 1%).
- Use variable speed drives on large boiler combustion air fans with variable flows.
- Burn waste, if permitted.
- Insulate exposed heated oil tanks.
- Clean burners, nozzles, strainers, etc.
- Inspect oil heaters for proper oil temperature.
- Close burner air and/or stack dampers when the burner is off to minimize heat loss up the stack.
- Improve oxygen trim control (e.g., limit excess air to less than 10% on clean fuels). (A 5% reduction in excess air increases boiler efficiency by 1% or 1% reduction of residual oxygen in stack gas increases boiler efficiency by 1%.)
- Automate/optimize boiler blowdown. Recover boiler blowdown heat.
- Inspect door gaskets.
- Inspect for scale and sediment on the water side.
  (A 1-mm thick scale (deposit) on the water side could increase fuel consumption by 5–8%.)
- Inspect for soot, fly ash, and slag on the fire side.
  (A 3-mm thick soot deposition on the heat transfer surface can cause an increase in fuel consumption to the tune of 2.5%).
- Optimize boiler water treatment.
- Add an economizer to preheat boiler feed water using exhaust heat.
- Recycle steam condensate.
- Study part-load characteristics and cycling costs to determine the most efficient mode for operating multiple boilers.
- Consider multiple or modular boiler units instead of one or two large boilers.
- Establish a boiler efficiency maintenance program. Start with an energy audit and follow-up, then make a boiler efficiency maintenance program a part of your continuous energy management program.

Steam system

- Fix steam leaks and condensate leaks. (A 3-mm diameter hole on a pipeline carrying 7 kg/cm^2 steam would waste 33 kiloliters of fuel oil a year).
- Accumulate work orders for repair of steam leaks that cannot be fixed during the heating season due to system shutdown requirements. Tag each such leak with a durable tag with a good description.
- Use back pressure steam de-superheating methods.
- Ensure process temperatures are correctly controlled.
- Maintain lowest acceptable process steam piping.
- Reduce hot water wastage to drain.
- Remove or blank off all redundant steam piping.

[4] Energy Efficiency in Thermal Utilities, BEE Book 2.

- Ensure condensate is returned or reused in the process. (6°C raise in feed water temperature by economizer/condensate recovery corresponds to a 1% saving in fuel consumption in boiler).
- Preheat boiler feed water.
- Recover boiler blowdown.
- Check operation of steam traps.
- Remove air flow indirect steam using equipment. (A 0.25-mm thick air film offers the same resistance to heat transfer as a 330-mm thick copper wall).
- Inspect steam traps regularly and repair malfunctioning traps promptly.
- Consider recovery of vent steam (e.g., on large flash tanks).
- Use waste steam for water heating.
- Use an absorption chiller to condense exhaust steam before returning the condensate to the boiler.
- Use electric pumps instead of steam ejectors when cost benefits permit.
- Establish a steam efficiency maintenance program as a part of your continuous energy management program.

Furnaces

- Check against infiltration of air: Use doors or air curtains.
- Monitor O_2/CO_2/CO and control excess air to the optimum level.
- Improve burner design, combustion control, and instrumentation.
- Ensure that the furnace combustion chamber is under slight positive pressure.
- Use ceramic fibers in case of batch operations.
- Match the load to the furnace capacity.
- Retrofit with a heat recovery device.
- Provide temperature controllers.
- Ensure that the flame does not touch the stock.

Insulation

- Repair damaged insulation. (A bare steam pipe of 150-mm diameter and 100-meter length carrying saturated steam at 8 kg/cm^2 would waste 25,000 liters of furnace oil in a year.)
- Insulate any hot or cold metal or insulation.
- Replace wet insulation.
- Use an infrared gun to check for cold wall areas during cold weather or hot wall areas during hot weather.
- Ensure that all insulated surfaces are clad with aluminum.
- Insulate all flanges, valves, and couplings.
- Insulate open tanks (Heat losses of 70% can be reduced by floating a layer of 45-mm diameter polypropylene [plastic] balls on the surfaces of 90°C hot liquid/condensate).

Waste heat recovery

- Recover heat from flue gas, engine CW, engine exhaust, LP waste steam, drying oven exhaust, boiler blowdown, etc.
- Recover heat from incinerator off-gas.
- Use waste heat for fuel oil heating, boiler feed water heating, outside air heating, etc.
- Use chiller waste heat to preheat hot water.
- Use heat pumps.
- Use absorption refrigeration.
- Use thermal wheels, run-around systems, heat pipe systems, and air-to-air exchangers.

Electrical subsystems

Electricity

- Optimize the tariff structure with the utility supplier.
- Schedule your operations to maintain a high load factor.
- Shift loads to off-peak times, if possible.
- Minimize maximum demand by tripping loads through a demand controller.
- Stagger start-up times for equipment with large starting currents to minimize load peaking.
- Use standby electric generation equipment for on-peak high load periods.
- Correct power factors to at least 0.90 underrated load conditions.
- Relocate transformers close to main loads.
- Set transformer taps to optimum settings.
- Disconnect primary power to transformers that do not serve any active loads.
- Consider on-site electric generation or cogeneration.
- Export power to grid if you have any surplus in your captive generation.
- Check utility electric meter with your own meter.
- Shut off unnecessary computers, printers, and copiers at night.

Motors

- Properly sized to the load for optimum efficiency. (High efficiency motors offer 4–5% higher efficiency than standard motors.)
- Use EE motors where economical.
- Use synchronous motors to improve power factors.
- Check alignment.
- Provide proper ventilation (for every 10°C increase in motor operating temperature over recommended peak, the motor life is estimated to be halved).
- Check for under-voltage and over-voltage conditions.
- Balance the three-phase power supply. (An imbalanced voltage can reduce 3–5% in motor input power.)
- Demand efficiency restoration after motor rewinding. (If rewinding is not done properly, the efficiency can be reduced by 5–8%).

Drives

- Use variable speed drives for large variable loads.
- Use high efficiency gear sets.
- Use precision alignment.
- Eliminate variable pitch pulleys.
- Check belt tension regularly.
- Use flat belts as alternatives to v-belts.
- Use synthetic lubricants for large gearboxes.
- Eliminate eddy current couplings.
- Shut them off when not needed.

Fans

- Use smooth, well-rounded air inlet cones for fan air intakes.
- Avoid poor flow distribution at the fan inlet.
- Minimize fan inlet and outlet obstructions.
- Clean screens, filters, and fan blades regularly.
- Use aerofoil-shaped fan blades.
- Minimize fan speed.
- Use low-slip or flat belts.
- Check belt tension regularly.

- Eliminate variable pitch pulleys.
- Use variable speed drives for large variable fan loads.
- Use EE motors for continuous or near continuous operation.
- Eliminate leaks in ductwork.
- Minimize bends in ductwork.
- Turn fans off when not needed.

Blowers

- Use smooth, well-rounded air inlet ducts or cones for air intake.
- Minimize blower inlet and outlet obstructions.
- Clean screens and filters regularly.
- Minimize blower speed.
- Use low-slip or no-slip belts.
- Check belt tension regularly.
- Eliminate variable pitch pulleys.
- Use variable speed drives for large variable blower loads.
- Use EE motors for continuous or near continuous operation.
- Eliminate ductwork leaks.
- Turn blowers off when they are not needed.

Pumps

- Operate pumping near the best efficiency point.
- Modify pumping to minimize throttling.
- Adapt to wide load variation with variable speed drives or sequenced control of smaller units.
- Stop running both pumps—add an auto start for an online spare or add a booster pump in the problem area.
- Use booster pumps for small loads requiring higher pressures.
- Increase fluid temperature differentials to reduce pumping rates.
- Repair seals and packing to minimize water waste.
- Balance the system to minimize flows and reduce pump power requirements.
- Use siphon effect to advantage: Do not waste pumping head with a free-fall (gravity) return.

Compressors

- Consider variable speed drive for variable load on positive displacement compressors.
- Use a synthetic lubricant if the compressor manufacturer permits it.
- Be sure lubricating oil temperature is not too high (oil degradation and lowered viscosity) and not too low (condensation contamination).
- Change the oil filter regularly.
- Periodically inspect compressor intercoolers for proper functioning.
- Use water heat from a very large compressor to power an absorption chiller or preheat process or utility feeds.
- Establish a compressor efficiency maintenance program. Start with an energy audit and follow-up, then make a compressor efficiency maintenance program a part of your continuous energy management program.

Compressed air

- Install a control system to coordinate multiple air compressors.
- Study part load characteristics and cycling costs to determine the most efficient mode for operating multiple air compressors.
- Avoid oversizing—match the connected load.
- Load up modulation-controlled air compressors (they use almost as much power at partial load as at full load).

- Turn off the backup air compressor until it is needed.
- Reduce air compressor discharge pressure to the lowest acceptable setting. (Reduction of 1 kg/cm^2 air pressure [8 kg/cm^2 to 7 kg/cm^2] would result in 9% input power savings. This will also reduce compressed air leakage rates by 10%.)
- Use the highest reasonable dryer dew point settings.
- Turn off refrigerated and heated air dryers when the air compressors are off.
- Use a control system to minimize heatless desiccant dryer purging.
- Minimize purges, leaks, excessive pressure drops, and condensation accumulation. (Compressed air leaks from a 1-mm hole at 7 kg/cm^2 pressure would mean power loss equivalent to 0.5 kW.)
- Be sure that air/oil separators are not fouled.
- Monitor pressure drops across suction and discharge filters and clean or replace filters promptly upon alarms.
- Use nozzles or venturi-type devices rather than blowing with open compressed air lines.

Chillers

- Increase the chilled water temperature set point, if possible.
- Use the lowest temperature condenser water available that the chiller can handle. (Reducing condensing temperature by 5.5°C results in a 20–25% decrease in compressor power consumption.)
- Increase the evaporator temperature. (5.5°C increase in evaporator temperature reduces compressor power consumption by 20–25%.)
- Clean heat exchangers when fouled. (A 1-mm scale build-up on condenser tubes can increase energy consumption by 40%.)
- Optimize condenser water flow rate and refrigerated water flow rate.
- Replace old chillers or compressors with new higher-efficiency models.
- Use a water-cooled rather than air-cooled chiller condenser.
- Isolate off-line chillers and CTs.
- Establish a chiller efficiency maintenance program. Start with an energy audit and follow-up, then make a chiller efficiency maintenance program a part of your continuous energy management program.

HVAC

- Tune up the HVAC control system.
- Consider installing a building automation system or energy management system or restoring an out-of-service one.
- Balance the system to minimize flows and reduce blower/fan/pump requirements.
- Eliminate or reduce reheating whenever possible.
- Use appropriate HVAC thermostat setback.
- Use morning precooling in summer and preheating in winter (i.e., before electrical peak hours).
- Use building thermal lag to minimize HVAC equipment operating time.
- In winter, during unoccupied periods, allow temperature to rise as high as possible without damaging stored materials.
- Improve control and utilization of outside air.
- Use air-to-air heat exchangers to reduce energy requirements for heating and cooling of outside air.
- Reduce HVAC system operating hours (e.g., night, weekend).
- Install ceiling fans to minimize thermal stratification in high bay areas.
- Eliminate obstructions in front of radiator, baseboard heaters, etc.
- Check reflectors on infrared heaters for cleanliness and proper beam direction.
- Use professionally designed industrial ventilation hoods for dust and vapor control.
- Use local infrared heat for personnel rather than heating the entire area.

- Purchase only high efficiency models for HVAC window units.
- Put HVAC window units on timer control.
- Minimize HVAC fan speed.
- Consider ground source heat pumps.
- Seal leaky HVAC ductwork. Seal all leaks around coils.
- Zone HVAC air and water systems to minimize energy use.

CTs

- Control CT fans based on leaving water temperatures.
- Control of the optimum water temperature as determined from CT and chiller performance data.
- Turn off unnecessary CT fans when loads are reduced.
- Balance flow to CT hot water basins.
- Cover hot water basins (to minimize algae growth that contributes to fouling).
- Reline leaking CT cold water basins.
- Optimize chemical use.
- Optimize blowdown flow rate.
- Automate blowdown to minimize it.
- Send blowdown to other uses (remember, the blowdown does not have to be removed at the CT. It can be removed anywhere in the piping system).
- Implement interlocks to prevent fan operation when there is no water flow.
- Establish a CT efficiency maintenance program. Start with an energy audit and follow-up, then make a CT efficiency maintenance program a part of your continuous energy management program.

6.2 Energy-saving opportunities in TPP

Steam

- The steam mains should be run with a falling slope of not less than 125 mm for every 30-meter length in the direction of the steam flow.
- Drain points should be provided at intervals of 30–45 meters along the main.
- Drain points should also be provided at low points in the mains and where the steam main rises. Ideal locations are the bottom of expansion joints and before reduction and stop valves.
- Drain points in the main lines should be through an equal tee connection only.
- To ensure dry steam in the process equipment and in branch lines, steam separators can be installed as required.
- Expansion loops are required to accommodate the expansion of steam lines while starting from cold.
- The branch lines from the mains should always be connected at the top. Otherwise, the branch line itself will act as a drain for the condensate.

Compressed air system

- Ensure air intake to compressor is not warm and humid by locating compressors in well-ventilated areas or by drawing cold air from outside. Every 4°C rise in air inlet temperature will increase power consumption by 1%.
- Clean air-inlet filters regularly. Compressor efficiency will be reduced by 2% for every 250-mm Water Column (WC) pressure drop across the filter.
- Keep compressor valves in good condition by removing and inspecting once every 6 months. Worn-out valves can reduce compressor efficiency by as much as 50%.
- Install manometers across the filter and monitor the pressure drop as a guide to replacement of elements.

- Minimize low-load compressor operation; if air demand is less than 50% of compressor capacity, consider changing over to a smaller compressor or reduce compressor speed appropriately (by reducing motor pulley size) in case of belt-driven compressors.
- Consider the use of regenerative air dryers, which use the heat of compressed air to remove moisture.
- Fouled intercoolers reduce compressor efficiency and cause more water condensation in air receivers and distribution lines resulting in increased corrosion. Periodic cleaning of intercoolers must be ensured.
- Compressor FAD test must be done periodically to check the present operating capacity against its design capacity, and corrective steps must be taken, if required.
- If more than one compressor is feeding to a common header, compressors must be operated in such a way that only one small compressor should handle the load variations, whereas other compressors will operate at full load.
- The possibility of heat recovery from hot compressed air to generate hot air or water for process application must be economically analyzed in case of large compressors.
- Consideration should be given to two-stage or multistage compressors, as they consume less power for the same air output than a single stage compressor.
- If pressure requirements for processes are widely different (e.g., 3–7 bar), it is advisable to have two separate compressed air systems.
- Reduce compressor delivery pressure, wherever possible, to save energy.
- Provide extra air receivers at points of high cyclic air demand, which permits operation without extra compressor capacity.
- Retrofit with variable speed drives in big compressors, say over 100 kW, to eliminate the "unloaded" running condition altogether.
- Keep the minimum possible range between the load and unload pressure settings.
- Automatic timer-controlled drain traps waste compressed air every time the valve opens. So, frequency of drainage should be optimized.
- Check air compressor logs regularly for abnormal readings, especially motor current CW flow and temperature, interstage and discharge pressures, and temperatures and compressor load cycle.
- Compressed air leakage of 40–50% is common. Carry out periodic leak tests to estimate the quantity of leakage.
- Install equipment interlocked solenoid cut-off valves in the air system so that air supply to a machine can be switched off when not in use.
- Present energy prices justify liberal designs of pipeline sizes to reduce pressure drops.
- Compressed air piping layout should be made preferably as a ring main to provide desired pressures for all users.
- A smaller dedicated compressor can be installed at load point, located far off from the central compressor house, instead of supplying air through lengthy pipelines.
- All pneumatic equipment should be properly lubricated, which will reduce friction and prevent wear of seals and other rubber parts, thus preventing energy wastage due to excessive air consumption or leakage.
- Misuse of compressed air such as for body cleaning, agitation, general floor cleaning, and other similar applications must be discouraged to save compressed air and energy.
- Pneumatic equipment should not be operated above the recommended operating pressure, as this not only wastes energy but can also lead to excessive wear of equipment components, which leads to further energy wastage.
- Pneumatic transport can be replaced by a mechanical system, as the former consumes about 8 times more energy. The highest possibility of energy savings is by reducing compressed air use.
- Pneumatic tools such as drills and grinders consume about 20 times more energy than motor-driven tools. Hence, they must be used efficiently. Wherever possible, they should be replaced with electrically operated tools.

- Where possible, welding is a good practice and should be preferred over threaded connections.
- Because of high pressure drop, ball, or plug or gate valves are preferable over globe valves in compressed air lines.

Refrigeration and AC systems

- Cold insulation
  - Insulate all cold lines/vessels using economic insulation thickness to minimize heat gains and choose appropriate (correct) insulation.
- Building envelope
  - Optimize air conditioning volumes by measures such as use of false ceiling and segregation of critical areas for air conditioning by air curtains.
- Building heat load minimization
  - Minimize the air conditioning loads by measures such as roof cooling, roof painting, efficient lighting, precooling of fresh air by air-to-air heat exchangers, variable volume air system, optimal thermo-static setting of temperature of air-conditioned spaces, sun film applications, etc.
- Process heat load minimization
  - Minimize process heat loads in terms of ton of refrigeration (TR) capacity, as well as refrigeration level, that is, temperature required by way of:

    ✓ Flow optimization;
    ✓ Heat transfer area increase to accept higher temperature coolant;
    ✓ Avoiding wastages like heat gains, loss of chilled water, and idle flows; and
    ✓ Frequent cleaning/descaling of all heat exchangers.

- At the refrigeration/air conditioning plant area:

  - Ensure regular maintenance of all air conditioning (A/C) plant components as per manufacturer's guidelines. Ensure adequate quantity of CW and CT water flows and avoid bypass flows by closing valves of idle equipment.
  - Minimize part load operations by matching loads and plant capacity online; adopt variable speed drives for varying process load.
  - Make efforts to continuously optimize condenser and evaporator parameters for minimizing SEC and maximizing capacity.
  - Adopt VAR system where economics permit as a non-CFC solution.

Fan systems

- Minimizing demands on the fan:
  - Minimizing excess air level in combustion systems to reduce FD fan and ID fan load.
  - Minimizing air in-leaks in hot flue gas path to reduce ID fan load, especially in case of kilns, boiler plants, furnaces, etc. Cold air in-leaks increase ID fan load tremendously, due to density increase of flue gases and in-fact choke up the capacity of fan, resulting as a bottleneck for the boiler/furnace itself.
  - In-leaks/out-leaks in air conditioning systems also have a major impact on EE and fan power consumption and need to be minimized.
- The findings of performance assessment trials will automatically indicate potential areas for improvement, which could be one or a more of the following:
  - Change of impeller with a higher efficiency impeller along with cone.
  - Change of fan assembly with a higher efficiency fan.
  - Impeller derating (with a smaller diameter impeller).
  - Change of metallic/glass-reinforced plastic impeller by the more EE hollow Fiberglass Reinforced Plastic (FRP) impeller with aerofoil design, in case of axial flow fans, where significant savings have been reported.

- Fan speed reduction by pulley diameter modifications for derating.
- Option of two speed motors or variable speed drives for variable duty conditions.
- Option of EE flat belts or cogged raw edged V belts in place of conventional V belt systems, for reducing transmission losses.
- Adopting inlet guide vanes in place of discharge damper control.
- Minimizing system resistance and pressure drops by improvements in the duct system.

<u>Pumping systems</u>

- Ensure adequate NPSH at site of installation.
- Ensure availability of basic instruments at pumps like pressure gauges and flow meters.
- Operate pumps near the best efficiency point.
- Modify pumping system and pump losses to minimize throttling.
- Adapt to wide load variation with variable speed drives or sequenced control of multiple units.
- Stop running multiple pumps—add an autostart for an online spare or add a booster pump in the problem area.
- Use booster pumps for small loads requiring HPs.
- Increase liquid temperature differentials to reduce pumping rates in case of heat exchangers.
- Decrease outlet cold water temperature of CT to reduce the pumping flow rates in case of mixing.
- Separate HP and LP systems.
- Repair seals and packing to minimize water loss by dripping.
- Balance the system to minimize flows and reduce pump power requirements.
- Avoid pumping head with a free-fall return (gravity). Use siphon effect to advantage.
- Conduct water balance to minimize water consumption.
- Avoid CW recirculation in DG sets, air compressors, refrigeration systems, CT feed water pumps, condenser pumps, and process pumps.
- In multiple pump operations, carefully combine the operation of pumps to avoid throttling.
- Provide booster pump for few areas of higher head.
- Replace old pumps with EE pumps.
- In the case of an over-designed pump, provide variable speed drive, or downsize/replace impeller or replace with correct sized pump for efficient operation.
- Optimize the number of stages in multistage pump in case of head margins.
- Reduce system resistance by pressure drop assessment and pipe size optimization.

<u>Lighting</u>

- Design of CTs with FRP impellers and film fills, PVC drift eliminators, etc.
- Use of softened water for condensers in place of raw water.
- The use of economic insulation thickness on cold lines and heat exchangers, taking into account the cost of heat gains, and by utilizing practices such as infrared thermography for monitoring—applied especially to large chemical, fertilizer, and process industries.
- Adoption of roof coatings/cooling systems/false ceilings, as applicable, to minimize refrigeration load.
- Adoption of EE heat recovery devices like air-to-air heat exchangers to precool the fresh air by indirect heat exchange; control of relative humidity through indirect heat exchange rather than use of duct heaters after chilling.
- Adopting variable air volume systems, adopting sun film application for heat reflection, optimizing lighting loads in the air-conditioned areas, and optimizing the number of air changes in the air-conditioned areas are a few examples.
- Consider painting the walls a lighter color and using less lighting fixtures or lower wattages.
- Use task lighting and reduce background illumination.
- Reevaluate exterior lighting strategy, type, and control. Control it aggressively.
- Change exit signs from incandescent to LED.

6.3 Energy conservation best practices in TPP

Overall TPP

Table 92: Energy conservation best practices in TPP

Energy-saving opportunities for GT compressor	Monitor the compressor plant's coefficient of performance (COP) regularly and correct deviations from the standard.
	Maintenance of mechanical adjustments—to ensure that drive belts are kept at the correct tension, which drive components are properly maintained and lubricated, and that sheaves and couplings are aligned (correct vibrations).
	In multiple-compressor installations, schedule the use of the machines to suit the demand, and sequence the machines so that one or more compressors are shut off rather than having several operating at part-load when the demand is less than full capacity.
Energy-saving opportunities for refrigeration and HRSG	If idle or unoccupied, shut down unnecessary equipment.
	Shut down lights, computers, photocopiers, and other heat-generating equipment when not in use and upgrade the lighting technology.
	Whenever possible, consider increasing the use of (northern) day lighting.
	Recalibrate and check control components, such as room thermostats and air and water temperature controllers and verify that the time clocks are set correctly.
	During occupied and unoccupied periods, establish minimum and maximum temperatures for heating and cooling and adjust controls accordingly.
	Adjust air flow rates to suit changing occupancy conditions and use of building space.
	Ensure that vents are open in summer and closed in winter.
	Adjust and tighten damper linkages.
	Check and adjust motor drives on fans and pumps for belt tension and coupling alignment.
	Prevent restrictions of air flow by checking/replacing air system filters.
	Shut off exhaust and make up air systems to areas such as kitchens and laundries when they are not in use.
	Replace damaged or missing insulation on piping and duct systems.
	Replace or repair crushed or leaking ducts in the air system.
	Clean heat exchange surfaces, heating units, and heating coils.
Energy-saving opportunities for CW	Monitor water consumption on an ongoing basis by installing meters in different process areas. To correct deficiencies and set progressively tighter consumption targets, analyze the data to identify zones, equipment, and crews performing inconsistently or inefficiently.
Energy-saving opportunities for CT	Ensure free circulation of air around condensing units and CTs.
	If water for condensers is supplied from CTs, ensure that they are effectively maintained to obtain the lowest water temperature possible.
	Equip the CT with an automatic water treatment system.
	Install variable speed drive fan motors on CTs.
Energy-saving opportunities for pumping systems	Pumps should be carefully sized to suit the flow requirements. If a review shows that a pump can produce more flow or head than the process requires, the following measures can be considered:
	Reduction in the size of the impeller on a centrifugal pump, if possible, in the applications where the flow is constant. This usually permits use of a smaller motor.
	Installation of a variable speed drive on pumps where the load fluctuates.
	Optimization of pump impellers (change-out) to ensure that the duty point is within the optimum zone on the pump curve.
	Maintenance of pumps through regular inspection and maintenance to monitor performance for an early indication of failure.
Energy-saving opportunities for fan system	Implement a program of inspection and preventive maintenance to minimize component failures: ○ Check and adjust belt drive regularly. ○ Clean and lubricate fan components. ○ Correct excess noise and vibration. ○ Clean or replace air filters regularly. ○ Clean ductwork and correct duct and component leaks to reduce energy costs. ○ Shut down fans when no longer required.
	Low-cost energy-saving opportunities: ○ Streamline duct connections for fan air entry and discharge to reduce losses. ○ Optimize or reduce fan speed to suit optimum system air flow, with balancing dampers in their maximum open positions for balanced air distribution.

	Retrofit energy-saving opportunities: ○ Add a variable speed motor to add flexibility to the fan's performance in line with changing requirements. ○ Replace outdated units with more efficient equipment, correctly sized. ○ Replace oversized motors with high-efficiency motors, correctly sized. ○ Where a central system must satisfy the requirements of the most demanding subsystem, consider decentralizing the major system into local subsystems, each serving its own unique requirements. ○ Consider controlling the local ventilation system with ultrasonic occupancy sensors.
Energy-saving opportunities for electric motor	Use one of the demand side management (DSM) applications that are available on the market that provide predictive, "smart" results. It refers to installing efficiency devices to reduce or manage peak electric loads or demands.
	Using online electrical meters, real-time data can be collected from the meters, and the computerized energy management system can predict and control electrical demand.
	To reduce peak demand, nonessential operations are stopped when the demand approaches preset targets.
	Use one of the DSM applications that are available in the market that provide predictive, "smart" results. It refers to installing efficiency devices to reduce or manage peak electric loads or demands.
Energy-saving opportunities for steam system	Low-cost energy-saving opportunities: ○ Improve condensate recovery. ○ Overhaul pressure-reducing stations. ○ Operate equipment efficiently. ○ Insulate uninsulated pipes, flanges, fittings, and equipment. ○ Remove redundant steam and condensate piping. ○ Reduce steam pressure where possible. ○ Repipe systems or relocate equipment to shorten pipe lengths. ○ Repair, replace, or add air vents. ○ Optimize location of sensors. ○ Add measuring, metering, and monitoring equipment.
	Retrofit energy-saving opportunities: ○ Upgrade insulation. ○ Eliminate steam use where possible. ○ Institute a steam trap replacement program. ○ Optimize pipe sizes. ○ Recover flash steam. ○ Stage the depressurization of condensate. ○ Recover heat from condensate. ○ Install closed-loop pressurized condensate return. ○ Meter steam and condensate flows.

6.4 GT operations and CCPP operations[5]

Table 93: GT operations and CCPP operations

S. No.	Topics
1	**Performance improvement: —HR and APC:**
	Smart wall blowing system for optimizing wall blowing and improving HR
	Improvement in hot reheat temperature in boiler
	Modification in auto furnace draft control logic in ID fan vane scoop combination control
	Utilization of Performance Analysis, Diagnosis and Optimization System (PADO) and the benefits for the TPP
	Latest techniques for HR improvement of power plant
	Continuous improvement of HR of CCPP
2	**Performance improvement—reliability and availability:**
	Reliability improvement by avoiding inadvertent errors
3	**O&M:**
	Equipment criticality analysis
	Introduction of super cleaning of turbine oil
	Innovative boiler maintenance techniques for minimizing boiler tube failure

[5] https://www.nri.ac.ir/Portals/0/images/Technology/OandM/document/Power_Plant.pdf

	Replacement of aero derivative turbine with very minimal time duration
	Innovative techniques to minimize the cold start-up time of a CCPP
4	**Environment improvement:**
	Flue gas conditioning by auto-controlled dosing of ammonia gas and improving performance of ESP
	Initiatives toward achieving zero effluent discharge
	Flue gas desulphurization system for reducing Sulphur oxides (SO_X) level
5	**Miscellaneous projects:**
	Rainwater harvesting in a TPP
	Departmental website—a tool for data and knowledge management

7 Annexure 7: Combined Cycle Thermal Power Plant

A CCPP system generates electricity based on two thermal units with two separate thermal cycles that include a GT cycle and a ST cycle. The CCPP, apart from generating electricity, utilizes the steam obtained from other energy generating processes for industry.[6] The common elements of a CCPP are presented in Table 92.

Table 94: Common elements of a CCPP

CCPP equipment	Principle of operation and purpose of equipment
GT	Chemical energy from the fuel is converted by the GT. It converts one part of this energy into mechanical energy for rotation of the generator shaft, and another part into thermal energy for heating.
HRSG	The energy contained in the exhaust gases of a GT is converted by HRSG into potential energy of steam at a specific pressure and temperature.
Water-steam cycle	The water steam cycle comprises a set of components responsible for transferring steam from a HRSG to a ST.
ST	The potential energy of the steam is converted into the mechanical energy of the rotating shaft in the ST.
Generator	The efficient conversion of mechanical energy into electrical energy is accomplished by one or more generators (depending on the configuration of the power plant), which are connected to the shafts of the STs and GTs.
Electrical system	The electrical system of the CCPP is responsible for the power supply to the auxiliary equipment of the power plant and the export of the generated power to remote consumers.
Fuel supply system	The CCPP utilize NG as the primary fuel.
Cooling system	The thermal energy contained in the fuel cannot entirely be used and must be released into the environment. CTs can discharge it into the air or into water (natural reservoirs). In a CCPP, it is important to minimize the amount of heat that is released into the atmosphere or water.
Water purification system	Due to the high demands on the physicochemical properties of the liquid they use (usually water), modern CCPPs need additional systems for its processing and control.
Ancillary systems	CCPPs include other ancillary systems such as water treatment plants, fire protection systems, and compressed air systems.
Control system	The monitoring and controlling of all the elements are the responsibility of the control system. The system is usually fully automated.

Technical parameters in a CCPP:[7]

Table 95: Technical parameters in a CCPP

Cogeneration system	Heat-to-power ratio (kW_{th}/kW_e)	Power output (as percent of fuel input)	Overall efficiency (%)
Combined cycle	1.0–1.7	34–40	69–83

[6] https://esfccompany.com/en/projects/energy/gas-and-steam-power-plant-construction-and-equipment/

[7] Energy Efficiency in Thermal Utilities BEE

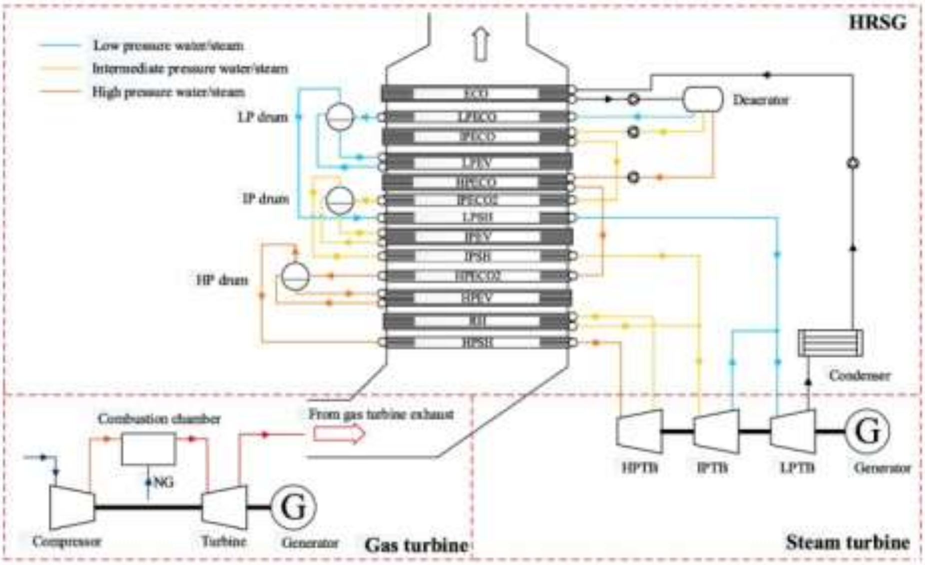

Figure 7: Schematic diagram of CCPP

8 Annexure 8: Useful Information while Conducting Energy Audits in Thermal Power Plants

8.1 Unit conversion factors[8]

Thermal conversion factors

Table 96: Thermal conversion factors

To convert from	To	Multiply by
Cubic feet, NG	Therms	0.01
Cubic feet, NG	British thermal units (Btu)	1,000
Cubic meter, NG	Btu	35,000
Therms, NG	Cubic feet	100
Therms, NG	Btu	100,000
Gallons, number 2 fuel oil	Btu	166,200
Gallons, number 4 fuel oil	Btu	173,000
Gallons, number 5 fuel oi	Btu	180,000
Gallons, number 6 fuel oil	Btu	182,000
Kilowatt hours	Btu	3,413
Kerosene	Btu 16	1,000
Horsepower hours	Btu	2,544
Horsepower hours	kWh	0.746
Horsepower	Btu/minute	42.4176
Horsepower (boiler)	Btu/hour	33.79
Liquefied butane (welding)	Btu/gallon	103,300
Liquefied propane (superior)	Btu/hour	12,000

Metric/imperial unit conversion factors

Table 97: Metric/imperial unit conversion factors

To convert from	To	Multiply by
Volume conversions		
Cubic feet	Cubic meters	0.0283
Cubic feet	Liters	28.31685
Cubic meters	Cubic feet	35.314667
Gallons (US)	Gallons (Imperial)	0.80
Gallons (Imperial)	Gallons (US)	1.25
Gallons (Imperial)	Liters	4.546090
Gallons (US liquid)	Liters	3.785412
Liters	Imperial gallons	0.219969
Energy conversions		
Btu (thermochemical)	Joules or Watt seconds	1.05435 x 10 1,055.06
Btu	Kilowatt hours	0.0002931
Joules	Btu	0.0009485
Kilowatt hours	Btu	3,409.52
Kilowatt hours	Horsepower	1.34102
Power conversions		
Btu/hour	Kilowatts	0.0002931
Btu/pound	Joules/gram or Kilojoules/kilogram	2.326
Horsepower	Kilowatts	0.746
Horsepower	Joules/second	746
Horsepower (mechanical)	Horsepower (boiler)	0.0760181
Horsepower (boiler)	Horsepower	13.1548
Horsepower (boiler)	Horsepower (electrical)	13.1495
Horsepower (electrical)	Watts	746

8 https://unhabitat.org/sites/default/files/download-manager-files/Energy%20Audit%20Manual%20for%20Use%20in%20the%20Operation%20of%20Buildings.pdf

8.2 Energy conversion factors

Table 98: Energy conversion factors

Energy type	Metric	British
Coal:		
Sub-bituminous	22,100 megajoules/ton	19.0 x 106 Btu/ton
Lignite	16,700 megajoules/ton	14.4 x 106 Btu/ton
Metallurgical	29,000 megajoules/ton	25.0 x 106 Btu/ton
Anthracite	30,000 megajoules/ton	25.8 x 106 Btu/ton
Bituminous	32,100 megajoules/ton	27.6 x 106 Btu/ton
Coke:		
Raw	23,300 megajoules/ton	28.0 x 106 Btu/ton
Metallurgical	30,200 megajoules/ton	26.0 x 106 Btu/ton
Calcined	32,600 megajoules/ton	28.0 x 106 Btu/ton
Pitch:		
Pitch	37,200 megajoules/ton	32.0 x 106 Btu/ton
Oil:		
Crude	38.5 megajoules/liter	5.8 x 106 Btu/bbl
Kerosene	37.68 megajoules/liter	0.167 x 106 Btu/IG
Diesel fuel	38.68 megajoules/liter	0.172 x 106 Btu/IG
Gasoline	36.2 megajoules/liter	0.156 x 106 Btu/IG
NG	37.2 megajoules/m^3	1,000 x 106 Btu/MCF
Butane	45.2 megajoules/kg	.01945 x 106 Btu/lb
Propane	50.3 megajoules/kg	.02165 x 106 Btu/lb
	26.6 megajoules/liter	0.1145 x 106 Btu/IG
LPG	45,200 megajoules/ton	38.9 x 106 Btu/ton
	24.51 megajoules/liter	0.1055 06 Btu/IG

8.3 Avoiding steam leakages

Steam leakage is a visible indicator of waste and must be avoided. It has been estimated that a 3-mm diameter hole on a pipeline carrying 7 kg/cm^2 steam would waste 33 kL of fuel oil per year. Steam leaks on HP mains are prohibitively costlier than on LP mains. Any steam leakage must be quickly attended to. In fact, the plant should consider a regular surveillance program for identifying leaks at pipelines, valves, flanges, and joints. Indeed, by plugging all leakages, one may be surprised at the extent of fuel savings, which may reach up to 5% of the steam consumption in a small- or medium-scale industry or even higher in installations having several process departments.

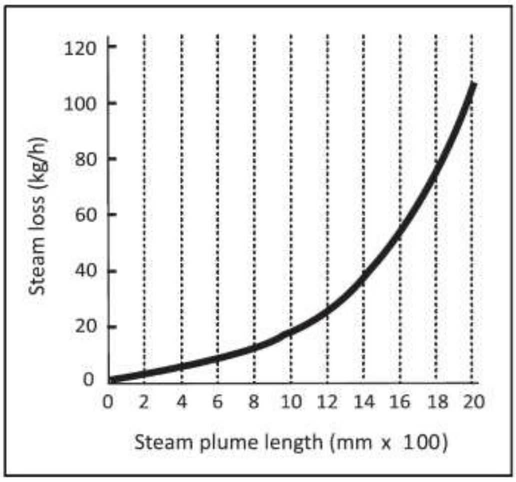

Figure 8: Steam loss Vs plume length

Table 97 highlights the significance of loss through steam leaks.

Table 99: Loss through steam leaks

S. No.	Diameter of leak (in mm)	Annual steam loss (tons/year)	
		At 3.5 kg/cm²	At 7.0 kg/cm²
1	1.5	29.1	47.3
2	3.0	116.4	192.7
3	4.5	232.7	432.7
4	6.0	465.4	767.3

8.4 Flash steam recovery

Flash steam is produced when condensate at a HP is released to a lower pressure and can be used for LP heating. Flash steam can be used on LP applications like direct injection and can replace an equal quantity of live steam that would be otherwise required.

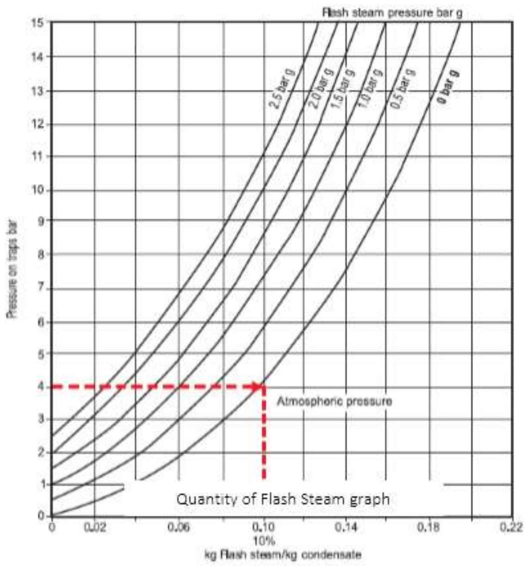

Figure 9: Quantity of flash steam graph

8.5 Transformer losses and efficiency

The efficiency varies anywhere between 96% and 99%. The efficiency of the transformers not only depends on the design, but also on the effective operating load.

Table 100: Typical three-phase transformer losses of various capacities

Typical 3-phase transformer losses of various capacities (for CRGO core transformers)		
Rating (kVA)	No load loss (W)	Load loss (W)
100	320	1,950
160	455	2,800
250	640	4,450
500	900	6,450
630	1,260	9,300
1000	1,800	13,300
1600	2,600	19,800
2000	3,200	21,000
3150	4,600	28,000
5000	6,500	38,000

6300	7,700	45,000
10000	11,000	63,000
12500	13,000	77,000
20000	18,000	107,000
31500	25,000	150,000
40000	30,000	180,000

8.6 Reducing delivery pressure

Typical power savings through pressure reduction are shown in Table 99.

Table 101: Typical power savings through pressure reduction

Typical power savings through pressure reduction				
Pressure reduction		**Power savings** (%)		
From (bar)	**To (bar)**	**Single-stage water-cooled**	**Two-stage water-cooled**	**Two-stage air-cooled**
6.8 6.8	6.1 5.5	4 9	4 11	2.6 6.5

9 Annexure 9: Useful Information Regarding Data Collection, Fuel Details, and Power Plant Efficiency Calculations in TPPs

9.1 Data collection

Assessment will include a collection of details about specifications of all the key, main, and subsystems and associated equipment(s), design parameters and limits, and performance guarantee test reports. Here, information on the data types, data logging frequency, performance mapping tests, energy cost records, energy bills, etc. in line with the energy audit objectives will be included. Table 100 contains a sample format for an energy audit questionnaire for TPP.

Table 102: Sample questionnaire

S. No.	Question	Response	
1	Name of the gas/oil power plant		
2	Address		
3	Phone numbers (landlines)		
4	Email address		
	CONTACT PERSON		
5	Name		
6	Designation		
7	Mobile number		
8	Email address		
9	**TECHNICAL DETAILS**	**Units**	
10	Station capacity	MW	
10	Total number of units	Number	
11	The capacity of each unit	MW	
12	Fuels used (names)	Gas/oil	
13	Gross calorific value (GCV) of fuels	Kcal/kg or Kcal/Sm³	
14	The density of fuels used		
15	Station generation	MW	
		MU/year	
16	Unit-wise generation	MW	
		MU/year	
17	Average annual gas or fuel oil consumption	Sm³/year or kg/year	
18	Average plant load factor (PLF)	%	
19	Specific fuel consumption	kg fuel or Sm³ gas/kWh	
20	Annual downtime	Hours/year	
21	Gas turbine or gas engine open cycle efficiency	%	
22	Gross heat rate-design	Kcal/kWh	
23	Net heat rate-actual	Kcal/kWh	
24	Net heat rate-design	Kcal/kWh	
25	Net heat rate-actual	Kcal/kWh	
26	Operating in open cycle or closed cycle	°C/CC	
27	Auxiliary power consumption (APC)		
28	Annual additional fuel used in HRSG (boiler)	kg fuel or Sm³ gas/year	
29	Flue gas outlet temperature of gas turbine or gas engine	°C	
30	Flue gas outlet temperature from HRSG (boiler)	°C	

31	Flue gas inlet temperature to HRSG (boiler)	°C	
32	Generation voltage	kV	
33	Air temperature	°C	
34	Pressure	kg/cm^2 g	
35	Dry bulb temperature	°C	
36	Wet bulb temperature	°C	
37	Differential pressure—Inlet air filter	mmWC	
38	Type of fuel-fired	gas/liquid	
39	Fuel flow rate	Sm^3/hr	
40	Auxiliary fuel for HRSG		
41	Flow	kg/second	
42	Temperature	°C	
43	Specific heat of flue gas	Kcal/kg°C	
44	GENERATOR DATA		
45	Average power output	kW	
46	Power factor		
47	Exhaust gas temperature at the inlet	°C	
48	Exhaust gas temperature at boiler exit	°C	
49	Flow	Tons/hr	
50	Temperature	°C	
51	Pressure	kg/cm^2 g	
52	Flow	kg/hr	
53	The temperature at drum inlet	°C	
54	Pressure	kg/cm^2 g	
55	Enthalpy at drum inlet	Kcal/kg	

9.2 Fuel analysis

Table 103: Specific gravity of various fuel oils

Specific gravity of various fuel oils			
Fuel reference	**Light diesel oil (LDO)**	**Furnace oil**	**Low sulphur heavy stock (LSHS)**
Specific gravity	0.85–0.87	0.89–0.95	0.88–0.98

Table 104: Gross calorific values of fuels

Fuel oil reference	**GCV (Kcal/kg)**
Furnace oil	10,500
Diesel oil	10,800
Light diesel oil	10,700
Low sulphur heavy stock	10,600
Natural gas (at dry, standard condition)	9,630 ($Kcals/Sm^3$) (8,970–10,290)

Table 105: Percentage sulphur in fuels

Fuel oil reference	% Sulphur
Furnace oil	2.0–4.0
Diesel oil	0.05–0.25
Light diesel oil	0.5–1.8
Low sulphur heavy stock	<0.5
Natural gas	3–6 mg/m^3 (0.00052–0.0011%) (negligible)

The main disadvantage of sulphur is the risk of corrosion by sulphuric acid formed during and after combustion and condensing in cool parts of the chimney or stack, air preheater, and economizer.

Table 106: Typical specification of fuel oils

Typical specification of fuel oils			
Properties	Fuel oils		
	Furnace oil	LSHS	LDO
Density (approximately g/cc at 15°C)	0.89–0.95	0.88–0.98	0.85–0.87
Flash point (°C)	66	93	66
Pour point (°C)	20	72	18
GCV (Kcal/kg)	10,500	10,600	10,700
Sediment, % Weight maximum	0.25	0.25	0.1
Sulphur total, % Weight maximum	Up to 4.0	Up to 0.5	Up to 1.8
Water content, % Volume maximum	1.0	1.0	0.25
Ash, % Weight maximum	0.1	0.1	0.02

Table 107: Relationship between ultimate analysis and proximate analysis

Relationship between ultimate analysis and proximate analysis			
From ultimate analysis (% by weight)	% C	=	0.97C + 0.7 (VM - 0.1A) - M (0.6 - 0.01M)
	% H	=	0.036C + 0.086 (VM - 0.1 x A) - 0.0035M^2 (1 - 0.02M)
	% N	=	2.10 - 0.020 VM
	% S	=	Assumed (taken from general available data on the fuel)
	% O	=	Assumed (taken from general available data on the fuel)
Where, from proximate analysis (% by weight)			
	C	=	% of fixed carbon
	A	=	% of ash
	VM	=	% of volatile matter
	M	=	% of moisture

Table 108: Typical ultimate analyses of coals

Typical ultimate analyses of coals		
Parameter	**Indian coal, %**	**Indonesian coal, %**
Moisture	5.98	9.43
Mineral matter (1.1 x Ash)	38.63	13.99
Carbon	41.11	58.96
Hydrogen	2.76	4.16
Nitrogen	1.22	1.02

Sulphur	0.41	0.56
Oxygen	9.89	11.88

Table 109: Comparison of chemical composition of various fuels

Comparison of chemical composition of various fuels			
	Fuel oil	**Coal**	**Natural gas**
Carbon %	84	41.11	74
Hydrogen %	12	2.76	25
Sulphur %	3	0.41	-
Oxygen %	1	9.89	Trace
Nitrogen %	Trace	1.22	0.75
Ash %	Trace	38.63	-
Water %	Trace	5.98	Trace (0.0028 – 0.0055)

Table 110: Typical composition of NG

Component	Typical analysis (mole %)	Range (mole %)
Methane	94.7	87.0–98.0
Ethane	4.2	1.5–9.0
Propane	0.2	0.1–1.5
Iso-Butane	0.02	Trace–0.3
Normal-Butane	0.02	Trace–0.3
Iso-Pentane	0.01	Trace–0.04
Normal-Pentane	0.01	trace–0.04
Hexanes plus	0.01	trace–0.06
Nitrogen	0.5	0.2–5.5
Carbon dioxide	0.3	0.05–1.0
Oxygen	0.01	trace–0.1
Hydrogen	0.02	trace–0.05
Specific gravity	0.58	0.57–0.62
Gross heating value (MJ/m³), dry basis *	38.8	36.0–40.2
Wobbe number (MJ/m³)	50.9	47.5–51.5

Sulphur: The typical sulphur content of NG = 3 - 6 mg/m^3 (0.00052–0.0011%).

Water vapor: The water vapor content of NG in the Enbridge gas system is less than 65 mg/m^3 and is typically 16–32 mg/m^3 (0.0028–0.0055%)

Table 111: Typical combustion properties of NG

Ignition point	564°C
Flammability limits	4–15% (Volume % in air)
Theoretical flame temperature (Stoichiometric air/fuel ratio)	1,954°C
Maximum flame velocity	0.36 m/second

Table 112: Typical physical and chemical properties of various gaseous fuels

Typical physical and chemical properties of various gaseous fuels					
Fuel gas	**Relative density**	**Higher heating value, Kcal/Nm^3**	**Air/fuel ratio, m^3 of air to m^3 of fuel**	**Flame temperature, °C**	**Flame speed, m/s**
NG	0.584	9,980 (9,630 Kcal/Sm^3)	10	1,954	0.36
Propane	1.52	22,200	25	1,967	0.460
Butane	1.96	28,500	32	1,973	0.870

9.3 Power plant efficiency evaluation

Running hours = 24 (hr/day) x 365 (day/year) – FOH (hr/year) - POH (hr/year)

Where:

- FOH (hr/year) is the annual forced outage hours and POH (hr/year) is the annual planned outage hours.
- The forced outage factor can be calculated as follows: FOF (%) = FOH (hr/year) x (100) / {24 (hr/day) x 365 (day/year)}
- The planned outage factor can be calculated as follows: POF [%] = POH (hr/year) x (100) / {24 (hr/day) x 365 (day/year)}
- The power output of the plant in MW was obtained as follows: Power output = Pout [MW] = (Electricity generated, Eg, MWh) / (Annual running hours)
- The availability of the power plant is calculated using the following equation: Availability [%] = (Running hours, hr/year) x 100 / [24 (hr/day) x 365 (day/year)]
- Plant load factor: (PLF) = [(Energy generated during the period, MWh) x 100] / [(Total capacity, MW) x (Total hours in the period)]

The energy performance of the TPP, and that of the main subsystems, viz. the boiler and the turbine, are evaluated using the following "energy performance indices." To evaluate them, the empirical relations are presented below:

(The energy performance evaluation of all other main and auxiliary subsystems is dealt with in the section, "Evaluation of the performance of equipment.")

- Overall gross plant (or unit) HR, Kcal/kWh =
  - [(Fuel consumed, TPH) * (GCV of fuel, Kcal/kg)] / [Generator output, MW], or
  - (Gross turbine HR, Kcal/kWh) / (Boiler thermal efficiency), or
  - [(Overall plant fuel rate, kg/kWh) * (GCV of fuel, Kcal/kg)]
- Overall net plant (or unit) HR, Kcal/kWh =
  - [Total fuel consumed, tons) * (GCV of fuel, Kcal/kg)] / [(Total electricity generation, MWh) – (Total APC, MWh)], or
  - Gross plant HR / [(1 – (APC %) / 100)]

- Overall plant efficiency (η plant) % =
  - [(Generator output, MW) * 860] * 100 / (Mass flow rate of fuel, TPH) * (GCV of fuel, Kcal/kg), or
  - (860) * 100 / (Gross HR, Kcal/kWh)
- THR-G, Kcal/kWh =
  - $[Q_1 * (H_1 - h_2)] + [Q_2 * (H_3 - H_2)]$ / (Generator output)

Where:

Q_1 = Average main steam flow, kg/hr
H_1 = Main steam enthalpy at average Pressure (Pr) and temperature, Kcal/kg
h_2 = Average feed water enthalpy at average Pr and temperature, Kcal/kg
Q_2 = Average reheat steam flow, kg/hr
H_3 = Average hot reheat enthalpy at average Pr and temperature, Kcal/kg
H_2 = Average cold reheat enthalpy at average Pr and temperature, Kcal/kg
E_g = Average generator output, kW

- THR-N, Kcal/kWh =
  - $[Q_1 * (H_1 - h_2)] + [Q_2 * (H_3 - H_2)]$ / {[Average generator output, MW] * [1 – (APC % / 100)]}
- Turbine cycle efficiency (thermal efficiency), η t % =
  - [860 * 100] / [Turbine HR] %

Turbine cycle efficiency is defined as the amount of electricity produced by the heat input to the turbine. It is the reciprocal of HR in consistent units.

- Boiler efficiency (η b) (thermal efficiency) =
  - {[(Steam generation, TPH) * (Steam enthalpy, Kcal/kg)] - [(Feed water consumption, TPH) * (Feed water enthalpy, Kcal/kg)]} / [(Fuel consumed, TPH) * (GCV of fuel, Kcal/kg)]
  - This is the evaluation of boiler thermal efficiency by the direct method, based on steam flow and fuel flow measurements; preferably the boiler thermal efficiency is evaluated by the indirect method.
- Turbine stage (isentropic) efficiency, % =
  - [(Actual enthalpy drop across the turbine, Kcal/kg) * 100] / (Stage [isentropic] enthalpy drop across the turbine, Kcal/kg)
- GT and heat recovery steam generator performance
  - GT, overall plant HR, Kcal/kWh = (Overall plant fuel rate, Sm^3/kWh) * (NCV of gas, Kcal/Sm^3)
  - Efficiency of HRSG boiler, η HRSG: {[(Steam flow rate, kg/hr) * (Enthalpy of steam, Kcal/kg – Enthalpy of feed water, Kcal/kg)] * 100} / {[(GT exhaust gas flow rate, kg/hr) * (Inlet enthalpy of gas, Kcal/kg)] + [(Auxiliary fuel consumption rate, kg/hr) * (GCV of auxiliary fuel, Kcal/kg)]}
  - SSC, kg steam/kWh =
    $860 / \{(H_1 - H_2) * (\eta_{mech} * \eta_{gen} * \eta_{gear})\}$
    Where:
    H_1 = Enthalpy of steam at turbine inlet conditions of Pressure and temperature, Kcal/kg
    H_2 = Enthalpy of steam at turbine outlet conditions of Pressure and temperature, Kcal/kg
    $\eta_{mech} = 0.985$
    $\eta_{gen} = 0.95$
    $\eta_{gear} = 0.98$
- Turbine stage (isentropic) efficiency, (%)
  [(Actual enthalpy drop) * 100] / (Isentropic enthalpy drop across the turbine)

- ✓ This procedure is the enthalpy drop efficiency method. It determines the ratio of actual enthalpy drop across the turbine section to the isentropic enthalpy drop. This method provides a good measure for monitoring purposes.
- ✓ Each section of the turbine must be considered as a separate turbine. Each section should be tested, and the results should be trended separately. While conducting the tests, it must be ensured that they are conducted over the normal operating load range.

After evaluating the turbine HR and efficiency, the deviation from the design, if any, should be assessed, and the factors contributing to the deviations must be identified. The major factors to be checked out are:

- Main steam and reheat steam inlet parameters
- Turbine exhaust steam parameters
- Reheater and super heater spray
- Passing of high energy draining
- Loading on the turbine
- Boiler loading and boiler performance
- O&M constraints
- Condenser performance and CW parameters
- Silica deposition and its impact on the turbine efficiency
- Interstage sealing, balance drum, and gland sealing
- Nozzle blocks
- Turbine blade erosion
- Functioning of the valves
- Operational status of HPHs
- Performance of reheaters

Table 111 displays the typical APC in a power plant.

Table 113: Typical APC in a power plant

Equipment reference	500 MW		210 MW		110 MW	
	% Generation	% APC	% Generation	% APC	% Generation	% APC
Boiler Feed Pump	0.00 (turbine-driven)	0.00 (turbine-driven)	2.70	33.60	2.94	24.50
Condensate Extraction Pump	0.40	5.70	0.27	3.34	0.36	3.00
CW pump	1.00	14.20	0.66	8.31	1.26	10.50
ID fan	1.30	18.70	1.26	15.80	1.71	14.23
PA fan	0.60	8.50	0.68	6.50	1.78	14.46
FD fan	0.30	4.10	0.40	5.00	0.26	2.13
Mills	0.60	8.20	0.58	7.23	0.83	6.92
CT fans	0.23	3.20	0.32	3.54	0.48	4.00
Air compressor	0.08	1.20	0.12	1.56	0.24	2.00
Air conditioner (A/C) plant	0.04	0.50	0.08	0.94	0.11	0.92
Coal Handling Plant	0.12	1.70	0.14	1.70	0.29	2.41
Ash Handling Plant	0.09	1.20	0.13	1.66	0.31	2.54
Lighting	0.06	0.80	0.08	1.00	0.08	0.68
Others	2.23	31.90	0.60	7.44	1.36	11.32
Auxiliary Power Consumption	7.00	100.00	8.00	100.00	12.00	100.00

Table 112 summarizes the CERC norms (2014–2019) for auxiliary energy consumption of coal-based generating solutions.

Table 114: Auxiliary energy consumption of coal-based generating solutions

S. No.	Capacity	With natural draft CT or without CT	With ID CTs	With direct cooling; air cooled condensers with mechanical draft fans	Indirect cooling system employing jet condensers with pressure recovery turbine and natural draft tower
1.	200 MW series	8.5%	9.0%	9.5%	9.0%
2.	300/330/350/500 MW and above having				
(i)	Steam-driven BFPs	5.25%	5.75%	6.25%	5.75%
(ii)	Electrically driven BFPs	7.75%	8.25%	8.75%	8.25%

10 Annexure 10: Link to Manual

Please follow this link to access the Energy Audit Manual for Thermal Power Plants: https://pubs.naruc.org/pub/3759D21B-1866-DAAC-99FB-BD1AE03D10BD

That document contains useful background information on the Bangladesh power system, as well as the following information:

- Bangladesh Energy Sector and Energy Efficiency Overview
- Pre-Audit Preparation
- Energy Audit Methodology

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