



NORMALIZATION DOCUMENT AND MONITORING & VERIFICATION GUIDELINES

Thermal Power Plant Sector



MINISTRY OF POWER
GOVERNMENT OF INDIA



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GOVERNMENT OF INDIA



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Disclaimer

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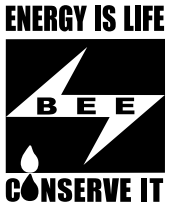
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Ajay Mathur, Ph.D.
Director General

Foreword


Perform Achieve and Trade (PAT), a flagship initiative under National Mission for Enhanced Energy Efficiency (NMEEE), is a regulatory intervention for reduction of specific energy consumption, with an associated market based mechanism through which additional energy savings can be quantified and traded as ECSerts.

Thermal Power Plant sector is one of the 8 notified energy intensive sectors under which a total of 144 plants are participating in this program. The targets are specified in terms of specific percentage of their present deviation of Net Operating Heat Rate from the Net Design Heat Rate. The total reported energy consumption of these Designated Consumers (DCs) is about 104 million toe. By the end of the first PAT cycle, the energy saving of 3.211 million toe /year is expected to be achieved, which is around 48% of total notional energy saving targets assessed under PAT.

The publication of “**Normalization Document and M&V Guidelines**” for Thermal Power Plant Sector is an effort to facilitate the DCs to comply with notified PAT rules to participate with the PAT scheme and contribute towards achieving national target of energy savings. This document will also be helpful to all empanelled Accredited Energy Auditors (EmAEAs) and State Designated Agencies (SDAs) in the monitoring and verification process of PAT.

I want to record my appreciation for members of the Technical Committee on Thermal Power Plant Sector, chaired by Shri. Alok, Deputy Director General (Technical), Bureau of Energy Efficiency (BEE), Shri A.K. Asthana, Senior Technical Expert, GIZ, Dr. Ashok Kumar, Energy Economist, BEE, and Shri Abhishek Kumar Yadav, Project Engineer, BEE, Shri Piyush Sharma, Technical Expert (GIZ) who worked tirelessly to put together the baseline data, normalization factors and M&V methodology for the sector. I especially want to record my appreciation for Shri S. Vikash Ranjan, Technical Expert (GIZ) who has put together the data and methodology associated with normalization.

I also compliment the efforts of all participating industrial units towards their endeavor in contributing to the national energy saving targets.


(Ajay Mathur)

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1. Introduction

The National Action Plan on Climate Change (NAPCC) released by the Prime Minister on 30 June, 2008, recognises the need to maintain high economic growth to raise the living standards of India's vast majority of people and simultaneously reducing their vulnerability to the impacts of climate change.

The National Action Plan outlines eight national missions that represent multi-pronged, long-term, and integrated strategies for achieving key goals to mitigate the impact of climate change. These missions are listed below:

- National Solar Mission
- National Mission for Enhanced Energy Efficiency
- National Mission on Sustainable Habitat
- National Water Mission
- National Mission for Sustaining the Himalayan Ecosystem
- National Mission for a Green India
- National Mission for Sustainable Agriculture
- National Mission for Strategic Knowledge for Climate Change

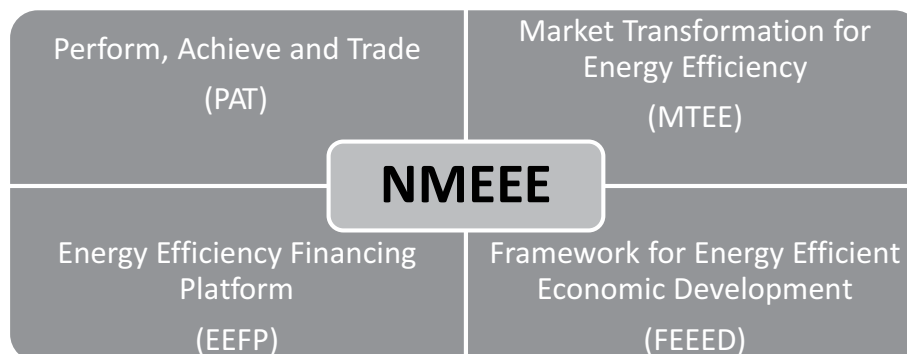
1.1 National Mission for Enhanced Energy Efficiency

The National Mission for Enhanced Energy Efficiency (NMEEE) is one of the eight national

missions with the objective of promoting innovative policy and regulatory regimes, financing mechanisms, and business models which not only create, but also sustain, markets for energy efficiency in a transparent manner with clear deliverables to be achieved in a time bound manner. It also has inbuilt provisions for monitoring and evaluation so as to ensure transparency, accountability, and responsiveness. The Ministry of Power (MoP) and Bureau of Energy Efficiency (BEE) were tasked to prepare the implementation plan for NMEEE.

NMEEE spelt out the following four new initiatives to enhance energy efficiency, in addition to the programmes on energy efficiency being pursued. These are:

- **Perform, Achieve and Trade (PAT)**, a market based mechanism to make improvements in energy efficiency in energy-intensive large industries and to make facilities more cost - effective by certification of energy saving that can be traded.
- **Market Transformation for Energy Efficiency (MTEE)** accelerates the shift to energy-efficient appliances in designated sectors through innovative measures that make the products more affordable.
- **Energy Efficiency Financing Platform (EEFP)**, a mechanism to finance demand side management programmes in all sectors by capturing future energy savings.
- **Framework for Energy Efficiency**



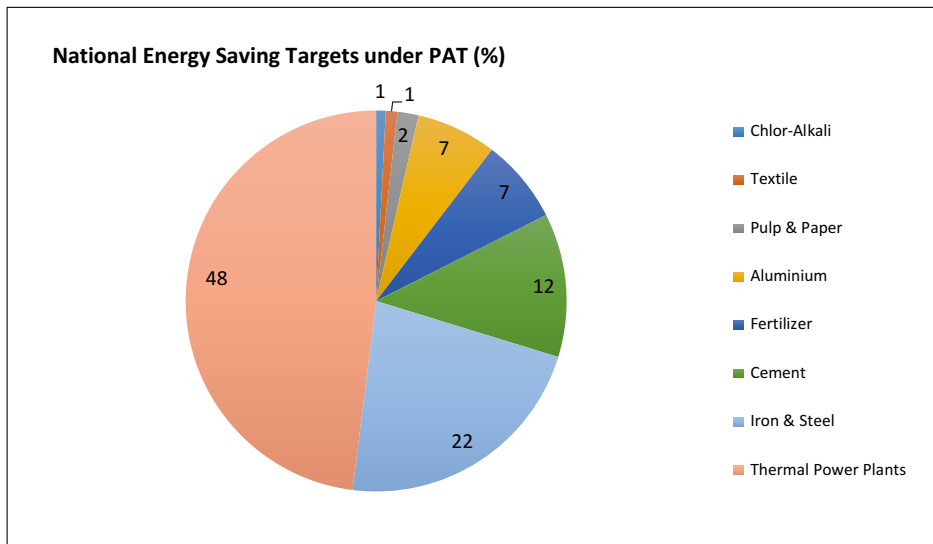


Economic Development (FEEED), for developing fiscal instruments to promote energy efficiency.

1.2 Perform, Achieve and Trade (PAT) Scheme

Under the National Mission on Enhanced Energy Efficiency (NMEEE), a market based mechanism known as Perform, Achieve and Trade (PAT)

has been developed and launched to improve energy efficiency in the large energy intensive industries. It is envisaged that 6.686 million tonnes of oil equivalent will be reduced by 2014-15, which is about 4% of energy consumed by these industries. Under the PAT scheme, targets have been specified for all energy intensive industries notified as designated consumers (DCs) under the Energy Conservation Act, including thermal power stations.



2 Background

The methodology of setting targets for designated consumers is transparent, simple and easy to use. It is based on reduction of specific energy consumption (SEC) on a gate-to-gate (GtG) basis to achieve targeted savings in the first commitment period of 3 years (2012-2015); the reduction in this phase is of 4.1% which is estimated to 6.686 million tonnes of oil equivalent (mtoe). Out of the 23 mtoe set as target from NMEEE, the PAT scheme is focussed on achieving 6.686 mtoe by 2015.

With the threshold limit of 30,000 toe energy consumption for a power station to become a designated consumer, 144 thermal power stations, with Coal/Lignite/Gas/Diesel as primary energy consumption, have been identified in Cycle I of PAT. The categorisation

of plants based on fuel such as coal, gas and diesel made the setting of target simple. The total reported energy consumption of these designated consumers is about 104 million tonne of oil equivalent. By the end of the first PAT cycle, energy savings of 3.211 million tonne of oil equivalent/year is expected to be achieved, which is around 48% of the total national energy saving targets assessed under PAT.

3 Categorisation and Distribution

The Thermal Power Plants can be categorised into coal, gas, and oil/diesel based. The categorisation of the DCs under PAT cycle has been shown below. Apart from the type of fuel source, the plants are also categorised into State, Central and Private. However, the target and normalisation methodology for all are same.



Fuel based Power Plant	State			Central			Private			Total		
	Total No.	Capacity (MW)	%	Total No.	Capacity (MW)	%	Total No.	Capacity (MW)	%	Total No.	Capacity (MW)	%
Coal	56	41534	46	23	30095	33	18	7231	8	97	78860	87
Gas	20	3823	4	9	4392	5	11	3122	3	40	11337	12
Diesel	4	385	0	0	0	0	3	412	0	7	797	1
Total	80	45742	50	32	34487	38	32	10765	12	144	90994	100

It can be clearly observed from the table above that coal based thermal power plants occupy the major chunk in all the sectors, i.e., state, central and private, followed by gas and diesel, respectively. Coal based plants contribute to more than 75 per cent of the total target.

4. Baseline value establishment

Section 4.01 Definition

(a) Baseline Year

Baseline year is declared as 2009-10.

(b) Baseline Generation (P base)

The arithmetic average of gross generation figures in MUs of 2007-08, 2008-09 and 2009-10.

(c) Baseline Specific Energy Consumption (SECbase)

The arithmetic average of Net Design Heat Rate (Kcal/kWh), Net Operative Heat Rate (kcal/kWh), Auxiliary Power Consumption (APC %) and

Plant Load Factor (PLF %) figures of 2007-08, 2008-09 and 2009-10

(d) Baseline Capacity Utilization in % (CUbase)

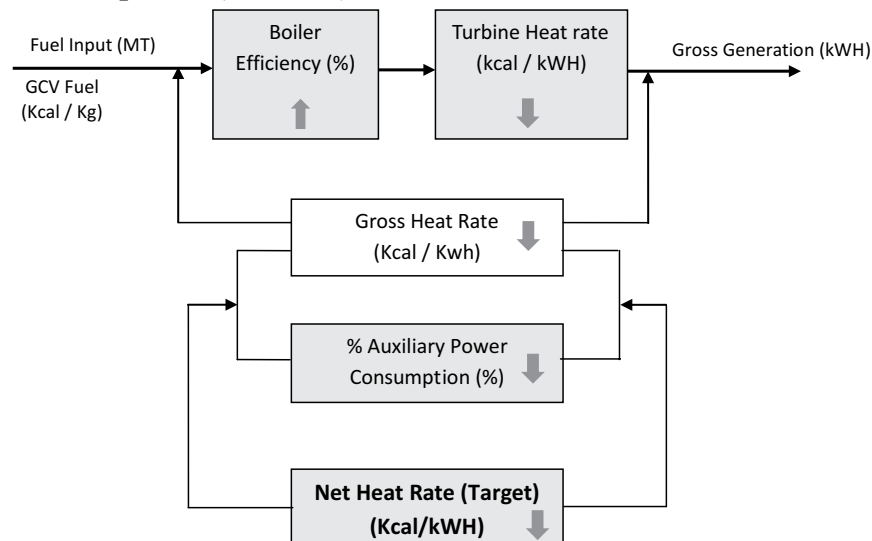
Arithmetic average of PLF figures of 2007-08, 2008-09 and 2009-10 is taken as the baseline capacity utilization

5. Methodology for establishing the target

The methodology adopted for target setting is based on arithmetic average of Gross Design Heat Rate (kcal/kWh), Gross Operating Heat Rate (kcal/kWh) and Auxiliary Power consumption (%) figures of 2007-08, 2008-09 and 2009-10.

Section 5.01 Relationship

Based on the arithmetic average figure of three years, the Net Design Heat Rate (kcal/kWh) and Net Operating Heat Rate (kcal/kWh) has been calculated using the following formulae





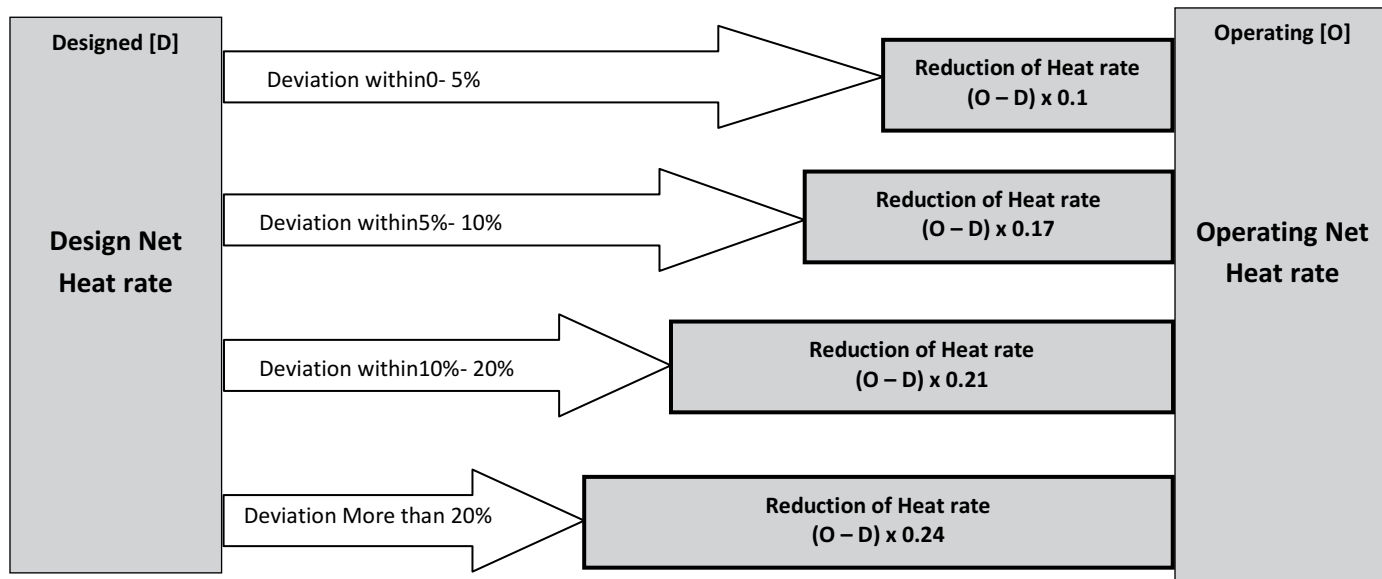
Net Operating Heat Rate = Gross operating Heat Rate / (1-APC %)
Net Design Heat Rate = Gross Design Heat Rate / (1- APC %)
Actual Deviation of net operating Heat Rate from net Design Heat Rate = Net Operating Heat Rate - Net Design Heat Rate
% Deviation = Actual deviation from net design heat rate x 100/ net design heat rate

The targets are specified in terms of specific percentage of their present deviation of Net Operating Heat Rate from the Net Design Heat Rate. The stations are classified in to various bands according to their present deviations of operating heat rate from design heat rate and stations with higher deviations has given higher targets. The indicative classification and targets for various bands for the generating stations are as under:-

Section 5.02 Percentage Reduction Target methodology

The energy consumption norms and standards for power stations shall be specified in terms of

specific percentage of their present deviation of net operating heat rate, based on the average of previous three years, namely, 2007-08,2008-09 &2009-10 for the first cycle ,and for cycles thereafter in accordance with the provision of Rule 14 from the net design heat rate. The power stations shall be grouped into various bands according to their present deviations, of operating heat rate from design heat rate and for power stations with higher deviations the energy consumption norms and standards shall be established at lower level and shall be grouped taking into account percentage deviation as under



Category	Variation in Net Station Heat Rate from Design Net Heat Rate	Reduction Target for % deviation in the Net Station Heat Rate
I	Up to 5%	10%
II	More than 5% and up to 10%	17%
III	More than 10% and up to 20%	21%
IV	More than 20%	24%



6. Formula for Target Setting

Section 6.01 Formula for target setting for Coal based Thermal Power Plant

(a) Design Net Heat Rate

Station Installed Capacity (MW)

$$= [U\#1 \text{ Capacity (MW)} + U\#2 \text{ Capacity (MW)} + \dots \dots \dots]$$

Station Design Boiler Efficiency

$$= ([U\#1 \text{ Installed Capacity (MW)} \times U\#1 \text{ Boiler Efficiency (\%)}] + [U\#2 \text{ Installed Capacity (MW)} \times U\#2 \text{ Boiler Efficiency (\%)}]) / \text{Station Installed Capacity (MW)}$$

Station DGHR(kcal/kWh)

$$= ([U\#1 \text{ DGHR} \times U\#1 \text{ Installed Capacity (MW)}] + [U\#2 \text{ DGHR} \times U\#2 \text{ Installed Capacity (MW)}] + \dots \dots \dots) / \text{Station Installed Capacity (MW)}$$

$$\text{Efficiency (\%)} + \dots \dots \dots] / \text{Station Installed Capacity (MW)}$$

Station THR (kcal/kWh)

$$= ([U\#1 \text{ THR} \times U\#1 \text{ Installed Capacity (MW)}] + [U\#2 \text{ THR} \times U\#2 \text{ Installed Capacity (MW)}] + \dots \dots \dots) / \text{Station Installed Capacity (MW)}$$

Unit DGHR (kcal/kWh)

$$= \text{Unit THR (kcal/kWh)} / \text{Boiler Efficiency (\%)}$$

$$\text{Station Design Net Heat Rate (kcal/kWh)} = \frac{\text{Station DGHR (kcal/kWh)}}{(1 - \% \text{Operating APC})}$$

Where

DGHR = Design Gross Heat Rate (kcal/kWh)

THR = Turbine Heat Rate (kcal/kWh)

DNHR = Design Net Heat Rate (kcal/kWh)

APC = Auxiliary Power Consumption (%)
[Operating APC in Baseline Year]

(b) Operating Net Heat Rate

Station Operating Load (MW)

$$= U\#1 \text{ Operating Load (MW)} + U\#2 \text{ Operating Load (MW)} + \dots \dots$$

Operating Load (MW)

$$= \text{Unit Gross Generation (MWh)} / \text{Unit Operating hours}$$

Station Loading Factor (%)

$$= ([U\#1 \text{ loading factor (\%)} \times U\#1 \text{ Gross Generation (MU)}] + [U\#2 \text{ loading factor (\%)} \times U\#2 \text{ Gross Generation (MU)}] + \dots \dots \dots) / \text{Station Gross Generation (MU)}$$

Station Gross Generation(MU)

$$= (U\#1 \text{ Gross Generation (MU)} + U\#2 \text{ Gross Generation (MU)} + \dots \dots \dots)$$

Station Net Generation (MU)

$$= \text{Station Gross Generation (MU)} \times [1 - \% \text{Operating APC}] / 100$$

Station OGHR (kcal/kWh)

$$= ([U\#1 \text{ OGHR (kcal/kWh)} \times U\#1 \text{ Gross Generation (MU)}] + [U\#2 \text{ OGHR (kcal/kWh)} \times U\#2 \text{ Gross Generation (MU)}] + \dots \dots \dots) / \text{Station Gross Generation (MU)}$$

$$\text{Station ONHR (kcal/kWh)} = \frac{\text{Station ONHR (kcal/kWh)}}{1 - \% \text{Operating APC}}$$



Where

OGHR = Operating Gross Heat Rate

ONHR = Operating Net Heat Rate

APC=Auxiliary Power Consumption [Operating APC in Baseline Year]

(c) Heat Rate Reduction Target

The target in Thermal Power Sector under PAT Scheme is set by taking the deviation of NHR of Baseline year and design NHR. Based on the deviation percentage (to design), the target values for Heat Rate reduction are set in the slab.

Let the deviation percentage be “X”, then

If X is <= 5(five), then the HR reduction target is 10% of the deviation.

If X is >5, but <=10, then the HR reduction target is 17% of the deviation.

If X is >10, but <=20, then the HR reduction target is 21% of the deviation.

If X is >20, then the HR reduction target is 24% of the deviation.

(d) Coal based thermal Power Plant Station Target Net Operating Heat Rate without Normalization

The Station Net Operating Heat Rate without Normalization is the ONHR of baseline year minus the heat rate reduction target given to it.

Target Station ONHR (kcal/kWh)

= Station Operating NHR for BY- Heat Rate Reduction Target

Where

OGHR = Operating Gross Heat Rate

ONHR = Operating Net Heat Rate

APC= Auxiliary Power Consumption

This Heat Rate has to be attained by the Station. If the station fails to meet its target, i.e., operates

on a Heat Rate higher than the target, penalty will be levied on the Station. On the other hand, if the station over achieves its target, i.e., operates at a Heat Rate lesser than the target, it will be granted E-Certs, which can be traded in open market.

Section 6.02 Formula for target setting for Gas based Thermal Power Plant

(a) Design Parameters

Station Installed Capacity (MW)

= [U#1 Capacity (MW) + U#2 Capacity (MW) +]

Station Design Module Efficiency

=([U#1 Installed Capacity (MW) X U#1 Module Efficiency} + {U# 2 Installed Capacity (MW) XU# 2 Module Efficiency} +... ..])/(Station Installed Capacity (MW))

Station Module Heat Rate (Gross Heat Rate) (kcal/kWh)

=([U#1 THR X U#1 Installed Capacity (MW)} + {U#2 THR X U#2 Installed Capacity (MW)}+...])/(Station Installed Capacity (MW))

Station Design Net Heat Rate (kcal/kWh)

= $\frac{\text{Station DGHR (kcal/kWh)}}{(1-\% \text{Operating APC})}$

(b) Operating Parameters

Station Operating Load (MW)=U#1 Operating Load (MW)+U# 2 Operating Load (MW)+...

Station Gross Generation(MU)=

(U#1 Gross Generation (MU)+U#2 Gross Generation (MU) + ...)

Station OGHR (kcal/kWh)

=([U#1 OGHR (kcal/kWh) X U#1 Gross Generation (MU)} +{U#2 OGHR (kcal/kWh) X U#2 Gross Generation (MU) }+... ..



...])/(Station Gross Generation (MU))

Station Operating Net Heat Rate

$$\text{Station ONHR (kcal/kWh)} = \frac{(\text{Station OGHR (kcal/kWh)})}{1 - \% \text{ Operating APC}}$$

Where

- OGHR = Operating Gross Heat Rate
- ONHR = Operating Net Heat Rate
- APC = Auxiliary Power Consumption

(c) Heat Rate Reduction Target

The target in Thermal Power Sector under PAT Scheme is set by taking the deviation of NHR of Baseline year and design NHR. Based on the deviation percentage (to design), the target values for Heat Rate reduction are set in the slab.

Let the deviation percentage be “X”, then

If X is <= 5(five), then the HR reduction target is 10% of the deviation.

If X is >5, but <=10, then the HR reduction target is 17% of the deviation.

If X is >10, but <=20, then the HR reduction target is 21% of the deviation.

If X is >20, then the HR reduction target is 24% of the deviation.

(d) Target Station Net Operating Heat Rate without Normalization for AY

The Station Net Operating Heat Rate without Normalization is the ONHR of baseline year minus the heat rate reduction target given to it.

Target Station ONHR (kcal/kWh)

= Station Operating NHR for BY- Heat Rate Reduction Target

Where

- OGHR = Operating Gross Heat Rate
- ONHR = Operating Net Heat Rate
- APC = Auxiliary Power Consumption

This Heat Rate has to be attained by the Station. If the station fails to meet its target, i.e., operates on a Heat Rate higher than the target, penalty will be levied on the Station. On the other hand, if the station over achieves its target, i.e., operates at a Heat Rate lesser than the target, it will be granted E-Certs, which can be traded in open market.

7. Examples for target setting

Section 7.01 Sample Calculation for Target Setting for Coal based Thermal Power Station

Coal based thermal power plants are plants having single primary fuel, which is coal. Oil is also used in these plants, but usually during the start-ups/shut-downs. These plants may be designed on a variety of grade of coal. Some plants are even designed for lignite. The normalization given caters to all the variety of coal and lignite used. Coal/Lignite Based Thermal Power plants operated on Rankine Cycle. For understanding the calculations and normalizations, we assume a Coal Based Thermal Power Station having 3(three) units of 210MW each.

Units	Design Capacity	As Provided by Original Equipment Manufacturer (OEM)			As established during Performance Guarantee Test (PG Test) **		
		Boiler Efficiency	Turbine Heat Rate	Unit Heat Rate	Boiler Efficiency	Turbine Heat Rate	Unit Heat Rate
	MW	%	kcal/kWh	kcal/kWh	%	kcal/kWh	kcal/kWh
U#1	210	87.3	2045	2342.50	87.3	2100.00	2406.88
U#2	210	87.3	2045	2342.50	87.3	2045.00	2343.84
U#3	210	87.3	2045	2342.50	87.3	2045.00	2343.84

** Parameters established during Performance Guarantee Test shall only be considered if OEM data parameters are not available.



The entire examples shall be worked out on the above mentioned table. Calculations based on the above mentioned Plant shall be:

(a) Design Parameters

Station Installed Capacity (MW)

$$= [U\#1 \text{ Capacity (MW)} + U\#2 \text{ Capacity (MW)} + \dots \dots \dots]$$

$$= 210 + 210 + 210$$

$$= 630 \text{ MW}$$

If the configuration of unit is complex, like 2X210MW + 3X500 MW, the same formula holds good. The station Installed capacity in this case shall become

$$= 210 + 210 + 500 + 500 + 500$$

$$= 1920 \text{ MW}$$

Station Design Boiler Efficiency

$$= \frac{([U\#1 \text{ Installed Capacity (MW)} \times U\#1 \text{ Boiler Efficiency}] + [U\# 2 \text{ Installed Capacity (MW)} \times U\#2 \text{ Boiler Efficiency}] + \dots \dots \dots)}{(\text{Station Installed Capacity (MW)})}$$

$$= \frac{[210 \times 87.3 + 210 \times 87.3 + 210 \times 87.3]}{630}$$

$$= 87.3 \%$$

Station THR (kcal/kWh)

$$= \frac{([U\#1 \text{ THR} \times U\#1 \text{ Installed Capacity (MW)}] + [U\#2 \text{ THR} \times U\#2 \text{ Installed Capacity (MW)}] + \dots \dots \dots)}{(\text{Station Installed Capacity (MW)})}$$

$$= \frac{(2045 \times 210 + 2045 \times 210 + 2045 \times 210)}{630}$$

$$(210 + 210 + 210)$$

$$= 2045 \text{ kcal/ kWh}$$

Unit DGHR (kcal/kWh) = (Unit THR (kcal/kWh) / Boiler Efficiency %)

$$U\#1 \text{ DGHR} = 2045 / 87.3 = 2342.5 \text{ kcal/kWh}$$

$$U\#2 \text{ DGHR} = 2045 / 87.3 = 2342.5 \text{ kcal/kWh}$$

$$U\#3 \text{ DGHR} = 2045 / 87.3 = 2342.5 \text{ kcal/kWh}$$

Station DGHR(kcal/kWh)

$$= \frac{([U\# 1 \text{ DGHR} \times U\# 1 \text{ Installed Capacity (MW)}] + [U\# 2 \text{ DGHR} \times U\# 2 \text{ Installed Capacity (MW)}] + \dots \dots \dots)}{(\text{Station Installed Capacity (MW)})}$$

$$= \frac{(2342.5 \times 210 + 2342.5 \times 210 + 2342.5 \times 210)}{(210 + 210 + 210)}$$

$$= 2342.5 \text{ kcal/kWh}$$

Station Design Net Heat Rate (kcal/kWh)

$$= \frac{(\text{Station DGHR (kcal/kWh)})}{((1 - \% \text{ Operating APC}))}$$

$$= \frac{2342.5}{(1 - 0.0757^*)}$$

$$= 2534.35 \text{ kcal/Kwh}$$

* The Designed Auxiliary Power Consumption (APC) is considered as 7.57%

(b) Operating parameters

Now let us assume that the same Thermal Power Plant was operating with some parameters in the baseline year and assessment year. Table below represents the data of the plant

Units	Capacity (MW)	Current/ Assessment/ Target Year (20.... 20....)				Baseline Year (20.... 20....)			
		Operating Load	Loading Factor	Gross Generation	Unit Gross Heat Rate##	Operating Load	Loading Factor	Gross Generation	Unit Gross Heat Rate ##
		MW	%	MU	kcal/kWh	MW	%	MU	kcal/kWh
U#1	210	165	70	1445	2636	150	60	1314	2635
U#2	210	166	72	1454	2637	130	58	800	2636
U#3	210	150	60	1456	2800	120	55	714	2584



Station Operating Load (MW)

$$= \text{U\#1 Operating Load (MW)} + \text{U\#2 Operating Load (MW)} + \dots$$

$$\text{Station Operating load in Baseline Year} = 150 + 130 + 120 = 400 \text{ MW}$$

$$\text{Station Operating load in Assessment Year} = 165 + 166 + 150 = 481 \text{ MW}$$

Station Loading Factor (%)

$$= \left(\frac{[\{\text{U\# 1 loading factor (\%)} \times \text{U\# 1 Gross Generation (MU)}\} + \{\text{U\#2 loading factor (\%)} \times \text{U\# 2 Gross Generation (MU)}\} + \dots \dots \dots]}{\text{Station Gross Generation (MU)}} \right)$$

$$\text{Station loading factor in Baseline Year} = \frac{\{60 \times 1314 + 58 \times 800 + 55 \times 700\}}{(1314 + 800 + 714)} = 57.89 \%$$

$$\text{Station loading factor in Assessment Year} = \frac{\{70 \times 1445 + 72 \times 1454 + 60 \times 1456\}}{(1445 + 1454 + 1456)} = 67.32\%$$

Station Gross Generation (MU)=

$$\text{U\# 1 Gross Generation (MU)} + \text{U\#2 Gross Generation (MU)} + \dots$$

$$\text{Station gross Generation in Baseline Year} = 1314 + 800 + 714 = 2828 \text{ (MU)}$$

$$\text{Station gross Generation in Assessment Year} = 1445 + 1454 + 1456 = 4355 \text{ (MU)}$$

Station OGHR (kcal/kWh)

$$= \left(\frac{[\{\text{U\#1 OGHR (kcal/kWh)} \times \text{U\#1 Gross Generation (MU)}\} + \{\text{U\#2 OGHR (kcal/kWh)} \times \text{U\#2 Gross Generation (MU)}\} + \dots \dots \dots]}{\text{Station Gross Generation (MU)}} \right)$$

$$\text{Station Operation GHR for Baseline Year} = \frac{(2635 \times 1314 + 2636 \times 800 + 2584 \times 714)}{2828} = 2622.40 \text{ kcal/kWh}$$

$$\text{Station Operation GHR for Assessment Year} =$$

$$\frac{(2636 \times 1445 + 2637 \times 1454 + 2800 \times 1456)}{4355} = 2691.2 \text{ kcal/kWh}$$

Station Operating Net Heat Rate

The Station Operating Gross Heat rate of Assessment and Baseline year has been calculated above. Now, considering the Auxiliary Power Consumption to be 6.89% and 7.57% for Assessment Year and baseline Year respectively, we can calculate the Net Operating Heat Rate.

$$\text{Station ONHR (kcal/kWh)} = \frac{\text{Station OGHR (kcal/kWh)}}{1 - \% \text{ Operating APC}}$$

Where

OGHR = Operating Gross Heat Rate

ONHR = Operating Net Heat Rate

APC = Auxiliary Power Consumption

$$\text{Station Operating Net Heat Rate for Baseline Year} = \frac{2622.4}{(1 - 0.0757)} = 2837.17 \text{ kcal/kWh}$$

$$\text{Station Operating Net Heat Rate for Assessment Year} = \frac{2691.2}{(1 - 0.0689)} = 2890.3 \text{ kcal/kWh}$$

(c) Heat Rate Reduction Target

The target in Thermal Power Sector under PAT Scheme is set by taking the deviation of NHR of Baseline year and design NHR. Based on the deviation percentage (to design), the target values for Heat Rate reduction are set in the slab.

Let the deviation percentage be "X", then

If X is ≤ 5 (five), then the HR reduction target is 10% of the deviation.

If X is > 5 , but ≤ 10 , then the HR reduction target is 17% of the deviation.

If X is > 10 , but ≤ 20 , then the HR reduction target is 21% of the deviation.

If X is > 20 , then the HR reduction target is 24% of the deviation.



Accordingly, the target for the above mentioned Thermal Power Station has been calculated as below:

From Sections 1.6 and 2.5, we have-

$$\begin{aligned}
 &\text{Design Net Heat Rate (DNHR)} \\
 &\quad = 2534.35 \text{ kcal/KWh} \\
 &\text{Station Operating Net Heat Rate for Baseline Year (ONHR)} \\
 &\quad = 2837.17 \text{ kcal/kWh} \\
 &\text{Difference between Design and Operating NHR} \\
 &\quad = \text{ONHR-DNHR} \\
 &\quad = 2837.17 - 2534.35 \\
 &\quad = 302.82 \text{ kcal/kWh} \\
 &\text{Difference/ Deviation Percentage from design} \\
 &\quad = \text{Difference/DNHR} \times 100 \\
 &\quad = 302.81 / 2534.35 \times 100 \\
 &\quad = 11.91\%
 \end{aligned}$$

As the deviation percentage is greater than 10, but less than 20, it qualifies for 21% slab.
i.e., $302.82 \times 21\% = 63.59 \text{ kcal/kWh}$

Heat Rate Reduction Target = 63.38 kcal/kWh

(d) Target Station Net Operating Heat Rate without Normalization for AY

The Heat Rate Reduction Target is given on the basis of Baseline year and design parameters.

Section 3 depicts the Target Heat Rate that needs to be reduced, i.e., The station has to operate at a Net Heat Rate which is 63.38 kcal/kWh lesser than its baseline year. Hence,

The Station Net Operating Heat Rate without Normalization is ONHR for baseline year minus the HR reduction target

$$\begin{aligned}
 &\text{Target Heat Rate Reduction} = 63.38 \text{ kcal/kWh} \\
 &\text{Target Operating Net Heat Rate in baseline Year} \\
 &\quad = 2837.17 - 63.38 \\
 &\quad = 2773.79 \text{ kcal/kWh}
 \end{aligned}$$

This Heat Rate has to be attained by the Station. If the station fails to meet its target, i.e., operates on a Heat Rate higher than 2773.79 kcal/kWh, penalty will be levied on the Station. On the other hand, if the station over achieves its target, i.e., operates at a Heat Rate lesser than 2773.79 kcal/kWh, it will be granted E-Certs, which can be traded in open market.

Section 7.02 Sample Calculation for Target Setting for Gas based Thermal Power Station

Gas based Thermal Power plants are basically based on combined cycle. These plants may use gas as primary source of fuel or a mixture of gas and other fuels such as Naptha. These may be further divided into open and closed cycle depending upon the type/ load of operation. For understanding the calculations, let us take the example of a Station having three units of 210MW capacity each.

Table below, represents the capacity, THR with module efficiency is given in the table below.

Design Capacity	As Provided by Original Equipment Manufacturer (OEM)		As established during Performance Guarantee Test (PG Test) **	
	Module Efficiency	Module Heat Rate@	Module Efficiency	Module Heat Rate
MW	%	kcal/kWh	%	kcal/kWh
210	45.0	1911.11	45.0	1911.11
210	45.0	1911.11	45.0	1911.11
210	46.0	1869.57	47.0	1829.79

** Parameters established during Performance Guarantee Test shall only be considered if OEM data parameters are not available.



The entire examples shall be worked out on the above mentioned table. Calculations based on the above mentioned Station shall be:

(a) Design Parameters

Station Installed Capacity (MW)

$$= [U\#1 \text{ Capacity (MW)} + U\#2 \text{ Capacity (MW)} + \dots \dots \dots]$$

$$= 210 + 210 + 210$$

$$= 630 \text{ MW}$$

If the configuration of unit is complex, like 2X210MW +3X500 MW, the same formula holds good. The station Installed capacity in this case shall become

$$= 210 + 210 + 500 + 500 + 500$$

$$= 1920 \text{ MW}$$

Station Design Module Efficiency

$$= (\{U\#1 \text{ Installed Capacity (MW)} \times U\#1 \text{ Module Efficiency}\} + \{U\#2 \text{ Installed Capacity (MW)} \times U\#2 \text{ Module Efficiency}\} + \dots \dots \dots) / (\text{Station Installed Capacity (MW)})$$

$$= (210 \times 45 + 210 \times 45 + 210 \times 46) / (210 + 210 + 210)$$

$$= 45.33 \%$$

Station Module Heat Rate (Gross Heat Rate) (kcal/kWh)

$$= (\{U\#1 \text{ THR} \times U\#1 \text{ Installed Capacity (MW)}\} + \{U\#2 \text{ THR} \times U\#2 \text{ Installed Capacity (MW)}\} + \dots \dots \dots) / (\text{Station Installed Capacity (MW)})$$

$$= (1911.11 \times 210 + 1911.11 \times 210 + 1869.57 \times 210) / (210 + 210 + 210)$$

$$= 1897.26 \text{ kcal/ kWh}$$

Station Design Net Heat Rate (kcal/kWh)=

$$\frac{\text{Station DGHR (kcal/kWh)}}{(1 - \% \text{Operating APC})}$$

$$= 1897.26 / (1 - 0.0566)$$

$$= 2011.08 \text{ kcal/kWh}$$

* The Designed Auxiliary Power Consumption (APC) is considered as 5.66%

(b) Operating parameters

Now let us assume that the same Thermal Power Plant was operating with some parameters in the baseline year and assessment year. Table below represents the data of the plant

Units	Capacity (MW)	Current/ Assessment/ Target Year (20... 20...)			Baseline Year (20... 20...)		
		Operating Load	Gross Generation	Unit Gross Heat Rate##	Operating Load	Gross Generation	Unit Gross Heat Rate ##
		MW	MU	kcal/kWh	MW	MU	kcal/kWh
U#1	210	165	1445	2636	150	1314	2635
U#2	210	166	1454	2637	130	800	2636
U#3	210	150	1456	2800	120	714	2384

Station Operating Load (MW)=U#1 Operating Load (MW)+U# 2 Operating Load (MW)+...

Station Operating load in Assessment Year

$$= 165 + 166 + 150$$

$$= 481 \text{ MW}$$

Station Operating load in Baseline Year

$$= 150 + 130 + 120$$

$$= 400 \text{ MW}$$

Station Gross Generation(MU)=

U#1 Gross Generation (MU)+U#2 Gross Generation (MU) + ...



Station gross Generation in Baseline Year

$$= 1314 + 800 + 714$$

$$= 2828 \text{ (MU)}$$

Station gross Generation in Assessment Year

$$= 1445 + 1454 + 1456$$

$$= 4355 \text{ (MU)}$$

Station OGHR (kcal/kWh)

$$= \left(\left[\left\{ \text{U\# 1 OGHR (kcal/kWh)} \times \text{U\# 1 Gross Generation (MU)} \right\} + \left\{ \text{U\#2 OGHR (kcal/kWh)} \times \text{U\#2 Gross Generation (MU)} \right\} + \dots \right] / \text{Generation (MU)} \right)$$

Station Operation GHR for Baseline Year

$$= (2635 \times 1314 + 2636 \times 800 + 2384 \times 714) / 2828$$

$$= 2571.91 \text{ kcal/kWh}$$

Station Operation GHR for Assessment Year

$$= (2636 \times 1445 + 2637 \times 1454 + 2800 \times 1456) / 4355$$

$$= 2691.2 \text{ kcal/kWh}$$

Station Operating Net Heat Rate

The Station Operating Gross Heat rate of Assessment and Baseline year has been calculated above. Now, considering the Auxiliary Power Consumption to be 6.89% and 5.66% for Assessment Year and baseline Year respectively, we can calculate the Net Operating Heat Rate.

$$\text{Station ONHR (kcal/kWh)} = \frac{\text{Station OGHR (kcal/kWh)}}{1 - \% \text{ Operating APC}}$$

Where

OGHR = Operating Gross Heat Rate

ONHR = Operating Net Heat Rate

APC = Auxiliary Power Consumption

Station Operating Net Heat Rate for Baseline Year

$$= 2571.91 / (1 - 0.0566)$$

$$= 2726.21 \text{ kcal/kWh}$$

Station Operating Net Heat Rate for Assessment

Year

$$= 2691.2 / (1 - 0.0689)$$

$$= 2890.3 \text{ kcal/kWh}$$

(c) Heat Rate Reduction Target

The target in Thermal Power Sector under PAT Scheme is set by taking the deviation of NHR of Baseline year and design NHR. Based on the deviation percentage (to design), the target values for Heat Rate reduction are set in the slab.

Let the deviation percentage be "X", then

If X is ≤ 5 (five), then the HR reduction target is 10% of the deviation.

If X is > 5, but ≤ 10, then the HR reduction target is 17% of the deviation.

If X is > 10, but ≤ 20, then the HR reduction target is 21% of the deviation.

If X is > 20, then the HR reduction target is 24% of the deviation.

Accordingly, the target for the above mentioned Thermal Power Station has been calculated as below:

From Sections 1.6 and 2.5, we have-

Design Net Heat Rate (DNHR)

$$= 2011.08 \text{ kcal/kWh}$$

Station Operating Net Heat Rate for Baseline Year (ONHR) = 2726.21 kcal/kWh

Difference between Design and Operating NHR

$$= \text{ONHR} - \text{DNHR}$$

$$= 2726.21 - 2011.08$$

$$= 715.13 \text{ kcal/kWh}$$

Difference / Deviation Percentage from design

$$= \text{Difference} / \text{DNHR} \times 100$$

$$= 715.13 / 2011.08 \times 100$$

$$= 35.56\%$$

As the deviation percentage is greater than 20, it



qualifies for 24% slab.

i.e., $715.13 \times 24\% = 171.63 \text{ kcal/kWh}$

Heat Rate Reduction Target = 171.63 kcal/kWh

(d) Target Station Net Operating Heat Rate without Normalization for AY

The Heat Rate Reduction Target is given on the basis of Baseline year and design parameters.

Section 3 depicts the Target Heat Rate that needs to be reduced, i.e., The station has to operate at a Net Heat Rate which is 66.01 kcal/kWh lesser than its baseline year. Hence,

The Station Net Operating Heat Rate without Normalization is the ONHR for baseline year minus the HR reduction target

Where

$$\text{Target Heat Rate Reduction} = 171.63 \text{ kcal/kWh}$$

Target Operating Net Heat Rate in Assessment

$$\text{Year} = 2726.21 - 171.63$$

$$= 2554.58 \text{ kcal/kWh}$$

This Heat Rate has to be attained by the Station. If the station fails to meet its target, i.e., operates on a Heat Rate higher than 2554.58 kcal/kWh, penalty will be levied on the Station. On the other hand, if the station over achieves its target, i.e., operates at a Heat Rate lesser than 2554.58 kcal/kWh, it will be granted E-Certs, which can be traded in open market.

8. Normalization/ Correction factor to be considered for target setting:

There are several factors that need to be taken into consideration on capacity utilization of DCs for Normalization of a product under PAT rules, so that the undue advantage or disadvantage could not be imposed on DC. There are many factors, which can influence the SEC of a DC are listed below

Section 8.01 Input Primary Energy

Sr No	Sub-Group	Elements	Reason/ Requirement	Impact	Documents
1	Coal Quality in Boiler IPP	%H, % Moisture, %Ash, GCV	Poor quality of Fuel effects the Power Station Performance	Boiler Efficiency / Gas Turbine	Ref Calculation provided for Boiler Efficiency (Coal Linkage with Coal Field leads to poor quality of Coal contains impurities like stone, Ash, high moisture etc because of poor performance of washeries)
	Non Availability of fuel [External Factor]	Loss of Generation	Beyond DC's control	Plant Load Factor	i. Documents from Coal Supplying company. ii. Characteristics curve of Load Vs Design Turbine Heat Rate from OEM



Section 8.02 Plant Load Factor

Sr No	Sub-Group	Elements	Reason/ Requirement	Impact	Documents
2	Scheduling [External factor] or Backing down	PLF and Station heat rate	<ul style="list-style-type: none"> Plant Load backing down due to lower power demand from the grid Variations in demand from the estimated or forecasted values, which cannot be absorbed by the grid. 	Boiler Efficiency / Gas Turbine	i. Scheduling Documents ii. Reference documents are required for deterioration in Plant Load Factor iii. Characteristics curve [Load Vs Heat Rate]
	Unscheduled Power and Outage [External Factor]	PLF and Station heat rate	Transmission outages resulting in reduced power availability.	Plant Load Factor	Characteristics curve-Heat Rate Vs Load

Section 8.03 Fuel Mix

Sr No	Sub-Group	Elements	Reason/ Requirement	Impact	Documents
3	Fuel	Use of different Fuel in same unit	Separate NHR for different fuel used in the unit	Boiler Efficiency	Fuel Quality and Quantity documentation

Section 8.04 Fuel Quality

Sr No	Sub-Group	Elements	Reason/ Requirement	Impact	Documents
3	Coal	Use of coal with different calorific value in AY and BY	Coal quality is beyond the control of plant	Boiler Efficiency, Auxiliary Power Consumption	Fuel Quality and Quantity documentation, Energy consumption of mills in AY and BY
	Gas	Use of Gas with different calorific value in AY and BY	Gas quality may be compromised due to limited availability	Net Heat Rate	Fuel Quality and Quantity documentation



Section 8.05 Environmental Standards

Sr No	Sub-Group	Elements	Reason/ Requirement	Impact	Documents
4	Additional Equipment Installation due to Environmental law	Auxilliary Power Consumption	The Energy will be normalized for additional Energy consumption. This is to be excluded from APC	APC	The DC has to maintain the documents for additional installation of Environmental Equipment
5	Flood, Earthquake etc		Proper weightage could be given in SEC in terms of capacity utilisation, energy used for re-establishment	Plant Load Factor	The DC has to maintain the authentic documents for natural disaster

9. Formulas of Normalization

Section 9.01 Common Calculations for Normalization

The target for Heat Rate Reduction is based on Baseline Year and Design parameters. However, there are factors which may have changed beyond control during the Assessment Year which may lead to higher Operating Net Heat Rate. These factors may be variation in coal quality, Plant Load Factor (PLF), Auxiliary Power Consumption (APC), number of start-

ups, etc. We cannot bring the station on a platform with similar operating conditions as the baseline year. However, we have given relaxations on these factors which are beyond the control of any Station. These relaxations are known as normalization.

In normalization, the deviation due to each external factor is calculated in terms of Heat Rate and is subtracted from the Station Operating Net Heat rate for Assessment Year.

Station Average Operating Hour (Hr) Caused by low ULF/MLF due to Fuel Unavailability

$$= \frac{([U\# 1 AOHr \times U\# 1 AOL (MW)] + U\# 2 AOHr \times U\# 2 AOL (MW) + \dots \dots \dots)}{\text{Station AOL (MW) due to Fuel Unavailability}}$$

Where:

ULF = Unit Load Factor

MLF = Module Load Factor

AOHr = Average Operating Hour

AOL = Average Operating Load

Station Average Operating Hour (Hr.) Caused by low ULF/MLF due to Scheduling

$$= \frac{([U\# 1 AOHr \times U\# 1 AOL (MW)] + [U\# 2 AOHr + U\# 2 AOL (MW)] + \dots \dots \dots)}{\text{Station AOL (MW) due to Scheduling}}$$



Where

ULF = Unit Load Factor

MLF = Module Load Factor

AOHr = Average Operating Hour

AOL = Average Operating Load

Station Average Operating Hour (Hr.) Caused by low ULF/MLF due to Backing down

$$= \frac{[U\# 1 AOHr \times U\# 1 AOL (MW)] + [U\# 2 AOHr + U\# 2 AOL (MW)] + \dots \dots \dots}{\text{Station AOL (MW) due to backing down}}$$

Where

ULF = Unit Load Factor

MLF = Module Load Factor

AOHr = Average Operating Hour

AOL = Average Operating Load

Station Average Operating Hours (Hr.) caused by ULF/MLF due to any other external Factor

$$= \frac{([U\# 1 AOHr \times U\# 1 AOL (MW)] + [U\# 2 AOHr + U\# 2 AOL (MW)] + \dots \dots \dots)}{\text{Station AOL (MW) due to backing down}}$$

Where

ULF = Unit Load Factor

MLF = Module Load Factor

AOHr = Average Operating Hour

AOL = Average Operating Load

External factors = Fuel Unavailability/ Scheduling/ backing down/ any other external factor etc.

Unit Average Operating Load (MW) Caused by low ULF/MLF due to External factors

$$= \text{Total Generation (MWHr)} / \text{Total Operating Hour (Hr)}$$

Where

Total Generation = (Unit AOL (MW) X Unit AOHr) due to Fuel Unavailability + (Unit AOL (MW) X Unit AOHr) due to Scheduling + (Unit AOL (MW) X Unit AOHr) due to Backing Down + (Unit AOL (MW) X Unit AOHr) due to any other external factor]

Total Operating Hour = [Unit AOHr due to Fuel Unavailability + Unit AOHr due to Scheduling + Unit AOHr due to Backing Down + Unit AOHr due to any other external factor]



ULF = Unit Load Factor

MLF = Module Load Factor

AOHr = Average Operating Hour

AOL = Average Operating Load

External factors = Fuel Unavailability/ Scheduling/ backing down/ any other external factor etc.

Station Average Operating Load (MW) caused by low ULF/MLF due to Fuel Unavailability/ Scheduling/ Backing down/ any other external factor

$$= [U\# 1 AOL (MW) + U\# 2 AOL (MW) + \dots \dots \dots]$$

Where:

ULF = Unit Load Factor

MLF = Module Load Factor

AOL = Average Operating Load

Unit Average Operating Hours at Low ULF/MLF due to external Factors

$$= \text{Total Generation (MWHr)} / \text{Total Average Operating load (MW)}$$

Where

$$\text{Total Generation} = (\text{Unit AOL (MW)} \times \text{U\# AOHr}) \text{ due to Fuel Unavailability} + (\text{Unit AOL (MW)} \times \text{Unit AOHr}) \text{ due to Scheduling} + (\text{Unit AOL (MW)} \times \text{Unit AOHr}) \text{ due to Backing Down} + (\text{Unit AOL (MW)} \times \text{Unit AOHr}) \text{ due to any other external factor}$$

$$\text{Total Average Operating Load} = [(\text{Unit AOL (MW) to Fuel Unavailability} + \text{Unit AOL (MW)}) \text{ due to Scheduling} + \text{Unit AOL (MW) to Backing Down} + \text{Unit AOL (MW) due to any other external factor}]$$

ULF = Unit Load Factor

MLF = Module Load Factor

AOHr = Average Operating Hour

AOL = Average Operating Load

External factors = Fuel Unavailability/ Scheduling/ backing down/ any other external factor etc.

Station Average Operating Hours at Low ULF/MLF due to external factors

$$= ([(\text{U\# 1 AOL (MW)} \times \text{U\# 1 AOHr}) \text{ at Low ULF/MLF due to external factor} + \{\text{U\# 2 AOL (MW)} \times \text{U\# 2 AOHr}\} \text{ at Low ULF/MLF due to external factor} + \dots \dots \dots]) / (\text{Station AOL (MW) caused by low ULF/MLF due to external factors})$$



Where

ULF = Unit Load Factor

MLF = Module Load Factor

AOHr = Average Operating Hour

AOL = Average Operating Load

External factors = Fuel Unavailability/ Scheduling/ backing down/ any other external factor etc.

Unit Availability Factor = $\frac{\text{Hours in a Year} - [\text{RSHr} + \text{FO or Unavailability hour} + \text{PMO or Planned Unavailability}]}{\text{Hours in a Year}}$

Where

RSHr = Reserve Shutdown Hour

FO = Forced Outage

PMO = Planned Maintenance Outage

Station RSHr

$$= \frac{(\{U\#1 \text{ RSHr} \times U\#1 \text{ Capacity (MW)}\} + \{U\#2 \text{ RSHr} \times U\#2 \text{ Capacity (MW)}\} + \dots \dots \dots)}{\text{Total Station capacity} \times \text{Hours in a Year}}$$

Station FO or Unavailability Hour

$$= \frac{(\{U\#1 \text{ FO} \times U\#1 \text{ Capacity (MW)}\} + \{U\#2 \text{ FO} \times U\#2 \text{ Capacity (MW)}\} + \dots \dots \dots)}{(\text{Total Station capacity} \times \text{Hours in a Year})}$$

Station PMO or Planned

Unavailability = $\frac{(\{U\#1 \text{ PMO} \times U\#1 \text{ Capacity (MW)}\} + \{U\#2 \text{ PMO} \times U\#2 \text{ Capacity (MW)}\} + \dots \dots \dots)}{\text{Total Station capacity} \times \text{Hours in a Year}}$

Station Availability Factor = $1 - [\text{Station RSHr} + \text{Station FO or Unavailability hour} + \text{Station PMO or Planned Unavailability}]$

Where

RSHr = Reserve Shutdown Hour

FO = Forced Outage

PMO = Planned Maintenance Outage

These formulas constitute the general working formulas which will find reference in all the calculations. These formulas are also used in day to day reporting to the plant management. The definition of terms mentioned above in sections shall be assumed only on above calculations in Sector specific Pro-forma (Form Sh)



Section 9.02 Normalization for Coal/ Lignite base Thermal Power Plant

(a) Coal/Lignite Quality in Boiler IPP

Coal is extremely heterogeneous, varying widely in their content and properties from country to country, mine to mine and even from seam to seam. The principle impurities are ash-forming minerals and sulphur. Some are interspersed through the coal seam; some are introduced by the mining process, and some principally organic sulphur, nitrogen and some minerals salts.

These impurities affect the properties of the coal and the combustion process, therefore the plant's boiler efficiency & Turbine Efficiency. The generating companies have no control over the quality of coal supplied. The raw coal mainly being supplied to the power stations could have variation in coal quality. Further, imported coal is also being used and blended with Indian coal by large number of stations, which could also lead to variations in coal quality.

The methodology should have provisions to take care of the impact of variations in coal quality. Therefore, average "Ash, Moisture, Hydrogen and GCV" contents in the coal during the baseline period as well as for Design Coal could be considered for Normalization and the correction factor has to be worked out based on the following boiler efficiency formula:

$$\text{Boiler Efficiency} = 92.5 - \frac{[50 * A + 630 (M + 9 H)]}{\text{G.C.V}}$$

Where:

A= Ash percentage in coal

M= Moisture percentage in coal

H= Hydrogen percentage in coal

G.C.V= Gross calorific value in kcal/kg

Station heat rate (Kcal/kWh) = Turbine heat rate/ Boiler efficiency

(i) Sample Calculation: Coal Quality- Designed Vs Actual

The quality of coal analyzed w.r.t. Proximate and Ultimate analysis. The ultimate analysis determines all coal component elements, solid or gaseous and the proximate analysis determines only the fixed carbon, volatile matter, and moisture and ash percentages. Coals of different ranks vary in chemical composition, lower ranks contains relatively lower carbon but higher oxygen, whereas for higher rank it will be reverse.

Proximate Analysis					
		Unit A		Unit B	
Item	Unit	Design	Operating	Design	Operating
Fixed Carbon	%	22			
Volatile matter	%	21	23.4		
Moisture	%	15	17.4	12	16
Ash	%	42	37.4	42	35.45
Grindability Index	HGI	55			
Higher Heating Value (GCV)	kcal/kg	3300	3137	2824	2776
Size of Coal to Mill	mm	50			

The table represents proximate and ultimate analysis of coal for a particular plant. The plant has been designed for a particular coal and any deviation from the designed could result in lower or higher efficiencies of Boiler.

Ultimate Analysis					
		Unit A		Unit B	
Item	Unit	Design	Operating	Design	Operating
Carbon	%	33.73	33.8	31.9	33.75
Hydrogen	%	2.35	2.69	2.44	2.47
Sulphur	%	0.37		0.5	0.5
Nitrogen	%	0.75	1.82	0.69	1.82
Oxygen	%	5.48	6.8	11.08	10.01
Carbonates	%	0.27			
Phosphorous	%	0.05			
Moisture	%	15		12	16
Ash	%	42	37.4	42	35.45



The main constituent of Proximate and Ultimate analysis such as Ash, Moisture and hydrogen needs to be analysed w.r.t. the efficiency of Boiler.

(ii) Non Availability of fuel (Coal/Gas/Lignite) [External Factor]

Due to fuel non- availability, plant may opt to reduce the load on turbine leading to low efficiency of units and Station. Due to decreased loading, the Plant load Factor will be worsened and affects the unit heat rate. The comparison between baseline year and assessment year will be carried out through characteristics curve of Load Vs Heat rate for correction factor and will be covered under Scheduling chapter in Section 9.02.

Similar approach could be followed in case of gas/liquid fuel based generating stations. However the average plant load factor of these stations is much lower than the coal based stations perhaps due to low availability of Gas/ Liquid fuel. Also the heat rate of the gas turbines is very sensitive to the unit loading and ambient air conditions. However, quality of gas supply does not vary widely and so correction for fuel quality would not be required.

(iii) Sample Calculation: Coal Quality-Effect of fuel quality on Boiler efficiency & Turbine Heat Rate

Coal Proximate and Ultimate Analysis

Item	Unit	Design	Operating
Ash	%	28	41.17
H	%	2.5	2.5
Moisture	%	8	10.35
GCV	kcal/kg	4440	3632.7

Boiler Efficiency by calculation

Item	Unit	Formulae	Design	Operating
% Boiler Efficiency	%	$[92.5 - \{50 \cdot A + 630 \cdot (M + 9 \cdot H)\} / \text{GCV}]$	87.86	86.25
Difference of Boiler Efficiency from Design to Operating	%		1.62	

In the above calculation for Unit A, Boiler was designed with specific coal having GCV of 4440 kcal/kg and certain Moisture, Ash, Hydrogen content. With the passage of time, the quality of coal deteriorates and reached lower level of GCV, Moisture and hydrogen. The plant has no option but to burn additional fuel and operate at lower efficiencies. The coal linked plant has to plug their fuel demand from the linkage mines only, hence without any alternative the plant needs to stay with their mines only. The poor quality coal not only deteriorates the efficiency of the plant, it also decreases the heat rate of station. As seen in the table, there is no major effect of Ash content in the efficiency of the boiler; however, the H&M factor determines the efficiency of the Boiler.

The efficiency of Unit A has come down from 87.86 to 86.25% with the use of low quality fuel, a decrease in 1.61% of Boiler Efficiency has been observed.

(iv) Normalization formula for Plant A due to coal quality

Any change in Coal Quality directly affects Boiler Efficiency. The composition of coal largely varies depending upon its source. Based on these consents, coal is graded and is used accordingly in power and other sector. However, while the boiler is recommended and designed for a certain quality of coal, it has to be run on alternate quality due to a number of reasons. These reasons could be in control sometimes, but most of times beyond the control of plant operator. In India, the coal



availability has become a crisis and hence the plant management is most of the times forced to use any quality of coal that is available. Under such situations, where the coal quality cannot be controlled, and the boiler efficiency is affected, a normalization factor has been introduced. This normalization factor will take care of coal quality and give relief in Heat Rate, calculated from boiler efficiency as a result of deferred coal quality. Boiler Efficiency has been calculated using the formula considering all the aspects of coal.

Unit's Boiler Efficiency (For design, BY and AY Coal)

$$= 92.5 - \frac{\{50 \cdot A + 630 \cdot (M + 9 \cdot H)\}}{\text{GCV of Coal}}$$

Where

BY = Baseline Year

AY = Assessment Year

GCV = Gross Calorific value (Kcal/ Kg)

M = Moisture (in %)

H = Hydrogen (in %)

A = Ash (in %)

Percentage Decrease in Efficiency from calculated Boiler Operating Efficiency to calculated Boiler Design Efficiency in BY

$$= \frac{\{\text{Calculated Boiler Design Efficiency} - \text{Calculated Boiler operating Efficiency in BY}\} \times 100}{(\text{Calculated Boiler Design Efficiency})}$$

Percentage Decrease in Efficiency from calculated Boiler Operating Efficiency to calculated Boiler Design Efficiency in AY

$$= \frac{\{\text{Calculated Boiler Design Efficiency} - \text{Calculated Boiler operating Efficiency in AY}\} \times 100}{\text{Calculated Boiler Design Efficiency}}$$

Degradation/ Upgradation of Actual Boiler Design Efficiency in BY

$$= \frac{\{\text{Actual Design Boiler } \eta \text{ of Unit (As per OEM)} \times \% \text{ Decrease in } \eta \text{ in BY}\}}{100}$$

Where

BY = Baseline Year

OEM = Original Equipment Manufacturer

Degradation/Upgradation of Actual Boiler Design Efficiency in AY

$$= \frac{\{\text{Actual Design Boiler } \eta \text{ of U\# (As per OEM)} \times \% \text{ Decrease in } \eta \text{ in AY}\}}{100}$$

Where

AY = Assessment Year

OEM = Original Equipment Manufacturer



Normalized Boiler Efficiency Design for Unit in BY

= (Actual Design Boiler Efficiency of Unit (As per OEM)
– Degradation or Upgradation of Actual Boiler Design in BY)

Where

BY = Baseline Year

OEM = Original Equipment Manufacturer

Normalized Boiler Efficiency Design for Unit in AY

= Actual Design Boiler Efficiency of Unit (As per OEM) - Degradation or Upgradation of Actual Boiler Design in AY

Where

AY = Assessment Year

OEM = Original Equipment Manufacturer

Difference in Normalized Boiler Efficiency between BY and AY

= Normalized Boiler Design Efficiency in BY – Normalized Boiler Design Efficiency in AY

Where

AY = Assessment Year

BY = Baseline Year

Normalized Boiler Efficiency Design for Unit for the AY as compared to the BY

If the difference in Normalized Boiler Efficiency between BY and AY is less than or equal to zero, then No Normalization

If the difference in Normalized Boiler Efficiency between BY and AY is greater than zero, then the normalization is as below:

= Actual Design Boiler Efficiency of Unit (as per OEM) – Difference in Normalized Boiler Efficiency between BY and AY

Where

BY = Baseline Year

AY = Assessment Year

OEM = Original Equipment Manufacturer

Normalized Boiler Efficiency Design for Station:

= $\left[\{U\# 1 \text{ Capacity (MW)} \times \text{Normalized Boiler Efficiency Design for } U\# 1 \text{ for the AY as compared to the BY}\} + \{U\# 2 \text{ Capacity (MW)} \times \text{Normalized Boiler Efficiency Design for } U\# 2 \text{ for the AY as compared to the BY}\} + \dots \right] / \text{Station total installed Capacity (MW)}$



Where

BY = Baseline Year

AY = Assessment Year

Normalized Unit THR

$$= \frac{(\text{Design THR} \times \text{Normalized Boiler Efficiency Design for Unit in BY})}{\text{Normalized Boiler Efficiency Design for Unit in AY}}$$

Where

THR = Turbine Heat Rate

AY = Assessment Year

BY = Baseline Year

Heat Rate to be normalized in the Unit Operating Heat Rate:

If the difference in Normalized Boiler Efficiency between BY and AY is less than or equal to zero, Then No Normalization.

If the difference in Normalized Boiler efficiency between BY and AY is greater than zero, then the Normalization is as below:

Turbine Heat Rate to be normalized = Normalized Unit Turbine Heat Rate - Unit Design Turbine Heat Rate

Turbine Heat Rate to be normalized in the station operating Turbine Heat Rate

$$= \left(\left[\text{HR to be normalized in U\# 1 THR} \times \text{U\# 1 Gross Generation (MU)} \right] + \left[\text{HR to be normalized in U\# 2 THR} \times \text{U\# 2 Gross Generation (MU)} + \dots \right] \right) / \left[\text{U\# 1 Gross Generation (MU)} + \text{U\# 2 Gross Generation (MU)} + \dots \right]$$

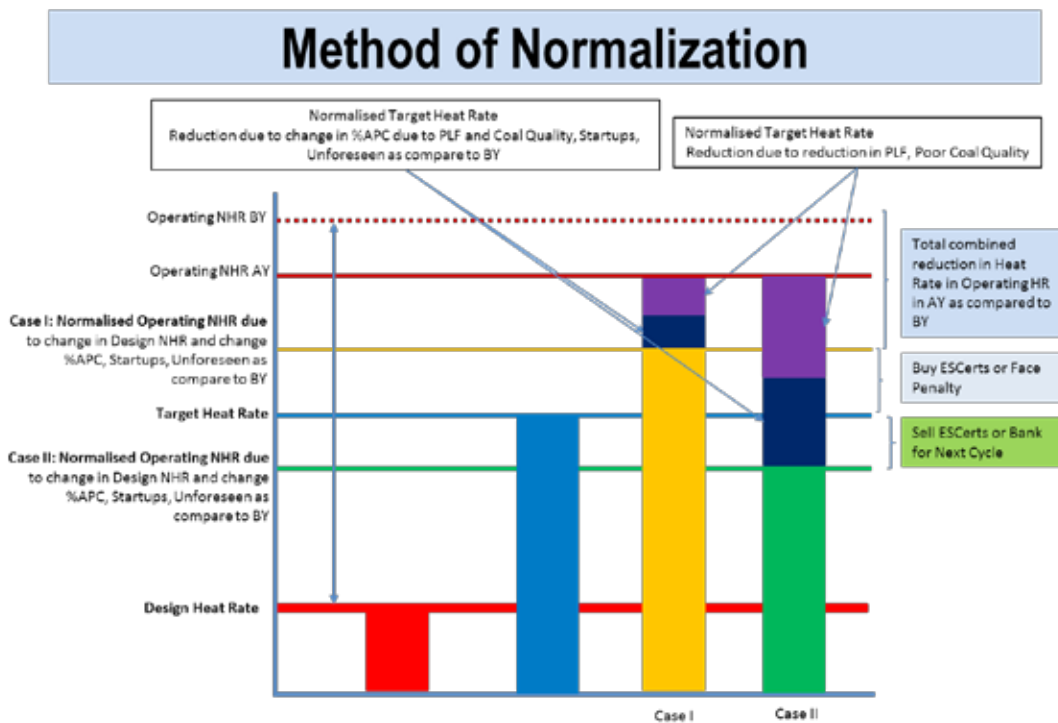
(b) Plant Load Factor [Scheduling]

Coal/ Lignite based plants continued to have major contribution towards electricity generation with a major share of 86.4% of the total thermal generation. Plant load factor (PLF) of thermal power stations at the national level, during 2011-12, reduced to 73.32% from 75.08% achieved during previous year. The Lower PLF was due to increased generation loss due to coal supply problem and transmission constraints and Reserve Shut down/Low system demand

PLF will also have an effect on the Auxiliary Power Consumption of the Station. Due to low PLF, the percentage APC will increase. This factor may be beyond the control of station, such as during low schedule, grid restriction, etc. However this shall be considered in different sub-section of APC normalization.

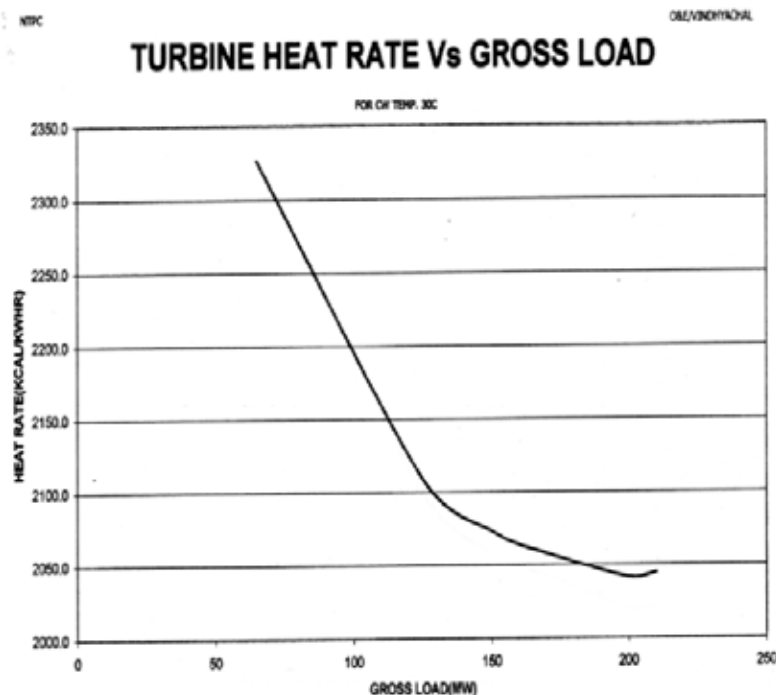


(i) Method of Normalization



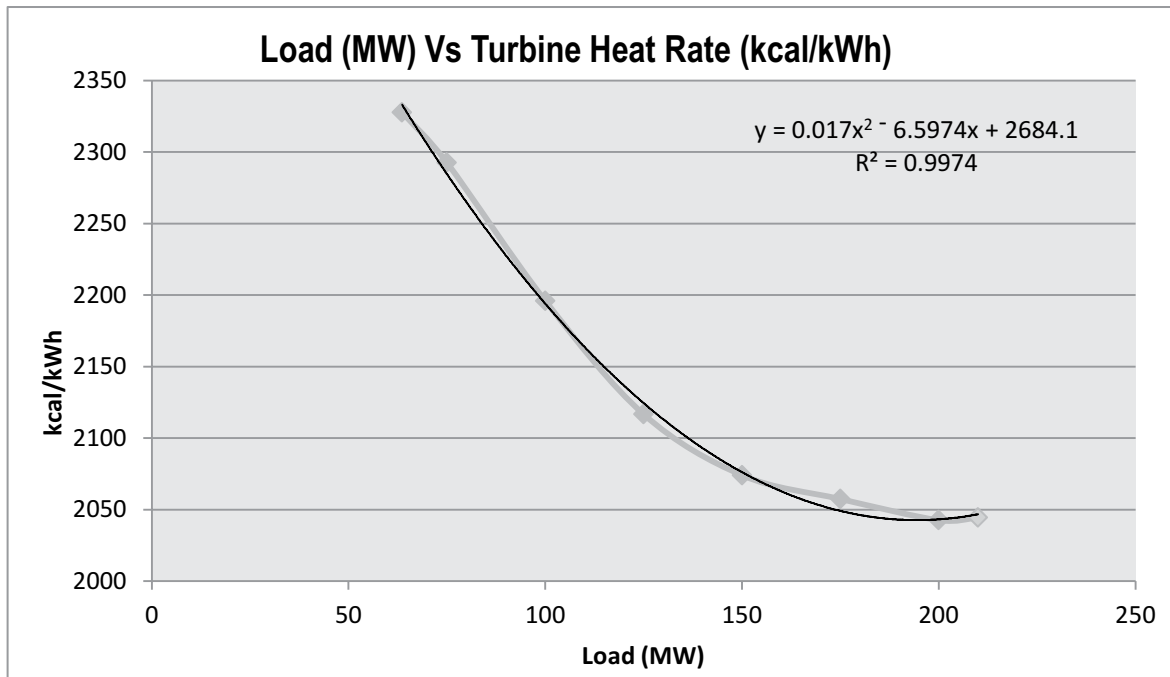
(ii) Normalisation Example: Coal Based Thermal Power Plant (210 MW): Change in Plant Load Factor (PLF)

210 MW Characteristics Curve





Excel topology 210 MW Characteristics Curve



(iii) Normalisation Example for Plant A due to PLF

Change in Plant Load Factor (PLF) do affects the plant efficiency and the heat rate. PLF depends on a number of factors. These factors are sometimes under the control of plant operators and sometimes not. Moreover, at different period of times during a year, a plant may not run on a consistent PLF. All such factors which affects the generation, ultimately affects the

PLF. It is understood that the plant may not be operating on the same PLF in the Assessment Year as in Baseline Year for internal as well as external reasons. Hence, in PLF normalization, all such factors which were beyond the control of the plant management, has been taken care off and due advantage has been given. In PLF normalization, like other normalizations, the benefit has been calculated and given in terms of Heat rate which will directly be subtracted from the Net Operating Heat Rate.

Percentage Difference between Design Turbine Heat Rate and Design Curve or HBD Turbine Heat Rate

$$= \frac{(\text{Design THR @ 100\% Load (OEM)} - \text{Design THR @ 100\% Load (Curve or HBD)}) \times 100}{\text{Design THR @ 100\% Load (OEM)}}$$

Where

THR = Turbine Heat Rate (kcal/kWh)

OEM = Original Equipment Manufacturer

HBD = Heat Balance Diagram



Total Operating hours in year as per Unit Availability factor (hrs/annum)

= Total hour in a year X Plant Availability Factor

Operating hours at full load (hrs/annum)

= Total Operating hours in year as per Unit Availability factor - AOHrs at Low ULF/MLF

Where

AOHr = Average Operating Hours (hr)

ULF = Unit Load Factor

MLF = Module Load Factor

Loading Vs Heat Rate Equation given as $y = ax^2 - bx + c$ will be used to calculate the Turbine Heat Rate as per Load Vs Heat Rate Equation due to external factor.

$$y = ax^2 - bx + c \quad (\text{kcal/kWh})$$

Where

X = Operating Load (MW)

A = Equation Constant 1 = 0.0171

b = Equation Constant 2 = 6.6159

c = Equation Constant 3 = 2684.8

Turbine Heat Rate as per Load Vs Heat Rate Equation due to external factor (kcal/kWh)

= Equation Constant 1

+ (Average Operating Load (MW) caused by low ULF, MLF due to external factor)²

+ Equation Constant 2

+ Average Operating Load (MW) caused by low ULF, MLF due to external factor

+ Equation Constant 3

Design Turbine Heat Rate after Curve correction and difference correction

= THR as per Load Vs HR Equation due to external factor X [1 + {% Difference between Design Turbine or Module HR and Design Curve or HBD Turbine or Module HR/100}]

Where

THR = Turbine Heat Rate (kcal/kWh)

L Vs HR = Load Vs Heat Rate

HBD = Heat balance Diagram

Normalized Design Turbine Heat rate due to external factor (kcal/kWh)

= [Design THR @ 100% Load (OEM) X Operating hours at full load + Design THR after Curve correction and difference correction X AOHrs at Low ULF/MLF] / Total Operating hours in year as per UAF

Where

THR = Turbine Heat Rate (kcal/kWh)

OEM = Original Equipment Manufacturer

AOHr = Average Operating Hours

UAF = Unit Availability Factor

Difference of Turbine Heat Rate due to external factor between AY and BY (kcal/kWh)

= Normalized Design THR due to external factor in AY - Normalized Design THR due to external factor in BY

Where

THR = Turbine Heat Rate (kcal/kWh)

AY = Assessment Year

BY = Baseline Year

Normalized Design Turbine Heat rate due to external factor as compared to BY

= Design THR @ 100% Load (OEM) + Difference of THR due to external factor between AY and BY



Where

THR = Turbine Heat Rate (kcal/kWh)

AY = Assessment Year

BY = Baseline Year

OEM= Original Equipment Manufacturer

Normalized Designed Station Turbine Heat Rate due to ULF as compared to BY

=[Normalized U# 1 Design THR due to external factor as compared to BY X U# 1 Capacity + Normalized U# 2 Design THR due to external factor as compared to BY X U# 2 Capacity +] / Station installed Total Capacity (MW)

Where

THR = Turbine Heat Rate (kcal/kWh)

BY = Baseline Year

Weighted Design Turbine Heat Rate of Station

=[U# 1 Capacity X U# 1 Design THR @ 100% Load (OEM) + U# 2 Capacity X U# 2 Design THR @ 100% Load (OEM) +] / Station installed Total Capacity (MW)

Where

THR = Turbine Heat Rate (kcal/kWh)

OEM= Original Equipment Manufacturer

Difference of THR between Normalized Design Heat Rate and Design Heat Rate

=Normalized Design Station THR due to ULF as compared to BY - Station Weighted Design THR

ULF = Unit Load Factor

THR = Turbine Heat Rate (kcal/kWh)

BY = Baseline Year

PLF Normalization = Difference of THR between NDHR and DHR

(c) Auxiliary Power Consumption (APC) Normalization

Auxiliary Power Consumption (APC) has a significant contribution in determining the Net Heat Rate of any Station. As other factors in a Power Plant, APC is also subject to change at different period of time. It primarily depends on the unit loading ultimately affecting the drives. It also depends on the ambient conditions at times. It is hence, very important to study the characteristics of APC during Assessment year and Baseline year. The APC in baseline Year and Assessment Year may not be same and therefore normalization for APC was needed to be introduced. Accordingly, The normalization has been worked out and, again as others, It gives the benefit in heat rate due to effect of APC.

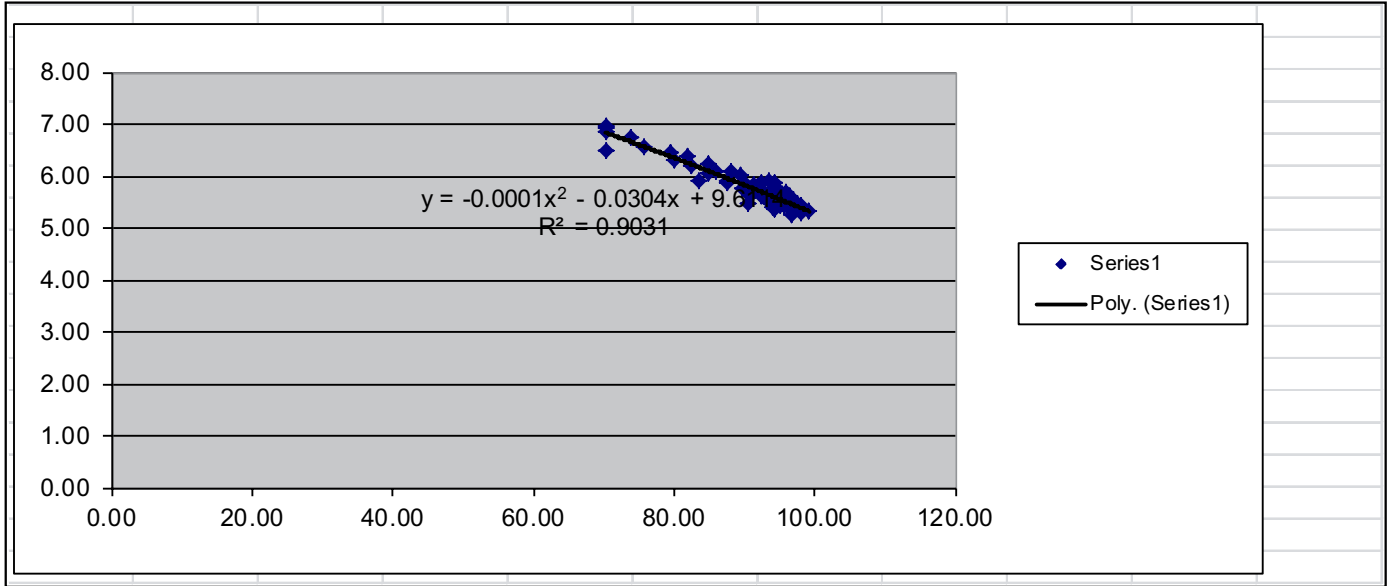
PLF will also have an effect on the Auxiliary Power Consumption of the Station. Due to low PLF, the percentage APC will increase. This factor may be beyond the control of station, such as during low schedule, grid restriction, etc. However this shall be considered in different sub-section of APC normalization.

The normalization of APC can be subdivided into three categories

- i) APC normalization due to external factors
- ii) APC normalization for PA Fan loading due to change in coal quality
- iii) APC normalization for Coal Grinding Mill, ID Fans and Ash Handling Plantloading due to change in coal quality

(i) APC normalization due to external factors

The APC of Thermal Power Plant is not fully dependent on the loading of plant. Due to decrease in PLF, the APC will not decrease with same ratio. Hence, a trend line equation could be generated from the normal operating condition of the Plant taking the data of APC and Plant loading for a station. The Excell topology of the Trendline equation is shown below



Auxiliary Power Consumption Trendline Equation

y = ax² - bx + c will be used to calculate the Turbine Heat Rate as per Load Vs Heat Rate Equation due to external factor.

y = ax² - bx + c

Where

X = Operating Load (MW)

A = Equation Constant 1

b = Equation Constant 2

c = Equation Constant 3

Operating Hours at full load

$$= (\text{Total hours in a year} \times \text{PAF}) - \text{Weighted AOHR at Low loading due to external factor} - \text{Weighted AOHR at Low loading due to internal factor}$$

Where

PAF = Plant Availability Factor

AOHR = Average Operating Hours

Weighted Operating Station Load

$$= \{[\text{Station Capacity} \times \text{Operating Hours at Full Load}] + \{\text{Station AOL (MW) caused}$$

by low loading due to external factor X Weighted AOHR at Low loading due to external factor} + {Station AOL (MW) caused by low loading due to internal factor X Weighted AOHR at Low loading due to internal factor}] / [Weighted AOHR at Low loading due to external factor + Weighted AOHR at Low loading due to internal factor+ Operating Hours at full load]

Where

AOHR = Average Operating Hours (Hrs)

AOL = Average Operating Load (MW)

Actual Loading Factor (%)

$$= \frac{(\text{Weighted Operating Station Load} \times 100)}{\text{Station Capacity}}$$

Actual Loading Factor for BY

$$= (461.92 \times 100) / 630 = 73.321 \%$$

Actual Loading Factor for AY

$$= (377.55 \times 100) / 630 = 59.929 \%$$

Weighted Station Load without external factor (MW)

$$= \{[\text{Station Capacity} \times \text{Weighted AOHR at Low}$$



loading due to external factor} + {Station Capacity X Operating hours at full Load} + {AOL (MW) caused by low loading due to Internal factor X Weighted AOHR at Low loading due to internal factor}] / [Weighted AOHR at Low loading due to external factor+Weighted AOHR at Low loading due to internal factor +Operating hours at full Load]

Where

AOHR = Average Operating Hours (Hrs)
AOL = Average Operating Load (MW)

Normalized Loading Factor

$$= \frac{\text{(Weighted Station Load without external factor (MW)X 100)}}{\text{Station Capacity (MW)}}$$

Percentage APC as per Trend Line for AY and BY

This shall be calculated by the % APC Trend Line equation mentioned above for Assessment Year and baseline year individually.

$$= \text{Constant 1} * (\text{Normalized Loading Factor})^2 - \text{Constant 2} * \text{Normalized Loading Factor} + \text{Constant 3}$$

Where

APC =Auxiliary Power Consumption
BY = Baseline Year
AY = Assessment Year

Difference in APC of AY From BY = % APC as per trend line in AY - % APC as per trend line in BY

Where

APC =Auxiliary Power Consumption
BY = Baseline Year
AY = Assessment Year

Normalized APC

If the difference in APC of AY From BY is

less than or equal to zero, then Normalized APC will be same as operating station APC.

If the difference in APC of AY From BY is greater than zero, then normalized APC is as below:

$$\text{Normalized APC} = \text{Station Operating APC} - \text{Difference in APC of AY From BY}$$

Where

APC =Auxiliary Power Consumption
BY = Baseline Year
AY = Assessment Year

APC Normalization in terms of Heat Rate

APC Normalization for external factors (kcal/kWh)

$$= \frac{\text{Operating GHR in AY}}{\text{(Operating GHR in AY)}} - \frac{\text{1-% APC of AY}}{\text{(1- % normalized APC)}}$$

Where

GHR =Gross Heat Rate (kcal/kWh)
AY =Assessment Year
APC =Auxiliary Power Consumption

(ii) APC normalization for PA Fan loading due to change in coal quality

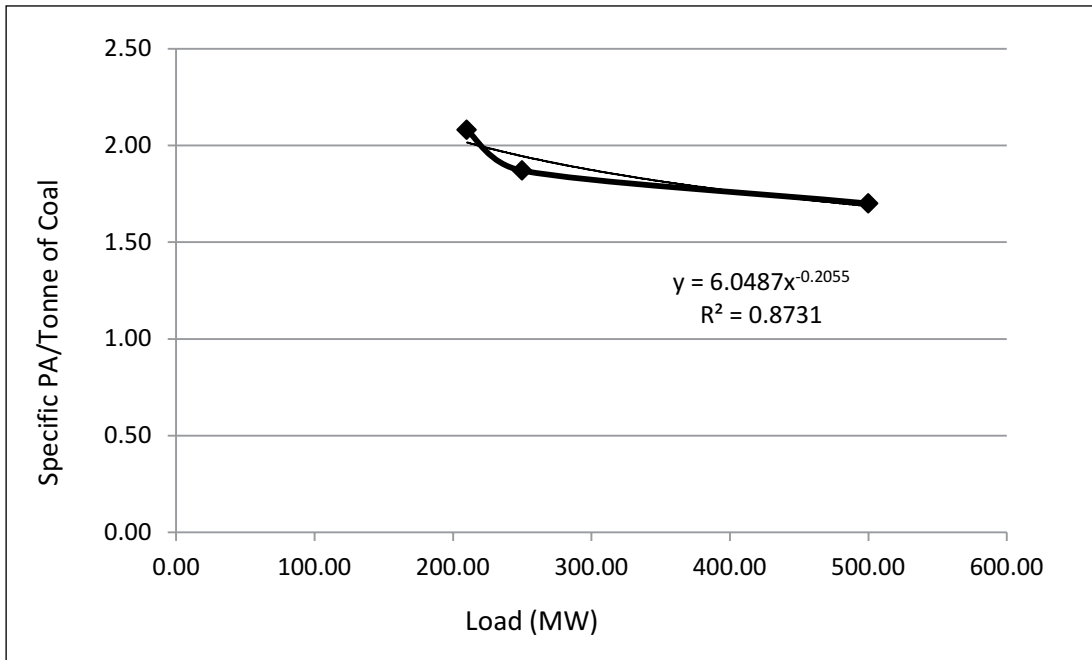
Due to change in coal quality, there may be a marginal/ significant impact on the energy consumption of PA fans. This is primarily due to the reason that poor coal quality will increase the coal consumption and increased coal consumption will need more Primary air. To calculate this we arrive to a Trendline equation of specific PA consumption per tonne of coal by comparing the design Specific PA consumption of different sized units.

By the GCV of coal, Generation and GHR of Baseline and Assessment year, we can calculate the actual coal consumption of BY and AY. By comparing the GCV of BY with AY and



multiplying it with the total coal flow of BY, we can obtain the normalized coal consumption of the unit. The excel topology of Trendline

equation for specific PA calculation is shown below.



From the above Trendline equation, we will calculate the total PA requirement with normalized coal consumption and that of BY. Now by calculating the volume of PA and ultimately the power consumption of PA, we can calculate the increase in Power consumption of PA as a result of change in Coal GCV. It shall be described with examples in the chapters ahead.

The formula for calculation of increase in energy consumption of PA as a result of change in coal quality is mentioned below.

Total Coal Consumption per unit (AY and BY) (Tonnes/Hr)

$$= (\text{GHR} \times \text{Operating Load}) / \text{Coal GCV}$$

Where

GHR = Gross Heat Rate (kcal/kWh)

GCV = Gross Calorific Value (kcal/kg)

Normalized Total Coal Consumption per unit(Tonnes/Hr) =

$$\text{Total Coal Consumption} \times \text{Coal GCV for BY} / \text{Coal GCV for AY}$$

Where

GHR = Gross Heat Rate (kcal/kWh)

GCV = Gross Calorific Value (kcal/kg)

Increase in coal consumption due to change in GCV of coal in AY (Tonnes/Hr)

$$= \text{Normalised Coal Consumption (tonne/hr)} - \text{Total consumption of BY (tonnes/hr)}$$

Total Primary Air requirement per tonne of coal Trendline equation

$$y = 6.048x^{-0.2055}$$

Where

Y= total PA requirement / tonne of coal (Tonnes)

x= operating load (MW)

Total Primary Air requirement (Tonnes/hr)

$$= \text{Normalised coal consumption (TPH)} \times \text{PA requirement per tonne of coal as per Trendline equation(tonne)}$$

Where