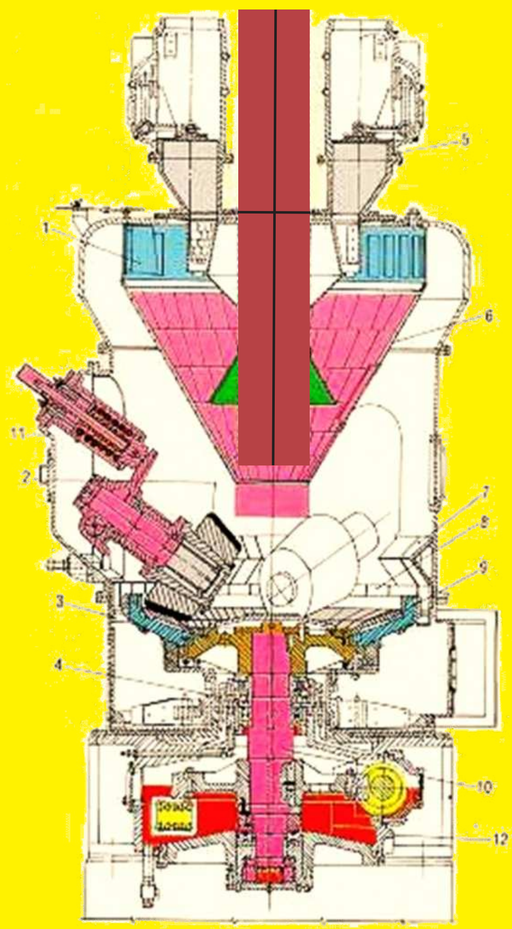
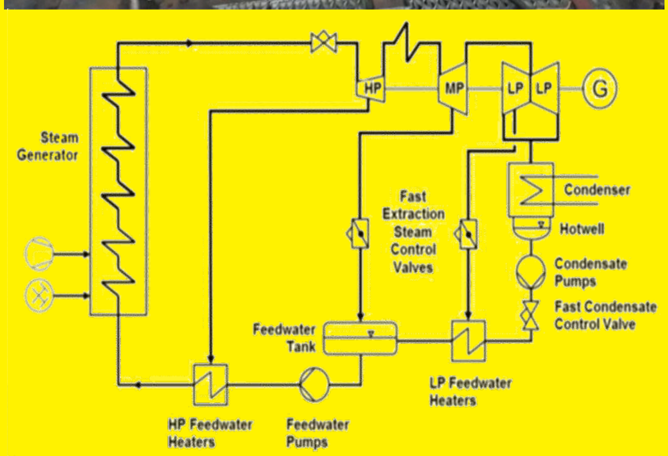
सत्यमेव जयते

Government of India
Ministry of Power
Central Electricity Authority

FLEXIBILISATION OF COAL FIRED POWER PLANT





A Roadmap for Achieving 40% Technical Minimum Load

February, 2023

Sewa Bhawan, Sector 1, R K Puram, New Delhi – 110066

घनश्याम प्रसाद
अध्यक्ष तथा पदेन सचिव भारत सरकार
GHANSHYAM PRASAD
Chairperson & Ex-officio Secretary
To the Government Of India

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केन्द्रीय विद्युत प्राधिकरण
भारत सरकार
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75 आज़ादी का अमृत महोत्सव

FOREWORD

India has great potential for renewables which has been recognized and a goal for attaining 500GW has been set by year 2030. To achieve the goal of integration of such high level of renewables there are both technical and financial challenges. The thermal units so far has been operated as base load plants which require overhauling. I am happy that TPRM Division, CEA has brought out a comprehensive report on flexible operation of base load thermal plants including operating procedure, challenges, retrofit and roadmap for achieving 40% load operation. The committee which was headed by B.C. Mallick, Chief Engineer, TPRM Division with members from various organizations have put in their valuable efforts and time to bring out an comprehensive reports covering important topics which shall be useful for the thermal utilities. It has also touched the cost aspects for achieving the flexibility of thermal units considering the requirement of retrofits and heat rate deterioration, etc. The pilot tests conducted under the support of CEA at various thermal units have added to the knowledge base of utilities/OEMs and highlighted the issues involved in our thermal units. The guideline has also deliberated on the issues as how these need to be tackled in effective manner.

It needs to be highlighted that flexible thermal units are one of the cheapest source of flexible power presently in the country. Hence, it will be crucial to ready the existing thermal units for the new operating regime enforced by the renewables. It shall help to optimize the operation of thermal units and reduce the emission burden of power generation.

I commend the efforts of Shri B. C. Mallick, Chief Engineer TPRM and Chairman of the committee for formulation of the entire report which shall lay the foundation of the flexibilisation of thermal power in the country.

(Ghanshyam Prasad)

सत्यमेव जयते

दूरभाष (का०)
TELEPHONE (O)
TELEFAX (O)

सदस्य
तथा पदेन अपर सचिव भारत सरकार
केन्द्रीय विद्युत प्राधिकरण
सेवा भवन, रामाकृष्णा पुरम्

MEMBER
& EX-OFFICIO ADDL. SECRETARY TO THE GOVERNMENT OF INDIA
CENTRAL ELECTRICITY AUTHORITY
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Preface

Flexibilisation of coal fired plants has become inevitable for integration of power generated from renewable energy sources into the grid. The report "Flexibilisation of Coal-fired Power plants - A Roadmap for Achieving 40% Technical Minimum Load" prepared under the Chairmanship of Shri B. C. Mallick, Chief Engineer (TPRM), CEA shall guide the thermal power utilities, regulators and professionals for better understanding of the issues linked to flexibilisation and help them in formulating their future course of action.

I have gone through the report and found it to be very useful. The report is very exhaustive covering important topics like details of the various pilot tests conducted under the direction of CEA, procedure for flexible tests, the control modifications required, impact on the tariff and the future roadmap. In addition report is suggesting to explore the future possibility of two shift operation of thermal units based on the grid requirement.

I congratulate Shri B. C. Mallick, Chief Engineer & Chairman of the committee and other committee members for their valuable efforts in preparing the report.

(A. Balan)
Member (Thermal)

Bikash Chandra Mallick
Chief Engineer

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सेवा भवन, रामाकृष्ण पुरम्
SEWA BHAWAN, RAMAKRISHNA PURAM

नई दिल्ली–110066, दिनांक :
NEW DELHI-110066, Dated : 14 July 2022

ACKNOWLEDGEMENT

The power sector is going through transformational changes due to the environmental concerns. There shall be increased share of renewables in the grid in future which shall impose new operational requirement on the large existing thermal fleet. Thermal power utilities are going to find themselves at the receiving end in future, hence thermal units would have to modernize to remain in the business of power generation. The present report shall help thermal utilities in understanding the issues/ up gradations required in the plants and in the skills of the operators. The contents of the report are very comprehensive, incorporates the learnings from the low load tests conducted at various thermal units.

The flexible power is available from Hydro Power Plants, Pump Storage System, Thermal Power Plant and Battery Storage System. The cheapest flexible power may be available from hydro plants/ pump storage system, costlier from thermal power plants and costliest power from Battery storage system. Therefore our first preference to utilize or develop flexible power shall be from hydro/pump storage, second from thermal power plants and lastly from battery storage system.

The committee has considered heat balance study report of BHEL, SIEMENS, GE and actual test report of Dadri TPS, Maithon RBTPS, DSTPS, Sagardighi TPS, WBPDL, Ukai TPS, GESCL, Mouda TPS of NTPC. Accordingly suggested a Road Map for preparing thermal power plants flexible including operating procedure, identification of measure and cost of flexible power.

I would like to thank all the committee members from NTPC, BHEL, POSOCO, Tata Power, Siemens, GE, GESCL, independent consultants, and divisions of thermal wing who have contributed in preparing the report. I am thankful to Chairperson, CEA, Member (Thermal), CEA for their valuable guidance. Finally, I appreciate the efforts of TPRM Div. for their support.

BMallik

(B.C. Mallick)
Chief Engineer (TPRM) &
Chairman of the Committee

CONTENTS

EXECUTIVE SUMMARY

GOI has set an ambitious target of 500 GW renewable generation by 2029-30 and 175GW by end 2022. There is a delay in capacity addition of 175GW RES due to covid-19 pandemic and the same may be achieved by end 2023. In near future thermal power plants fleet is expected to operate at an average minimum load of 40%. It shall drastically impact the schedule of most of the conventional generating plants and shall lead to operating thermal power plants at part load. Hence, thermal generating units shall haveto be tuned such that they can meet the new load demands in a very effective and efficient manner. And if any gaps are found, the same needs to be fixed.

A committee was constituted under the chairmanship of Sh. B. C. Mallick, Chief Engineer, TPRM Division, CEA with the members from various organizations. The committee would guide the central, state & private utilities in selecting thermal generating units and conducting low load test. The committee would also prepare a guideline for low load operation of TTPs, on the basis of experience gained from the pilot test, to help generating utilities in achieving flexibility in their units.

A comprehensive report has been prepared with the contribution of committee members from various organizations, consultants which are at the forefront for steering this new demand. The report comprises of eleven chapters which tries to covers the various important issues in details. The chapter-1 **"Need for Flexibilisation",** which gives the back ground for the new requirement which has arisen and the challenge faced by the thermal power sector. Chapert-2 "**Key Requirement of Flexibilisation"** elaborates the new regime of operation of power plants, i.e. minimum load, ramp rates requirement. For implementation of flexibilisation, the tests/studies are required to be conducted, the chapter-3, "**Studies Conducted"** describes the tests conducted so far and their major findings. The operation of thermal power plant in flexibilisation mode has lot of impact on the plant life, operation and maintenance, efficiency which has been briefly discussed in the chapter-4 "**Challenges of Flexibilisation".** The paradigm of operation of the plant changes due to the flexibilisation, hence new operating procedure which require changes and training of personnel is required to be upgraded (operating procedures). Based on the tests/ studies, there will be a clear picture obtained of the existing capabilities of the plant which shall require to be upgraded. The chapter-5 "**Procedures for low load tests"** describes the procedures in details for attaining the 40% low load operation without oil support and various parameters to be observed carefully during the test tofind the measures to be implemented in the generating unit. The chapter-6 "**Modification Required"** discusses in details the various options available for modification for the performance improvement. The flexibilisation has impact on the fixed and operating cost of the thermal power plant. The committee members have compiled costs for adopting measures for the improvement of flexible performance of thermal power plant as discussed in the chapter-7 "**Cost of Flexible power".** However, the capital costs for retrofit, given in the report, are only indicative in nature actual costs need to be ascertained by conducting a detailed feasibility study as the modifications are plant specific. Further, increased O&M cost form part of fixed tariff and efficiency degradation & increased oil consumption due to EFOR forms part of variable tariff. It has been found that impact of 40% low load operation on tariff (fixed + variable) is maximum about 7 to 8% which may increaseto some extent for old units. "**Two-shift operation"** of thermal power plants has been discussed in the chapter-8. The comparison of flexible power from the various sources is elaborated in the chapter -9 "**Flexible Power from Different Sources".** To refurbish the fleet of thermal units for flexibilisation, the time required for making them equipped forcycling has been presented in the chapter-10 "**Roadmap"**. Finally, in the last chapter-11 "**Conclusion and Way Forward"** the findings of the report have been summarized andsteps for implementation have been recommended.

Looking at the addition of renewables in future, the thermal power utilities will be required to play a very important role. The report prepared by thecommittee shall be beneficial for the utilities for understanding the need and implication of flexible operation of coal fired units.

BACKGROUND

India is moving ahead to achieve nationally determined contribution (NDC) of 40% of installed renewable capacity by 2030. The introduction of large scale renewable generation in the grid is bringing a new set of challenges in the power sector.

The inconsistency and intermittency of solar & wind power has to be managed by other sources of generation in order to ensure the grid stability. Flexible operation of existing coal-fired power plants is very much required to ensure security, reliability of power supply and stability of electricity grids while maximizing generation from renewable energies sources (RES) & integration of the same into grid. Because thermal generation capacity of 209 MW constituting 54% of total installed capacity is the dominant part of power generation in the country and more than 70% of country's energy demand is being met from thermal generation. Thus, flexible operation of thermal power plant is essential for handling the instability & intermittency of renewable generation.

The CEA report "Flexible operation of thermal power plants for integration of renewable generation" was finalized considering 175 GW RES by the committee constituted under chairmanship of Sh. B. C. Mallick, Chief Engineer (TPRM), CEA in January 2019. On the basis of net heat rate increase due to minimum thermal load (MTL) operation,thermal generating units are categorized under very flexible (40% MTL), flexible (45%MTL) and low flexible (50% MTL) group. In a particular day (with 175 GW RES) about 90 very flexible units (24 GW), 78 flexible units (42 GW) & 75 low flexible units (52 GW)from 243 grid synchronized thermal generating units (118 GW) are required for safe &secured grid operation.

In this regard, a committee was constituted under the aegis of CEA for implementation of findings of the above CEA's report and guide utilities for assessing their capabilities & identification of measures to be implemented to enhance flexibility with the following members.

1. Sh. B. C. Mallick, Chief Engineer, TPRM, CEA - Chairman
2. Sh. Rajeev Kumar, Dir./Sh. Pravir Kumar, Dir., TPRM, CEA - Convener
3. Sh. C.P. Jain, Director, TETD, CEA - Member
4. Sh. Y. M. Babu, GM /Sh P Mukherjee, GM /Sh. BVN Kishore, AGM BHEL - Member
5. Sh. N. Nallarasan, ED /Sh. Surajit Banerjee, GM POSOCO - Member
6. Sh. Snehesh Banerjee, AGM, NTPC - Member
7. Sh. A. K. Sinha, Technical Director , Intertek - Member
8. Sh. B.A. Gandhi, Executive Engineer, GSECL - Member
9. Sh. C.P. Tiwari, Head of technology & Process /Sh. Ashok Panda, Chief O&M, Tata Power - Member
10. Sh. Mahesh Kendhe, Head of Product Management, GE – Member

The Chairman of the committee coopted the following members:
1. Sh. Sandeep Chittora, Chief Manager, Siemens
2. Sh. Deepak Tiku, AGM, TPRM, CEA
3. Sh. Rohit Yadav, Dy. Director, TPRM, CEA

The committee shall guide the central, state & private utilities to conduct pilot test for flexible operation and prepare a report as per the following terms of reference -

i. Identify thermal units for pilot test and guide state/central private utilities to conduct pilot test of flexible operation.
ii. Prepare a guideline for pilot test of flexible operation of thermal unit.
iii. Identify measure for flexible operation and monitor implementation of measures at plant level.

OBJECTIVE

The majority of the power generation in the country is thermal, it has to be made flexible in its output for supporting the greening of grid. It would require identifying the thermal units which are technically and economical feasible for flexibilisation. The technical feasibility shall be decided by detailed studies/tests. The studies shall also explore the possibility of carrying out the required retrofits. The flexibilisation of thermal units involve capital expenditure depending upon the modifications required and the operating costs in terms of deteriorating performance, higher maintenance costs and loss of life. The main objectives of the committee are as follows-

- Explore the new technical minimum load of thermal generating units without oil support
- Assessment of thermal flexible power and ramp rate available for integration of renewable generation.
- Identify measures to be implemented thus Capex.
- Identify increase of net heat rate, O&M cost and consumption of life thus Opex.
- Targeting grid security and stability, less impact on tariff.
- Explore cost implication of flexible operation of thermal unit.
- Preparation of Roadmap for achieving new technical minimum load

ABBREVIATIONS

APH	Air Pre Heater
APRDS	Auxiliary steam Pressure Reducing and Desuperheating Station
AVT	All Volatile Treatment
BFP	Boiler Feed Pump
BMCR	Boiler Maximum Continuous Rating
C&I	Control & Instrumentation
CEP	Condensate Extraction Pump
CMC	Coordinated Master Control
CPU	Condensate Polishing Unit
CRH	Cold Reheat
DC	Declared Capacity
DCS	Distributed Control System
DM	De Mineralized
DNB	Departure from Nucleate Boiling
DO	Dissolved Oxygen
EFOR	Equivalent Forced Outage Rate
EHS	Equivalent Hot Start
EOH	Equivalent Operating Hours
ESP	Electro Static Precipitators
FAC	Flow Accelerated Corrosion
FD	Forced Draught
FEGT	Flue Exit Gas Temperature
FGD	Flue Gas Desulphurization
FRS	Feed Regulating Station
GCV	Gross Calorific Value
GW	Giga Watt
HBD	Heat Balance Diagram
HRH	Hot ReHeat
ID	Induced Draft
LRSB	Long Retractable Soot Blower
LTSH	Low Temperature Super Heater
MDBFP	Motor Driven Boiler Feed Pump
MS	Main Steam
MTL	Minimum Technical Load
PA	Primary Air
PC	Pulverised Coal
RAPH	Regenerative Air Preheater
RH	Re Heater
SCAPH	Steam Coil Air Pre Heater
SECD	Security Constrained Economic Dispatch
SH	Super Heater
TDBFP	Turbine Driven Boiler Feed Pump
TMCR	Turbine Maximum Continuous Rating
VM	Volatile matter
WWSB	Water Wall Soot Blower

1. NEED FOR FLEXIBILISATION

1.1 Global Commitments

The focus of power generation in the country had been on thermal power generation in the past as it was cheaper, having lower gestation time compared to hydro power and there are plenty of coal reserves for its sustenance. In recent times, there has been global environmental concerns regarding power generation from fossil fuel and steps are being taken in the country to make the power generation less carbon dependent. In October 2015, India submitted its Intended Nationally Determined Contribution (INDC) to UNFCCC. It aims is to achieve about 40 percent cumulative electric power installed capacity from non-fossil fuel based energy resources by 2030 with the help of transfer of technology and low cost international finance. It also aims to reduce the emission intensity of its GDP by 33% to 35% by 2030 from the 2005 level. Further, to create an additional carbon sink of 2.5 to 3 billion tons of CO_2 equivalent by resorting to additional forest and tree cover by 2030. The above national commitments have made it obligatory for the government to put greater emphasis on the renewables energy resources.

1.2 Thrust on Renewables

Renewable energy sources have the environmental advantages over fossil fuel fired plants, they are emission free, and however, the renewable alternative for bulk power generation was very costly earlier. The reduction in cost of renewable energy sources has given a push to the solar and wind based power generation. In fact, as per the recent cost trends, RE generation sources have become competitive with the conventional electricity generation. One of the major advantages is that India has vast renewable energy potential of around 1050GW which is largely untapped. It is estimated that the solar potential is around 748GWp and the wind potential is greater than 302GW* (MNRE Report 2019-20).

1.2.1 Target 2022

Considering the vast renewable potential, GOI has set an ambitious target of setting up of 175GW installed capacity from renewables (RE) by December 2022. Out of which, 100GW is planned through solar energy, 60GW through wind energy, 10GW through small hydro power, and balance 5GW through biomass-based power projects. The target for solar capacity is to be achieved through 40GW rooftop projects and balance through utility-scale solar plants and ultra-mega solar parks. The Covid-19 pandemic has slowed down the progress of Solar and Wind capacity addition in last 2 years.

1.2.2 Target 2030

To meet the INDC target by 2030, the installed capacity of renewables shall have to be increased. The recent CEA study indicates that the likely total installed capacity by the end of 2029-30 shall be 838.8GW which would include 454.4GW of renewables. With this renewable proposed capacity, the INDC target set for the country shall be easily met.

*at 100m agl.

1.2.3 Present Status

There is already a significant wind power capacity in operation and various initiatives have made solar PV more widespread. A significant growth has been experienced in past few years. The installed capacity of solar and wind is 94 GW as on 31st March, 2022 and total generation is 142 billion units for the period April to March, 2022 which is almost 9.5% of the total energy generation in the country.

1.3 Why stress on thermal generating unit?

Renewable power output has three major key limitations: *variability* varies from moment to moment, *uncertainty* cannot be predicted with any certainty in advance and *concentration,* is concentrated during a limited number of hours of the year. Thus creatinga need for the balancing the demand on various time scales for proper functioning, stability and security of the grid. The inconsistency and intermittency of solar & wind power has to be managed by other sources of generation in order to ensure the gridstability. Flexible operation of existing coal-fired power plants is very much required to ensure security, reliability of power supply and stability of electricity grids while maximizing generation from renewable energies sources (RES) & integration of the same
into grid, because thermal generation capacity of 209 MW constituting 54% of total installed capacity is the dominant part of power generation in the country and more than 70% of country's energy demand is being met from thermal generation. Thus, Flexible operation of thermal power plant is essential for handling the instability of renewable generation.

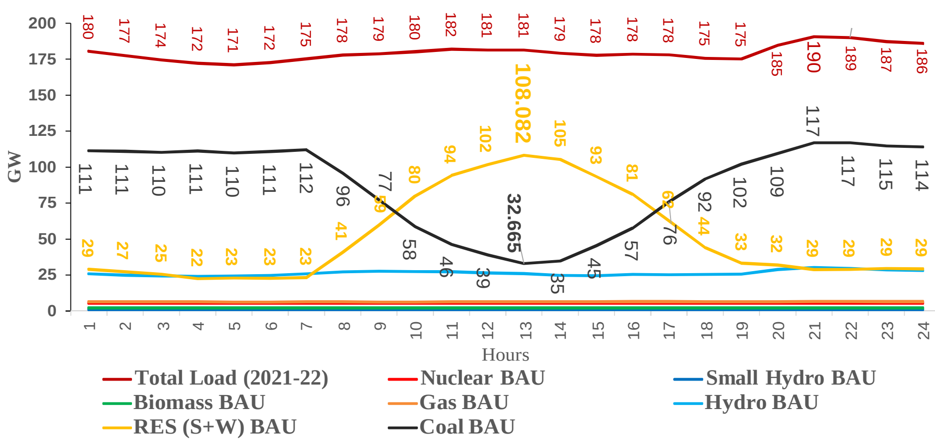


Figure 1.1 Demand & Generation on a critical day
(Source: CEA's report "flexible operation of thermal power plants for integration of renewable generation")

1.4 Load and Generation as predicted in CEA's Report (Jan 2019)

The above figure-1 shows the impact of the renewable generation on the daily net load demand of the grid. The top red curve is the forecasted load demand. The yellow curve is the power output considering the proposed installed capacity of solar and wind. The net load demand (black) is to be met by the fleet of thermal power units in the grid which is very steep. It creates demand of large flexible power from the base load thermal plants, reducing their minimum operating load and requiring steep ramp rates.

A significant proportion of the older coal-fired plants, are based on conventional sub-critical technology which were originally designed and built with steady base load operation. The major change like operating cyclically daily has major impact on coal-fired plant in several areas: operation and maintenance, plant life and economics. Hence, in a scenario of high penetration of renewables (175 GW) by 2023 (expected) there is an urgent requirement of developing the flexible capability of existing thermal power plants.

Further due to part load operation, the utilities will be forced to operate units at lower efficiency. It may therefore be required to undergo modernization of these plants with target of improving heat rate at lower minimum loads. The report presents various solutions that are available to be implemented in thermal power plants to have better operation and maintenance under flexible operation. These related issues are examinedin the following chapters.

2. KEY REQUIREMENT OF FLEXIBILISATION

2.1 Management of grid

The coal-based thermal generation is responsible for meeting more than 74% of India's electricity energy demand and this share is expected to stay near 50% by 2030. Thermal units would experience lower minimum loads and higher ramp rates as the share of variable renewable resources in the energy mix increases. Many studies performed toassess the impact of large scale renewable integration into the Indian power system have captured the aspect of increased flexibility demands on thermal power plants. As per CEA's report "*Flexible operation of thermal power plants for integration of renewable generation*", peak thermal flexible capacity (gross) required on the most critical day in year 2022 was found to be 140 GW considering 175 GW renewable installed capacity and the coordinated efforts from hydro, gas capacity and pumped storage system (PSS), the requirement of thermal capacity could be reduced to 117 GW. Further, the requirement of thermal flexible power is also reduced from 84 GW to 64 GW. Thus, coordinated efforts of hydro, PSS, gas is important for reduction of stress on thermal units and followings have been recommended for balancing the grid:

I. Final Balancing shall be done at national level which will minimize the requirement of balancing power.
II. Hydro power plants are especially suitable for quick supply of flexible power. Coordination with state hydro power plant for reallocation of generation and provision of separate (higher) tariff for flexible hydro power are suggested. If the tariff is increased, hydro rich states (those are continuously operating due to very low cost) will draw power from grid during day time and operate during peaking hours. Tariff (minimum) of flexible hydro power should be higher than the off-peak grid power.
III. Flexible operation of coal-fired plant (up to 40% minimum load).
IV. Study on demand side management (implement TOD metering) including measure targeted at domestic, industrial and e-mobility sector would enable more rationalconsumption pattern of electricity which will improve the off-peak to peak generation ratio of thermal power plants. Thus reduction of regional as well as national peak demand.
V. Study or land survey to avail the geographically advantage for establishment of pump storage.
VI. Two shift operation of smaller size thermal units.
VII. Shifting of Agricultural load from night hours to day during solar peak generation period
VIII. Battery Storage: One of the important source of flexible power is battery storage. This capacity should be as low as possible for the following reason:
    a) Lithium reserves are not available in India.
    b) High cost

c) Service life is about 10 years
d) Disposal issue

In the Indian power system, role of thermal generation has evolved from being operated as base load till recently to be used as the major source of flexible power. With increase in all-India ramping requirements over the years, most of the additional ramping is being met by thermal generation, with maximum thermal ramp touching 250 MW/ minute in 2018-22, as seen in figure 1. The maximum ramp up and ramp down rate as projected in CEA's "*Flexible operation of thermal power plants for integration of renewable generation*" report were 379 MW/min and 422 MW/min. considering 175 GW RES. The increasing need for flexibility is driven by change in demand pattern with round-the-clock power supply, and increasing penetration of RE resources.

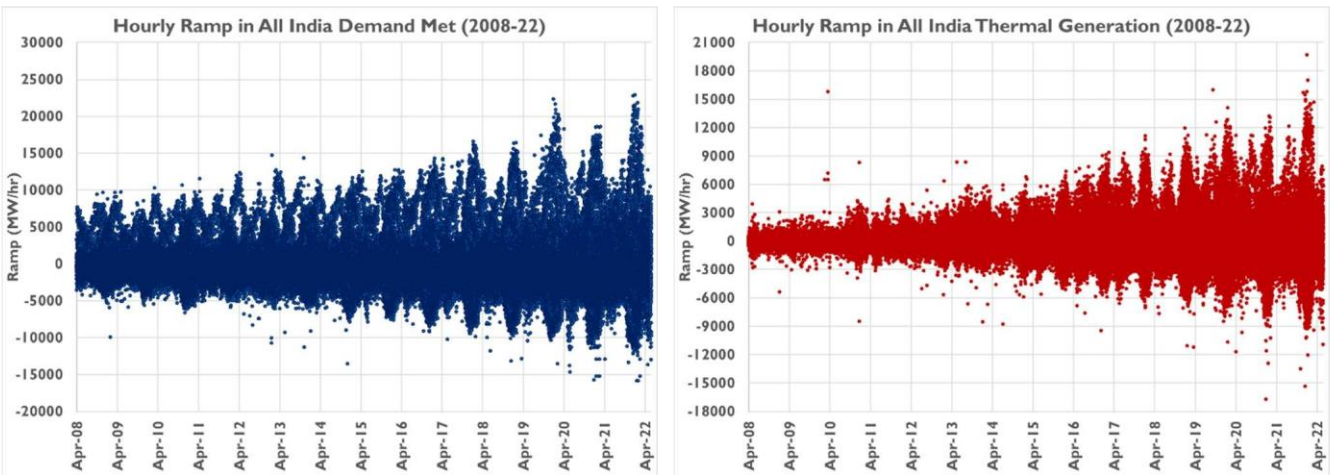


Figure 2.1 Hourly Ramp Rates of Demand and Thermal Generation in India - 2008 to 2022 (Source: POSOCO)

POSOCO report on Flexibility Analysis of Thermal Generation for RE integration utilized time series data of 438 thermal units to quantify flexibility across different units. Here flexibility is expressed as percentage of *(Daily Maximum Generation – Daily Minimum Generation)/Installed Capacity*. The day-wise flexibility requirement of the Indian power system demand is increasing at 8-9 GW/annum, and it reached a maximum of 72GW during winter of 2021-22 (Figure 2.2). On all India basis, thermal flexibility is on increasing trend, approaching 30-35% during 2021-22 (Figure 2.3). About 40% of India's thermal units are reaching minimum generation levels in the range of 60-70% of installed capacity (Figure 2.4).

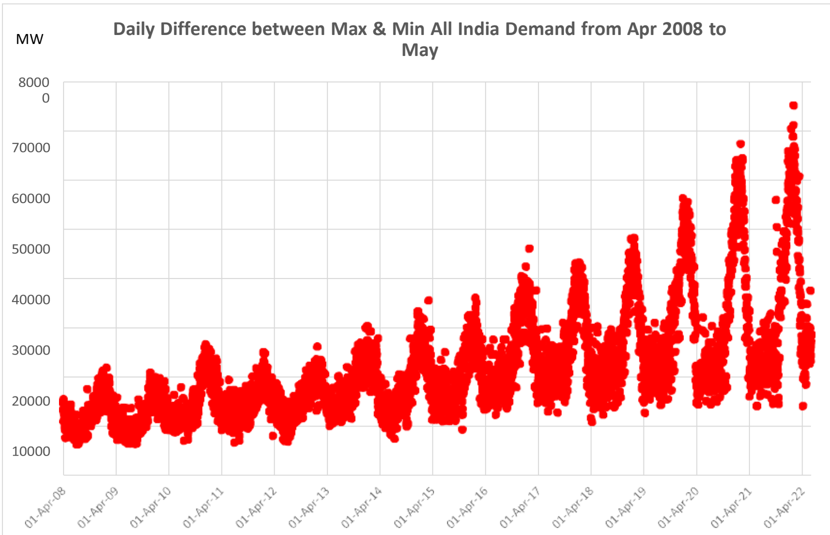


Figure 2.2 Difference between Max. and Min. All India Demand

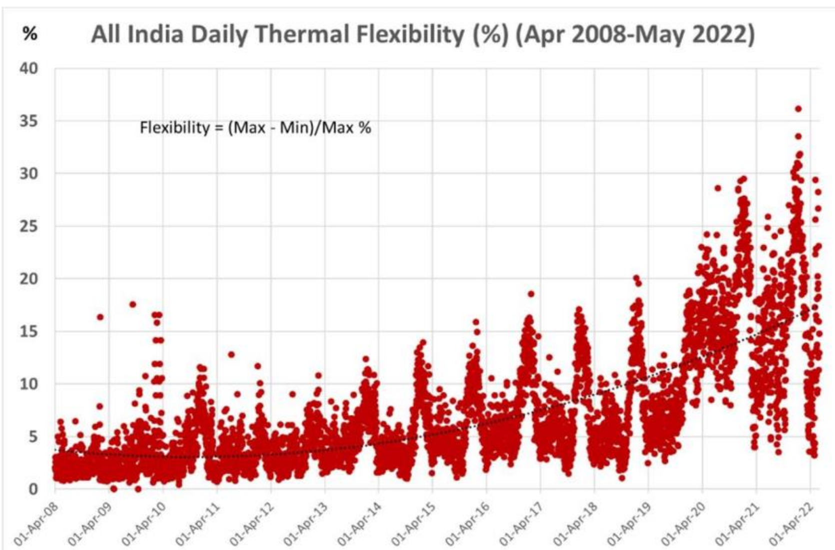
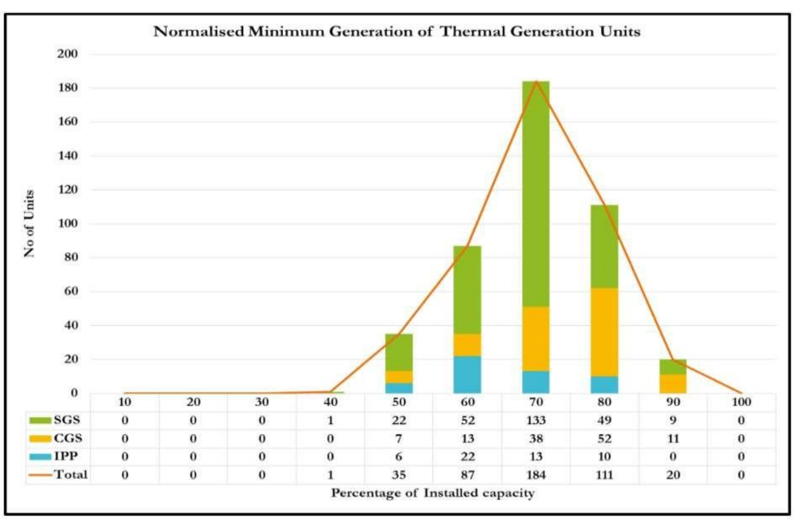


Figure 2.3 Trend of DailyThermal Flexibility



	10	20	30	40	50	60	70	80	90	100
SGS	0	0	0	1	22	52	133	49	9	0
CGS	0	0	0	0	7	13	38	52	11	0
IPP	0	0	0	0	6	22	13	10	0	0
Total	0	0	0	1	35	87	184	111	20	0

Figure 2.4: Distribution of average minimum generation of thermal units

A pilot study on *Security Constrained Economic Dispatch* (SCED) is operational in national grid since 1st April 2019. It aims at optimizing the production cost of generation at national level while satisfying all plant and system security constraints at all times. 52 thermal inter-state generating stations with 58GW capacity are part of the study. Technical minimum (55% at present) and ramp up/ramp down rates are part of the constraints honoured by SCED. The duals of the binding constraints in SCED have been extracted for the entire period and analyzed in the report on SCED pilot. As expected, the more expensive stations are constrained by technical minimum for most of the time (Figure 2.5).

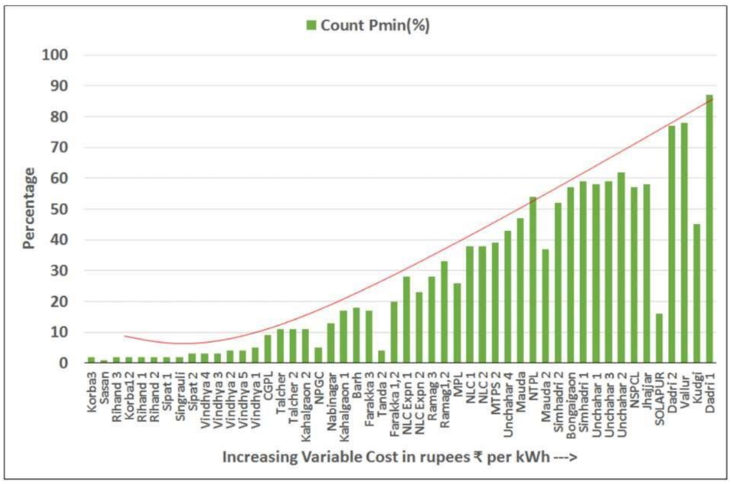


Figure 2.5 Percentage of time technical minimum constraints in SCED (Apr-Dec 2019)

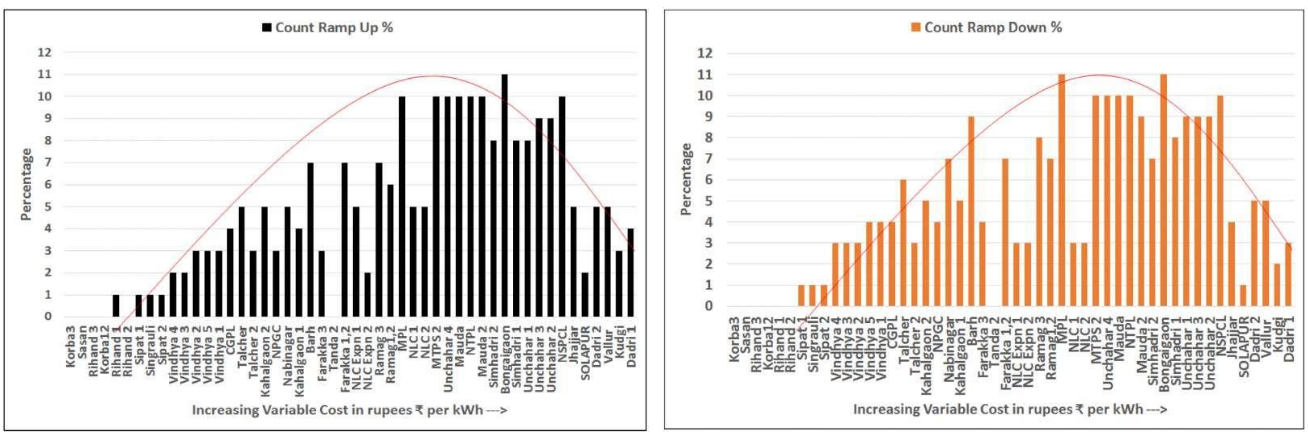


Figure 2.6 Percentage of time ramp up and ramp down constraints in SCED (Apr-Dec 2019)

In the present scenario, with maximum renewable penetration around 18-20% (in energy terms), there are some instances where thermal flexibility is exhausted. Figure 2.7 shows an example from 27th January 2019, showing the trend of total schedule for the thermal ISGS. It can be seen that the total ISGS generation moves from nearly technical minimum (during morning off-peak), to nearly DC (during morning peak), in a matter of a few hours due under drawl by states. Such need for flexibility would get exacerbated with increasing RE.

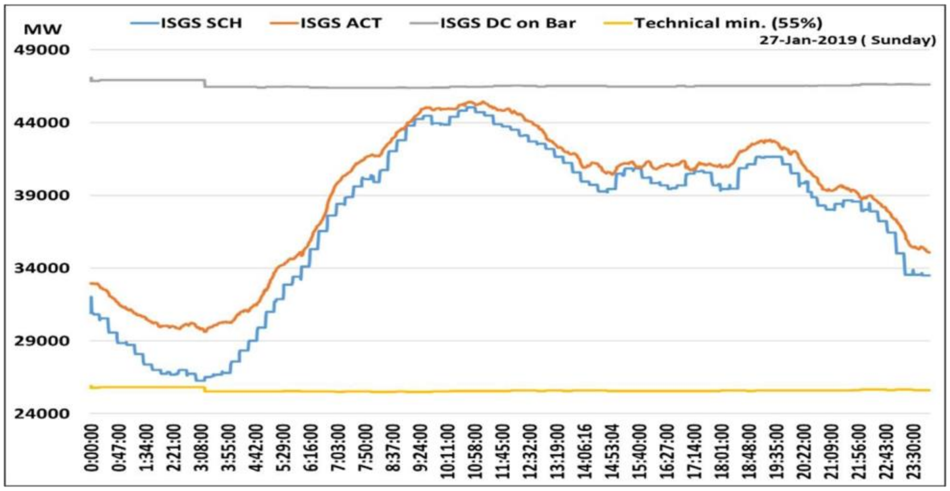


Figure 2.7 Trend of thermal ISGS schedule on 27th January 2019

There are major solar power parks in operation across several locations in the grid. A cloud cover over large solar parks has the potential to create large changes in solar output. These large changes in the generation may disrupt load-generation balance and pose as a potential threat to system operation. In order to manage these unexpected events, it is required that generation fleet has enough flexibility available with them.

2.2 Flexibility for Grid Support Services

The need for flexibility is also manifested in the primary and secondary frequency response provided by thermal units. Experiences from testing of primary frequency response and operation of Automatic Generation Control are summarized below:

2.2.1 Primary Response: Primary response is an important aspect for ensuring frequency control in the interconnected power system. IEGC 2010 mandates Free/RestrictedGovernor mode of operation in coal based units above 200MW. Onsite testing exercise is being carried out in compliance to IEGC, as per requirements it is desired that coal based unit displays sustained stable response corresponding to change in frequency. It is desired that primary response is sustained and stable at all load levels and there is minimum interaction with other control loops in the plants

Secondary Response: Continuous operation of Automatic Generation Control (AGC) has commenced from 20th July 2021. While doing so, all unit level constraints suchas P_{max}, P_{min} and ramp rates furnished by the stations are being honoured. Despite a significant capacity of 62GW included under AGC, the aggregate response obtained fromthe power plants for frequency control is often inadequate. A maximum of around +/- 1500 MW only is being obtained from all the power plants put together. A key reason forthis inadequate response from the power plants is attributed to a limit amounting to 5% of the unit capacity on the AGC, ΔP sent from NLDC imposed on the request of power plants. On account of the above, despite reserves being available in several plants, the same remains unutilized in secondary control.

2.3 Flexible Capacity Required/Available

As per CEA's report on optimal capacity mix for 2029-30 the likely total installed capacity by the end of 2029-30 projected is 8,38,783MW comprising of Hydro 61,657MW (including Hydro Imports 5,856MW), PSP 10,151MW, Small Hydro 5,000 MW, Coal 2,68,511MW, Gas 25,080MW, Nuclear 18,980MW, Solar 299,404MW, Wind 140,000MW and Biomass 10,000MW. With this installed capacity, the INDC target set for India i.e. the percentage of non- fossil fuel capacity in the total installed capacity is to be 40% by 2030 which is likely to be met. The likely renewable installed capacity shall be 450,000MW by March 2030. Recently, GOI has revised the commitment of renewables to 500GW. Hence with higher penetration of renewables (2030) and so as to avoid RE curtailment, the thermal units may have to operate below 40% minimum technical load.

As per the CEA report "*Flexible operation of thermal power plants for integration of renewable generation*" there will be maximum requirement of around 84GW flexible power (for integration of 175 GW RES capacity) from the grid connected thermal capacity of 140GW in year 2021-22. Study on maximum RES generation day in a month, 12 maximum RES generation days corresponding to 12 months of the year, 2021-22 have been calculated after prediction of hourly Generation for year, 2021-22 from Solar, Wind, Nuclear, Gas, small hydro, biomass and then coal. Actually coal generation is calculated figure and it is achieved by subtracting hourly generation of all sources except coal from hourly demand as predicted in EPS and the balanced generation to be met from thermal power plant.

The study highlighted that power generation BAU will lead to operation of the thermal plants at 26% capacity on the most critical day. However, considering flexing of the hydro power, gas based stations, pump storage station the minimum technical load could be improved to 46% from 26%. It is also found from the report that maximum RES generation of 107,798MW, 107,413MW will be available in the month of June, July respectively and ramp down & ramp up rate as calculated will be 380MW/min. & 375MW/min. respectively. As Indian high ash contained coal is not suitable for 26% minimum load operation, various steps have been proposed to improve the average minimum load operation of coal-fired power plant to 45%. However, this figure may be decreased further below 40% considering the 500 GW renewable integration by 2030. Detail study is proposed to ascertain the figure.

2.4 Ramp Rate Required/Available

The detailed analysis on average ramp rate required considering 175GW Renewable installed capacity has been done in CEA's report "Flexible Operation of Thermal Power Plant for integration of renewable Generation" which is reproduced below:

2.4.1 Maximum Ramp Up Rate

(379 MW/min when total demand is 200 GW)

Let us consider the day of highest ramp up rate, when maximum ex-bus generation from thermal plant is 154GW. After considering 10% reserve capacity and 7% APC, about 184GW thermal capacity would be synchronized on that day. Considering 1%/min ramping by the scheduled units, the system capability comes out to be 1840 MW/min. This is substantially higher than the ramp up rate required (379 MW/min.).

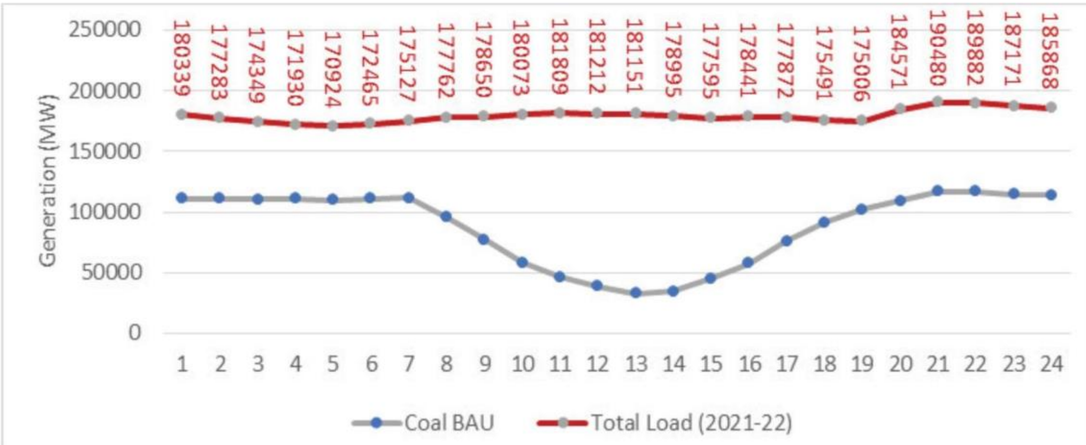


Figure 2.8

2.4.2 Maximun Ramp Down Rate

(422 MW/min when total demand = 185 GW)

Maximum ex bus generation required from thermal is 140GW. Considering 10% reserve and 7% APC, about 167 GW thermal capacity has to be synchronized. If we consider 1% ramp rate of each unit, then the system ramp capability comes out to be 1670 MW/min which is again substantially higher than the requirement on that day of 422MW/min. Hence, Indian grid is comfortably placed in case individual units maintain a basic ramping capability of 1%/min. Therefore, it may be concluded that ramp rates are not a challenge for integration of renewable generation from 175 GW RES into Indian grid.

However, the future ramp requirement may be increased to 1.5%- 2% considering 500GW renewable integration by 2030. The detail study is required to ascertain the figure in the light of 15-minute renewable generation time block.

3. STUDIES CONDUCTED

A number of flexibility studies in association with national/international partners (IGEF/VGB/GE/USAID/JCOAL/TEPCO/BHEL/Siemens) has been carried out at Central/State/Private plants. The flexible operational tests have been conducted at 40% load and higher ramps at number of stations in collaboration with OEM and others. These tests would add to the knowledge base and shall strengthen the understanding of the challenges involved in flexible operation of thermal units.

3.1 Pilot Tests/Studies

The pilot tests/studies conducted already under international cooperation and with the help of OEM are as follows:

1. Dadri TPS of NTPC in collaboration of IGEF, Germany
2. Mauda TPS of NTPC in collaboration of BHEL
3. Sagardighi TPS of WBPDCL in collaboration of BHEL
4. Ukai TPS of GSECL in collaboration of USAID, BHEL
5. RBTPS, JV of Tata Power, DVC in collaboration of IGEF/VGB, Germany
6. DSTPS of DVC in collaboration of IGEF/VGB, Germany

The results of concluded pilot tests at various power stations are as described below:

3.1.1 Dadri TPS, (NTPC), Dist. Gautambudh Nagar, UP

Test Date: 21 & 22/06/2018
Unit No.: 6
Unit Capacity: 500MW
Following tests were conducted:

	Test	Target	Achieved
a.	Minimum Load Test at 40%	200MW	200MW
b.	Ramp Up Test	3%/min	~ 1.5%/min
c.	Ramp Down Test	3%/min	~ 1.5%/min
d.	Ramp Up Test	1%/min	~ 0.86%/min
e.	Ramp Down Test	1%/min	~ 0.5%/min

The results are based on IGEF report dated 28/09/2018.

3.1.2 Mouda TPS, (NTPC), Dist. Nagpur, Maharashtra

Test Date: 16/02/2019
Unit No.: 1
Unit Capacity: 500MW
Following tests were conducted:

Test	Target	Achieved
a. Ramp up Test (3%)	3%/min	~ 2.04%/min
b. Ramp down Test (3%)	3%/min	~ 2.01%/min
c. Ramp up Test (1%)	1%/min	~ 1.04%/min
d. Ramp down Test (1%)	1%/min	~ 0.92%/min

Test Date: 29/05/2019
Unit No.: 2
Unit Capacity: 500MW
Following tests were conducted:

Test	Target	Achieved
a. Minimum Load Test at 40%	200MW	200MW
b. Ramp up Test (3%)	3%/min	~ 1.14%/min
c. Ramp down Test (3%)	3%/min	~ 1.68%/min
d. Ramp up Test (1%)	1%/min	~ 0.85%/min
e. Ramp down Test (1%)	1%/min	~ 0.9%/min

3.1.3 Sagardighi TPS, (WBPDCL), Dist. Musheerabad, West Bengal

Test Date: 27/06/2019
Unit No.: 3
Unit Capacity: 500MW
Following tests were conducted:

Test	Target	Achieved
a. Minimum Load Test at 40%	200MW	200MW
b. Ramp Up Test	3%/min	~ 1.6%/min
c. Ramp Down Test	3%/min	~ 2.6%/min
d. Ramp Up Test	1%/min	~ 1.1%/min
e. Ramp Down Test	1%/min	~ 0.67%/min

The flexibilisation test was conducted by BHEL team and was also witnessed by representative from TPRM Division, CEA.

3.1.4 Ukai TPS, GSECL, Gujarat

Test Date: 3rd to 7th March, 2020
Unit No.: 6
Unit Capacity: 500 MW
Following tests were conducted:

Test	Target	Achieved
Minimum Load Test at 40%	200 MW	200 MW
Ramp Test (3%)	3%/min	1.6%-2%/min
Ramp Test (1%)	1%/min	~1.0%/min

3.1.5 RBTPS, (Tata Power, DVC JV), DIST. Dhanbad, Jharkhand

Test Date: 22/07/2021 to 27/07/2021
Unit No: 2
Unit Capacity: 525MW
Following tests were conducted:

Test	Target	Achieved
Minimum Load Test (40%)	210MW	210MW 190MW (36%)* *achieved for short duration of 10min.
Ramp Up/Down Test	1%/min	

The ramp rates achieved were as follows:

	Upward direction	Downward direction
290 MW – 525 MW	0.95%/min	1.52%/min
MW – 290 MW	do	0.95%/min
210 MW – 225 MW	do	0.38%/min

3.1.6 DSTPS, (DVC), Andal, West Bengal

Test Date: 28/03/2022 to 31/03/2022
Unit No: 2
Unit Capacity: 500MW
Following tests were conducted:

Test	Target	Achieved
Minimum Load Test (40%)	200MW	201MW 173MW (34.6%)* *achieved for duration of over 2hrs.
Ramp Up/Down Test	1%/min	

The ramp rates achieved were as follows:

	Upward direction	Downward direction
From 55% – 72% Load	2.26%/min	
From 82% – 62% Load		1.54%/min

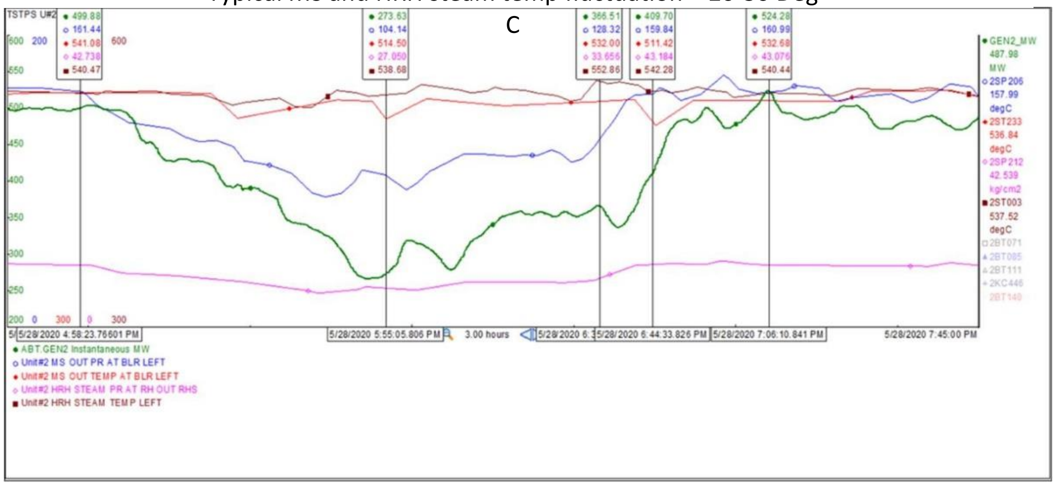
3.2 Observations from the Pilot Studies

Following were the observations for pilot project at

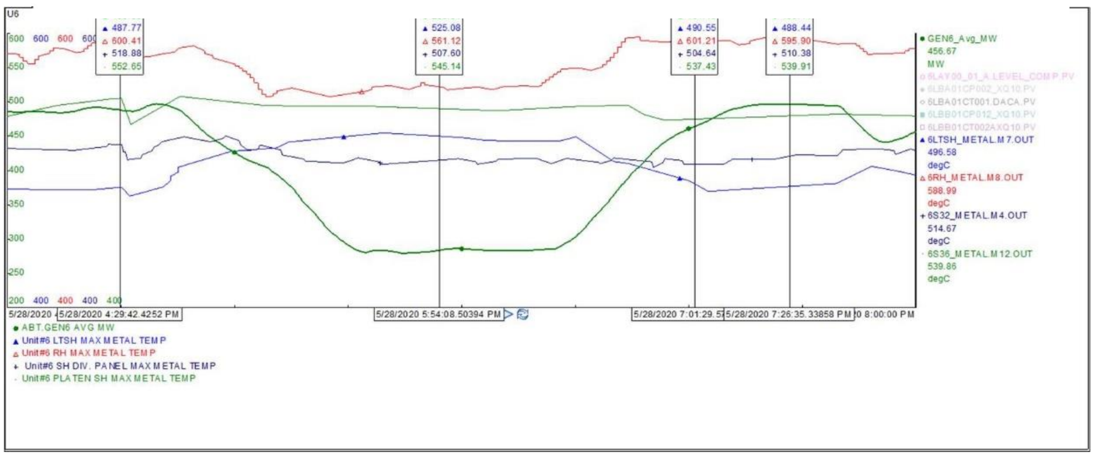
3.2.1 Excessive fluctuations in Steam temperatures- MS and HRH.

Steam temperature control becomes difficult as fuel flow rate and feed water flow rate decrease.

Typical MS and HRH steam temp fluctuation ~ 20-30 Deg C

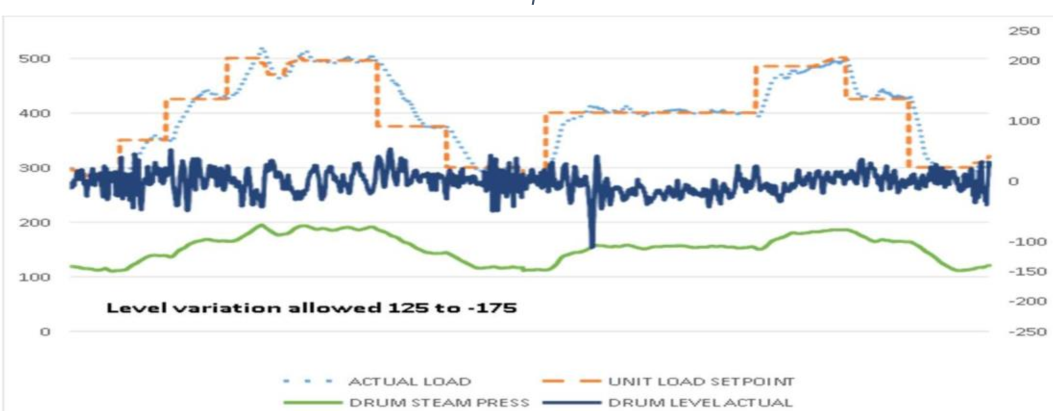


RH metal temperature crossing the excursion limit



3.2.1 High Drum level swings during ramping.

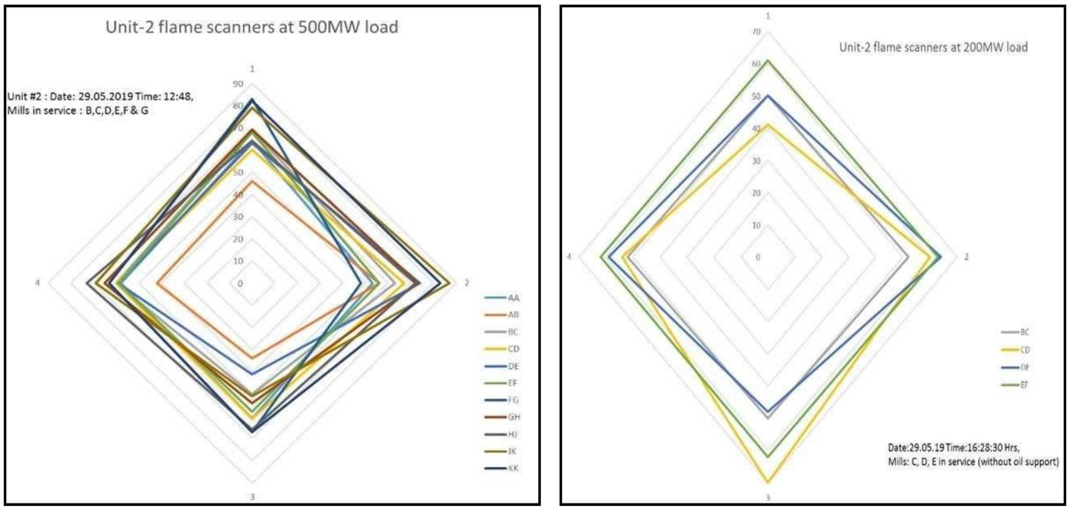
Drum level fluctuation



3.2.2 Flame disturbance during ramping and at MTL.

Fuel flow and air flow decrease, and balance of fuel and air sometimes collapses at some space in furnace of boiler, and combustion becomes unstable.

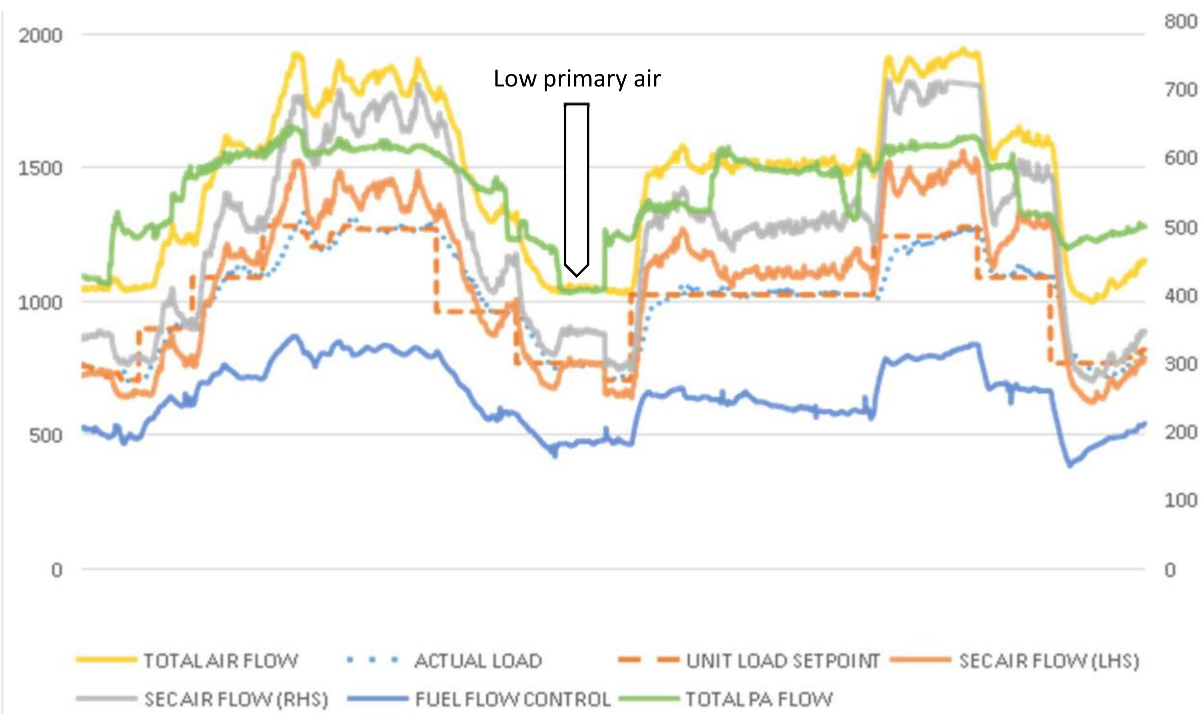
Flame scanners at 100% vs 40% load- Mouda U#2



3.2.3 Occasional furnace pressurization.

3.2.4 Chances of Stalling of Primary Air fans at low loads

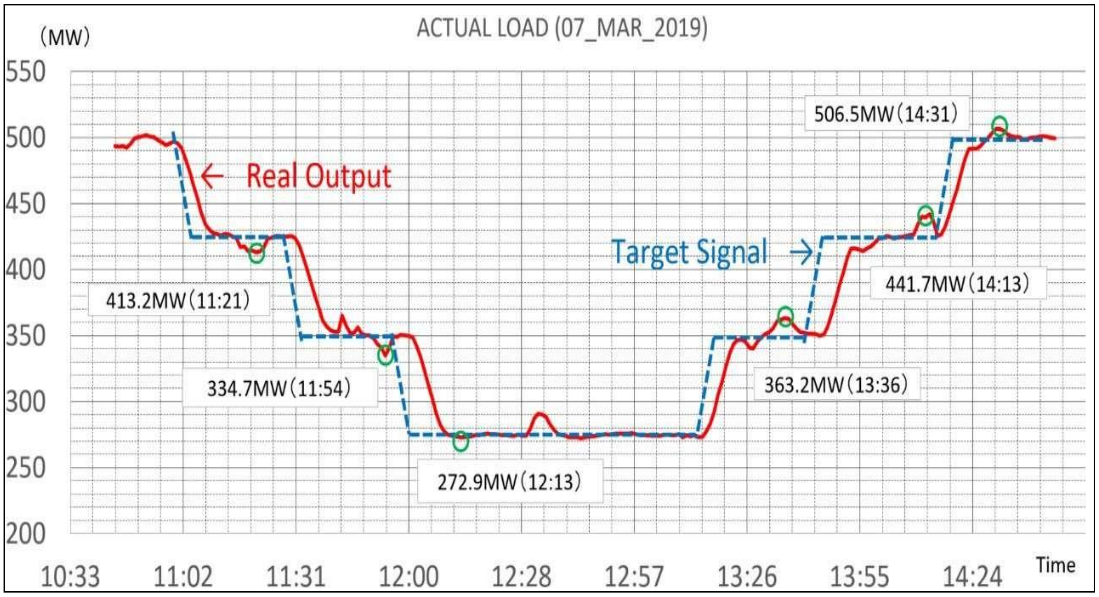
Low primary air flow can lead to stalling- Mouda U#2



3.2.6 Low boiler flue gas exit temperature, leading to acid corrosion?

3.2.7 With 3% ramp commands, actual ramp rate achieved in full load range from technical min. loading to full load was only 1.3% due to manual milling system operation.

Typical Ramp rate – Target vs Actual achieved



4. CHALLENGES OF FLEXIBILISATION

The challenges being faced for flexibilisation of the coal fired power plants are mainly due to the operation of thermal power plants as base load stations in the past so as to cater to unceasing power shortages in the country. It has resulted in low automation levels, low optimization of plant operation beyond the rated load and low ramping capability. The studies have generally found that on design basis, the units have enough flexibility of operation, but as a matter of fact, lack of some control logics and lack of enough tuning at test operation, actual flexibility of operation is limited. Further, the inferior quality of coal has added to the challenges of flexibilisation which impacts the stabilization of flame at low loads. After the introduction of new emission norms for thermal power plants in Dec, 2015, the compliance of SO2 and NOx limits are mandatory. Meeting NOx limits at low operating loads shall be a matter of concern needs to be tackled. The various roadblocks faced in flexibilisation of coal fired power plants and the possible mitigation strategies are discussed in details below:

4.1 Plant Capabilities

The flexing capability of a unit depends on the following factors

- Design- Thin-walled components/special turbine design will be better at flexing, shorter start-up time, higher ramp rate.
  - Boiler drum in Sub-critical units can pose challenges during flexible operation.
  - Super-critical units are better for load ramping operations but flexible operation at lower minimum load is challenging below benson point. However, operating the super-critical units on sub-critical mode has a very high impact on efficiency.
- Vintage- In older units the damage will be faster
- Coal- Poor coal quality will restrict flexible operation. (Discussed in the next section)
- Milling System- The start-up time and load ramp-up depend on the time to start the mills. It can vary from 10 minutes to 15 minutes.
- Control system- A good control system offers a huge advantage for maintaining proper parameters during flexible operation and to reduce the operational delays.

4.2 Impact on fuel quality

There is a large variation of quality amongst the different regions. Boilers are designed to burn coal of specified quality and any changes to the specified quality will significantly impact the performance and controllability of boilers. Change in coal from the design coal to a lower quality coal affects boiler operation and performance and particularly during low load operation with poor coal quality, the combustion stability of the boiler is severely affected and require additional support of secondary fuel (fuel oil). Challenges with poor coal quality include:

- Boiler slagging and fouling
- Increased corrosion and erosion
- Boiler tube metal temperatures excursion

- Lower boiler efficiency
- Overloading ash handling system
- Overloading of dust removal system and increased emissions

It is important to understand, how the different constituents in coal influence the performance during flexible operation and what improvements can be made. There is a wide variation in Indian coal fed to power stations from different sources. GCV varies from 2500 to 6000 Kcal/kg, Moisture - 8% to 15%, Volatiles- 18 to 30%, Ash- 25 to >50%.

4.2.1 Moisture – Part load efficiency is an important consideration of flexible operation and moisture affects unit efficiency by impacting thermal performance. Moisture has a flame quenching tendency and absorbs latent heat. High coal moisture content will lower the coal's gross calorific value (GCV), which means that that more fuel quantity will be required to be fired for the same heat input to the unit. The increased moisture in the fuel reduces boiler efficiency. Moisture also affects the pulveriser capacity and along with increased fineness in a coal adversely affects the coal handling capability. Coal moisture affects the following:

- Boiler efficiency
- Mill drying/ Tempering air requirements
- Gas velocities through the unit
- Choking in coal pipes
- Flame stability
- Precipitator efficiency

4.2.2 Ash -The challenges include, loss of reliability and availability, boiler slagging, fouling, high-temperature metal wastage, cold-end corrosion, stack emissions, increased deterioration in APH performance, duct leakages, increased water consumption, increased maintenance costs and lower unit efficiency. The quantity, chemical composition, and size of the ash are the variable that affect unit performance as well asthe marketability of ash & disposal. Ash quality affects the following:

- Mill wear
- Erosion
- Slagging and fouling
- Ash handling equipment performance
- APH performance
- SH/RH steam temperatures
- ESP Performance & Particulate emissions
- Capacity of CHP, bunkers, mills, boiler hoppers, ESP etc.

4.2.3 Volatile Matter - The volatile matter is an index of the gaseous fuels produced upon heating of the coal as it enters the furnace, mainly hydrogen and hydrocarbons that sustain ignition. Typical range of VM is 18% to 30%. Higher VM coals generally produce less NOx and are also easier to control in the combustion system, especially in low load operation.

Some of the Indian coals have VM of around 15% and stable combustion becomes extremely difficult, even at higher loads. There have been increased occasions of unit trips on flame failure (even during base load operation) at stations burning low VM coal. The problem gets aggravated further when coal fineness, A/F ratio and/or distribution of A/F is non-optimal, low volatile fuel results in furnace imbalances and increased amounts of de-volatilized carbon char seeking oxygen in the upper furnace and resulting in secondary combustion.

4.2.4 Sulphur Content - Sulphur in coal determines the degree of expected corrosion in the high/low temperature regions of the boiler. The amount of SO_2 that will be produced depends on the Sulphur content of the coal. A small part (2-3%) of the Sulphur in coal converts to SO_3, and the amount of SO_3 produced and retained in the flue gas determines the dew point of the flue gas and the collection efficiency of the precipitator. Sulphurcontent affects APH corrosion, duct & ESP corrosion. The problem is further aggravated during flexible operation when maintaining the flue gas temperature above the dew point becomes challenging.

4.2.5 Nitrogen Content- Nitrogen content (in volatile and fixed carbon) causes NOx formation. Fuel NOx ranges from 60–80% of the total NOx in pulverized coal units. The NOx formation can be reduced with staged combustion. During flexible operation, without sufficient automation for air flow control and combustion optimization NOx control becomes challenging.

4.2.6 Gross calorific Value (GCV) - The heat produced by combustion of unit quantity of a solid or liquid fuel when burned at constant volume in an oxygen bomb calorimeter under specified conditions, with the resulting water condensed to a liquid. There is alarge variation of GCV in Indian Coal, typically varying from 2500-6000Kcal/kg. The GCV of the fired coal is one of the key determinants of the technical minimum level.

4.2.7 Ash fusion temperatures

Ash fusion temperatures can be exacerbated by reducing atmospheres that are related with penthouse or convection pass air in-leakage that is upstream of the boiler O_2 probes. This can be a serious problem in Indian power stations with increased flexing and combined with high ash Indian coals.

4.3 Impact on Plant life

Flexible operation increases the creep-fatigue damage caused by thermal stresses, especially in units originally designed for base load operation. The creep-fatigue is a dominant failure mode for damage and failures of many fossil plant components. Creep-fatigue damage mostly occurs at stress concentration points like header bore holes, ligaments, rotor grooves, etc. due to large plastic strain. Accelerated Corrosion fatigue damage during flexible operation is another common factor. Maintaining optimum water and steam chemical parameters is challenging during frequent cycling. Almost all components of the Boiler, turbine and generator are affected ranging from severe to moderate. Following are some of the severely affected components:

Thick wall components	▪ Casting such as turbine valves and casings ▪ Turbine Rotor ▪ Thick-walled vessels ▪ MS, CRH, HRH headers (especially Y-piece section)
High temperature component	▪ Superheater, Reheater ▪ Ties used to support SH, RH tubing ▪ Tube to header joints etc. ▪ Gas duct work
Corrosion and scaling prone component	▪ Water wall tubing at attachments (wind box, corner tubes, wall box opening, buck stay) Heater tube ▪ APH - cold end ▪ Condenser tube ▪ Welded joints
Degeneration of insulation due to thermal transients	▪ Generator insulation ▪ Transformer insulation ▪ Insulation of HV drives (FD, ID, PA fans, mills motor)

The pilot studies carried out in the Indian power stations revealed the following deviations/damage mechanisms during flexible operation.

1) High exhaust hood temperatures
2) High steam seal temperatures
3) High rate of change of metal temperatures
4) Last stage blade vibration
5) Solid particle erosion
6) Main steam and reheat steam temperature differential
7) Internal corrosion and oxygen pitting of waterwall tubes
8) Higher rates of internal corrosion of steam tubing due to increased exfoliation
9) Accelerated creep damage to steam (superheater and reheater) tubing
10) Chemistry upsets/excursions resulting in hydrogen damage
11) Fatigue corrosion due to cycling stresses on waterwall tubes
12) Furnace subcooling resulting in external tube failures
13) Overheating during low load operation by improper burner configuration
14) Steam line quenching
15) Higher risk of furnace explosion due to low turn down of fuel capabilities
16) Economizer inlet header thermal fatigue cracking

These damages impact the thermal units by:

1) Increased life consumption leading to increased maintenance, operation (excluding fixed costs), and overhaul capital expenditures.
2) Increased time-averaged replacement energy and capacity cost due to increased Equivalent Forced Outage Rate (EFOR).
3) Efficiency loss- Increased cost of heat rate changes due to low load and variable load operation.
4) Increased cost of start-up fuel, auxiliary power, chemicals, water, and extra manpower for start-ups.
5) Environmental Impacts

4.4 Impact on Environment

4.4.1 ESP

At low loads, there can be instances when the temperature in the ESP falls below the dew point and there is a built up of ash due the moisture, which becomes difficult to remove. Moreover, with high Sulphur coal there can be severe acid corrosion due to maintaining lower flue gas outlet temperature. During frequent start-ups, the ESPs ate kept out ofservice during oil firing. During this period, maintaining the particulate emissions becomes challenging. Due to lower efficiency of the thermal units during minimum loads, the specific CO_2 emissions increase.

4.4.2 FGD operation during flexibilization

During flexible operation, there can be many issues with the FGD operation, which would need precise controls and modified operation procedures. Frequent start-up can have issues of solidification of slurry and accumulation of start-up oil on the linings. Long period of shutdown will require proper lay-up and flushing of slurry in order to ensure that lime slurry does not solidify. During load variations and frequent low loads, the operation of different streams and circulating pumps need to be optimized through automated controls.

A common problem observed during low load operation is reduction of inlet flue gas temperature, which is likely to impact the reaction rates. In some of the designs regenerative heat exchangers are used but in effect there may be a substantial decrease in exit temperature which in turn will reduce the gas buoyancy and induce dew point corrosion in the duct and chimney. Some FGD units bypass FGD plants (those with fluegas by-pass system), during start-up and low loads and charge the FGD after the temperatures stabilizes.

4.5 Impact on Efficiency

The loss on account of deterioration in efficiency of the unit at part loads is another major category of flexing costs. A typical deterioration of efficiency (net heat rate) for different categories (based on GE inputs is shown in figure-4(a). It may be noted that as per another study by NTPC this will vary from machine to machine and these losses will be significantly lower if the unit is run on sliding pressure (Figure-4(b)).

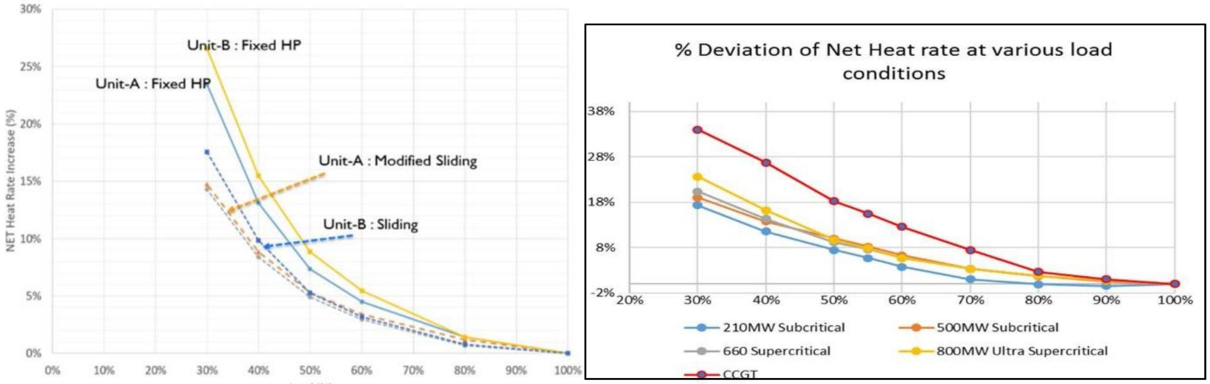


Figure-4(a): Net Heat rate Increase VS Loading Factor 4(b) NHR increase on fixed/slidingpressure

There is a good reason to put in extra efforts in modifying the operational practices for improvement in part load efficiency. Any plant modification/retrofits for improving the efficiency at part load will have a very short payback as degradation in efficiency is the biggest cost for low operation.

In a pulverized coal unit, there would be a less significant loss in efficiency if the unit operates on variable pressure mode. It is therefore worthwhile to make provision for sliding pressure operation for improved part load efficiency.

Combustion optimisation and reduced excess air, further improve the heat rate. Similarly, during test runs conducted at different units (500 MW coal fired of State Utilities, India), the heat rates were measured at different loads (90%, 55% and 40 %) under various conditions. One of the areas, where optimisation became difficult wasthe air flow requirements at 40% load which contributed to the increased stack losses. Otherwise at upper load conditions, significant improvement in heat rates were observed after optimization of air flow and operating the unit on sliding pressure. However, during varying load conditions, optimization is difficult and can interfere with the unit's ramping capability. Upgrading the C&I systems would be necessary for achieving the desired benefits.

Various auxiliaries in water and steam cycle of the unit have been designed with 2x50% configuration required at 100% TMCR for ensuring reliability. For low load operations at 40% TMCR, running both set of auxiliaries may not be required and thus single stream operation may be adopted which will allow for reduction in auxiliary power consumption. VFD installation may also be explored in units which operate on low loads for long duration.

A cautions decision would be required based on cost benefit analysis between APC reduction and controls and hardware modification cost for unit reliability.

4.6 Impact on Maintenance and unit Operators

As flexible operation leads to increased life consumption of plant components, increased outages and failures, it calls for revisiting the maintenance practices, increased inspection schedules and ensuring sufficient spares. Some of the components will have accelerated wear and failures during flexing operation (like mills, boiler pressure parts, valves) and would require increased maintenance. The maintenance strategy has to be devised, based on the extent of flexibilization. The frequency of significant load following, number of start-ups, coal quality, vintage of the machine.

Installing digital tools for online condition monitoring and damage assessment (like EOH/ EHS calculator) can be of great help in getting inputs of focused maintenance and on deciding the frequency of maintenance and component replacement.

Personnel safety is of first and foremost priority in operation and maintenance of coal based generating unit whether it is on flexible operation or on base load. Flexibilization of units adds to the safety risks and calls for added precautions. Sometimes serious and fatal injuries are caused by catastrophic equipment failure due to negligence and poor operation and maintenance practices.

In most of the cases, the boiler is often the most dangerous equipment, if not operated and maintained properly and in that case, it can act like a potential explosive.

Maintaining optimum chemical parameters is another challenge during flexible operation and the operating procedure must be modified to take care of the same. Moreover, flexible operation may require short of long shutdowns and adequate preservation needs to be ensured.

Some of the key takeaways from the field Tests for developing techniques for Low Load Operations:

4.6.1 For minimum load operation the mantra is sustaining stable combustion by manipulating the firing rates, maintaining even temperature distribution within the different zones of the boiler, managing the coordination between the boiler and turbine. Reducing the number of mills in service. At 40% load 3 mills were kept in service

4.6.2 **Optimisation of primary air flow**. The primary air flow in mills were reduced. A review of primary air flow curve should be considered for low load.

4.6.3 **Optimisation of secondary air flow**. Tertiary vanes of elevations that were not in service were reduced, ensuring just adequate flow for burners cooling. It was ensured that the wind box pressure did not collapse to zero. Measurement of secondary air flow was not available. This could have helped in further optimization of the process. It is therefore recommended to make provisions for SA measurements at individual burners.

4.6.4 **Measurement of excess air** for combustion /Flue gas O_2 measurement may be validated with CO measurement as CO is unaffected by air in-leakages. It is advisable to use both the measurements.

4.6.5 **Sliding pressure** induces a sluggish load response for drum boilers. But the advantages are far more. Modification of sliding pressure curve (increased slightly) in small steps is to be done to ensure that there is no steaming in economizer and no DNB.

4.6.6 **BFP recirculation valves** must be able to operate at intermediate positions (inching type). At 40 % load, one TDBFP can meet the feed water demands. The changeover of driving steam source must be ensured. Ensure readiness of MDBFP on hot standby.

4.6.7 During the test runs, a number of manual interventions were made in the presence and advice of the OEM. In particular, there were issues during fast load changes and manual intervention on the firing system raising the risk of combustion instability and boiler puffs. During such operation, the safe functioning of the burner management systems must be ensured. For severe demands during regular low load and ramping operation, enhancement of controls, monitoring and diagnostic systems is worthwhile and has been recommended in all the studied carried out, including the OEM's. As per the limitations encountered during the field tests, upgrades for automatic loading control and combustion management will be required.

4.6.8 The unit control system consists a number of loops and sub loops, with master controllers and coordinated by CMC. In older base load units, the C&I systems were designed to provide responsive control in the higher load range and oftenthe C&I specs aimed at automatic operation in the range of 60% to 100% MCR. The automatic control at lower loads becomes poor and sluggish mainly due to changing unit response characteristics.

4.6.9 Another limitation with low load operation is the improper sizing of many control valves for low load or low flows operation, causing poor control response and sometimes hunting of valves. All these control valves must be checked for correct operation at low load and necessary modifications be done. Replacement or placing additional valves may be necessary.

4.6.10 Additionally, for cyclic operation, review and modifications will be required for the alarms and protection logic. A review and evaluation of the alarms and protections setting is required as the unit would operate at different levels from those for which these were designed to operate. Before finalizing any changes, the opinion of the OEM must be taken. Examples include-minimum air flow, minimum mills loading, temperature setting, modification of sliding pressure curve, primary air flow curve, temperature settings etc.

4.6.11 When a base load unit is converted to operate on flexible mode, the operator's view of the process (displayed on LVS or other screen) needs to be modified to include the actions that may be needed during the particular operating regime. These screens can include the important or problematic processes along with trends to facilitate the operator to react fast in case of any process deviation during the cycling operations, for example, a screen for low load operation and for start-up (cold, warm & hot) and for shutdown.

4.6.12 The life of a steam turbine is directly related to thermal transients experienced over time. The typical steam turbine start-up ramp rate is well-defined by the OEM, as there are limits to the heating rates of the turbine parts.

4.7 Roadblocks & Mitigation strategies:

The pilot studies and subsequent operations presented some challenges which were taken up with international partners for suggestive mitigation plans. A brief of the roadblocks, mitigation plans and the retrofit requirements is given below:

S.no.	Roadblocks	Mitigation plan	Remedial measures
A	**Equipment Operating Mode:-**		
1	Achieving >1% Ramp rate (up and/or down); Increasing number of ramps up/down during the day.	Address excursions w/metal and steam temperatures, pressure swings, poor grid frequency response; condenser vacuum; limits on load range.	Advance process control loop tuning, Mill automation, providing additional tube metal sensors, heat flux sensors etc.
2	Minimum load program is not in place; Difficult to reduce load below 55% of MCR without oil support	Establish program; Implement a Systematic Approach to Minimum Load Reduction	Control loop tuning upto 40% MTL, mill automation, single fan/pump operation, implementation of hardwares like Variable Orifice in coal flow pipes-, coal pipe flow measurement, low load scanners.
3	Heat Rate at low operating loads w/ varying fuels; Net heat rate >2% deviation from design due to running at reduced loads; Influence on the Energy Charge Rate and overall production costs. Increase in Auxiliary Power	Benchmark performance; Evaluate controllable losses vs. fuel quality, Modified Sliding pressure operation during ramp up/down. Installation of VFDs for high energy drives.	Top heater installation, single drive operation pumps and fan, installation of VFDs for high energy drives.

S.no.	Roadblocks	Mitigation plan	Remedial measures
	Consumption at Part Load.		
B	**Pressure Parts and Life Availability**		
1	Flow Accelerated Corrosion (FAC) inEconomiser tube	FAC programintegration	Top heater installation, Automation in maintaining Boiler water pH
2	No thermal gradient measurement on economizers	Pegging/heating in deaerator and fillingof hot water in boiler filling during light up.	Installation of additional thermocouple in economiser tube
3	Thermal Fatigue	Possibility of inter connection of drains to hot fill the boiler tobe explored;	Interconnection of Deaerators among theunits. Thermal Fatigue can be minimized through maintaining the Startup/Shutdown curve provided by OEM. This can be done through plotting design Vs Actual curve during startup/ shutdown in the dashboard so that immediate correction canbe made in case of anomalies.
4	Steam Temperature control needs improvement following synchronization to mitigate reported excursions in major SH/RH/LTSH components; Mismatch in heat pick up in MS left & right.	Close monitoring of deviation of MS/HRH and metaltemp during ramping.	Advance process controlof steam/ water cycle and load control. Installation of additional metal temperature sensors. SH/RH spray controlvalves upgrade.

S.no.	Roadblocks	Mitigation plan	Remedial measures
C	**Operations**		
1	Operations team need overheat mitigation guidance	Better guidance to evaluate stress on boiler and turbine components	Control loop tuning and Boiler fatigue monitoring system
2	High Energy Drain / Boiler stop valve passing problem	Monitoring of high energy valves with temp gun in running condition	Replacement plan forthese valves during annual outages
3	Boiler insulation degradation impactsoperations	Insulation mapping in boiler in running condition	Phase wise replacementplan
4	No temperature sensorsin the furnace walls to assess overheating, heat flux, impacts of reduced load operation		Additional temperature sensors installation in S bend
5	APH gas temperature control; SCAPH not effective.	SCAPH to be made through for air heating.	Automation in SCAPH control to maintain APH gas temp. Increasing capacity of Steam Coil Air Preheater and APRDS System.
6	Drum level control challenges lead to load swings in drum level even with mild disturbance.	Auto loop tuning offeed water cycle	Single pump operation and installing regulating type recirculation Advance process controlof drum level
7	No simulators are available to carry out testof flexible operation to evaluate behaviour at varying load conditions.		Simulator to be upgraded with the measures of advance process control and withmore automation.
D	**Maintenance**		
1	High pressure control valves are passing e.g. sprays ,BFP recirculationvalves , high energy drains etc.	Integrate high pressure control valves modernisationplan.	Phased replacement. Changing on-off BFP re-circulation valve with modulating control valves.

S.no.	Roadblocks	Mitigation plan	Remedial measures
2	Frequent problem in PA fans as they run close to stalling zone.	Continuous tracking of PA fan characteristics curve and provisioning of alarm much before fan operating near the stalling zone.	Single PA fan operation, automated single drive control package to avoid stalling.
3	Thermal Fatigue and Creep Damage	Integrate thermal mitigation strategy.	Boiler fatigue monitoring system and Turbine stress monitoring system.
E	**Combustion and Boiler Performance**		
1	Furnace exit O2, Furnace Exit Temp measurement are not taken.	Furnace Exit O2 measurement and Furnace Exit Temp measurement to be done. Furnace Exit O2 measurement and Furnace Exit Temp measurement to be done.	Furnace exit O2% probe installation and Furnaceexit temperature measurement.
2	Mill Performance; No provision to measure fuel flow imbalance in mills; Frequent burner choking; Coal rejects from mill hoppers.	Mill performance mapping at various load & coal quality tobe done to identify best & worst mill; Need to establish mechanical blue-printideal for flexible operations. Mill performance evaluation, finesses measurement and coal flow balancing.	Milling system coal pipe measurement system installation. Installation of coal flow sensors and variable orifices* in coal pipes. (* may be only useful below 30% operation)
3	Implement program and strategy for low load and reduced mill operations	Optimize mill operations and/or identify roadblocks and/or issues during planned shut-downs (record observations)	Optimising no of milling operation with milling automation

S.no.	Roadblocks	Mitigation plan	Remedial measures
4	Poor flame stability and load response with 30% -50% high ash domestic Indian coal and/or low quality imported coals	Flame Quality Scanner Performance improvement- Explore application method to display both intensity and frequency; Identify opportunities to improve mill configurations for optimal A/F ratios	Flame scanner upgrade in control, repositioningof scanners and replacement of coal pipenozzles with low turn down of flame length, coal blending. Coal mill classifier upgrade for improving mill fineness, digital solutions for flame stability at low load operation and for achieving required ramp rates.
F	**Instrumentation and Controls**		
1	Control loops are not tuned at part loads.	Controls tuning.	Control tuning up to minimum load operation.
2	Water wall temp are not available.	Water wall metal temp. Monitoring.	Additional thermocouple installation.
3	No FEGT measurement.	Furnace Exit Gas Temp. Monitoring.	FEGT measurement installation.
G	**Environmental Controls**		
1	Dry ash evacuation Capacity is inadequate due to reliability issues.	ESP augmentation for dry ash evacuation.	Augmentation in Ash Handling System.
2	NOx control to achieve regulatory requirements	NOx controls	Implementation of NOx abatement system
3	Impact on NOx/SO2	NOx / SO2 controls	Implementation ofControl System
H	**Cycle Chemistry**		
1	Chemical dosing is mostly completed manually	Automation is needed.	LP Dosing automation with VFD drive.
2	Condenser tube leakage identification need modification.	Continuous monitoring of condensate cation conductivity.	Attending condenser tube leakages.
3	Deposits in HP turbine	Maintain Steam Purity	CPU installation

S.no.	Roadblocks	Mitigation plan	Remedial measures
4	Chemical parameters control at start-up (e.g. controlling DO)	Improve strategy for start-up and part load operations	Nitrogen purging in condensate storage system.
5	Maintaining Water Chemistry parameters at load less than 55% say at 40% will be challenging due to Absence of CPU in several stations.	Improving Water Chemistry for load load operation.	CPU installation
6	Some stations do not havea practice for Turbine/ Hot well/feed water/ Generator layup, recently Preparation of instrumentair connection is in progress for RH coil lay up; Common reserve shut-downs increased insome station from 1-2 weeks to 2 months.	Implement Layup program with required system equipment to managecorrosion when vacuum cannot be held.	Design Wet/Dry layup program & implement the same.
I	**Steam Turbine Generator**		
1	HPT heating takes 3-4 hrs time during cold start up;	Startup procedure need to be revisitedfor aligning with flexible operation.	Electric heater blanketingon HPT can reduce the time
2	Shaft Vibration / pedestal vibrations are important parameters which needs to be monitored in all operative conditions including low load operation.	TG vibration problemto be addressed for better load following and low load operation.	To be studied with OEMand solution to be implemented.
3	TDBFP recirculation - "open/close" type and often leads to drum level disturbance	Replacement of TDBFP recirculationvalve with control valve type.	Replacement of On-off re-circulation valve with control valve.
4	Main Steam Temperature variation during Ramping (10-20^{0}C).	Improve control	Advance process control

S.no.	Roadblocks	Mitigation plan	Remedial measures
5	Creep/Fatigue damage mitigation on high-temperature components needs to understood	Installation of Turbine and BoilerStress Monitoring System	Equivalent Operating Hours (EOH) installation
6	At low load, both TDBFP operation is not possible as CRH source of motive steam for drive turbine is not lined-up.	Motive steam source from CRH shall be made operational.	Control Valve operationto be tuned higher parameter
7	Increase in cation conductivity at CEP discharge during minimum technical load operation.	Possibility of installing condensatepolishing unit shall be studied if not installed for improving condensate and feed water chemistry.	CPU Installation.
8	Drop in Main / ReheatSteam Temperature.	Load ramping to be limited	MS/RH Spray isolation valve internal checkingto be scheduled during shutdown/AOH. • Calibration of instrument for Spray Flow, Temperature Tx etc shall be planned on a scheduled timeline.

5. PROCEDURE FOR LOW LOAD TESTS

5.1 General

With increase in Renewable Energy Integration to grid, conventional thermal power plants would be required to cycle. The plant would then be required to operate below current technical minimum load and require faster ramp up and ramp down rates. In such a scenario the life of critical components such as Boiler, Steam Turbine & Pumps gets affected. The increased fuel cost also presents the challenge to utility to achieve optimum efficiency. In order to generate electricity economically utilities need to revisit the conventional operation and maintenance practices and, optimize their operation with advanced digital solutions. The typical operating modes of thermal power plants are undergoing changes especially as a result of the increasing percentage of renewable in electric power generation. The future trend comes along with expanding the grid, increasing power storage capacity, participation of renewable power generation in grid control and residual load generation by thermal power plants. Main challenges are the fast start-ups, fast load change rates as well as efficient low load operation and high demand of primary frequency response.

This chapter discusses procedures to be adopted for pilot testing of coal-fired power plants that serve the aforementioned circumstances without any additional measures.

The pilot test runs should be conducted after careful study of the unit beforehand and accordingly the test targets should be decided in consultation with OEM. Study should involve the evaluation of process limitations and an assessment of the impact of low load operation (temperature/pressure gradients) on the components. Any stretching of the targets during the test run should be avoided for the safety and security of the plant.

5.2 Good O&M Practices/Prerequisites for flexibilisation

It is essential that some basic practices are followed before preparing a unit for flexing. The below indicative list contains the broad preparation items and is not exhaustive.

a) All auto loops should be available and fine tuning of CMC must be carried out to minimize the deviation of parameters like MS/HRH steam temperature, throttle pressure, drum level, excess O_2% at economiser outlet and flue gas temperature at boiler outlet.

b) Attemperator system (isolating valves and control valves) and control valves are to be set tight and must give fast response to the changing system demand.

c) Optimise minimum coal loading in a mill by fine tuning primary air flow vs coal flow curve to avoid lean air mixture and possible flame failure tripping.

d) Dirty air flow test at regular interval to evaluate partially plugged coal pipes and burners

e) Burner tilts should be operational in full range in auto mode.

f) SADC damper operation should be checked any leakage from damper should be minimized and correct feedback must be made available. (Feedback is not available in DCS for BHEL units)
g) WWSB and LRSB operation scheduling should be done at higher load during such opportunity.
h) Air heater soot blowing must be carried out at least once in a shift
i) Air heater air leakages and other tramp air should be minimised.
j) Replacement or repairing of expansion joints if required and major duct revamping if any.
k) Water chemistry instrumentation (SWAS System) should be set right and linked with DCS.
l) SCAPH auto operation to be made through to contain flue gas temperature less than acid dew points
m) Check leakages in system under vacuum. Helium leak detection test may be conducted to identify leakages. Air Leakages above 20 kg/hr (observed in Rotameter installed in Vacuum Pump / Main Ejector exhaust) needs to be attended.
n) Boiler side high energy piping hanger indicator are to be marked and monitored.
o) Low load FRS (30% FRS) to be used to reduce deviation in or maintain flow rate in economiser during cold or warm start up.
p) Turbine stop and control valves to be inspected w.r.t valve position in control room.
q) Boroscopic inspection provisions shall be made available for LP turbine.
r) Ensuring availability of deaerator pegging / heating with auxiliary steam sources and from turbine extraction.
s) Feed water treatment with AVT(O) or AVT(R) is to be suitably deployed.

5.3 Procedure for low load tests

For a 500 MW unit, the test procedure for ramp down from full load **(500 MW)** to 40% load **(200 MW)** and vice versa is tabulated below: -

5.3.1 Test procedure for load ramp down tests from full load (500 MW) to 60% load (300 MW) at 1% (5 MW) per minute (Target Time: 70 minutes) and 3% (15 MW) per minute (Target Time: 13 minutes):

a) Stabilize the unit load at full load with 6 mills with CMC in service & APC ON.
b) Give the load set point of 450 MW.
c) Start reducing the mill loading of bottom most Mill gradually after putting in manual mode to meet firing demand.
d) Stabilize the unit around 450 MW for 10 mins.
e) Give the load set point of 400 MW.
f) Start reducing the mill loading of bottom most mill gradually till the mill is completely unloaded. Trip the bottom most mill.
g) Stabilize the unit around 400 MW for 10 mins.
h) Give the load set point of 350 MW.

i) Start reducing the mill loading of bottom most mill gradually to meet firing demand.
j) Stabilize the unit around 350 MW for 10 mins.
k) Give the load set point of 300 MW.
l) Start reducing the mill loading of bottom most mill gradually till the mill is completely unloaded. Trip the bottom most mill.
m) Stabilize the unit around 300 MW.

5.3.2 Test procedure for load ramp down tests from 60% load (300 MW) to 40% load (200 MW) at 1 % (5 MW) per minute (Target Time: 30 minute) and 15 MW per minute (Target Time: 37 minutes):

a) Stabilize the unit load at 60% load with 4 mills and CMC in service (APC On)
b) Give the load set point of 250 MW.
c) Start reducing the mill loading of all mills gradually with higher unloading of bottom most mill to meet firing demand.
d) Maintain both PA Fans in service if 3 or more mills are in service, if further load ramp down is taken up and fans are operating near to their stall zone then manually switchover to single PA Fan operation. Switchover to Single FD and ID fans can be done to optimize Aux power consumption.
e) Stabilize the unit around 250 MW. (for 10 mins)
f) Give the load set point of 200 MW.
g) Start reducing the mill loading of all mills gradually with higher unloading of bottom most mill to meet firing demand.
h) Stabilize the unit around 200 MW. 60%-40% load ramp rate of 3% will cause wide temperature fluctuations. It requires multiple iterations with different combination of mills.

5.3.3 Test procedure for load ramp up tests from 40% load (200 MW) to 60% load (300 MW) at 1% (5 MW) per minute (Target Time: 10 minutes) and 3% (15 MW) per minute (Target Time: 7 minutes):

a) Stabilize the unit load at 40% load with 3 mills and lesser loading in bottom most mill.
b) Give the load set point of 250 MW.
c) Start increasing the mill loading of all mills gradually with higher loading of bottom most mill to meet firing demand.
d) Stabilize the unit around 250 MW for 10 mins.
e) Give the load set point of 300 MW.
f) Start increasing the mill loading of all mills gradually with higher loading of bottom most mill to meet firing demand.
g) Manually take second BFP also in service, if not taken earlier, and balance both BFP.
h) Manually take second PA Fan in service, if not taken earlier, and balance both fans.
i) Equalize loading of all mills. FD & ID Fans as well
j) Stabilize the unit around 300 MW for 10 mins.

5.3.4 Test procedure for load ramp up tests from 60% load (300 MW) to full load (500 MW) at 1% (5 MW) per minute (Target Time: 40 minutes) and 3% (15 MW) per minute (Target Time: 13 minutes):

a) Stabilize the unit load at 60% load with 4 mills with CMC in service.
b) Take the fifth mill in service (preferably adjacent to mills already in service and topmost amongst the standby mills) with minimum loading and allow the mill to stabilize.
c) Give the load set point of 350 MW.
d) Increase the mill loading of fifth mill gradually to meet firing demand. Simultaneously adjust the mill loading of other four mills to meet firing demand and till the time fifth mill is sufficiently loaded and stabilized.
e) Stabilize the unit around 350 MW for 10 mins
f) Give the load set point of 400 MW.
g) Increase the mill loading of fifth mill gradually to meet firing demand. Simultaneously adjust the mill loading of other four mills to meet firing demand and till the time fifth mill is sufficiently loaded and stabilized.
h) Stabilize the unit around 400 MW and equalize the mill loading.
i) Take the sixth mill in service (preferably adjacent to mills already in service and topmost amongst the standby mills) with minimum loading and allow the mill to stabilize.
j) Give the load set point of 450 MW.
k) Increase the mill loading of sixth mill gradually to meet firing demand. Simultaneously adjust the mill loading of other five mills to meet firing demand and till the time sixth mill is sufficiently loaded and stabilized.
l) Stabilize the unit around 450 MW for 10 mins.
m) Give the load set point of 500 MW.
n) Increase the mill load of sixth mill gradually to meet firing demand. Simultaneously adjust the mill loading of other five mills to meet firing demand and till the time sixth mill is sufficiently loaded and stabilized
o) Stabilize the unit at full load and equalize the mill loading.

5.4 Critical Operating Parameters

- Generator Load
- Main Steam Pressure, Temperature, Flow
- Reheat Steam Pressure, Temperature
- Drum Level, Deaerator Level and Hotwell Level
- Oxygen % in FG at Economiser outlet
- Windbox pressure, SA flow, PA Flow, PA Header pressure, Furnace pressure
- SADC & Burner tilt positionFlame intensity
- Air Heater outlet temp – Flue gas
- Metal temperatures – SH, RH, Drum / Separator
- Condensate flow / FW Flow
- Condenser Vacuum

- Extraction Steam Pressure, Temperature
- Casing Metal temperatures of HP /IP Turbines
- Vibrations of HPT, IPT, LPT, Generator bearings and shafts.
- Chemical Parameters for Main Steam, Feed water, Condensate system, etc.

5.5 Data Logging

Following time stamp data from DCS should be recorded for further analysis and study.

a. Boiler load vs

- Feed water Temp at Economiser Inlet/Outlet
- Platen SH I/L Header Temp
- Final SH O/L Header Temp
- Separator Level
- Excess Oxygen
- Separator Metal Temperature

b. Turbine

- Turbine First Stage Pressure
- First Stage Temperature
- HP Control Valve Body Temperature
- IP Control Valve Body Temperature
- Turbine Inner Casing Temperature
- Turbine Outer Casing Temperature

The template for observing some of the important parameters are as indicated in the Table 5.1 on the following page.

Table 5.1 Template for Study of Minimum Load Operation

Load (MW) :
Coal Flow (TPH) :
Air flow (TPH) : **Date :**
O2 (%) : **Time :**

S.No.	System	Parameter Description	Unit	Value	Observation
1	Boiler	Main Steam Pressure Left	Kg/cm2		
		Main Steam Pressure Right	Kg/cm2		
		Main Steam Temp Left	°C		
		Main Steam Temp Right	°C		
		HRH Pressure Left	Kg/cm2		
		HRH Pressure Right	Kg/cm2		
		HRH Temp Left	°C		
		HRH Temp Right	°C		
		SH DSH SPRY WTR FLOW	TPH		
		RH DSH SPRY WTR FLOW	TPH		
		Seperator Level	M		
		BRP Status			
		Burner Tilt Position	%		
		Steam Flow	TPH		
		Secondary AiR Flow	TPH		
		DP across Windbox to Furnace	MMWC		
		RAPH outlet FG Temp	°C		
		RAPH Flue Gas Inlet Temp	°C		
		PRS Pressure & PRDS Pressure	Kg/cm2		
2	Flame Intensity	Eleveation wise Intensity	%		
		Furnace Draft	MMWC		
		Flue Gas Furnace Exit Temp	°C		
		Flame Position			
3	Boiler Tube Metal Temp	HRH Max Temp	°C		
		SH PLATEN Max Temp	°C		
		Right Spiral Temp	°C		
		Front Spiral Temp	°C		
		Left Spiral Max Temp	°C		
		Rear Spiral Max Temp	°C		
		Final SH Max Temp	°C		
4	Boiler Header Temp	SH Left OL Hdr Temp	°C		
		SH Right OL Hdr Temp	°C		
		RH Left OL Hdr Temp	°C		
		RH Right OL Hdr Temp	°C		
		RH Left IL Hdr Temp	°C		
		RH Right IL Hdr Temp	°C		
		Sep OL Metal Temp Left	°C		
		Sep OL Metal Temp Right	°C		
		Eco Link Header Temp 1	°C		
		Eco Link Header Temp 2	°C		

5	**Fans (PA/ID/FD)**	Pitch (Fan-A/ Fan-B)	%		
		Head (PA Fan)	**MMWC**		
		Current	**AMP**		
		Flow (Primary)	**TPH**		
6	**Milling System**	No of mills in Service	**NOS**		
		Mill loading (TPH)	**TPH**		
		Mill current	**AMP**		
		Mill vib	**MM/SEC**		
		Mill Inlet temp	**°C**		
		Mill Outlet Temp.	**°C**		
		Mill Bowl DP	**MMWC**		
		Air Fuel Ratio	**TPH**		
		PA Flow through Standby Mill			
7	**TDBFP parameters**	Recirculation valve position			
		Speed (A/B)	**RPM**		
		Flow (A/B)	**TPH**		
		Live Steam pressure (A/B)	**Kg/cm2**		
		No of BFP in service	**NOS**		
		Aux. Control Valve Position	**%**		
		Scoop position	**RPM**		
		TPBFP Exhaust Hood Temp (A/B)	**°C**		
8	**Turbine Parameter**	4th Stage Pressure	**Kg/cm2**		
		HP Exhaust Temp L-1	**°C**		
		Turbine HP Exh Ur/Lr casing inner meta	**°C**		
		Turbine HP Lower Casing Inner metal tem	**°C**		
		Turbine HP Upper casing Inner metal tem	**°C**		
		Turbine IP Exhaust Pressure	**°C**		
		Turbine IP Exhaust Temp	**°C**		
		Turbine LP Exhaust temp	**°C**		
		Turbine Gland Steam Seal Header Temp	**°C**		
		Gland steam temp	**°C**		
		Gland steam supply CV position	**%**		
		Gland steam leak off CV position	**%**		
		Turbine IP Exh Ur/Lr casing inner metal	**°C**		
		Turbine IP Lower Casing Inner metal tem	**°C**		
		Turbine LP Upper casing Inner metal tem	**°C**		
		Condenser Vaccum	**°C**		
		Heater Drain Pump Status	**bar(abs)**		
		Heater Drain Pump Status	**°C**		
		CEP Pump & Motor Vibration			
9	**Turbovisory System**	TG Shaft & Pedestal Readings			
10	**Turbine Bearing Metal Temp**	TG Bearing Temp Readings			
Note	**Based on initial discussion with Technical Teams,indicative problem areas are provided in Observation Cum Remarks cell. However actual issues/deviations faced during the trial shall be**				

Source: PPGCL

6. MODIFICATIONS REQUIRED

The previous chapters have analyzed and emphasized the need for thermal power plants to be flexible, to explore the capability to flex and limitations thereof. This chapter focuses on modifications needed and retrofit options for increasing operational flexibilityof coal fired units. For getting more flexibility, it does not require to retrofit the entire plant but retrofit only certain subsystem of power plant that are most effective in tackling plant flexibility. The technical measures shall depend on the levels of minimum load operation to be adopted (50%, 40% or below). The operation at 55-50% load may onlyneed reassessment of O&M practices, maintenance of critical components, automation/optimization of controls. However, lower load operation shall require additional measures like proper flame detection systems, efficient measures to optimize combustion process (A/F ratio), stable minimum mill operation, use of steam coil air preheater. Temperature measurements are crucial to optimize the startup and shutdown procedure. The technical solutions are primarily aimed at

- Ensuring safety & reducing the detrimental impact of the flexible operation on the life of the unit.
- Achieving flexibility with lowest cost.

Once there is a certainty that the unit can support flexible operation, then options of optimizing the costs and reducing lifetime impacts/improving reliable operation need to be exercised. Decreasing the technical minimum load (w/o oil support) is beneficial, because it provides a larger range of generation capacity. This helps plant operators maintain operation when power demand is low and avoid expensive start-up and shutdown procedures. Reducing the minimum load in hard coal-fired power plants is subject to certain technical limitations. These limitations are fire stability, flame control, ignition, unburned coal and CO emissions. In low load operations, the fire can become unstable when the hot flue gases do not completely ignite the inflowing pulverized coal and hence additional support from oil firing is needed to maintain flame stability and achieve complete combustion of the coal. There are several retrofit options that can be deployed for achieving stable technical minimum load operation of 40% and below (w/o oil support) and increasing ramps to 3%, while using Indian coal.

6.1 Measures for Minimum Load Operation

The operating data recorded during the minimum load test conducted at various plants indicated that several process limits were reached. The APH flue gas outlet temperature dropped below the dew point and the flame stability could not be assured. As these limits cannot be pushed further by means of controls, several technological changes would be required to achieve a stable minimum load operation. Using the test data, a thermal study of the boiler can be carried out in order to find and avoid damages to the boiler systems. Evaluation of the process limitations also need to be carried out. The most commonly used coal, as well as the potential range of coal, including coal with maximum problematic contents (ash, moisture, etc.) should be analyzed. Based on the thermal study findings, relevant remedial measures can be identified.

6.1.1 Control Optimization

Controls play a pivotal role in the operation of coal-fired power plants. It allows smooth transition between different operating loads and ensures stable operation by adjusting all relevant process variables. The control system monitors and controls the critical parameters viz. - temperature, pressure inside the boiler, the feed-water mass flow in the water-steam circuit, the loading of the coal mills and the turbine valve positions. Basedon the plant specific needs control modifications can be adopted for improving the flexibility. Based on assessment of individual units following improvements may be explored, some of which may require improvement by implementing modified controlsolutions and hardware (valves, etc.) as follows:

6.1.1.1 Drum Level Control

The pilot tests conducted showed that drum level controls were not tuned for the wide operating ranges (100%-40%). In this context the replacement of the feed water recirculation valves with modulating type valves will improve the drum level control. Currently, the opening of the valves causes large disturbances. Furthermore, an upgrade or implementation of new controls is necessary for the turbine-driven boiler feed water pumps when fed by auxiliary steam from another unit's. These controls are not generally working satisfactorily, thereby increasing the risk of a trip and demanding maximum operator attention– The BFPs would be run through a sequence control in auto mode.

6.1.1.2 Flue Gas Temperature Control

At 30% load APH outlet temperature is expected to be around 90 deg C, which is below the acid dew point temperature. On account of low APH cold end temperatures, corrosion on the APHs may occur. SCAPH should be deployed, which would enable the flue gas temperature to be controlled through the use of the steam APH. The SCAPH should be taken into operation automatically, whenever needed. This control combined with the upgraded temperature control would prevent corrosion in the APH. Economizer bypass system will also maintain the flue gas temperature above acid dew point to avoid corrosion. At low load, to meet required mill inlet temperature, economizer bypass system can improve flue gas temperature entering RAPH.

6.1.1.3 Automated Start/Stop of Mills

Automated start-up and shut-down sequences for the mills are necessary to enhance the flexible operation.

6.1.1.4 RH Steam Temperature Control

The RH steam temperature should be sufficiently high for the turbine for improving heat rate at part load operation. The RH steam temperature should be controlled using burner tilts as part of the automated control. Currently, burner tilts are operated manually and consequently RH steam temperatures are dropping during low load operation. This causes an avoidable loss of efficiency. The influence of the burner tilts needs to be further tested as well as the design and integration of the logics for the automated RH steam temperature control.

6.1.1.5 Measures for Ramp Rate Improvement

The thermal feasibility study of the boiler will also be useful for enhancing the ramp rates of the plant. With the help of the model study, it will be possible to explore measures to decrease SH and RH MTMs in cycling operation regimes, e.g. by effectively applying the burner tilts. The findings of the thermal study will also provide the basis for the optimization of various controls. The ramp rate improvements, as well as stable minimum load operation, strongly depend on a stable and optimized combustion. In addition to the control modification mentioned in 6.1.1 following may be required:

6.2.1 Control Optimization

6.2.1.1 Burner Tilt Controls

Burner tilts should be used to control RH MTMs in addition to RH steam temperatures. A feed forward from the load to burner tilts should be added, which needs to be validated through physical tests. Furthermore, an observer to both RH steam and RH MTM should be added, to predict where the temperature will be in few minutes based on actual temperature developments. This would make it easier to anticipate changes and enhance the control.

6.2.1.2 Furnace/Differential Pressure (Δp) Control

The set point should be given automatically depending on load. SADC passing should be minimized to make this control effective.

6.2.1.3 Furnace Pressure Control Upgrade

The secondary air is controlled is based on FD fan operation (blade pitch /VFD). Usually at part load since the air requirement reduces and because of passing of SADC windbox Δp is difficult to maintain, therefore SADC passing should be reduced by proper maintenance.

6.2.1.4 Unit CMC

These changes should enable the load to change sooner in the upward direction, and the pressure later. This would have two effects:

› Better cooling of RH tubes when steam flow increases, less MTM increase
› Better drum level stability

6.2.1.5 SADC Damper Control

Schedule check to be made for checking the DCS value and actual value at local for all the SADC dampers. Digitalization initiatives shall be taken for fine control of SADC dampers. Modifications in O_2 vs Load curve to be reviewed in consultation with OEM.

6.3 Measures for Startup Time Improvement

Decreasing start-up time enables a more rapid response to power demand. Start-up procedures are complex and expensive since they usually require auxiliary fuel, such asoil, during the ignition & stabilization period. There are various technical factors that limit the reduction of start-up time. Thick-walled components allow higher operating parameters (steam temperature and pressure, say) which increase efficiency. But quick temperature changes in thick-walled components induce thermal stress, which acts as a limiting factor for the start-up time. With "thinner" component designs, flexibility can be higher but efficiency is compromised. Since temperature changes induce thermal stress, each material is assigned a maximum allowable value. Exceeding this value reduces the materials lifespan. In general, reducing wall thickness increases the allowable temperature change rate. This translates into a faster start-up by boosting the ramp rate. Wall thickness can be reduced by using superior materials

6.3.1 Optimized Startup Control

An upgrade of control system with modified logics can improves precision, reliability and speed. For instance, it allows operation closer to the material limitations of important components, such as the boiler. This can mean operation at higher temperatures without significantly reducing the material lifespan, unlocking the available margins within the design limits of the system. Predictive digital solutions can be used to optimize several parameters to shorten boiler/turbine start-up time. Start up control system with modified logics can not only shorten the startup time but also improve repeatability & reliability of the startups.

6.3.2 Startup Curve

Design vs actual trending can be checked by using real time data source dashboard during start up for easy monitoring. With this immediate deviation of different start up parameter against corresponding design start up parameter can be corrected.

6.4 Other Measures

There are various other options available for increasing the flexibility aspects, some of the solutions are summarized below.

6.4.1 Boiler Combustion System

6.4.1.1 Minimum Mill Operation

In the direct firing configuration, reducing the net power of a power plant requires burners and coal mills to both run at part load. At a certain firing rate, the fire becomes unstable, requiring the power plant controller to limit the low load operation to avoid damaging pressure pulses that can occur inside the boiler. The fire stability typically represents the lowest threshold for the low load operation. At a certain lower net power output, it is feasible to shut down some of the mills and have the remaining mills operate closer to their design point. Since coal mills typically supply a single burner level, turning off a mill leads to a boiler operation with a reduced number of firing levels.

In the Indian context, with typical use of high ash content coal, one must take care of the minimum flue gas velocity in the system to avoid accumulation of ash within boiler/ducts and a 2-mill operation philosophy with related control system/logics modification is suggested. Further following are recommended for the mill operations

- Adjacent mill operation is recommended to achieve the stable flames and fire ball.

- With bottom mills steam temperatures cannot be achieved and hence bottom mill operation is not recommended.
- Mills shall not be operated below 60% of mill rated capacity or 50% of feeder speed to maintain uniform air & fuel mixture.
- Modification of the control philosophy to control primary & secondary air flow.
- Modification/ change in Mill outlet temperature control set point.

6.4.1.2 Firing System

The aspect of flame stability is particularly important at lower loads for safe operation of the boiler. It's important to have physically healthy flame. It is evident that burner redesign modification is an important for achieving lower technical minimum load without oil firing support. The re-design focuses on stabilizing the near field conditionsof the burner by manipulating the entry velocity, turbulence and therefore flame stability at low load, while minimizing changes to the balance of the burner system and maintaining the full load capability. The major issue with firing system is to stabilize coalflame and detection of low intensity flames inside furnace.

6.4.1.3 Combustion/Flame monitoring

In low load operation, complete combustion of fuel/fireball condition & stability is of utmost importance from safety point of view. Improved control over fireball stability is required. Due to lean air/fuel mixtures and less number of mills/firing levels in operation, flame stability may be an issue. At lower loads, the pressure drop in the coal piping can negatively affect fuel-air distribution between burners and thereby reduce flame stability. With only two to three mills in service it is more important that stable combustion be maintained locally as well as in the fireball and that the flame scanners detect properly when a stable flame is established. At full load operation, flame scanners see a bright flame; whereas at low load operation the devices see a dim flame. The combustion monitoring flame scanners sensors should have a wide dynamic range that can prove flame at full load as well as at the lowest loads without recalibration. These features help avoid "nuisance" trips where a scanner may not "see" a still stable flame.

6.4.2 Condensate Throttling

Condensate throttling is a proven measure for primary control to enable fast increase of turbine power in case of grid frequency deviations. In this case the main condensate control valve is throttled to a calculated position allowing a reduced condensate mass flow flowing through the LP feed water heaters. Considering a certain response time, the extraction steam mass flows of the LP feed water heaters and the deaerator/feed water tank are reduced. The surplus steam remains in the turbine and generates additional power. A sketch of the system is shown in Figure 6.1. This condensate throttling compensates the transient time behavior of the boiler. The accumulated condensate is stored in the condenser hotwell or a separate condensate collecting tank. Parallel to the above mentioned measures the firing rate of the boiler has to be increased to meet the load requirements.

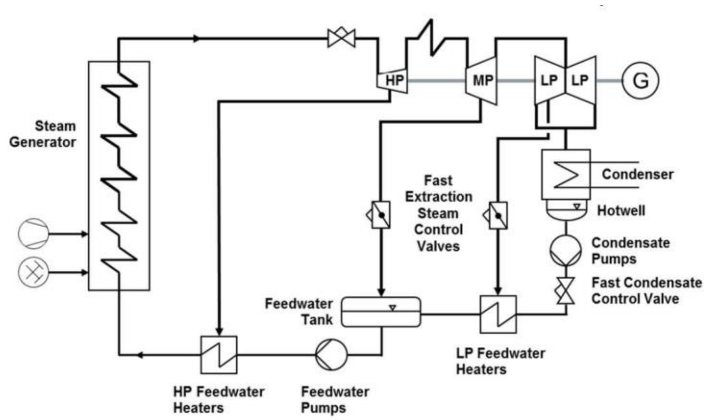


Figure 6.1 Condensate Throttling

6.4.2.1 Response time

The response time of condensate throttling depends on the time required for reduction of condensate mass flow. Therefore, normally a fast acting main condensate control valve is used. By means of additional fast acting valves in the extraction steam lines the response time behavior can be optimized. The response time of 20s for 7% power at 100% load has been achieved through condensate throttling and main steam valve throttling at NTPC Dadri. Standalone, condensate throttling is able to provide 3-4% power at 100% load. The results of tests conducted by BHEL at Unit-1 of 2x600 MW SCCL plant with valve wide open condition are 2.9% at 30secs to 4.0% of running load in 120 secs.

6.4.2.2. Capacity

The resulting turbine power increase depends on the amount of throttling of the main condensate control valve and the actual unit load. The higher the unit load, the higher is the amount of additional turbine power which can be generated by condensate throttling.

6.4.2.3 Duration

Duration of condensate throttling operation depends on the amount of buffer volumes provided for condensate and feed water. The slower the boiler, the larger the buffer volumes have to be.

6.4.3 Heat Conservation System

Steam turbine heat conservation systems can support in reducing the startup time by eliminating cold startups by keeping the unit in warm condition.

6.4.4 HP Turbine Deactivation

Few advanced supercritical turbines have feature of HP deactivation. At very low load there are chances of HP turbine exhaust temperature reaching material limits and causing windage. To prevent this usually turbine trip is initiated if the temperature reaches to 510^{0}C. With HP deactivation, instead of tripping the entire turbine, only HP turbine is tripped and protecting the unit to operate at lower load to bring back to grid again quickly. Advanced supercritical turbines are benefitting from this feature and the same could also be implemented in existing 210MW and 500MW units with suitable in measurement.

6.4.5 Co-Start

To enable faster hot startup time, turbines can be rolled via IP turbines. In the Co-Start sequence the steam turbine already starts to accelerate from turning gear speed when the reheat steam temperature exceeds the IP component temperature. In the standard start- up sequence the steam turbine starts to accelerate from turning gear speed when both,the main and reheat steam temperature exceed the HP and IP component temperature. With the Co-Start feature the steam turbine start-up under hot conditions is up to 90 minutes earlier compared to a standard hot start. The exact time saving depends on several boundary conditions e.g. boiler temperature gradients, initial component and steam temperatures.

6.5 Measures for Efficiency Improvement (Heat rate)

6.5.1 Sliding Pressure Control (Modified)

- Achieving lower minimum load with relatively higher efficiency levels.
- For a cycle operating with constant boiler pressure, the efficiency of the unit at part load will be better by adopting sliding pressure control than it is by throttling to control the power on machine.
- For a cycle operating with sliding boiler pressure, it may be very useful to have an overload arc available to respond to fast changes in power demand. This would support better frequency response and short peak needs.
- Turbines that feature partial arc can be readily adapted to the specific requirements of a utility by careful selection of appropriate admission arc areas.

6.5.2 Top Heater

Usual steam turbine power plants have regenerative feed water heating cycles to increase the feed water temperature and thereby improving the cycle efficiency. This optimization is carried out in consideration that units are running in base load operation. In part load scenario, the final feed water temperature starts dropping and leading to more thermal stress on boiler and many a times limiting the NOx devices to operate. Therefore, an innovative method of keeping the final feed water temperature constant irrespective of load can be achieved by having the additional feed water heater with controlled extraction. The top heater gets only activated in part load and could increase the heat rate upto 0.6% at corresponding 50% part load efficiency*. This additionally benefits the Boiler as then economizer temperature is not changing with load change thus saving the life consumption in Boiler components with less fatigue. A typical configuration of Top Heater arrangement is shown in Figure 6.2.

6.5.3 Optimization of Auxiliaries

The thermal power units are designed for high efficiency performance at rated load. Operating at lower loads deteriorates the efficiency of the unit. The efficiency of the unit can be improved by many means including reducing the auxiliary power consumption.

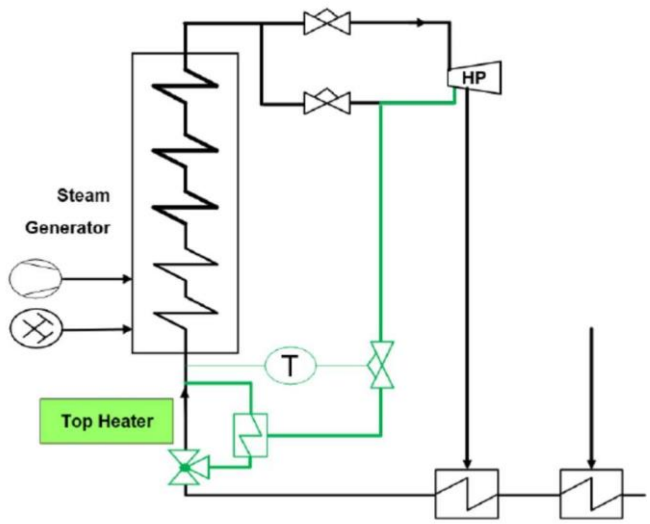


Figure 6.2: Typical arrangement of Top Heater

The plants have most of the auxiliaries rated for 2x50% which are both operated at any operating point. Hence to reduce the auxiliary power consumption at loads less than 50% the auxiliaries should be operated as 1x50% mode without affecting the safety and security of the plant. This will reduce the auxiliary power consumption at low loads.

Further, at variable load operation of the unit from 100% to 40% MCR, optimization of the auxiliary load for lower power consumption can be achieved by utilizing variable frequency drives.

6.6. Measures for Condition Monitoring

Part load operation leads to changes in main and reheat steam temperature. Usually conventional operating hours' calculations are based on normal operating hours and sometimes accounting for startup. With frequent load changes resulting in temperature changes which leads to changes in thermal stresses of high temperature rotors and casings, thick-walled components like Boiler drum & headers. Therefore, conventional maintenance intervals may not be sufficient. Now with possibility of real time monitoring, it is possible to account for both load changes and equivalent operating hours (EOH) based on actual thermal stresses. This helps utilities for better maintenance planning by clearly identifying the need of inspections based on the actual operation. Also this helps utilities identifying which operating modes are causing higher damages to component life therefore mitigating/avoiding such operations. The primary requirement for long term reliable operation is to adapt operation and maintenance for the new operation regime. Few of the solutions presented in this chapter are to enhance monitoring health of the plant.

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*The solution is implemented in Wai Gao Qiao, 1040 MW unit, China). (https://www.energyforum.in/fileadmin/user_upload/india/media_elements/misc/20200000_Misc/20200515_lr_Fast_Ramping_VGB_Webinar/3_Improved_Ramp_rates_Chittora_Rev1_komp.pdf).

Condition monitoring systems monitor components like boiler and piping for creep and fatigue. It monitors the temperature differences, pressure, and sends alarms when the allowable limits during load changes have been exceeded. It is integrated into the existing C&I system. Condition monitoring leads to effective life cycle asset management. Condition Monitoring for flexibilisation should include the following modules.

- Fatigue Monitoring System
- Vibration Monitoring System including Blade Vibration
- Generator Monitoring System

6.6.1 Fatigue Monitoring System

In today's environment only very few power plants can operate in the pure base load mode. Continual output/ load changes shall be common, this means stressing the boiler and turbine components far beyond the traditional operational levels. The boiler and turbine maintenance has to meet these new requirements. The fatigue monitoring provides the power plant maintenance and the operating personnel with a tool that contributes to better scheduling of maintenance. Further the operational conditions and procedures (e.g. start up, load changes) can be optimized based on the results of the monitoring system.

By computing the creep and low-cycle fatigue the residual life of the boiler and turbine, which is dependent on the operating mode of the power plant, can be recalculated time and again. For the power plant operator, the implementation of FMS provides a continuous overview of the service life utilization of the major equipment's, so that

- The time for a necessary inspection can be selected optimally and thus the operating time between two inspections maximized,
- Power plant safety can be increased,
- Operating modes causing heavy wear can be detected and if possible prevented,
- Components can be operated close to the material limits, so that the operating time of the plant can be maximized and operating costs minimized.

6.6.2 Vibration Monitoring System

Availability of steam turbine in a power plant depends on its performance in all operating conditions. In recent past, there has been couple of Low Pressure Turbine free standing stage blades failure experienced. LP turbine blades due to highest centrifugal forces and operation in wet region are susceptible for failures. Operational risks for blade failure could be monitored through non-contact type blade vibration monitoring system. While the system can provide the useful insight on vibration behavior, it is even more important to get it monitored by experts.

Apart from all the above solutions, some digital solutions can be leveraged to monitor health of key components of the turbine and help reduce the negative impact on flexible operation & avoid unforeseen forced outages. Simple solutions like the following can provide advance notice to take corrective actions. Valve monitoring can avoid unplanned outage due to valve failures. Torsional vibration monitoring system can avoid rotor cracking due to Grid excitations. Turbine monitoring can alert about the excessive lifetime consumption of the critical ST parts and helps avoid unplanned outage.

6.6.3 Generator Monitoring

Although from capability point of view, generator may not pose serious constraints for flexible operation, it is important to monitor its health and take utmost preparatory care of generator going to be subjected to cyclic operation. Real time monitoring of certain generator key parameters goes long way in identifying impending problems and helps users to prepare and take corrective actions much in advance. Moving to condition-based maintenance (instead of regular preventive maintenance) by monitoring key parameters like partial discharge (PD), rotor flux, rotor shaft voltage, end winding vibrations, stator temperature etc. are important.

Following impacts of flex operation need to be observed/anticipated for and suitable timely corrections need to be done to avoid unplanned generator failures.

- i. Possible relative movements between bars and core.
- ii. De-cohesion between bars and between bars and supporting rings.
- iii. Deformation and crack of pole to pole connection.

6.7 Recommendation

The utilities shall conduct detailed study/tests and cost benefit analysis for finding the most optimal solutions to improve the flexibility of plants as the measures required are plant specific and shall depend on the level of flexibilisation. This may be done in consultation with OEM/main plant (BTG) manufacturer /BTG designer.

7. COST OF FLEXIBLE POWER

As discussed in earlier chapters, the flexible operations for coal power plants are technically feasible by upgradation of controls, etc. The pilot tests conducted at various plants is the proof that Indian plants are capable to flex. Converting the baseload coal fired power plants into flexible plants would most likely incur costs, which would require compensation. To improve the availability of flexible power in the grid by conversion of baseload coal fired power plant into flexible power plants, it should be economically feasible for the generating companies. In this chapter, we shall discuss some indicative costs involved for converting a baseload coal plant into a flexible plant. Since majority of the energy transacted is through the long-term power purchase agreements, the discussion shall be centered on the cost based approach.

7.1 Factors Influencing Cost

a) The cost of undertaking flexibilisation in the plant is dependent on the following factors:
b) Automation levels in the plant.
c) Coal quality.
d) Age & size of units.
e) Type of machine, component material composition and design philosophy.
f) Maintenance philosophy, lay-up practises and water chemistry controls.
g) Operational expertise and practises adopted.
h) Extent of cyclic operation - depth, breadth and frequency.

7.2 Cost Components

The impact of thermal power plant flexibility on the costs are mainly exhibited through *Capital Expenditure (CAPEX)* - one-time expenditure incurred in the installation /retrofitting of various equipment required to make the plant capable of low load operation, and *Operational Expenditure (OPEX)* - the recurring cost of flexible operation due to decreased efficiency, loss due to the reduced life of the plant, increased O&M cost, increased forced outages, increased oil consumption. Increased spends on water, chemicals, manpower and other miscellaneous activities. Increased chances of non-conformance to grid regulations leading to financial losses.

7.3 Studies with International Partners

Cost related studies have been conducted with international agencies having vast experience in the field of flexibilisation. The studies were conducted from year 2016 to 2018. The details of the scope are summarized in Table 7.1. The cost implication has been brought out by the various studies under the heading of capital and operational expenditure.

Table 7.1 Studies conducted by International partners

Associates	Owner/ Plant	Study	Scope
IGEF/VGB	NTPC: Dadri Unit 2 (200MW) Simhadri Unit 1 (500MW)	Dec 2016- June 2017	Special Task Force on Flexibilisation. Flexibility assessment
USAID/Intertek	NTPC: Ramagundam Unit 2 (200MW), Jhajjar Unit 1 (500MW)	Jan-July 2018	Cost of flexing due to start up and load following
USAID/Intertek	GSECL: Ukai Unit 4 (200MW), Ukai Unit 6 (500MW)	Aug- Nov 2018	Cost of flexing due to start up and load following
Engie Lab	Dadri Unit 4 (200MW) Farakka Unit 6 (500MW)	Nov 2018- Sept 2019	Capital Cost estimation to enable flexibility & increase in running cost due to load ramping and start up.
Siemens	NTPC Simhadri (500MW) Dadri (490MW)	Feb-Aug 2018	Technical and Commercial Proposal for interventions after study
GE	NTPC Talcher Kaniha (500MW)	Feb-Aug 2018	Technical and Commercial Proposal for interventions after study

7.3.1 Capital Expenditure (Capex)

Capital expenditure is required at plant level for the various interventions to meet the demands of flexible operation. The type of interventions required would vary from plant to plant depending on the unit age, etc. as detailed in item 7.1 and accordingly scope of work shall vary. The outcome of various studies conducted are detailed as below:

7.3.1.1 IGEF Study. The special Task Force on flexibilization with the support of IGEF provided an estimate of the Capex. The VGB studies at NTPC Dadri (210MW) and Simhadri (500MW) provided one-time cost required for preparing units for low minimum load operation and indicated the cost of interventions below 40% load will be significantly higher. The estimates are summarized in the following table:

Table 7.2 Capital Expenditure

S.no.	Intervention	Rs. Crore / Unit
1	For 40% Technical Minimum Load	3.9 to 7.8
2	Start-up Optimization	2.25 to 7.8
3	To manage the consequences of cycling	0.65 to 1.95

(Source: IGEF Task Force Sub-Group1 Committee Report on Flexibilisation of Thermal Plants Oct, 2017)

(Source: NTPC)

It is important to understand the cost difference between the actual costs required to guarantee flexible operation (one-time Capex) and the provision of Capex to be able to repair the damages that occur due to flexible operation and reclaim back the machine to normal. The damages get accumulated till the breakdown of components, which may need replacement to be able to run again.

7.3.1.2 Siemens Study Based on Siemens proposal for the implementation of flexibilization measures at Dadri and Simhadri NTPC stations, approximately Rs.20 to Rs.50 crores is estimated considering the measures required in the units. The proposal consisted of implementations of the following:

- Temperature Optimizer
- Fatigue Monitoring System
- EOH Counter
- Optimization of Control Loops
- BFP Recirculation Valve
- Auto ON/OFF of Fans and Pumps
- Mill Scheduler

7.3.1.3 GE Study. Based on the proposal for the implementation of flexibilization measures at Talcher NTPC station, approximately Rs.20 to Rs.50 crores is estimated based on the measures required in the units.

7.3.1.4 Engie Study. As per the study done for Dadri and Farakka NTPC stations the cost of capital expenditure is estimated:

- Between Rs.3.2 crore and 5.6 crore for extended load following with P_{min} 40%.
- Between Rs.4.1 crore and 8.0 crore for frequent warm starts.

7.3.1.5 Capex at Dadri

The order for retrofit work for flexible measures at Dadri 500MW unit to reduce the minimum load operation to 40% was placed by NTPC in 2019. The retrofit work included the implementation of following measures-

a) Predictive MS Temperature Control
b) RH Temperature control
c) Installation of Modulating Recirculation Valves in BFPs
d) Automation in Milling System
e) Flue Gas Temperature Control
f) Single Drive Operation- Automated Start/Stop of ID/FD/PA Fans.
g) Condition Monitoring System- Boiler Fatigue Monitoring System and Equivalent Operating Hours.

Total capex implication of the above retrofits for Dadri unit is around rupees five and half crore. The results of the retrofit works undertaken are awaited.

7.3.2 Operational Expenditure (OPEX)

The increase in OPEX is clubbed in the following three broad categories:

a) Cost due to increase in Net Heat Rate.
b) Cost due to increase in O&M due to reduction in life of components.
c) Cost due to increase oil consumption for EFOR

Generally, units are designed to be operated on a base load condition and all the components are accordingly designed for operation for certain creep life hours and certain fatigue life in terms of no. of starts. As the operation regime changes and moves away from base load operation to cycling operation, the component life gets consumed at a faster rate. Life consumption, Increase in Equivalent Forced Outage (expressed in terms of increased O&M costs have been derived based on the costs on assessment studies at Ramagundam, Jhajjar and Ukai plants conducted by USAID GTG-RISE with technical support from Intertek AIM, US.

7.3.2.1 Cost due to increase in Net Heat Rate

It has been observed that the extent of deterioration in Net Heat Rate depends on the percentage unit loading. The estimates are based on combustion engineering boiler design and GE make turbines. For a typical 200/210/500/660 MW unit the increase in tariff due to increase in Net Heat Rate at different loading factors is as given in table below. The base Energy Charge Rate (ECR) has been assumed to be 200 paisa/kWh based on the average ECR of NTPC stations from April 2018 to October 2018.

Table 7.3 Increase in Variable Costs due to HR deviation

S.no.	Unit loading %	200/210 MW		500 MW		660 MW	
		Increase in NHR (%)	Addl. Paisa/ Kwh	Increase in NHR (%)	Addl. Paisa/ Kwh	Increase in NHR (%)	Addl. Paisa/ Kwh
1	90%	NIL	0	1.0%	1.1	1.0%	1.6
2	80%	0%	0	1.7%	3.4	1.7%	3.5
3	70%	1.1%	2.1	3.3%	6.7	3.3%	6.6
4	60%	3.8%	7.5	6.3%	12.6	5.7%	11.5
5	50%	7.5%	15.0	10.0%	20.0	9.2%	18.4
6	40%	11.6%	23.2	13.8%	27.6	14.4%	28.7
7	30%	17.3%	34.6	19.0%	38.0	20.4%	40.8

(**S**ource: *NTPC)*

7.3.2.2 Cost due to Increased Life Consumption (Damage costs)

Flexible operation leads to a higher rate of deterioration of components. This is observed in increased failure rate and more frequent replacement of components. The impact on life of components increases with increase in no. of start stops the unit undergoes in a year. As a result, the operation and maintenance cost are significantly higher in units operated on a daily or weekly start-stop basis.

USAID-Intertek Study: An estimate of the increase in O&M Cost due to reduction in life of components is given below. It is based on study conducted under USAID GTG-RISE program with technical support from M/s Intertek AIM, USA at Ramagundam, Jhajjar TPS of NTPC and Ukai of GSECL. The study was based on the five to ten-year historical cost data of the units (all the costs are at 2017 levels for NTPC & 2018 for GSECL Units). The corresponding level costs 28.7 Lakhs/MW for 210 MW unit and 19.22 Lakhs/MW for 500 MW unit is based on the CERC normative O&M cost for year 2016-17.

As per estimates by USAID-Intertek study, the cost of flexibilization at two stations is summarised below. These costs are as per defined typical cycle. Most of the wear-and-tear cycling costs are owing to the O&M and capitalized maintenance costs and the increased Equivalent Forced Outage Rates (EFOR) costs. The table below provides the best estimates of the costs which includes forced outages. There is a variation in cost estimates of similar type of units at NTPC and GSECL. In fact, no two units will have the same costs due to variation in factors affecting the costs like coal, age of plant, operating practices, operator's skill and design. The incremental cost due to each event is expressed as percentage of the normative O&M costs.

Table 7.4 O&M Cost Impacts on 200 MW & 500 MW Units

MW	Event	NTPC- O&M Cost (INR-Lakh)				GSECL- O&M Cost (INR-Lakh)			
		Per Event	Per MW	Per MW (Current level) As allowed by CERC 2017	% Addl. / event	Per Event	Per MW	Per MW (Current level) As allowed by CERC 2017	% Addl. / event
200	Cold Start	91.3	0.46	28.7	1.59%	42	0.21	28.7	0.73%
	Warm Start	51.4	0.26		0.90%	28.9	0.14		0.49%
	Hot Start	38.0	0.19		0.66%	20.6	0.1		0.35%
	Significant load following	0.5	0.00		0.01%	0.2	0.001		0.003%
500	Cold Start	262.2	0.52	19.22	2.73%	174.9	0.35	19.7	1.78%
	Warm Start	151.6	0.30		1.58%	127.7	0.26		1.32%
	Hot Start	123.0	0.25		1.28%	78.4	0.16		0.81%
	Significant load following	2.7	0.01		0.03%	2	0.004		0.02%

(S*ource: USAID GTG-RISE Pilot on Coal Flexibility, data furnished by NTPC)*

As per the estimates of Intertek (table above), the per event impact ranges from 0.01% to 2.73%. Surely, the actual costs will depend on the number of such events.

Engie Lab estimates that on a yearly basis, the capital expenditures and additional maintenance result in a 0.3% to 4.3% cost impact versus the total costs of a unit, or expressed in rupees per kWh produced on such a unit: 0.01 to 0.15Rs/kWh. The absolute non-fuel costs over a 10-year period are approximately (not discounted over 10 years with a weighted average cost of capital). But this estimate is based on the current level of flexibilization, where units are operating on 55% and above without much load following. There can be a significant variation, based on the level of flexibilization (number of events in a year).

7.3.2.3 Cost due to additional oil consumption due to increased EFOR

As per studies carried out by EPRI based on global data, there is a significant increase in EFOR due to varying operational modes and on units ageing. The norms for specific oil consumption had been fixed at 0.5ml/kWh as per CERC norms for 2014-19. Based on the increased EFOR (as per EPRI) the norms for specific oil consumption may be allowed as per the Table 7.5. The loading factor calculation is done with on-bar availability i.e. Reserve Shut Down (RSD) is to be ignored.

Table 7.5 Oil Consumption due to increased EFOR

S. No.	Operation Mode	EFOR	Increase in EFOR	Sp. Oil Consumption
1	Base Load	5	-	0.5
2	Load Following (Loading Factor <60%)	7.06	2.06	0.70
3	Minimum Load (Loading Factor 40 % to 50%)	7.19	2.19	0.72
4	Minimum Load (Loading Factor 30-40%)	>7.19	>2.19	0.8
5	Minimum Load (Loading Factor 30-40%) with provisions for varying coal			1.0

(**S***ource: NTPC)*

In the Indian context, with varying coal quality, providing for additional secondary oil for low load operation will positively impact the safety and reliability of the units.
Assuming the cost of oil at Rs. 45,000/kL, the impact on ECR due to oil is shown in Table 7.6 below:

Table 7.6 ECR Impact due to increased Oil Consumption

S. No.	Specific Oil Consumption	Increased ECR (p/kWh)
1	CERC Norms (Present): 0.5 ml/kWh	2.5
2	At 0.7 ml/kWh	3.5
3	At 0.8 ml/kWh	4.0
4	At 1.0 ml/kWh	5.0

In addition to the above costs, the increase in fixed costs/unit due to lower PLFs of units providing flexibility needs to be recovered. Due to flexible operation there would be loss of availability due to increased maintenance requirements and increased EFOR which will make it difficult for the generator to recover full capacity charges.

7.4 Efficiency Studies/ Tests

To arrive at the plant efficiency, the efficiency of turbine is multiplied by the boiler efficiency. Turbine generator cycle heat rate (TGCHR) is defined as the heat supplied to the steam divided by the electric power generation. It does not include losses in the combustion or heat losses in flue gases and therefore represents the efficiency of a part of the process. The heat supplied to the cycle is calculated as

$$Q=Q_{MS}+Q_{RH}+Q_{SHspray}$$

Where, Q heat supplied to the cycle Q_{MS} heat supplied to main steam Q_{RH} heat supplied to RH steam $Q_{SHspray}$ heat supplied to SH spray. The heat is calculated as mass flow multiplied by difference of specific enthalpy. The mass flows of main steam and SH spray are measured, the RH steam mass flow is calculated as main steam flow minus extraction flow. The extraction flows are calculated from heat and energy balances of preheaters.

For determining the heat rate degradation at low operating load of 40%, it was decided by CEA to conduct the efficiency performance tests in thermal units at various thermal plants in collaboration with international partners, IGEF, Germany and TEPCO, Japan. Further, CEA entrusted the OEMs (BHEL/GE/Siemens) to conduct heat rate degradation computational studies based on heat balance.

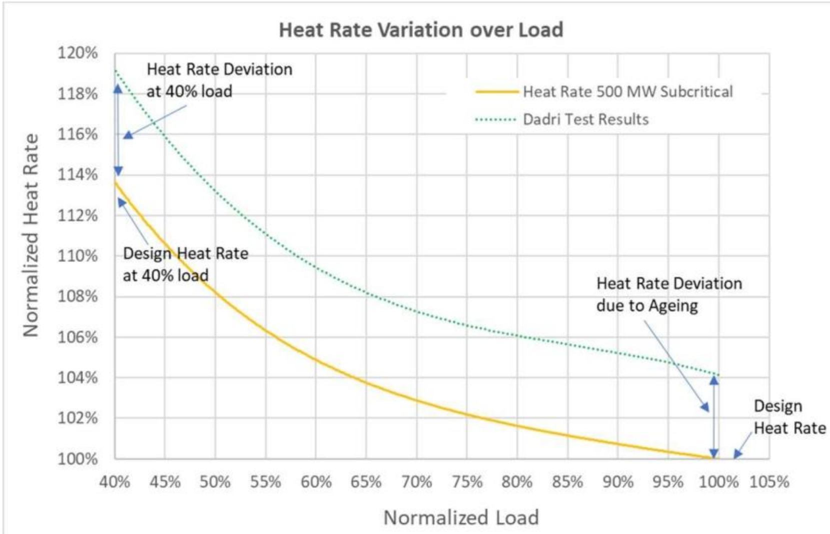
7.4.1 Efficiency Tests at Low Load

The efficiency tests were conducted at Dadri TPS, Maithon RBTPS, DSTPS, Andal and Mouda TPS in collaboration with IGEF, Germany and TEPCO, Japan, respectively. The data collected from these tests has been analysed to understand the performance deterioration at part loads. To analyse the data, NTPC Dadri 490MW (subcritical), NTPC Mouda 660 MW (supercritical), DSTPS, DVC and Tata power Maithon 525MW (subcritical) have been considered.

In order to study the effect, the load and heat rate are normalized i.e. load has been normalized to rated capacity of unit and heat rate has been normalized to rated heat rate at 100% TMCR conditions. The results of the heat rate and load are as represented in following figure.

7.4.1.1 Dadri Efficiency Test

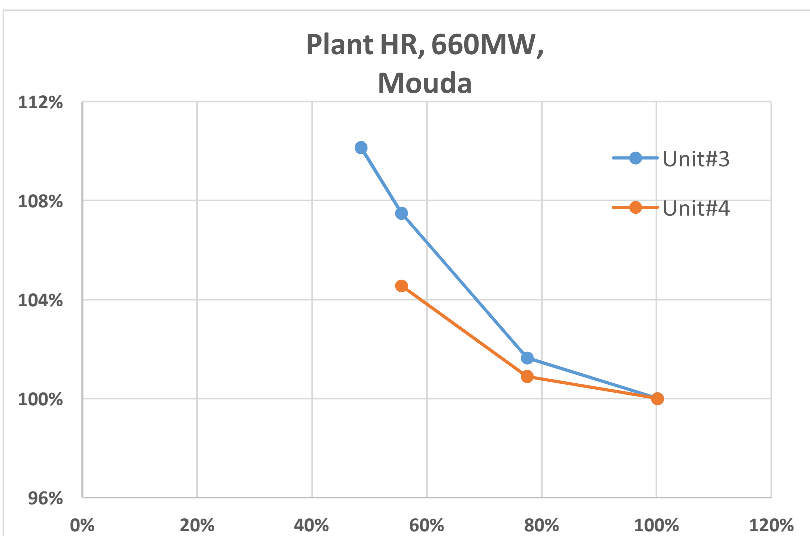
For part load efficiency assessment of 490MW Dadri Unit 5 of NTPC, data was analysed by Siemens. The TGCHR was done during the minimum load test on while the average load was 195MW.



(**S***ource: Siemens)*

7.4.1.1 Mauda Efficiency Test

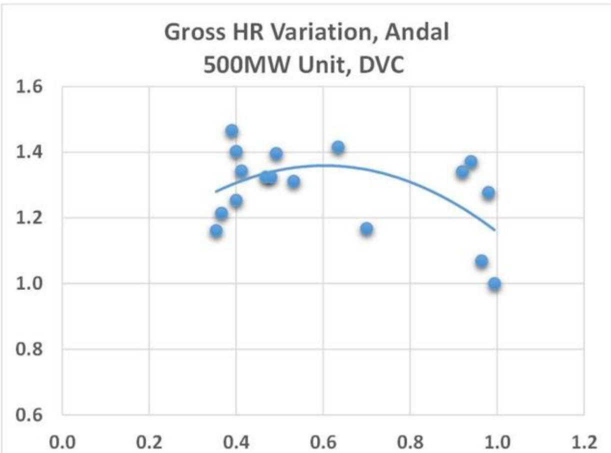
The tests were conducted from Jan 6 to 9, 2020 at Mouda STPS, NTPC on unit 3 and 4 of rated capacity 660MW.The tests were conducted in collaboration with TEPCO/JERA, Japan. The test results of the heat rate degradation with respect to loading is given in the chart below. The tests could not be conducted at low load of 40% due to theapprehensions of the owner, however, on unit 3 test could be completed at 49% load condition.



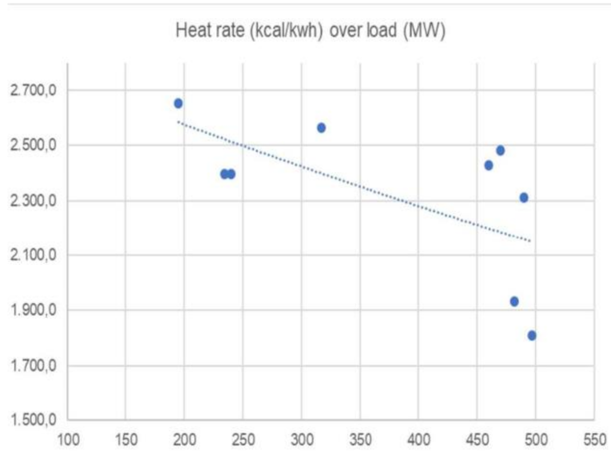
(**S***ource: JCOAL Report)*

7.4.1.3 Andal Efficiency Test

The efficiency test was conducted on unit 2 of rated capacity 500MW in collaboration with IGEF/VGBE, Germany. The heat rate has been calculated at around fifteen load points, however, the results are not showing normal trend of deterioration, refer plot above (left side). These results as such cannot be effectively used for assessing the impact at low loads. However, it needs to be considered that the coal quality variation was very high, GCV was in a range between 3,545 kcal/kg to 5,640 kcal/kg. Excluding the datawhich have the highest coal variations, the graph changes accordingly (right side). It reflects the deterioration in heat rate with respect to the loads. From the revised plot (rightside) the heat rate deterioration can be estimated as 20% at a low load of 40% when compared at rated load (100%).



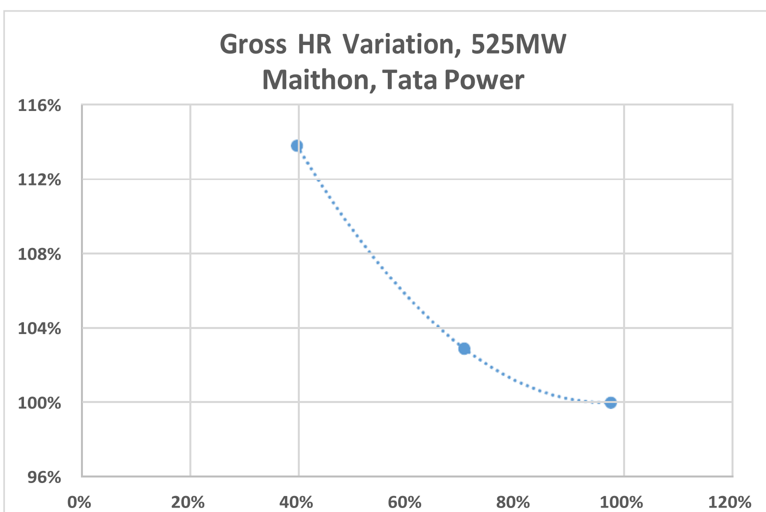
(**S***ource: IGEF Report)*



(**S***ource: VGBE/IGEF)*

7.4.1.2 Maithon Efficiency Test

The Maithon efficiency test was conducted on unit 2 of rated capacity 525MW in collaboration of IGEF Germany. The TGCHR was done during the minimum load test on 22 July, 2021 between 14:30 and 15:30 while the average load was 211 MW. Boiler efficiency was assumed as 88%, the overall plant HR was calculated from the TGCHR.



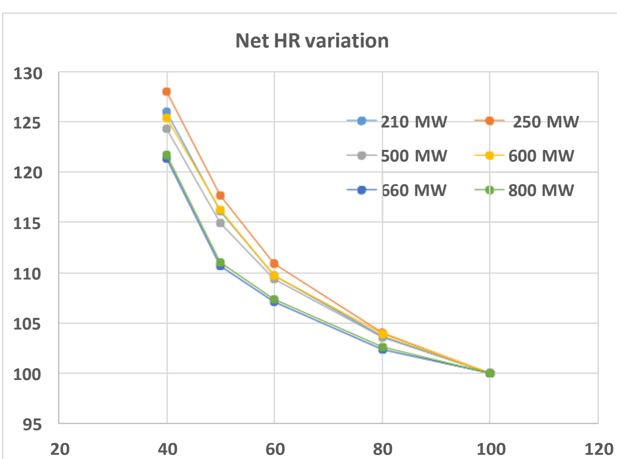
(**S***ource: IGEF Report)*

7.4.1.4 Summary- Efficiency Tests

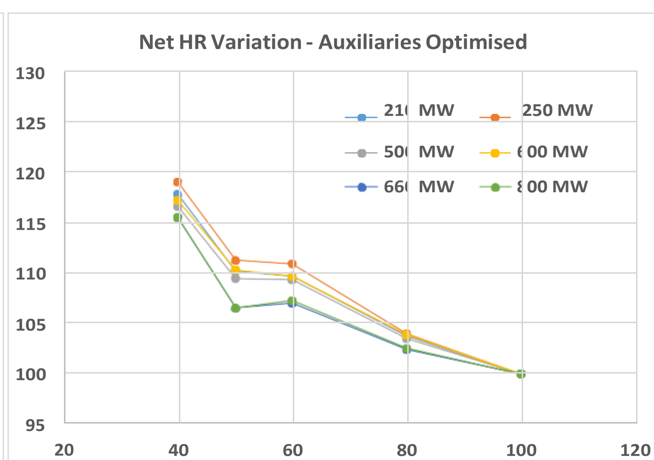
In Maithon, DVC TATA JV the efficiency tests were carried at three load points (515MW, 373MW and 211MW) and it is seen from the test report that the gross HR degradation is 14% at 40% load from 98% load. Similarly, in the case of Mauda, NTPC the efficiency test was carried on supercritical unit at four loading points (660.8 MW/511.3 MW/366.8 MW/320.4MW) and it is seen from the test report that the gross HR degradation is about 10% at 49% load from the full load. In the case of Andal, DVC, as discussed above the gross heat rate deterioration is predicted as 20% at a load of 40%. It is seen in the case of Dadri, the overall plant HR behavior was found to follow the same pattern as of original HBD calculations. The deviation from design heat rate at 100% and at 40% is found to be same and this deviation can be attributed to ageing of the plant as per standard ASME degradation curves. Therefore, HBD calculations with applied ageing can predict the performance at part load with reasonable accuracy. However, to confirm the HR degradation, efficiency tests needs to be conducted as per the prescribed standard procedures on sufficient number of units of different unit sizes to arrive at HR deterioration figures.

7.4.2 Heat Balance Studies

The heat rate degradation studies were performed by OEMs (*BHEL/GE/Siemens*) for various unit sizes at different loading conditions based on heat balance. The heat balance calculations done by *BHEL* indicates the heat rate (gross) degradation from full load to 40% load is in the range of 13.5% to 16.5% and heat rate (net) degradation in the range of 21.3% to 27.9%. However, when considering *modified* auxiliary power scheme at 50% to 40% load, the heat rate (net) degradation is drastically reduced (about 30%). Hence, it is obvious that the scheme of auxiliary control needs to be modified for low load operationat 50% and below to get the significant performance benefits.



(*Source: BHEL HB Study)*



(*Source: BHEL HB Study)*

GE, India has also conducted study for the heat rate deterioration at different loads levels for different unit sizes of thermal units. The heat rate (net) degradation is found to be in the order of 12% to 14% for different unit sizes at a load of 40%. The degradation of HR is found to be very low when compared to BHEL study (estimated) which is in the range of 21.3% to 27.9%. Similarly, *Siemens, India* conducted the heat balance study details of which are tabulated in Table 7.9.

Table 7.8 Heat Balance Study (GE)

% Load	% Deviation NHR			
	210MW	500MW	660MW	800MW
100%	0%	0%	0%	0%
90%	0%	1%	1%	1%
80%	0%	2%	2%	2%
70%	1%	3%	3%	3%
60%	4%	6%	6%	6%
55%	6%	8%	8%	8%
50%	7%	10%	9%	10%
40%	12%	14%	14%	16%
30%	17%	19%	20%	24%

Table 7.9 Heat Balance Study (Siemens)

% Load	% Deviation NHR			
	210MW	500MW	6600MW	800MW
100%	0%	0%	0%	0%
90%	1.1%	0.8%	1.0%	0.8%
80%	2.3%	1.4%	2.0%	1.3%
60%	6.1%	4.5%	4.2%	3.0%
50%	7.3%	7.7%	6.2%	4.8%
40%	9.5%	10.0%	8.9%	7.0%
35%	13.0%	15.0%	14.0%	13.8%

7.4.3 Impact of low load on Tariff

The impact of low load operation on HR was studied by major OEMs (BHEL/GE/ Siemens) while conducting heat balance for various unit sizes. As there was sizable variation in the HR deterioration among the studies, the deterioration in HR was considered by the committee based on the heat balance study report of BHEL, SIEMENS, GE and actual efficiency tests to study its impact on tariff. Further, the impact of capital cost for upgradation of controls has been considered as six to ten crores and the amount may increase upto 30 crores for older units commissioned before 2010. The increase in O&M cost has beenconsidered based on the loading levels of the units and at 40% loading it has been assumed as 20%.

The study conducted by CEA indicates the impact of low load operation at 40% on variable part of tariff is around 15% whereas the impact on fixed part of tariff is around 2.77%-7.63% depending on the unit size. The summary of the study conducted is given inTable 7.10 below and the assumptions considered are given in Annexure-I.

Table 7.10 Possible Impact of Low load Operation on Tariff

(a) Impact in Paisa/kWh

Capacity (MW)	Loading	NHR (% Increase)	Variable Tariff (Increase in Paisa/kWh)	Fixed Tariff (Increase in Paisa/kwh)						
				Due to O&M	Capex (Rs 6 cr./ Unit)	Total	Capex (Rs 10 cr./ Unit)	Total	Capex (Rs 30 cr./ Unit)	Total
200	50%	10.0	13.74	5.14	1.71	6.85	2.85	7.99	8.56	13.70
	45%	13.0	17.86	7.99	1.71	9.70	2.85	10.84	8.56	16.55
	40%	16.0	21.97	11.42	1.71	13.13	2.85	14.27	8.56	19.98
500	50%	10.9	14.60	3.42	0.68	4.11	1.14	4.57	3.42	6.85
	45%	13.6	18.30	5.33	0.68	6.01	1.14	6.47	3.42	8.75
	40%	16.0	21.50	7.61	0.68	8.29	1.14	8.75	3.42	11.03
660	50%	8.7	11.10	3.08	0.52	3.60	0.86	3.95	2.59	5.67
	45%	11.9	15.30	4.79	0.52	5.31	0.86	5.66	2.59	7.39
	40%	14.6	18.70	6.85	0.52	7.37	0.86	7.71	2.59	9.44
800	50%	8.6	10.66	2.74	0.43	3.17	0.71	3.45	2.14	4.88
	45%	12.0	14.86	4.26	0.43	4.69	0.71	4.97	2.14	6.40
	40%	15.0	18.58	6.09	0.43	6.52	0.71	6.8	2.14	8.23

(b) Impact in Percentage terms per kwh

Capacity (MW)	Loading	NHR (% Increase)	Variable Tariff (% Increase)	Fixed Tariff (% Increase)						
				Due to O&M	Capex (Rs 6 cr./ Unit)	Total	Capex (Rs 10 cr./ Unit)	Total	Capex (Rs 30 cr./ Unit)	Total
200	50%	10.0	9.82	1.96	0.65	2.62	1.09	3.05	3.27	5.23
	45%	13.0	12.76	3.05	0.65	3.71	1.09	4.14	3.27	6.32
	40%	16.0	15.70	4.36	0.65	5.02	1.09	5.45	3.27	7.63
500	50%	10.9	10.60	1.41	0.28	1.69	0.47	1.88	1.41	2.82
	45%	13.6	13.29	2.19	0.28	2.48	0.47	2.66	1.41	3.61
	40%	16.0	15.61	3.14	0.28	3.42	0.47	3.61	1.41	4.55
660	50%	8.7	8.44	1.29	0.22	1.51	0.36	1.65	1.09	2.38
	45%	11.9	11.63	2.01	0.22	2.22	0.36	2.37	1.09	3.09
	40%	14.6	14.22	2.87	0.22	3.08	0.36	3.23	1.09	3.95
800	50%	8.6	8.39	1.17	0.18	1.35	0.30	1.47	0.91	2.08
	45%	12.0	11.70	1.81	0.18	1.99	0.30	2.12	0.91	2.72
	40%	15.0	14.63	2.59	0.18	2.77	0.30	2.89	0.91	3.50

Note:

1. Increased tariff = increased fixed tariff + increased variable tariff
2. Increased fixed tariff = due to increase capex + increase O&M expenses

7.4.4 Recommendations

7.4.4.1 Modifications (Retrofit)

For achieving minimum technical load (40%) and higher ramp rate, the primary focus of the utility shall have to be on optimizing the existing control system. Improvements in some of the areas shall be essential, like achieving automated control operation whichshall include proper tuning of operation so as to avoid temperature and pressure excursions. Control optimization shall include main/reheat steam temperature control,boiler feed water recirculation control, flue gas temperature control. Better combustion control shall include, optimum fuel to air ratio, fuel to load coordination, furnace pressure control, burner tilt control and proper flame monitoring at low loads. Condition monitoring of boiler and turbine, flame monitoring is essential from the safety point of view. To reduce the running cost of the unit at low loads, the optimization of auxiliariesis essential for improving heat rate. The above measures are essential for a unit and may require a capital investment of around six to ten crores. In case of very old units which have not upgraded their plant control and instrumentation system previously, the capital investment will be about 30 crores depending on the retrofit.

7.4.4.2 Compensation Mechanism

i) Cost of modification/retrofit shall form part of the capital investment, and wherever applicable, this shall be recoverable through fixed part of tariff separately in 5 to 7 years' time periods as done in case of R&M.

ii) Costs due to increase in O&M expenses, shall have to be compensated as part of the fixed tariff. The increase in O&M costs shall depend on level of flexibilisation and in the study conducted by CEA (refer Table 7.10) the increase in annual O&M cost has been considered as 9%, 14% and 20% at 50%, 45%, 40% loading, respectively.

iii) Below 55% technical minimum load, the heat rate deterioration becomes even steeper and thermal power plants are not compensated for this deterioration. Units running technical minimum load below 55% can be additionally compensated in ECR to the extent of heat rate deterioration. As per the study conducted by TPRM Div., CEA, unit operating at loads lower than 55% technical minimum load can be suitably compensated in their variable tariff as summarized in Table 7.10, initially, which can be modified suitably after receiving sufficient data.

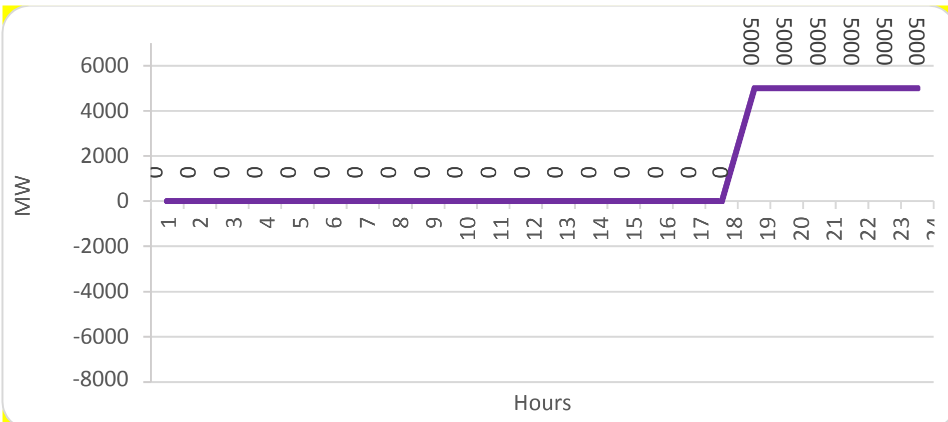
iv) Further, the compensation on account of forced outage due to operation at lower loads may have to be compensated as per the details indicated in Table 7.5.

v) There may be scenarios, wherein the flexible capabilities may have been created, however, the opportunity or the schedule to flexibilise may not become available to the particular unit. Hence, increased O&M cost may not be considered as part of fixed cost whereas the increased capital cost on account of retrofit shall continue to be recovered. The variable costs related to flexibilisation should be reimbursed for the cycling period by way of increase in the tariff.

vi) The Compensation on account of EFOR may be allowed 1.0 paisa/kWh initially as specific oil consumption may increase from 0.5 to 0.7 ml/KWh. It is also suggested to review after one year considering actual start/stop due to low load operation.

8. TWO-SHIFT OPERATION

CEA's 2019 report, "Flexible operation of thermal power plants for integration of renewable generation" suggested to run 5000 MW out of 10000 MW old small size (151 MW or less) units for six hours in the evening peak hours for integration of generation from 175 GW RES. Most of these units are more than 25 years old and have high Energy Charge Rating (ECR).



CEA reports, 2019 - Two shift Operation of thermal units

8.1 Classification of Two-Shift Operation

Category 1 - Operate during Peak Demand period: these plants will have to deliver the peak loads with full available capacity during the peak hours (about 6 to 7 hrs.), with increased demand and reduced or no solar, After the peak hours are over, these plants will not be required to deliver any power and therefore would be put on hot standby. Plants in this category are likely to have an annual PLF of 30% or lower.

Category 2 - Shutting down during Peak Solar Generation Period**:** In this category plants will be under shut down during of solar peak generation period (10 am to 4 pm or 10 am to 5 pm) and units will generate in the evening peak with hot startup. The PLF of plants will be better than plants under category-1.

Two-shift operation is a costly mode of operation because of lower PLF and accelerated equipment life consumption due to daily start stop and increased forced outages. In the Indian market context, it will make economic sense for the older plants (with near-zero fixed costs/fully depreciated capital costs) to be retrofitted for a two-shifting mode of operation. As these plants would be on bar for a limited duration, the overall emissions will be much lower, compared to the plants operating on lower loads for a longer duration.

The start-ups in daily two-shifting operations will mostly be hot start-ups, which are less damaging (equipment life consumption) than warm or cold start-ups. These plants are best placed, economically to deliver the peaking power (which can be opted as an Ancillary service product or suitable compensation mechanism to be installed). More study regarding startup optimization, minimization of equipment damage is required for two shift operation of thermal power plants.

8.2 Two-Shift Operating Experience

8.2.1 CESC Limited is operating the 2x67.5MW, BHEL make units of Southern Replacement TPS, commissioned in 1990 and 1991 respectively, in single/two shift mode for last 5 to 6 years, depending on merit order and system/network requirement. Running hours varies from 6 to 18 hours per day and type of start is hot or warm or cold depending on the number of hours of shutdown. No retrofitting (hardware/software) was done for single/two shift operation.

8.2.2 Another example of two-shift operation is of TANGEDCO, Tamil Nadu which is classified under category 2. The two shift mode operation was started in April 2022 and is being continued to accommodate the renewable generation as and when required. The units are at full load during evening peak hours and mostly units are operating for 16 hrs. in a day from 5pm to 11am, daily in hot startup mode. About all 210 MW units of the TANGEDCO are being operated in two shift mode which are more than 30 years old and 3 of which are more than 40 years old. The unit operated in two shift mode are given in table 8.1.

The following have been experienced during two shift operation of the units by M/s.TANGEDCO.

1. Oil consumption is more and the generation cost & Auxiliary power consumption percentage have increased.
2. Heat rate, Specific Coal Consumption, Specific Oil consumption have increased. Overall efficiency is under study. The operational issues, equipment condition and other safety related issues are being monitored meticulously during the two shift operation periods. The details of outcome of the study by TANGEDCO shall be available after monitoring the two shift operation for a longer period.

Table 8.1 TANGEDCO Units Operated in TwoShift Mode

S.no	Station	Unit	Commissioning Date
1	TTPS, 5x210 MW	I	07.09.1979
		II	17.12.1980
		III	16.04.1982
		IV	11.02.1992
		V	31.03.1991
2	MTPS, 4X 210 MW	I	07.01.1987
		II	01.12.0987
		III	22.03.1989
		IV	27.03.1990

Source : TANGEDCO Ltd.

8.3 Recommendation

It is proposed to initiate study by an expert committee for two shift operation of thermal power plants considering integration of 500 GW non fossil fuel capacity by 2030. The technical feasibility and recovery of cost system of two shift operation need to be elaborated by the committee. Further, the committee may also explore the possibility of exemption of FGD installation in these power plants considering the limited hours of operation and daily/ monthly average SO2 emission will be within prescribed limits.

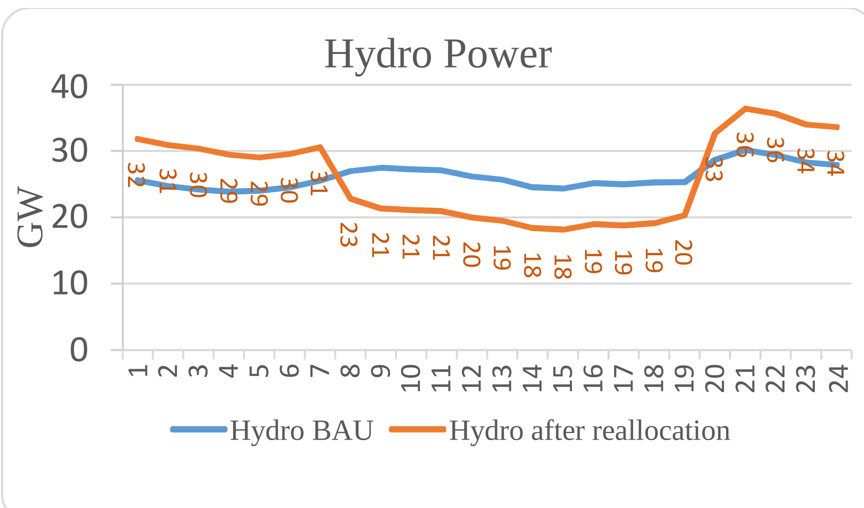
9. FLEXIBLE POWER FROM DIFFERENT SOURCES

Flexible power required for the balancing of grid may be available from following sources:

- Reallocation of hydro generation
- Gas flexing
- Pump Storage
- Low load operation of thermal power plants
- 2-shift operation thermal power plants
- Demand Side Management
- Battery Storage

9.1 Reallocation of Hydro Generation

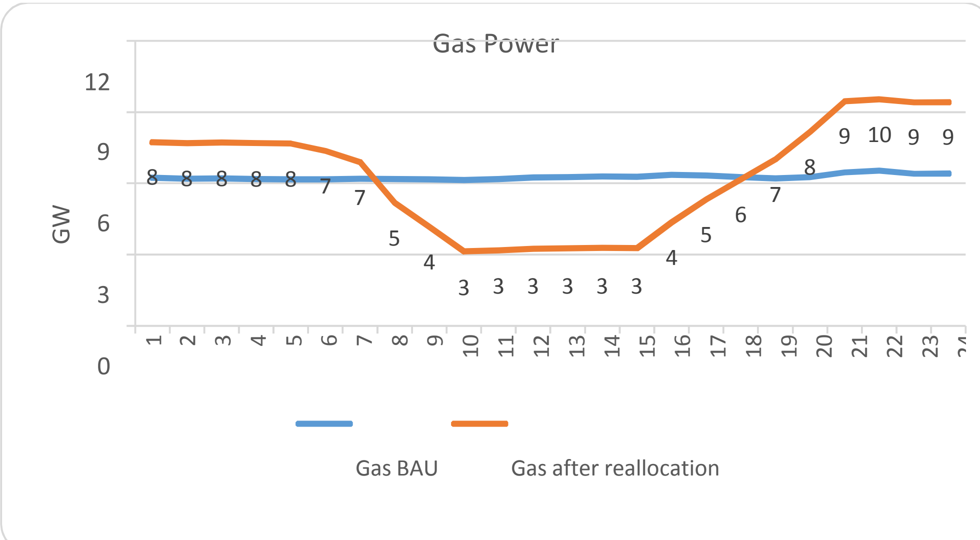
Present hydro generation is shown in blue colour in fig. below. Proposed reschedule is shown as in brown colour where reduced generation during day time and higher generation during peak demand hours is proposed. To achieve the target, the coordination with central and state hydro generator is essential. It has been observed that states hydro plants are operating continuously to meet the demand of states and states do not draw power from grid during day time because of their very cheap hydro power compared to grid power.



It is suggested to implement separate tariff for flexible hydro power which will be higher than cost of peak grid power and cost of solar power may be reduced specially from 11 am to 4 pm. If the tariff is revised as above, many hydro rich states will draw power from grid during day time and operate hydro plants during peaking hours for financial benefit of the organization. The minimum tariff of flexible hydro power should be greater than the off-peak grid power.

9.2 Gas Flexing

Presently installed Gas Power Plant capacity is about 25GW but about 9 GW is operating due to low availability of gas. Out of 9 GW, a few cannot operate intermittently as they are directly connected to oil fields. There is possibility of flexible operation of gas power plant which are connected with the gas grid. Present generation and proposed generation of the gas power plants are shown in blue and brown colour in the fig below.



9.3 Pump Storage

We have enormous potential for small pump storage with a cost of 3-4 cr/MW,it is possible to develop PSS by identifying the location in consultation with Hydro wing, CEA, NHPC or state hydro sector. In fact, development of pumped hydro storage schemes is a precursor to integrate renewable power generation.Central/State/Private Pump Storage plants should operate in pumping mode during the solar generation period and generating mode during peak demand period. They can be utilized for meeting the peak demand of the grid or balancing the grid only.

9.4 Flexibilisation of Thermal Power Plants

9.4.1 Low Load Operation of Thermal Power Plants

About 70 percent of the country's energy demand is being met from thermal generation thus it is essential that maximum flexible power will be available from thermal power plants. The maximum and minimum gross thermal capacity of 232GW and 148GW are required in 2029-30 as specified in CEA's report on "Optimal Generation Capacity Mix for 2029-30". If required measures shall be implemented for operation of TPPs at 40% load instead of present 55 percent minimum load, then it shall be possible to achieve about 21GW additional flexible power from the thermal fleet. The details are as under:

Max. Gross Coal Capacity Required (as per Optimal gen. report)	= 232 GW,
Max. gen. (75% units)	= 174 GW
Spinning reserves (7%)	= 12.18 GW
Auxiliary consumption (7%)	= 11.32 GW
Ex-bus gen.	= 150.49 GW
55% min. load (aux. 7.5%)	= 76.56 GW
40% min. Load (aux. 8%)	= 55.38 GW

21.18 GW (76.56-55.38) more Renewable integration is possible by lowering the min load from 55% to 40%.

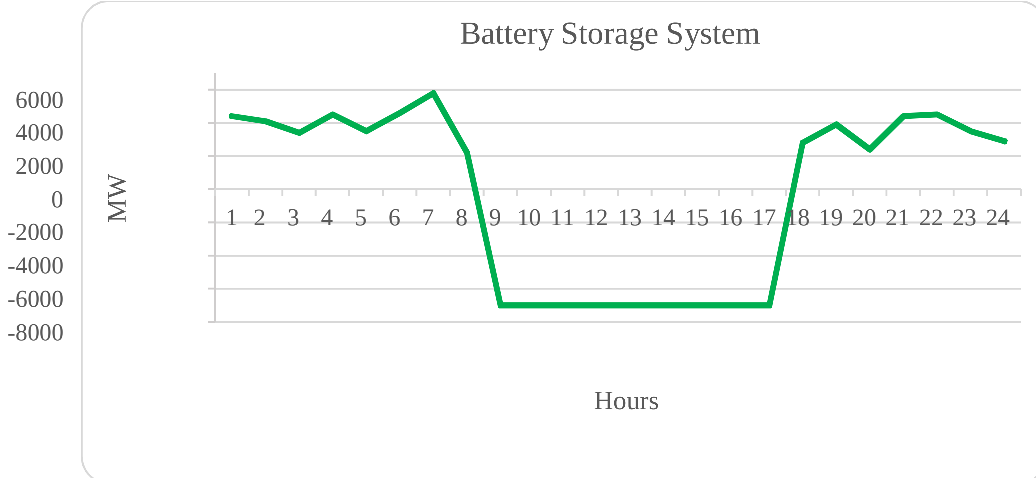
Capex = 10 Crore per unit (average)
Total no. of Units = 600
Total investment = 600X10 = 6000 Crore

9.4.2 Two-Shift Operation of Thermal Power Plants

After implementing low load operation up to 40% at thermal generating units, iffurther flexible power is required it can be available from 2-shift operation of old& small size thermal generating units. These units may run 6 to 7 hrs only duringpeak grid demand period or 6 to 7 hrs. shutting down during peak solar generation period.

9.5 Battery Storage System

The cost of battery energy storage system is assumed to be reducing uniformly from 7 Crore in 2021-22 to 4.3 Crore in 2029-30 for a 4-hour battery system which also includes an additional cost of 25% due to depth of discharge. If we consider 27GW BSS with an average cost of 5.65 Crore/MW, total cost shall be more than one lakh fifty thousand crore. Thus BSS shall be costly, which shall have to be imported, having less life about 9-10 years and disposal issues. Considering the above it is suggested to reduce BSS capacity accordingly.



9.6 Demand Side Management

Demand side management (implementing TOD metering) including measuretargeted at domestic, agricultural, industrial and e-mobility sector and hydrogengeneration would enable more rational consumption pattern of electricity. The cost of grid power will be of least during high solar period and highest in evening/morning peak. It shall encourages consumption of energy during day time than in the peak hours.

Supply of electricity to agriculture sector by dedicated feeders

Agricultural consumption = 211,295 MU
Agricultural consumption = 16.94 %

Shifting of 1000MW load from night hours to peak solar hour will improve about 1% technical minimum load of thermal generating units.

9.7 Recommendation

It is suggested that existing capacity of hydro, pumped storage, gas and thermal available for flexibilisation in the system should be utilized first in a safe and secure manner before adopting newer options such as Battery storage system, etc. on a large scale.

10. ROADMAP

The conduction of low load study/test run is essential for each unit to find the measures required to be implemented for flexible operation, as has been discussed in earlier chapters of the report. To implement measures in a unit as identified in low load test/study, it shall require a minimum six months' time. Hence, it is necessary to formulate a time frame for achieving flexibilisation of a very large fleet of 600 thermal units. It is expected that non-pithead thermal power plant shall be given minimum technical generation schedule in first stance and thereafter pithead based plants if required. This section deals with devising a phasing schedule based on the age of units andinputs received from the major OEMs.

10.1 Phasing Plan

On accomplishing 175GW RES capacity in the December, 2022 (may be in 2023), there shall be grid requirement of the operation of thermal units at 40% minimum load on an average as per the findings of CEA 2019 report. So far to the knowledge of committee, work has been awarded for the upgradation/flexibilisation of one unit in central sector in 2019. The final outcome of the flexibilisation work carried out has to be established. CEA consulted three major OEMs (BHEL, Siemens and GE) and also tried to consult others for their capabilities to carry out the flexibilisation work. The data provided by one of the vendors already conducting the flexibilisation work on one of the units seemed tobe more realistic than the other two vendors. There has been no response from the othersub vendors. Based on the present vendor capabilities, the following preliminary phasing plan has been drawn up by TPRM Div. CEA.

More than 24.64% thermal capacity is newly commissioned, January 2016 onwards (refer Table 9.1). These new units should necessarily be having advanced digital controls and features which shall help in faster adoption of the 40% load following operational regime. It shall be obligatory that such units numbering 101 units are brought under the purview of flexibilisation operating regime first.

Table 10.1

Commissioning Period	Units	Capacity(MW)
Since 2016 to till date	101	52,152
Between 2012 & 2015	160	80,384
Between 2001 & 2011	143	34,840
Upto 2000	196	44,143.5
Total	**600**	**211,519.5**

In the pilot phase, it is proposed that 11 units of central/state/pvt sector which were commissioned from Jan 2016 to December 2022 shall be taken for refurbishment (refer

Table 9.2). It is estimated that the refurbishment shall be completed in a period of one year, which shall be followed by performance evaluation and rectification period of six months. The experience gained in pilot phase shall be useful for future planning. The complete phasing plan as proposed is given in the Table 10.2. A minimum estimated time period of 8 years' may be required to make these units compliant of flexibility upto 40% load following and having higher ramp rates. The complete refurbishment work is estimated to end by December 2030, considering the work starts in January 2023. This phasing will help in proper identification and planning.

Table 10.2 Phasing Plan

<table>
<tr><th>Phasing</th><th>Sector</th><th>No. of Units</th><th>Time Period (Year)</th><th>Unit commissioned</th></tr>
<tr><td rowspan="3">Pilot Phase
Jan,2023-Dec,2023</td><td>Central</td><td>4</td><td>1</td><td rowspan="3">Jan,2016 to Dec,2022</td></tr>
<tr><td>State</td><td>3</td><td>1</td></tr>
<tr><td>Private</td><td>4</td><td>1</td></tr>
<tr><td>Jan,2024-Jun,2024</td><td colspan="4">Performance analysis and modification, if required.</td></tr>
<tr><td rowspan="3">1st Phase
July,2024-Jun,2026</td><td>Central</td><td>32</td><td>2</td><td rowspan="3">Jan,2016 to Dec,2022</td></tr>
<tr><td>State</td><td>26</td><td>2</td></tr>
<tr><td>Private</td><td>32</td><td>2</td></tr>
<tr><td rowspan="3">2nd Phase
July,2026-Jun,2028</td><td>Central</td><td>24</td><td>2</td><td rowspan="3">Jan,2012 to Dec,2015</td></tr>
<tr><td>State</td><td>30</td><td>2</td></tr>
<tr><td>Private</td><td>106</td><td>2</td></tr>
<tr><td rowspan="3">3rd Phase
July,2028-Dec,2029</td><td>Central</td><td>41</td><td>1.5</td><td rowspan="3">Jan,2001 to Dec,2011</td></tr>
<tr><td>State</td><td>52</td><td>1.5</td></tr>
<tr><td>Private</td><td>50</td><td>1.5</td></tr>
<tr><td rowspan="3">4th Phase
Jan,2030-Dec,2030</td><td>Central</td><td>67</td><td>1</td><td rowspan="3">up to December,2000</td></tr>
<tr><td>State</td><td>111</td><td>1</td></tr>
<tr><td>Private</td><td>18</td><td>1</td></tr>
<tr><td colspan="2">Total</td><td>600</td><td>8</td><td></td></tr>
</table>

In the 1st phase, the plants commissioned between January 2016 and December 2022, about 22.64% capacity (~15% Units) shall be considered and two years' time shall be required to complete the refurbishment.

Units commissioned between January 2012 and December 2015 shall be taken in 2ndphase (~27% Units) and unit commissioned January 2001 to December 2011 (~24% Units)shall be considered in 3rd phase and a shorter period one and half years' time is considered to be required due to the experience gained in earlier phase.

In the last 4th phase, remaining units (33%Units) commissioned up to December 2000 shall be considered requiring one year's time period for refurbishment. The details of all the phases including timeline is summarized in Table 10.2. The phasing may have to be reviewed considering the actual progress achieved on site.

10.2 Study/ Test Run of Each Unit

The conduction of low load study/test run is essential for each unit to find the measures required to be implemented for 40% low load operation without oil support. The measure shall also be identified for achieving minimum 1% ramp rate particularly in the lower load range 40% to 55%, 2% ramp rate in the load range of 56 to 70% and 3% in higher load range of 71 to 100%.

10.3 Measures Implementation

To implement measures in a unit as identified in low load test/study, it shall require a six months' time (approximately). (Refer Chapter-6 and Section 7.4.3.2.1 of Chapter 7)

10.4 Operator Training

Flexibilization of units adds to the safety risks and calls for added precautions. Equipment failure can take place due to negligence, poor operation and maintenance practices and low operator confidence due to the operation of plants for base load. For safe and efficient plant operation at very low load and frequent load cycling, there is an essential need for trained personnel. Training curriculum for trainer and power plant operators shall have to be prepared in association with major power plant operator and NPTI.

The training simulators provide a strong base for ensuring the right operational procedures and practices which need to be followed by operators. The existing training simulators may need to be upgraded for low load/high ramp rate operation at 40% load, which shall need to be ascertained. The training of personnel needs to be scheduled in advance before the units are put in high flexible mode of operation.

11. CONCLUSION AND WAY FORWARD

11.1 Conclusion

11.1.1 Low load operation (40%) of coal fired power plants is primarily required to fulfil theneeds of integration of renewables in the grid. Flexible power plants in the system enable the integration of more renewables, avoid wasteful curtailment, leading to a more efficient power system. Although, there maybe many options of flexible power for integrating renewables, coal fired plants is thebest option considering its availability, proportion and low cost.

11.1.2 The existing capacity of hydropower, pumped storage and gas-fired generation having good peaking performance is too small to meet the balancing requirements. It is of importance that the existing thermal resources available for flexibilisation in the system should be utilized first in a safe and secure manner before adopting newer options such as Battery storage system, etc. on a large scale.

11.1.3 Flexible operations for coal power plants are technically feasible by upgradation, tuning of controls, etc. The pilot tests conducted at various plants is the proof that Indian plants are capable to flex. Converting the base load coal fired power plants into flexible plants would most likely incur expenditure.

11.1.4 To assess the flexible capability, the thermal units need to be tested from safety, security & stability point of view and quantification of available flexible power, ramp rate, etc. These tests are also essential for accessing the need for retrofits which are plant specific. The low load test runs should be conducted after careful study of the unit beforehand and accordingly the test targets should be decided in consultation with OEM. Any stretching of the targets during the test run should be avoided for the safety and security of the plant.

11.1.5 The technical measures shall depend on the levelsof minimum load operation to be adopted. Lower load operation (40%) shall require measures like automation/optimization of controls, proper flame detection systems, efficient measures to optimize combustion process, stable minimum mill operation, reassessment of O&M practices, etc.

11.1.6 Indian power sector has got large fleet of subcritical coal fired units of capacity 500 MW and less, which are considered suitable for flexibilisation. Super-critical units are better for load ramping /flexible operation and more care is required around benson (dry/wet) point.

11.1.7 To ensure the security of the grid and safety of plants, presently the low load operation of coal-fired power plants should not be less than 35–40% of ratedpower due to Low VM and high ash content of Indian coal.

11.1.8 The coal-fired power units shall remain the main source of flexible power. However, there are many commercial issues like cost of retrofit, increased O&M cost, heat rate degradation cost, increased EFOR which would need to be compensated by the central and state regulators.

11.1.9 There is low operator confidence for flexibilisation due to operation of thermal plants as base load plants. Low load operation of units at forty percent calls for added precautions. Catastrophic equipment failure can take place due to negligence and poor operation and maintenance practices. Hence, operator training is essential for the implementation of flexibilisation.

11.1.10 Two shift operation of old thermal generating units is being carried out in some parts of the country in a piecemeal manner to meet the load generation balance. The need arises for carefully planning of two-shift operation countrywide.

11.2 Way Forward

11.2.1 Immediate action needs to be taken for preparing thermal generating units flexible as per the road map discussed in the report. Initially, the pilot phase of flexibilisation/refurbishment of 11 units of Central/State/Private sector may be carried out for performance evaluation (refer para 7.4.4.1). For funding some of the units under pilot phase, INDC *Technology Development & Transfer/ Fund Mobilization* or Govt. funding like PSDF may be utilized.

11.2.2 Availability of training simulators need to be ensured for the trainingof operators at 40% low load operation.

11.2.3 Regulation should be introduced for 40% minimum technical load operation of thermal generating units.

11.2.4 Suitable regulatory mechanism, should be introduced in central and state level, wherever applicable, for the compensation as discussed in the report (refer para 7.4.4.2).

11.2.5 Keeping in mind the requirement of flexible power in future, design of new thermal units should be such that it can be possible to operate these with optimized auxiliaries, at loads lower than 40% (say 30%) without oil support and, at higher ramp rates of 2-3% in lower load range.

11.2.6 Study should be initiated for finding the possibility of two shift operation of existing thermal generating units as per the grid requirement (refer para 8.4). Design of new thermal units should be such that it can be possible to operate in 2 shift mode on a regular basis.

ANNEXURE - I

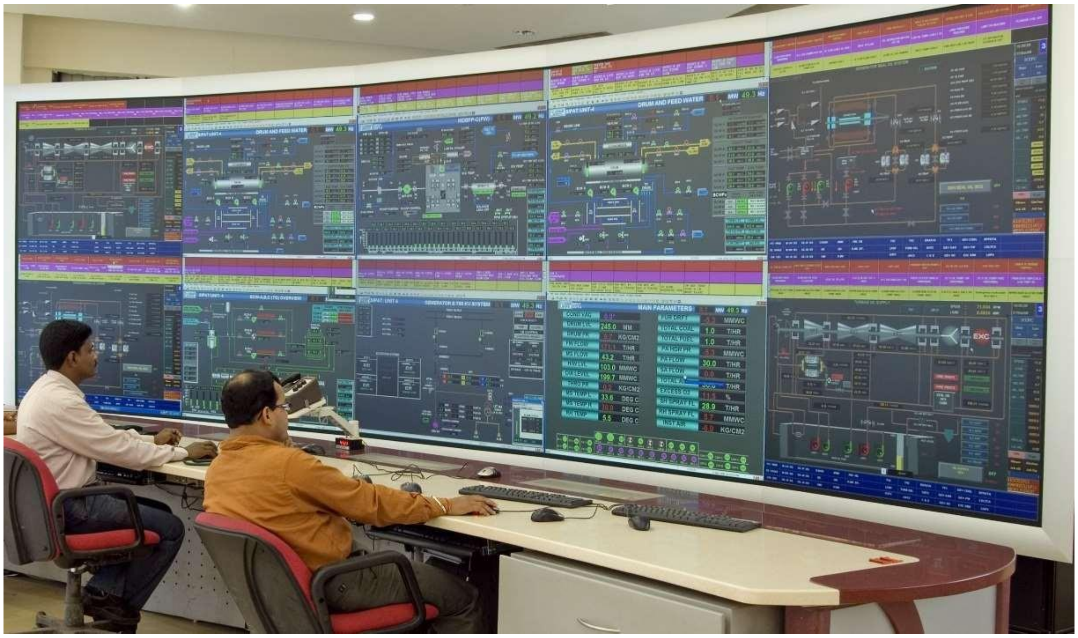
Assumptions:

1. **Unit size 200 MW**
   BAU Mode:
   Capital Cost 6Cr/MW, O&M Cost 30lakh/MW, Coal Cost Rs 2000/ton, Heat rate 2430 Kcal/Kwh.
   Flexible Mode:
   Capital Expenditure w.r.t Flex. of 6/10/30 Cr./Unit, Increase in O&M Cost- 9% for 50%loading, 14% for 45% loading, 20% for 40% loading.

2. **Unit size 500 MW**
   BAU Mode:
   Capital Cost 6Cr/MW, O&M Cost 20lakh/MW, Coal Cost 2000Rs/ton., Heat rate 2390 Kcal/Kwh
   Flexible Mode:
   Capital Expenditure w.r.t Flex. of 6 /10/30 Cr./Unit, Increase in O&M Cost- 9% for 50%loading, 14% for 45% loading, 20% for 40% loading.

3. **Unit size 660 MW**
   BAU Mode:
   Capital Cost 6Cr/MW, O&M Cost 18lakh/MW, Coal Cost 2000Rs/ton., Heat rate 2280 Kcal/Kwh.
   Flexible Mode:
   Capital Expenditure w.r.t Flex. of 6/10/30 Cr./Unit, Increase in O&M Cost- 9% for 50%loading, 14% for 45% loading, 20% for 40% loading.

4. **Unit size 800 MW**
   BAU Mode:
   Capital Cost 6Cr/MW, O&M Cost 16lakh/MW, Coal Cost 2000Rs/ton., Heat rate 2200 Kcal/Kwh.
   Flexible Mode:
   Capital Expenditure w.r.t Flex. of 6/10/30 Cr./Unit, Increase in O&M Cost- 9% for 50%loading, 14% for 45% loading, 20% for 40% loading.


DRUM AND FEED WATER
MAIN PARAMETERS