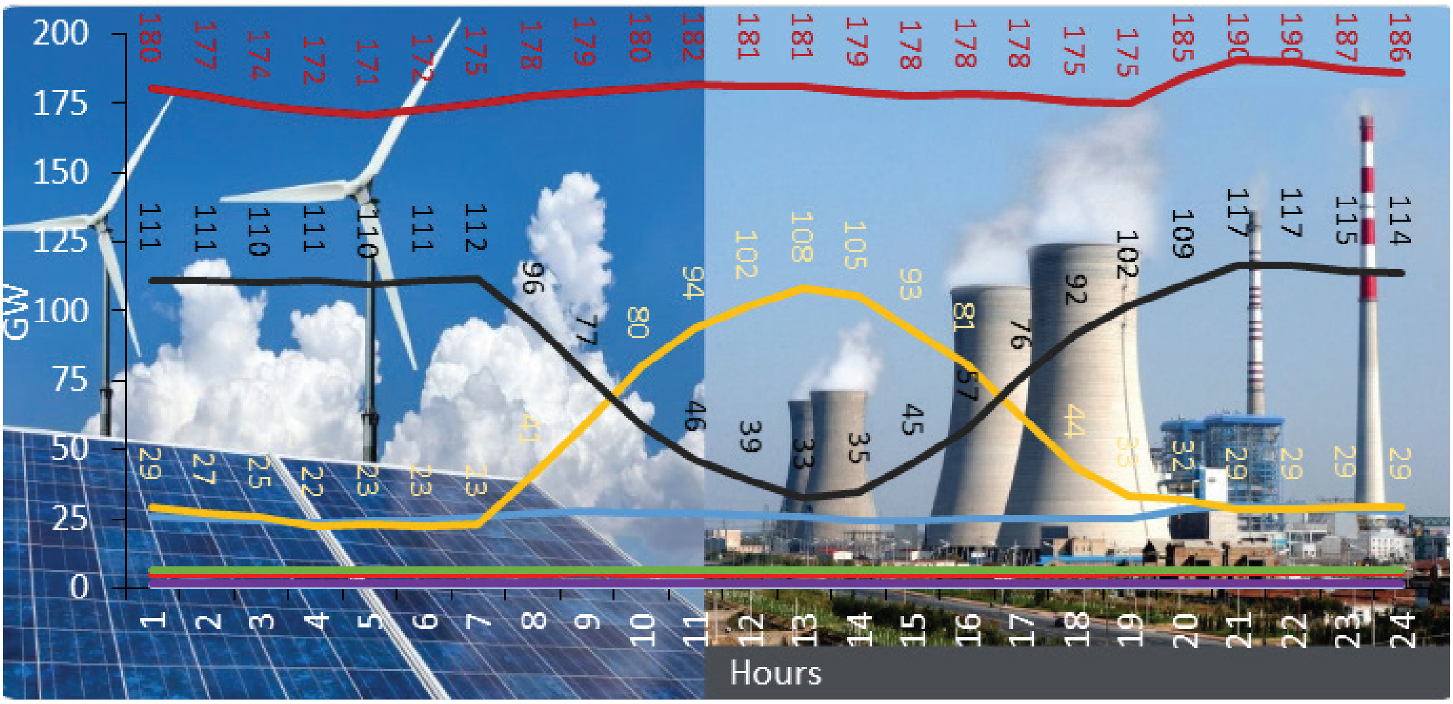
Government of India
Ministry of Power
Central Electricity Authority

FLEXIBLE OPERATION OF THERMAL POWER PLANT FOR INTEGRATION OF RENEWABLE GENERATION



A Roadmap for Flexible Operation of Thermal, Gas and Hydro Power Stations to Facilitate Integration of Renewable Generation

January 2019

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

Central Electricity Authority

Thermal Project Renovation and Modernization Division

Prakash Mhaske
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NEW DELHI-110066, Dated : 17 January 2019

Foreword

Our Country has an ambitious plan to install 175 GW Renewable Generation capacities by 2022. Such a large scale integration of renewable energy would require balancing by the conventional power generators to manage the variation in the generation from renewable resources.

Flexing of Coal based generating units to accommodate renewable generation would be major challenge in our country, where the electrical energy generation is predominantly Coal based. Multipronged approach, including use of pumped storage hydro and Battery storage, cyclic operation of Gas based generation, optimisation of hydro generation, renewable curtailment etc. would be needed to ensure optimum technical & economic flexibility of Coal based generation.

This report is a small step towards achieving a gigantic goal. The report covers different possible scenarios of demand and generation in the country in the year 2022 as well as the possible solution for meeting the demand from various available resources with minimisation of generation curtailment from renewable resources. Assessment of requirement for storage, cyclic operation of Gas based generation, peaking support from hydro generation, ramp rate and flexing of Coal based generation has been made for typical maximum renewable generation scenario, based on the available data. The effort has also been made to give some indicative cost of flexing of Coal based generation and identification of Coal based generating units for flexing. However, more exhaustive and intensive study, by using suitable modelling software, may be done to find out specific category of thermal units fit for economic flexing and the related commercial aspects like Capex & Opex cost etc.

I hope that this report would provide a roadmap for further studies and it would facilitate various stakeholders to formulate strategy for managing the large penetration of renewable in the Indian Electricity Grid.

(Prakash Mhaske)

P.D. SIWAL
Member

सत्यमेव जयते

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PREFACE

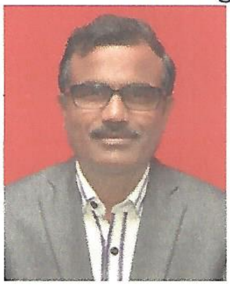
Electricity at affordable price having minimal environmental footprint will be the focus of future growth in the country. India is committed to achieve nationally determined contribution (NDC) of 40% of installed renewable capacity by 2030. Considering 175GW installed capacity of renewables in the year 2021-22 out of the total installed capacity of 479 GW and the mandate of must run for the renewables will require extensive support. It was with this intention; a committee was constituted by CEA on 8th February,2018 to study remedial measures required to maintain the grid integrity. The first meeting was held on 16thFeb 2018which was attended by the members from CEA, POSOCO, NTPC.

The report covers assumptions made, study methodology, Business-As-Usual (BAU) case, coordinated effort, flexibility at the power plant level, optimum scheduling and the costs involved in the flexible operation of coal-fired units.The problem in hand was compiling the existing data regarding the installed capacity as well as generating capability of various type of generation and daily load profile curves. This data was extrapolated for the year 2022. The restrictions imposed by must run renewable generation on othertype of generation was evaluated. To meet the load profile on a high renewable generation day,firstly all options of shifting the storage type generation were examined, followed by the operation of base load units at part load. It would call for the review of - the capability of existing units, design requirement of units which will be commissioned in future for the safe flexible operation with minimum loss of equipment's life. Finally, the methodology for optimum scheduling and cost involved for flexible operation of thermal units in Indian context have been envisaged in the report.

I wish to express my profound gratitude to all the members of committee and experts for their active participation and valuable suggestions during the deliberations of the committee and presentations made to the authority. I would specially like to place on record the contribution of Sh. B. C.Mallick, Chief Engineer, TPRM, CEA for formulation of the entire report.

(P.D.Siwal)
Member (Thermal)

Bikash Chandra Mallick
Chief Engineer



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Acknowledgement

The report, “Flexible Operation of Thermal Power Plant for Integration of Renewable Generation” has been brought out considering renewable installed capacity of 175 GW in the year,2021-22. The variability of solar & wind generation has to be taken care by supplying flexible generation from other sources of generation to ensure the grid security and stability. As about 80% of country’s energy demand is being met from thermal power plant, the responsibility of providing maximum flexible generation remains on the thermal sector.

In the first meeting of the committee held on 16th January,2018 the methodology to find out the amount of flexible generation required for integration of generation from 175 GW installed renewal capacity was discussed. It was decided to forecast the hourly generation from all type of sources for each day of the year,2021-22. Basic data was collected from Planning, Hydro and thermal wing of CEA, POSOCO and MNRE to predict the future generation.

In the subsequent meetings the committee analyzed all basic data received and predicted figure of generation, ramp rate, minimum thermal load etc. The committee received three sets of basic renewable generation data from MNRE and Soft Bank. On the basis of these data, three sets of hourly renewable generation were predicted for 365 days of the year,2021-22. The maximum generation of 107 GW, 108 GW and 97 GW were predicted on 25th June, 27th July and 9th July respectively in the year,2021. The committee accepted the highest renewable generation of 108 GW for further study to find out the amount of flexible generation required for integration because it will create worst case in terms of minimum load operation of thermal units. It is inferred that smooth integration of 108 GW on 27th July,2021 would ensure integration of any amount of renewable generation less than 108 GW into grid.

The committee has considered hydro & gas generation flexing and two shift operation of old & small size thermal units and also suggested to utilize existing pumped storage for optimization of total system instead of individual system. The committee has proposed regulatory intervention to make the attractive tariff for flexible power. It is also suggested to establish pumped storage / battery storage and finally the flexible operation of thermal units. Further, demand side management would enable more rational consumption pattern of electricity facilitating integration

of renewable generation. All the efforts have been made to reduce the burden of flexible operation on consumers. Financial analysis of flexible operation of thermal units was also done on the basis of the study conducted by NTPC. Finally, the methodology for selecting thermal units for optimum flexible operation has been identified.

I express my sincere thanks to all the members of the committee for providing inputs on methodology, base data and for active participation & valuable suggestions made during the deliberations of the committee. I am thankful to Shri Prakash Mhaske, Chairperson, CEA, Shri P. D. Siwal, Member (Thermal), CEA and Shri Aniruddha Kumar, Joint Secretary, MoP for their valuable guidance to the committee. The efforts made by Shri Prabhjot S. Sahi, Deputy Director, TPRM Division in analysis of data and formulating the report is appreciable. I also like to thank Shri A. K. Sinha, Deloitte, Shri Mahesh Kumar, GE and Smt. Rishika Sharan, Director, PSPA-II, CEA for providing valuable inputs for the study.

Bmallik

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

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Abbreviations and Acronyms

ACE	Area Control Error
AGC	Automatic Generation Control
APC	auxiliary power consumption
BAU	Business-as-Usual
CAES	compressed air energy storage
CAPEX	capital expenditure
CCGT	combined cycle gas turbine
CEA	Central Electricity Authority (India)
CERC	Central Electricity Regulatory Commission (India)
CUF	capacity utilisation factor
CTU	central transmission utility
DC	direct current
DCS	Distributed Control Systems
DR	demand response
DSM	deviation settlement mechanism
ED	economic dispatch
FD	forced draft
FR	frequency response
FRAS	Fast Response Ancillary Services
FL	full load
GDP	gross domestic product
GE	General Electric
GIZ	Gesellschaft für Internationale Zusammenarbeit (Germany)
GTG	Greening the Grid
HP	high pressure
ID	induced draft
IEA	International Energy Agency
IGEF	Indo German Energy Forum
INDCs	Intended Nationally Determined Contributions
IPP	Independent Power Producer
IT	information technology
NEMMP	National Electric Mobility Mission Plan
NESM	National Energy Storage Mission
Net Load	Total load minus renewable generation
MTL	Minimum Thermal Load

MOP	Ministry of Power,India
OCGTs	Open-cycle gas turbines
O&M	operation and maintenance
OEM	original equipment manufacturer
OPEX	operational expenditure
PA	primary air
PC	Pulverised coal
POSOCO	Power System Operation Corporation (India)
PPA	power purchase agreements
PSH	pumped storage hydro
PV	photovoltaic
RES	renewable energy sources
RRAS	Reserve Regulation Ancillary Services
RTE	round trip efficiency
TOD	time of day
TSO	Transmission system operator
USAID	United States Agency for International Development
VRE	variable renewable energy

Units of Measure

GW	gigawatt
h	hour
Hz	hertz
kV	kilovolt
kW	kilowatt
kWh	kilowatt-hour
Rs/KWH	Rupees per Kilowatt hours
min	minute
MMSCMD	million metric standard cubic meter per day
MVA	megavolt ampere
MW	megawatt
MWh	megawatt hour
MW/min	megawatts per minute
s	second

1. Executive Summary

Integration of Renewable generation into the Indian electricity grid is a challenge as well as an opportunity. In anticipation of the changing role of thermal power in the Indian power sector and its crucial role in making best use of renewable sources, this report has been brought out. Here in, an attempt has been made to capture the gravity of the situation by analyzing the generation trends expected in 2021-22 based on historic data, provide preliminary estimates of the costs involved and the measures required for flexibilisation as discovered in low load pilot tests and studies of thermal units.

Under Part I of the report, the implications of large-scale renewable generation integration and the need for flexible operation of other type of generating units has been described. It is found that, in the Indian context, while Coal is expected to provide majority of the flexibility, Hydro and Gas are also expected to play a pivotal role. Along with flexible operation of Coal, Hydro & Gas plant, Demand Side Measures would ease the constraints posed by large-scale integration of renewable generation.

Maximum renewable generation entering the grid is found to be around 108 GW, which occurs in the month of July, 2021. This is on expected lines due to availability of high wind and solar generation during the monsoon season in India. Considering daily total demand as per 19th EPS and RE generation as projected, the maximum & minimum generations required in a day from thermal plants are calculated. Similarly, the minimum thermal load (MTL) and maximum ramp up/ ramp down rates required from coal-fired units are projected for 365 days of the year 2021-22 (given in Annexure-IA). The most critical day from the point of view of maximum flexing of thermal generation is found on 27th July 2021 when required minimum load operation of thermal plant is as low as about 26%.

Factors deciding the minimum thermal load (MTL) of coal-fired plant are off-peak & peak grid demand, solar & wind generation as well as generation from other type of sources at the time of off-peak and peak grid demand. An analysis of lowest Minimum Thermal Loading (MTL) day, an average day during monsoons, an average day during non-monsoon and the best-case scenario is presented. Next, three steps of coordination among fuel sources are envisaged under part II of the report, to tackle the issues & challenges of RE integration into the Indian grid. Step-I invites flexible power from Hydro & Gas with both sources generating less during day and more during the peak hours compared to the present trend of generation. Under Step -2, flexible power from pump or battery storage or combination of both and evening peak support from coal-plants under two-shift operation has been considered. Under Step-3, option of RE curtailment has been explored. It is found that even though RE curtailment ought to be discouraged in the long run, considering current high prices of storage technologies around 1% curtailment of renewable energy on annual basis may be allowed for security & stability of the grid.

Fortunately, in the Indian context, ramp rates, which are calculated from the hourly renewable and conventional generation figures, are not a challenge for integration of renewable generation. Individual power plants, however, need to be capable of ramp rates of at least 1%/min.

Establishment of a financial framework is essential in order to enable countrywide adoption of flexible operation by the thermal power plant operators. In this regard, technical analysis of flexible operation has been conducted exclusively on various size of thermal generating units and a preliminary estimate of the capital investment & increase in operational expenditure for flexible operation of thermal generating unit has been reflected in part-III of the report. Accordingly, a road map has been suggested for economical flexible operation of various size of thermal units in part IV of the report. A case study, on the lowest MTL day, is carried out based on suggested methodology.

2. Background

Technology advancements within the power sector are keeping the industry in a state of continuous learning and adoption. The global community has set an exalted objective of limiting global warming to well below 2°C under Paris agreement and this can only be achieved with significant decarbonisation of energy systems over the long run. Renewable energies, especially wind and solar PV along with efficiency improvement measures are playing a fundamental role in reaching this goal.

Given the specific characteristics, renewable energy technologies are fundamentally changing electricity systems and markets. More variable power production increases the flexibility requirements placed on the overall power system particularly on the supply side. Similarly, higher and more variable residual loads increase flexibility requirements placed on overall power system. While challenges have increased and become more and more complex for the policy makers, investors and power system operators, it also offers unprecedented opportunities.

India's Intended Nationally Determined Contributions (INDCs) include reduction in the emissions intensity of its GDP by 33 to 35 per cent by 2030 from 2005 level, and to create an additional carbon sink of 2.5 to 3 billion tons of CO2 equivalent. Generating power from renewable sources of energy is of cardinal importance if India is to meet its INDC targets. The country expects to have a renewable install capacity of 175 GW and daily net load swings of up to 80 GW by 2021-22. This creates an urgent need to lay out clear roadmap to address large renewable integration in a very short time.

The present report is an outcome of the committee constituted under the Chairmanship of CE (TPRM), CEA having representation from CEA, NTPC and POSOCO. The terms of reference of the committee are the following: -

- Identify the quantum of flexible thermal power and ramp rate required from thermal power plants in terms of GW and MW/min respectively, in order to maintain secure and stable grid in the year,2021-22.
- Suggest a methodology for identification of units for implementation of required minimum load operation on priority basis.
- Develop a road map for implementation of the measures on all India basis.

The committee members include: -

1. Shri B. C. Mallick, CE (TPRM), CEA – Chairman
2. Shri Rajeev Kumar, Director (TPRM), CEA – Convener
3. Shri Upendra Kumar, SE, NRPC, CEA- Member
4. Shri Rakesh Kumar, Director (HPP&I), CEA – Member
5. Shri Vikram Singh, Director (GM), CEA- Member
6. Shri A. K. Sinha, AGM, NTPC – Member
7. Shri N. Nallarasan, DGM, POSOCO - Member
8. Smt. P. E. Kamala, DD (IRP), CEA - Member

In a review meeting chaired by Joint Secretary (Thermal) on 11th July 2018, it was decided to cover technical capability and economic feasibility of the power stations for flexible operation under the study. Further, it was recommended to include an analysis of the framework required to facilitate and incentivize flexibilisation of thermal power stations. The minutes of the seven meetings of the committee held on 16th Feb, 23rd Feb, 5th Apr, 26th Apr, 12th June, 9th July and 11th July 2018 are enclosed at Annexure V.

The current study derives expertise from various divisions of CEA, and studies done by POSOCO, NTPC, GE & SIEMENS and tries to address these concerns through a data driven analysis.

3. Objective

The first objective of the study is to forecast the future generation scenario for the year 2021-22 and compare with demand as projected in the 19th EPS to estimate the extent of flexibility & ramp rate required in the system on account of demand as well as solar & wind generation variation considering entire renewable generation to be accommodated in the grid round the clock. The second objective is to view the situation from the point of thermal plant operation and find out the kind of minimum loads that thermal plants would be required to run at in future. The third objective is to suggest various combinations of generation which can achieve the required integration at minimum cost. The fourth and final objective is to identify the measures to be implemented in Thermal Power Stations in order to make them capable of flexible operation.

The entire power system & policies are addressed to ensure integration of renewable with following key objectives:

- Grid security
- Reliability of generating unit
- Minimize the cost of flexible operation
- Maximize renewable integration
- Minimize investments by optimal utilization of existing assets and infrastructure

The aim is to ensure security, reliability & stability of electricity grids for supplying affordable & reliable power to the consumer while maximizing generation of power from renewable energy sources (RES) & integration of the same into grid.

4. Basic Definitions

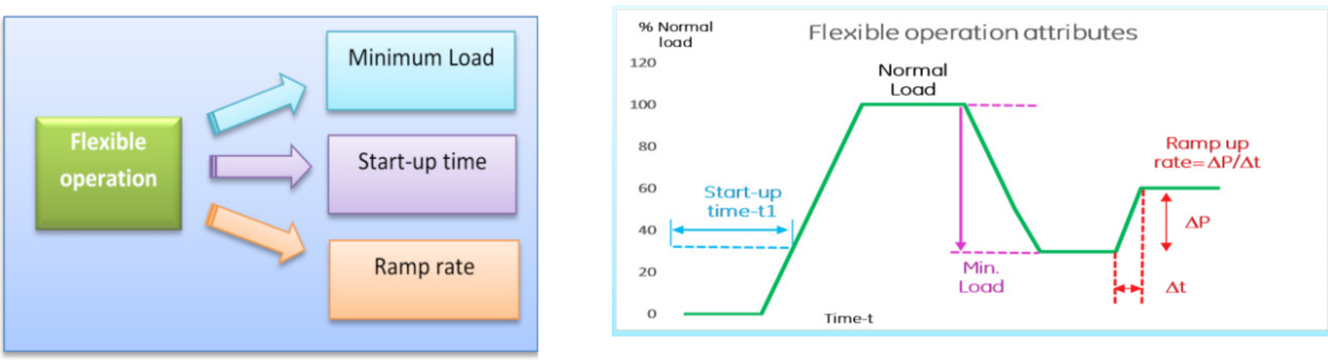
Flexibility: The term and concept of power system flexibility has evolved over time to reflect the way technology and power markets have evolved. The term was first introduced in IEA (2008) as: "…The ability to operate reliably with significant shares of variable renewable electricity."

A more specific definition was put forward in IEA (2011): "*Flexibility expresses the extent to which a power system can modify electricity production or consumption in response to variability, expected or otherwise.*" IEA (2014) introduced a distinction between a broader concept of flexibility and a narrower concept of ramping flexibility: "*In a narrower sense, the flexibility of a power system refers to the extent to which generation or demand can be increased or reduced over a timescale ranging from a few minutes to several hours.*"

RES: Unless mentioned otherwise, the term RES or Renewable Energy Sources has been used to represent Solar and Wind power. Biomass and Small Hydro have been mentioned separately whenever required.

Minimum Load: The minimum load is the lowest possible net load a generating unit can deliver under stable operating conditions. It is measured as a percentage of normal load or the rated capacity of the unit. Graphical representation of minimum load is depicted in the chart.

Figure 1 Flexible operation attributes



Start-up time: The start-up time is defined as the period from starting plant operation till reaching minimum load. The start-up time of different generation technologies varies greatly. The other factors influencing the start-up time are, down time (period when the power plant is out of operation) & the cooling rate. Type of start-up for power plants is given below:

Table 1 Type of start-up for power plants

Type of start-ups	Time unit is out of operation	Typical time-coal	Typical time-CCGT
Hot	**<8 hrs.**	**2-3 hrs.**	**<1.5 hrs.**
Warm	**Between 8 to 48 hrs**	**3-5 hrs.**	**~2 hrs.**
Cold	**>48 hrs.**	**5-10 hrs.**	**~2-3 hrs.**

Ramp rate: The ramp rate describes how fast a power plant can change its net power during operation. Mathematically, it can be described as a change in net power, ΔP, per change in time, Δt. Normally the ramp rate is specified in MW per minute (MW/min), or in the percentage of rated load per minute (% P/min). In general, ramp rates greatly depend on the generation technology.

Minimum Thermal load (MTL): The MTL is the ratio of actual minimum load on the prime mover of a thermal power station and its rated capacity. E.g. if a 200 MW plant runs at minimum load of 120 MW during a day, then the MTL for that plant is 120/200 i.e. 60%.

Thermal: The term "thermal" is generally used to represent both Coal and Gas based power stations. However, in the context of this report, Gas based power stations are considered a separate category. The term "thermal" in this report is used to represent only coal-fired power plants including the lignite-based ones.

5. Assumptions

While estimating the quantum of flexibilisation required from coal-fired power plants, the following assumptions have been made in the absence of which the modelling becomes too complex and error-prone.

- The hourly generation pattern of Hydro, Nuclear and Gas in 2021-22 is a function of the historic pattern followed by them.
- Nuclear, Biomass and Small Hydro power plants are operated as base load in the study.
- Certain unplanned changes / events like rare or excess monsoon have not been accounted for. Current targeted capacity addition of RES i.e. 175 GW is considered in the analysis.
- Assumptions made for calculation of flexibilisation costs are given in Annexure III.

6. Methodology of the Study

In order to identify the quantum of flexibilisation required from coal-fired power plants, the future demand and generation from all types of sources needs to be anticipated. The national electricity demand for the year 2021-22 has been collected from 19th EPS. The generation from different technologies in future can be reliably predicted from their historic generation profiles. The year for analysis in our report has been fixed to be 2021-22 when 175 GW RE installed capacity is available for generation.

For part IV of the report, the analysis is based on the capacity of the thermal plant in the year 2021-22 to meet the quantified flexibility requirements of the system. This has been done by analyzing the countrywide data of all the units. Analysis was done to find how different types of power plant are positioned to provide different types of flexibility modes.

For this purpose, the committee has collected data from all individual thermal units in the country to get an estimate of flexible power. The data on the following parameters was collected.

Table 2 List of variables on which data was collected from thermal units in the country

Unit Capacity	**Boiler make**	**Heat Rate**	**Energy Charge Rate**
Age of Unit	**Turbine Make**	**APC**	**Coal Source**
Plant Load Factor	**Mills Type**	**Minimum Load**	**Ramp Rate**

Part I: Power System Analysis

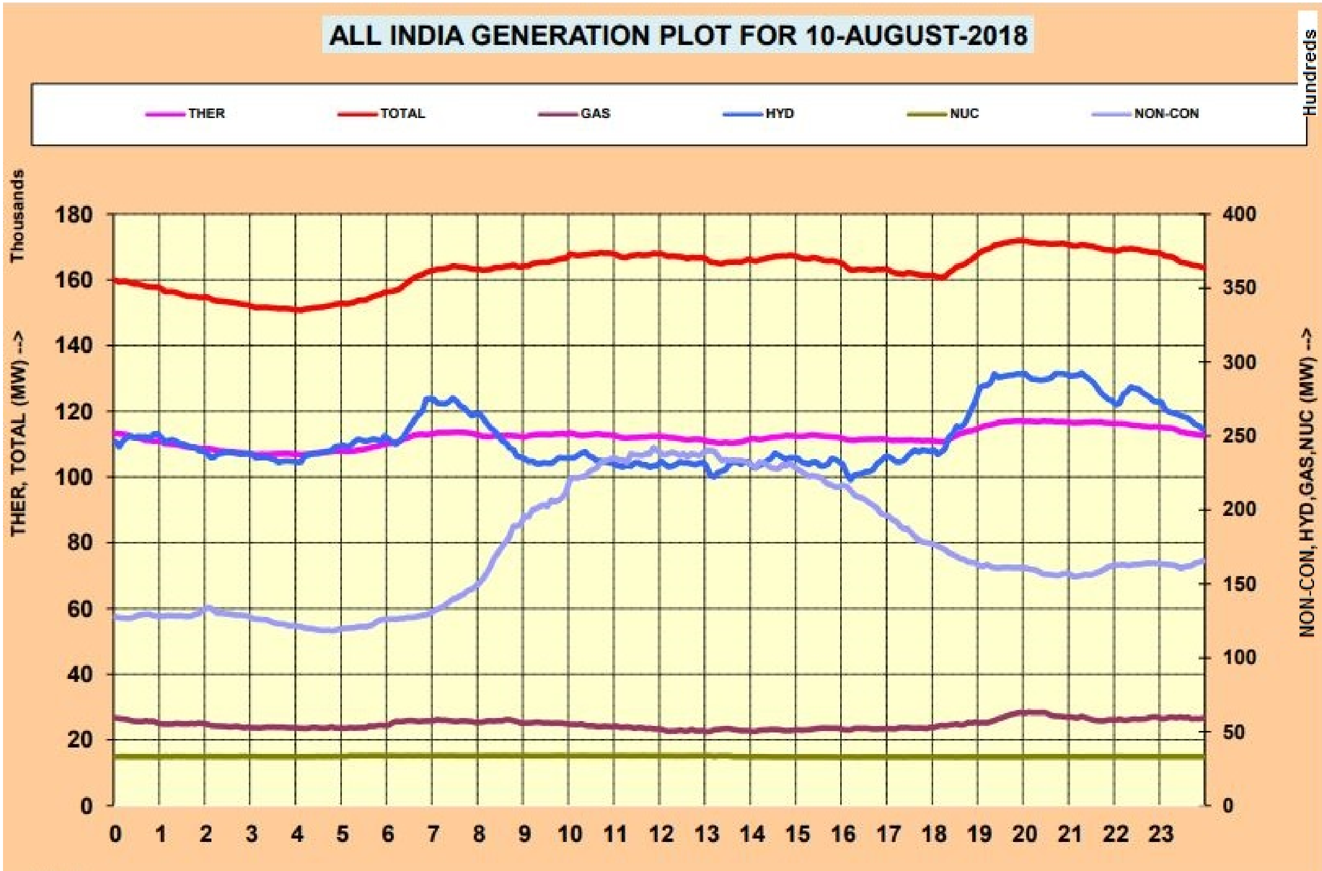
7. Present Scenario

The generation scenario for highest demand day of August 2018, sourced from POSOCO, is given in the table and chart below. The current installed capacity of renewables is 70 GW out of which maximum power during the day produced by RES is around 23.5 GW, which reduces to around 11.7 GW at night. As online generation data is not received from all RE plant, the actual generation figure may be higher than what is recorded at the NLDC. The percentage variation gives an idea as to how much flexing is currently being done by each fuel source. Even though quantum of total ramp up done by coal is more it is still running at a much stable load, in comparison to hydro, due to its larger installed base. Compared to coal, hydro is a major contributor here due to its ability of quick start-stop and quick ramping.

Table 3 Variation in demand met on 10-August-2018

Fuel Source	Minimum Demand Met (GW)	Max Demand Met (GW)	Difference (GW)	% variation (%)
Coal	107	118	11	10.28%
Hydro	22	29	7	31.82%
Gas	5	6	1	20.00%
RES	11.7	23.5	11.8	100.85%

Figure 2 All India Fuel-wise Generation Patterns for 10-August-2018



Source: POSOCO Monthly Report August 2018

8. BAU Generation Forecast for 2021-22

Historic generation profile is used to estimate the future generation. The historic data has been collected from IRP Division, CEA and POSOCO.

The installed capacities for 2021-22 of various sources are given below.

Table 4 Installed Capacity for 2021-22 of various sources

Fuel Type	Capacity (MW)	%
Hydro	51,301	10.7
Coal + Lignite	2,17,302	45.3
Gas	25,735	5.4
Nuclear	10,080	2.1
Total Conventional Capacity*	**3,04,419**	**63.5**
Total Renewable Capacity	**1,75,000**	**36.5**
Total Capacity by 2021-22	**4,79,418**	**100.0**

Source: National Electricity Plan (NEP), CEA.

8.1 Scaling of Historic Data

The historic generation data has been scaled as follows:

Solar, Wind, Nuclear & Hydro: The previous three-year generation (years 2014 to 2017) is averaged on hourly basis for the complete year. The average is then scaled based on the installed capacity in 2021-22.

Gas: The data for generation from gas in the year 2016-17 has been scaled based on installed capacity of gas in 2021-22.

Small Hydro, Biomass: Since no reliable data is available for these small renewable sources, straight-line assumption of 1000 MW and 2000 MW generation for Small Hydro and Biomass respectively have been considered.

Coal: Generation from coal-fired plants (coal + lignite) is a derived quantity and is calculated after subtracting total hourly generation of other types of sources in a day from the hourly demand of that day.

8.2 Demand, Generation and MTL

The historic generation data has been scaled as follows:

An analysis of the generation, demand, Minimum Thermal Load (MTL) of coal-fired power plant for 365 days of the year 2021-22 is given in Annexure IA. A summary of maximum demand, maximum RES and MTL on some significant days (Highest Demand Day, Lowest Demand Day, Highest RE Day, Highest Ramp Down Day, Highest Ramp Up Day, Lowest MTL Day) of the year 2021-22 is given in Annexure IB. As stated earlier, electricity demand for the year 2021-22 has been collected from 19th EPS and generation has been predicted for conventional as well as non-conventional power plant.

A month-wise summary is presented below.

Month	Maximum Total Power Demand in the month (MW)	Max RE (W+S) in the month (MW)	Minimum Coal Based Generation (MW)	Maximum Coal Based Generation (MW)	MTL (Monthly Average)	Critical Day of the month	MTL on critical day
1	2	3	4	5	6	7	8
April	199528	81274	65863	153321	50.27%	19	41.23%
May	199811	92496	59368	146312	46.22%	29	39.41%
June	205164	105715	40589	149471	43.22%	25	29.91%
July	203396	108926	32665	129603	34.56%	27	25.73%
August	207558	101046	37897	140967	42.46%	15	29.29%
September	209907	80771	70462	157679	54.29%	1	47.60%
October	225751	62580	94310	175611	60.93%	18	58.04%
November	201763	71101	82151	156651	58.90%	16	51.77%
December	198987	83154	80071	158497	56.23%	29	50.67%
January	202651	81285	79493	160862	54.26%	27	50.96%
February	206484	82015	81150	161981	54.79%	4	50.01%
March	206749	75316	73474	161301	54.57%	13	48.21%

Column 1 represents a month of the year 2021-22.
Column 2 gives the maximum total national demand anticipated in a day of the month.
Column 3 gives the maximum renewable generation in the month.
Column 4 gives the minimum demand to be fulfilled by coal-fired units after BAU generation from other fuel sources. This usually occurs at the time of peak solar generation.
Column 5 gives the maximum demand to be fulfilled by coal-fired units after BAU generation from other fuel sources. This usually occurs when solar generation is zero.
Column 6 is the monthly average value of the daily minimum thermal load
Column 7 represents the day of lowest minimum thermal load in a month.
Column 8 gives lowest minimum thermal load (%) in a month.

9. Analysis of Critical Period in the Year 2021-22

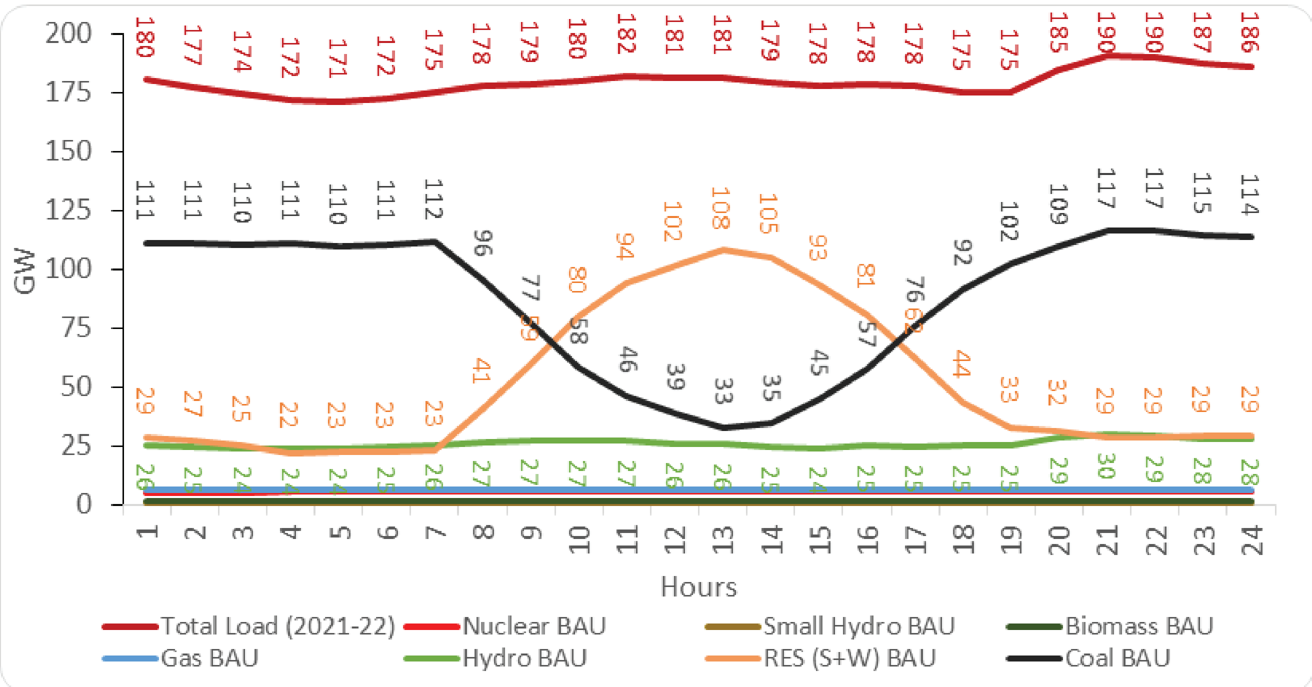
As per prediction, highest ever renewable generation of 108926 MW will be integrated into the grid on 1st July 2021, at a time when grid demand would be 192322 MW. However, the day of lowest MTL (25.73%) is found to be 27th July 2021, when 108082 MW of solar & wind generation will be integrated into the grid at 1200 hrs. and the grid demand would be 181151 MW during the integration. This integration during off-peak hours (12:00 hrs) would cause thermal generation to back down to 79207 MW with a maximum ramp down rate of 310 MW/min.

The Peak grid demand on 27th July would be 190480 MW at 20:00 hrs. and maximum ex-bus generation of 116769 MW will be required from thermal units at 21:00 hrs on the day. Considering 10% reserve of the maximum thermal generation required and assuming 7% average auxiliary consumption, 139508 MW thermal capacity out of a total available capacity of 217 GW shall be synchronised. The same capacity connected to the grid will run at partial load during off-peak / high RES generation hours and produce 32665 MW ex-bus generation to balance the grid. Assuming 9% APC at partial load the gross generation will be 35895 MW. Thus, the ratio of minimum to maximum generation of thermal units will be 25.73%. Thus, about 26% minimum load operation of thermal power plant will be required on 27th July 2021. Perhaps, that is the worst situation in terms of minimum load operation of thermal power plants.

The 108 GW is the highest available generation from RES in the year 2021-22. Thermal power plants are required to operate at average 25.73% minimum load to accommodate the RES generation into grid and to balance the system. This is the most challenging situation in the system to maintain a stable & secure grid.

The forecasted contribution from different fuel sources in meeting the grid demand on 27th July 2021 as per the BAU scenario is shown in the following chart.

Figure 3 Contribution from different fuel sources in meeting demand - 2021



The following inferences are drawn from the above graph.

RES Generation
RES generation on 27th July 2021 varies from a minimum of 22295 MW at 300 hrs. to 108082 MW at 1200 hrs. The highest generation from RES during the entire year is 108926 MW and occurs at 1200 hrs on 1st July 2021.

Hydro Generation
Maximum generation from hydro during the entire year is 37228 MW that occurs on 19th August 2021.

Gas Generation
Gas generation in BAU case varies between 4.5 and 11 GW in the whole year. However, on one particular day the variation is not more than 2 GW. It may be noted that this much generation is being obtained against a substantially higher installed capacity of around 26 GW in 2022.

Biomass and Small Hydro Generation
Biomass and Small Hydro have been assumed to operate at constant load of 2000 and 1000 MW respectively.

10. Analysis of Ramp Rate of Coal Generation in 2021-22

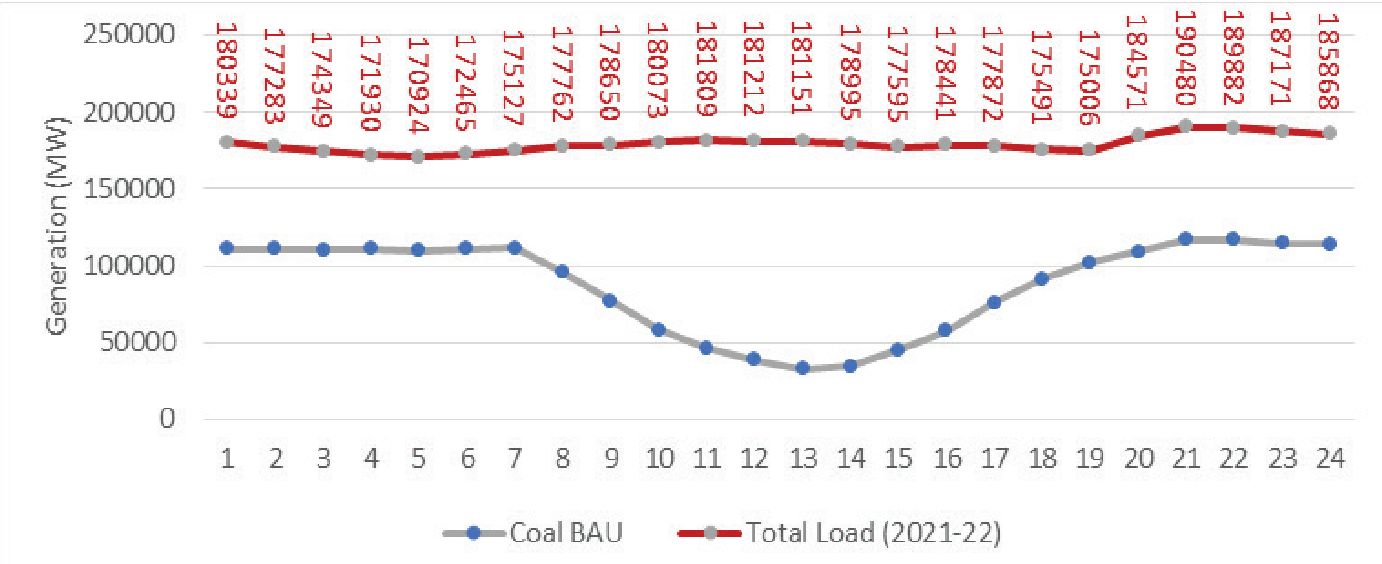
An analysis of the coal ramp rates in the year 2021-22 has been conducted and following maximum values are observed.

1. Maximum Ramp Up Rate: 379 MW/min on 3rd February 2022 (Demand = 200 GW)
2. Maximun Ramp Down Rate: - 422 MW/min on 13th March 2022 (Also the lowest demand day, Demand = 185 GW)

On both days renewable generation is about 75 GW and expected MTL on 3rd February & 13th March is 53% & 48% respectively. Refer Annexure I-B for more details.

The maximum value of ramp up and ramp down on 27th July,2021 is given in the following chart.
Ramp Down Rate: Max. ramp down rate is 310 MW/min. at 9:00 am.
Ramp up Rate: Max. ramp up rate is 305 MW/min. at 16:00 hrs

Figure 4 Coal Ramp values on 27th July, 2021



Since 15 minutes' renewable generation data was not available, the analysis was conducted on hourly basis. Therefore, the actual ramp rate may be slightly higher than the predicted figure.

Required value of ramp rate in 2021-22 can be achieved as explained below. Let us consider the day of highest ramp up rate, 3rd Feb, 2022, when maximum ex-bus generation from thermal plant is 154 GW. After considering 10% reserve capacity and 7% APC, about 184 GW thermal capacity would be synchronized on that day. Considering 1%/min ramping by the scheduled units, the system capability comes out to be 1841 MW/min as shown in Table 6. This is substantially higher than the ramp up rate required on 3rd February 2022 (379 MW/min).

Table 6 Projected ramping capacity in 2021-22

S. no.	Unit Size	Capacity utilization	Capacity on Bar	Assumed Ramp	Ramp Rate
	MW	%	MW	Rate (%)	(MW/Min.)
1	< 150	40	4073	1%	41
2	200/210	80	25824	1%	258
3	250 to 360	80	30885	1%	309
4	500	80	37276	1%	373
5	600 to 800	82	86043	1%	860
	Total		184100		1841

Similarly, let us consider the highest ramp down day, 13th March, 2022. Maximum ex bus generation required from thermal is 140 GW. 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 -422 MW/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 into Indian grid.

11. Study of Transmission Systems

The study of Indian transmission network was conducted to ensure that there is no constraint in the grid during integration of renewable generation in the year 2021-22. For the purpose of transmission planning, about 60 GW of wind, 100 GW of Solar, 9 GW of Biomass and 6 GW of Small Hydro capacity have been considered. Out of the 100 GW solar, 33 GW has been considered as grid connected. The rest is considered as local consumption and have been adjusted against demand of the respective states.

11.1 Load Generation Balance: Studies have been carried out for the year, 2021-22.

Generation:

Total installed capacity of all the generation projects expected to be materialized by 2021-22 is about 480 GW including above mentioned Renewable energy sources. In this study about 4500 MW hydro import has been considered from Bhutan. All India Installed capacity and Peak Demand Expected at the end of 2021-22 are given in the table below:

Table 7 All India Expected Installed Capacity and Peak Demand (2021-22)

All figs. in MW

Region	Coal	Gas	DG	Hydro	Nuclear	Wind	Solar	Biomass	Small Hydro	Total	Peak Demand
Northern	48460	5781	0	22955	3020	8600	31119	2795	2652	125382	73770
Western	86281	11203	0	7392	3240	22600	28410	2786	533	162445	71020
Southern	42626	6844	762	12769	3820	28200	27530	2933	2045	127529	62975
Eastern	39186	100	40	6133	0	0	11737	548	297	58001	28046
North Eastern	750	1807	36	2052	0	0	1207	0	358	6210	4499
All_india	217303	25735	838	51301	10080	60000	100092	9062	6010	480421	225751
Bangladesh	0	0	0	0	0	0	0	0	0	0	1100
Nepal	0	0	0	0	0	0	0	0	0	0	600
Bhutan	0	0	0	4482	0	0	0	0	0	4482	0
All India + SAARC	217303	25735	838	55783	10080	60000	100092	9062	6010	484903	227451

Demand:

The All-India projected load demand as per 19th EPS in 2021-22 timeframe is around 227,451 MW including the demand to be met in Bangladesh and Nepal.

Hourly generation (MW) for 8760 hours of a year is considered for dispatches is considered for dispatches from different type of generations. Two cases, one for peak (21:00) and other for off-peak (12:00) has been considered for the study of power system.

The dispatches and CUF calculated from the hourly data for the peak load and off-peak load are given in the table below:

Table 8 Dispatch taken from hourly data for Peak load (21:00) - 2021-22

All figs. in MW

Region	Coal	Gas	DG	Hydro	Nuclear	Wind	Solar	Biomass	Small Hydro	Total	Average Demand	Surplus/ Deficit
Northern	31901	2000	0	17672	2312	538	0	500	200	55123	67695	-12572
Western	56799	2000	0	1682	1409	15588	0	500	200	78178	62941	15237
Southern	28061	1000	0	4309	3438	12220	0	0	50	49078	55300	-6222
Eastern	25796	0	0	4227	0	0	0	200	200	30423	25530	4893
North Eastern	494	500	0	1149	0	0	0	0	100	2243	3992	-1750
Total	143051	5500	0	29039	7159	28346	0	1200	750	215045	214689	355
Bangladesh	0	0	0	0	0	0	0	0	0	0	1100	-1100
Nepal	0	0	0	0	0	0	0	0	0	0	600	-600
Bhutan	0	0	0	1345	0	0	0	0	0	1345	0	1345
All India + SAARC	143051	5500	0	30384	7159	28346	0	1200	750	216389	216389	0

Table 9 CUF taken from hourly data for Peak load (21:00) - 2021-22

Region	Coal	Gas	DG	Hydro	Nuclear	Wind	Solar	Biomass	Small Hydro
Northern	0.66	0.35	0	0.77	0.77	0.06	0	0.18	0.08
Western	0.66	0.18	0	0.23	0.43	0.69	0	0.18	0.38
Southern	0.66	0.15	0	0.34	0.90	0.43	0	0	0.02
Eastern	0.66	0	0	0.69	0	0	0	0.36	0.67
North Eastern	0.66	0.28	0	0.56	0	0	0	0.00	0.28
All_ India	0.66	0.21	0	0.57	0.77	0.47	0	0.14	0.12
Bangladesh	0.66	0	0	0	0	0	0	0	0
Nepal	0.66	0	0	0	0	0	0	0	0
Bhutan	0.66	0	0	0.30	0	0	0	0	0
All India + SAARC	0.66	0.21	0	0.54	0.77	0.47	0.00	0.14	0.12

Table 10 Dispatch taken from hourly data for Off-Peak load (12:00) - 2021-22

All figs. in MW

Region	Coal	Gas	DG	Hydro	Nuclear	Wind	Solar	Biomass	Small Hydro	Total	Average Demand	Surplus/ Deficit
Northern	15401	2000	0	16523	2290	1007	23270	500	200	61191	67695	-6504
Western	27420	2000	0	1210	1395	18166	21835	500	200	72726	62941	9785
Southern	13547	1000	0	2481	3438	21351	12994	0	50	54861	55300	-440
Eastern	12453	0	0	2362	0	0	8470	200	200	23685	25530	-1845
North Eastern	238	500	0	1031	0	0	704	0	100	2573	3992	-1419
Total	69059	5500	0	23607	7123	40524	67273	1200	750	215036	214689	347
Bangladesh	0	0	0	0	0	0	0	0	0	0	1100	-1100
Nepal	0	0	0	0	0	0	0	0	0	0	600	-600
Bhutan	0	0	0	1345	0	0	0	0	0	1345	0	1345
All India + SAARC	69059	5500	0	24952	7123	40524	67273	1200	750	216380	216389	-9

Table 11 CUF taken from Hourly data for Off-Peak load (12:00) - 2021-22

Region	Coal	Gas	DG	Hydro	Nuclear	Wind	Solar	Biomass	Small Hydro
Northern	0.32	0.35	0	0.72	0.76	0.12	0.75	0.18	0.08
Western	0.32	0.18	0	0.16	0.43	0.80	0.77	0.18	0.38
Southern	0.32	0.15	0	0.19	0.90	0.76	0.47	0.00	0.02
Eastern	0.32	0.00	0	0.39	0	0	0.72	0.36	0.67
North Eastern	0.32	0.28	0	0.50	0	0	0.58	0	0.28
All_ India	0.32	0.21	0	0.46	0.76	0.68	0.67	0.14	0.12
Bangladesh	0.32	0	0	0	0	0	0	0	0
Nepal	0.32	0	0	0	0	0	0	0	0
Bhutan	0.32	0	0	0.30	0	0	0	0	0
All India + SAARC	0.32	0.21	0	0.45	0.76	0.68	0.67	0.14	0.12

11.2 Result of the load flow studies

The load flow studies for peak as well as off-peak conditions were conducted for the day when solar and wind generation is about 108 GW. It was found from the analysis that there is no congestion in the 400 kV and above system of the National grid.

The details of the inter-regional power flows for peak condition and off-peak condition is given below respectively.

Figure 5 Inter-regional power flows for peak/off-peak condition (2021-22)

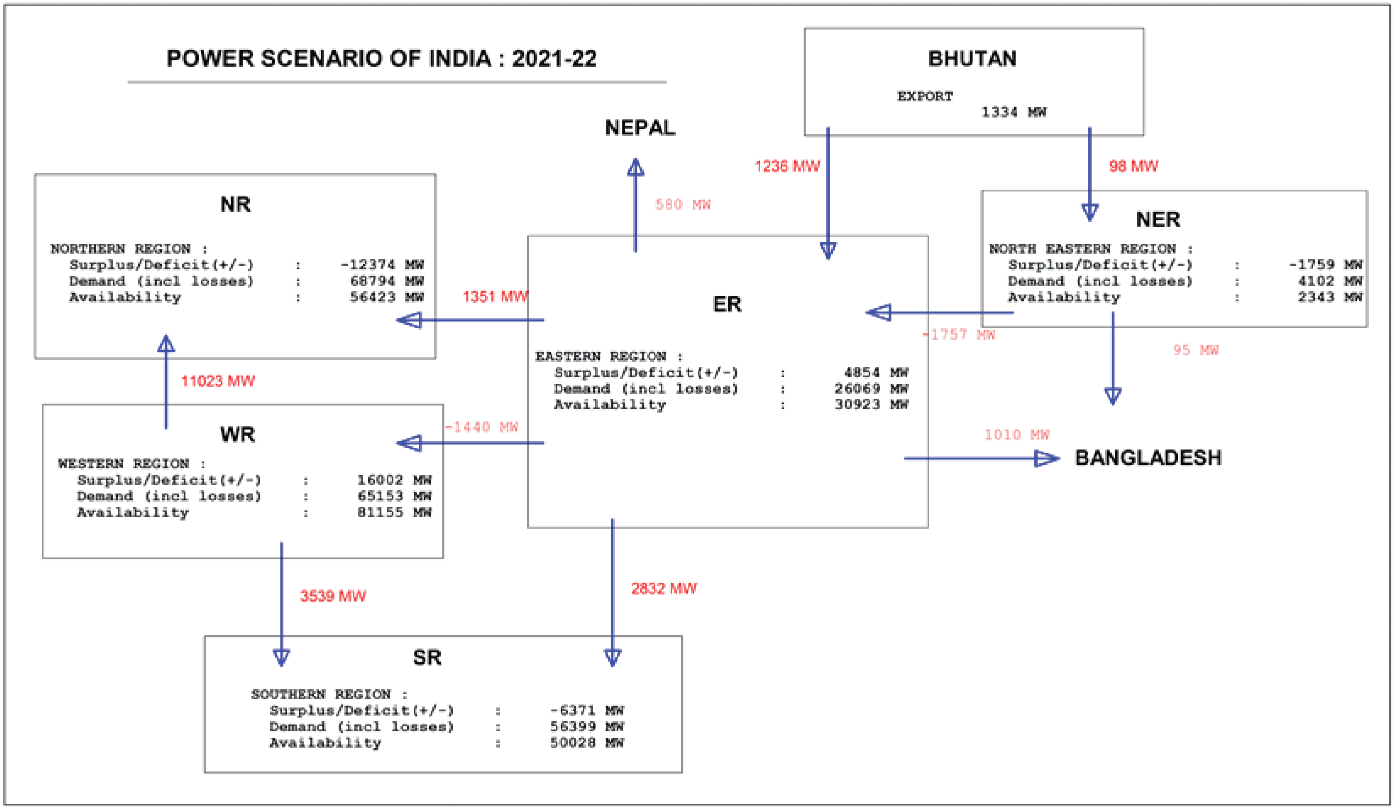
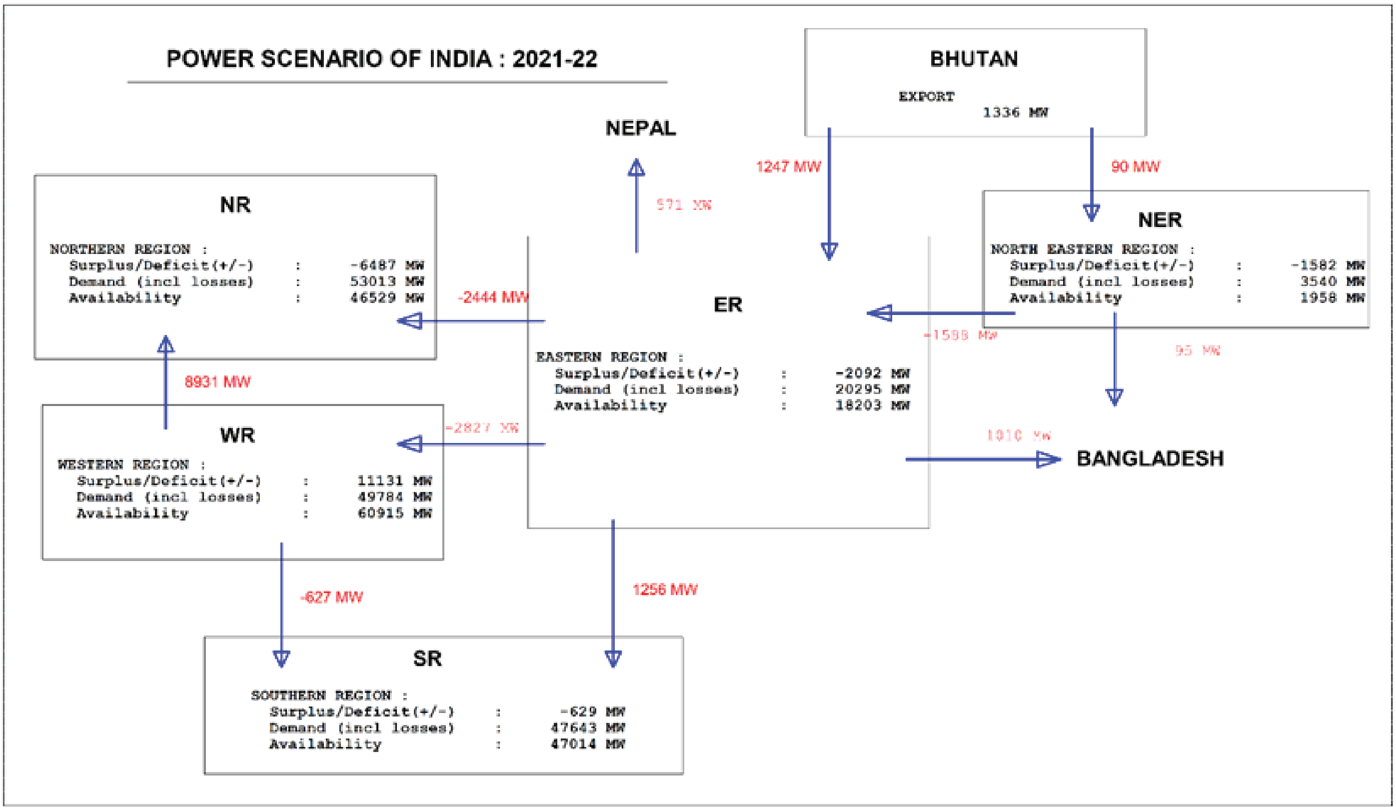


Figure 6 Inter-regional power flows for off-peak condition (2021-22)



Part II: RE Integration & Availability of Flexible Power

12. Options of Flexible Power

All over the world, the question of flexibility has been answered in different ways. In the Indian context, while Coal is expected to provide majority of the flexibility, Hydro and Gas are also expected to play a pivotal role. Along with that, Demand Side Measures would ease the constraints posed by large-scale renewable integration.

12.1 Hydro Power Plant

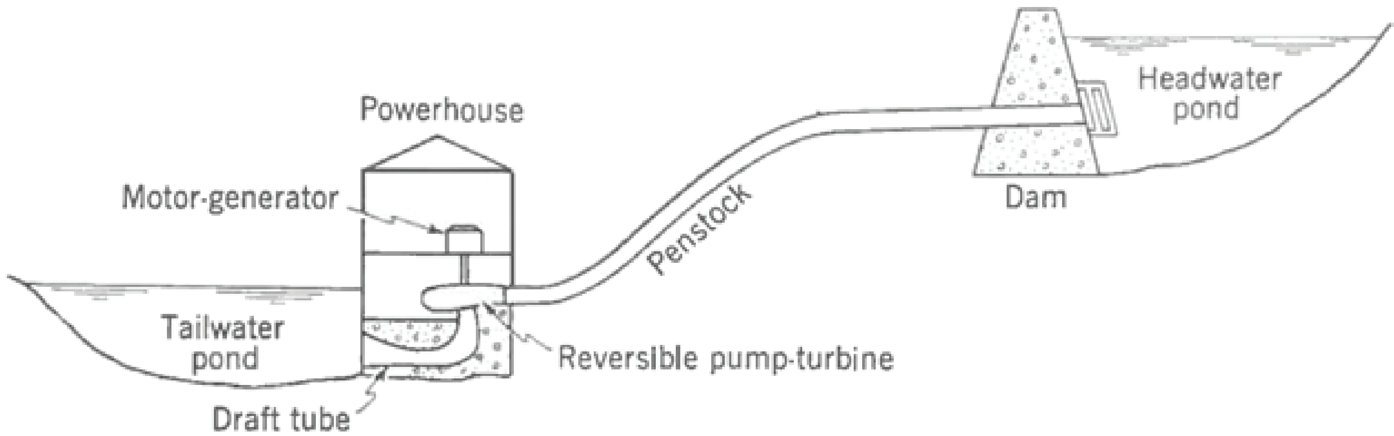
As on date, the flexible operation of hydro plant is being done to cope with the variation of peak & off-peak demand. More flexing of hydro generation is expected during integration of large-scale renewable generation. Quick start up and stop time of hydro plants make them suitable to handle the fluctuation of solar & wind generation.

12.2 Pumped Hydropower Storage

Pumped hydropower storage (PHS) is a variation of conventional reservoir hydropower technology. Its unique feature, compared to conventional schemes, is that it operates in a dual manner i.e. both as turbine and pump. A typical PHS station is presented in Figure below. When in production mode, the reversible pump-turbine feeds produced power to the grid. Conversely, power from an external source (e.g. grid, other plant) powers the pumps, when in storage mode. Dividing PHS energy output (from generation) by the recorded energy input (for pumping) provides the round-trip efficiency (RTE). The RTE is usually considered 70 to 80%. For the purpose of present study, we have taken a conservative estimate of 70%.

Figure 7 Pumped hydropower storage (PHS) illustration

$$RTE = E_{out} \ / \ E_{in}$$

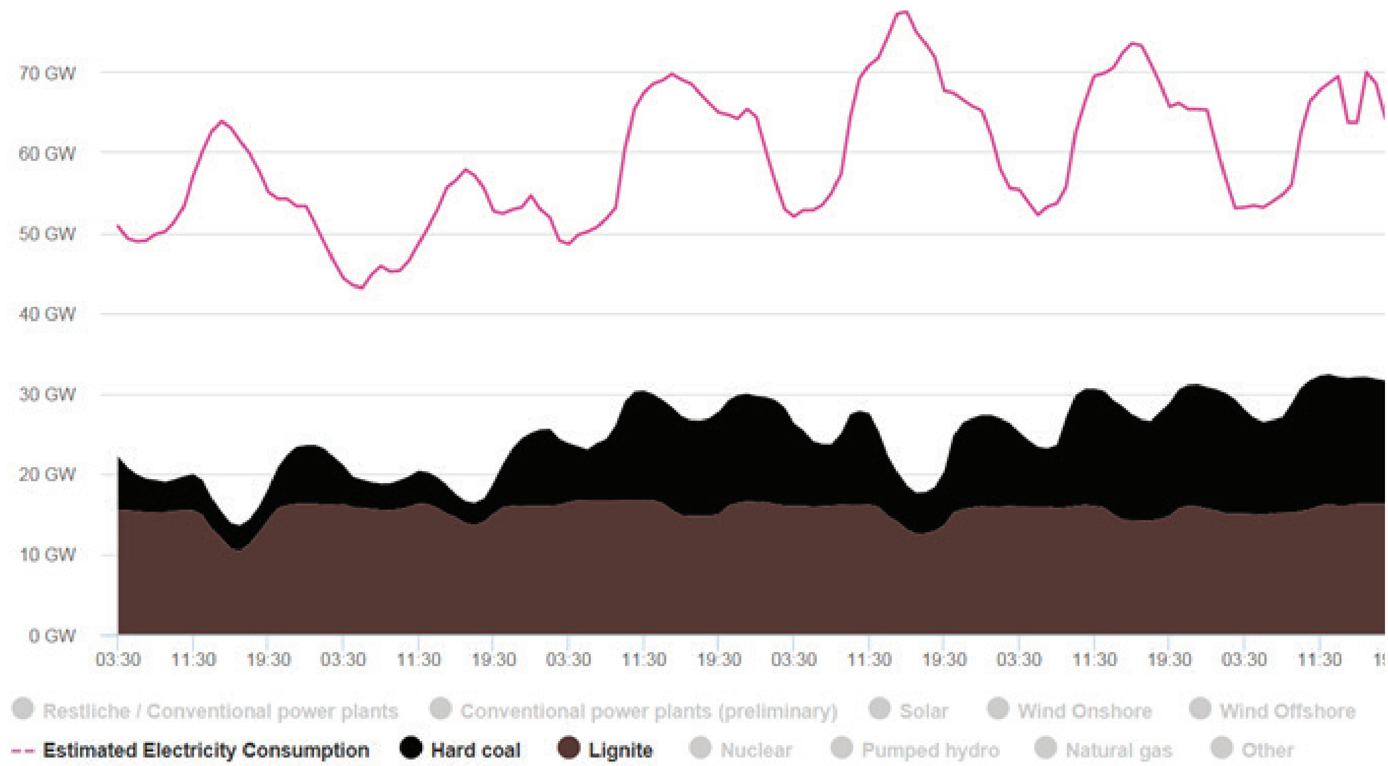


While Hydroelectricity and Gas based power are more technically capable for flexible operation, we have a small installed base of these technologies. In fact, development of pumped hydro storage schemes is a precursor to integrate renewable generation. However, in India we have a small installed base of PHS at 4785 MW. Our majority of the energy demand (around 79%) is supplied by coal-based capacity. Hence, majority of flexible power inevitably would come from the coal-based plants.

12.3 Coal Power Plants

In India, the coal fired thermal power plants have traditionally been operated as base load plants. This, however, is not the case in countries having large renewable capacities like Germany. The following graph represents hourly operation of coal-based plants in Germany for a week in September 2018.

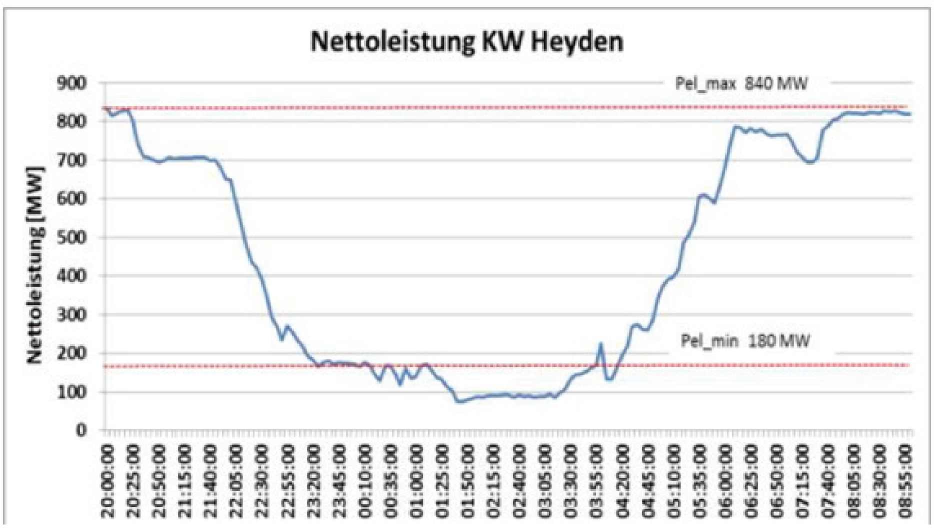
Figure 8 Operation of coal-based power in Germany - September 2018



Source: GIZ, Germany

As per a Uniper study, the Heyden power plant, an 875 MW German coal-fired power plant, located in the state of North Rhine-Westphalia, has demonstrated stable operation at 10% minimum load with one mill operation (Graph below).

Figure 9 Operation of Heyden power plant in Germany



As per CERC notification, under section 79(1) h of the Indian Electricity Act,2003, technical minimum load of thermal unit is 55%. Therefore, maximum flexible power available from thermal plant in any day is equal to about 45% of grid connected thermal capacity on that day. This is not the present situation of Indian grid as most of the state generating companies are not maintaining 55% minimum thermal load. It is therefore proposed that the similar provision of 55% technical minimum load of thermal units shall be adopted by SERC under the section 86 of the Electricity Act 2003.

12.4 Gas Power Plants

Open cycle gas plants are very suitable for balancing and ramping requirement of the grid because of their quicker start and stop time. However, efficiency of open cycle gas based plants is lower than that of the closed cycle ones. All India installed capacity gas based plants is around 24,937 MW, out of which 350 MW open cycle and the balance are closed cycle plants. The new gas-based combined cycle power plants offer higher efficiency and can go from start to full load quicker. Around 30 minutes are required by the unit for either start-up or shutdown. Therefore, these plants are suitable to cater the variability of Solar & Wind generation. Around 21 GW of capacity is connected to gas grid while 3 GW is fed through local gas field. Around 15 GW of gas stations are supplied with domestic gas. Currently, the all India gas generation profile shows an almost steady operation with the difference between maximum and minimum generation at around 15 - 20%.

As per NEP, to run a gas plant at a PLF of 85%, normative gas requirement would be about 110 MMSCMD. This is significantly more than the present availability of 29.88 MMSCMD. However, optimization studies have shown that for integrating renewables of 175 GW by 2021-22 and to meet the peaking and ramping requirement of the system, PLF of gas based capacity during 2021-22 is likely to be around 37% compared to around 22% at present. The gas requirement is of the order of about 45.27 MMSCMD.

12.5 Demand Side Management

Demand-Side Management (DSM) refers to initiatives that help end-users to optimize their energy use. With DSM, consumers can reduce their electricity costs by adjusting their time and quantity of use. Following measures are expected to contribute in improving the flexible power scenario from the demand side.

- **Time of Day Tariff:** Time of Day (or TOD) tariff is a tariff structure in which different rates are applicable for use of electricity at different time of the day. It means that cost of using one unit of electricity will be different in morning, noon, evening and night. The provision is currently under examination by the regulators and would contribute positively towards RE integration when it comes into force.
- **Open Electricity Market:** Separation of carrier and content as envisaged in Electricity (Amendment) Act, 2014 would encourage demand side response. Consumers would be able to manage their energy cost with more options available to them. Consumers (including households) would be able to choose their electricity retailer offering the best electricity price plans for their businesses and homes. Consumers can benefit from retailers offering diverse electricity plans including possibly time-varying pricing and energy management packages.
- **Demand response from High Voltage industrial consumers:** Energy consumption of high voltage electrical items such as arc furnace, HVAC, compressors, chillers or pumps can be managed in a more efficient manner by time varying tariff.
- **Supply of electricity to agriculture sector by dedicated feeders:** Separation of electricity feeders for agriculture from domestic and industrial load would be a measure in favour of grid security. Separate feeders would enable servicing of agricultural demand during the hours of high solar generation. This would enable improved minimum loads for conventional power and greater integration of renewable energy. An estimate of this opportunity is given below.

1. Electricity consumption by agriculture sector: 191150 MU
2. Connected agricultural load: 106265191 kW
3. No. of consumers: 21984102
4. Agricultural consumption as a percentage of total energy consumption: 17.30%

(Source: All India Electricity Statistics, General Review 2018 by CEA)

It is anticipated that if 2000 MW of agricultural load is shifted from night hours to hours of peak solar generation, the Minimum Thermal Load (MTL) of coal-fired units can be improved by 2%.

- **Charging of Electric vehicle when solar generation is available:** India has ambitious plans for shifting public and private vehicles to electricity and reduce its dependence on imported oil. The government has released the National Electricity Mobility Mission Plan (NEMMP) 2020 focused at encouraging adoption of e-vehicles. Delhi government has proposed to make 25% of all new vehicle registrations to be electric by 2023 in its draft 'Delhi Electric Vehicle Policy 2018.

- **Daytime** charging of e-vehicles is a measure that needs to be promoted for encouraging integration of renewable energy and make e-vehicles an even greener mode of mobility.

12.6 Battery Storage

NITI Aayog has released a draft National Energy Storage Mission (NESM) for promotion of battery manufacturing in the country. The key areas for energy storage application include:

- Integrating renewable energy with distribution and transmission grids;
- Setting Rural micro grids with diversified loads or stand-alone systems; and
- Developing Storage component of electric mobility plans.

13. Coordinated Effort for Integration of Renewable Generation: Need of the Hour

It is clear from the above arguments that business as usual generation from fuel sources other than coal will put undue pressure on coal units to flex upto loads as low as 26%, which they are not designed for. It is widely accepted that operation of coal-fired units at such low loads is not only financially unviable but also technically improbable considering high ash content in Indian coal. Hence, the committee is of the opinion that thermal load on coal units should not go below 35% in worst-case scenario in Indian conditions. This calls for coordinated effort from all fuel sources to provide flexible power in the grid.

13.1 Typical Days in future

In order to achieve the above objective, we take up typical days of 2021-22 from a thermal power standpoint and explore possible flexible operation from other fuel sources. One advantage that we can exploit, living within our constraints, is that we do not need more energy as such. We just need that energy to be produced at the right time.

Selection of Typical Days

1. Lowest MTL Day (27th July 2021)
2. Average Monsoon Day*
3. Average Non-Monsoon Day
4. Best MTL Day (23rd October 2021)

Table 12 Projected Demand, Generation, and MTL during key time.

Day	Maximum Demand (MW)	Max RES (W+S) (MW)	Minimum Coal Based Generation (MW)	Maximum Coal Based Generation (MW)	MTL on the day without coordinated effort
Lowest MTL Day (27th July 2021)	190480	108082	32665	116769	25.73%
Average Monsoon Day*	199055	91519	56604	128771	41.70%
Average Non-Monsoon Day	196492	67953	89073	149936	54.50%
Best MTL Day (23rd October 2021)	199211	50326	107338	155905	63.33%

For the purpose of this study, the Monsoon Period has been defined as three months of June, July & August.

13.2 Three Steps of Coordination

Three steps of coordinated effort have been defined below. In step-I, Hydro & Gas generations are flexed to produce more in peak and less in off peak keeping their total energy same as their corresponding Business-as-Usual scenarios. In step-II, flexible power from proposed pump or battery storage and two-shift operation of certain coal-fired plants is envisaged in addition to provisions of step one. Finally, in step-III, RE curtailment is explored, after considering the measures of Step one, with its corresponding impact on thermal minimum load. An example of the data used in the analysis is given in Annexure II while the graphs are presented in the following sections.

1. **Step I:** Hydro & Gas Reallocation
2. **Step II:** Pump or Battery Storage or combination of both and Two Shift Operation of old & small coal-fired plant
3. **Step III:** RE Curtailment

13.3 Step I: Hydro & Gas Reallocation

We propose the re-allocation of hydro and gas generation from off-peak to peak hours. The reallocation has been prepared considering the net water and gas requirement in Hydro and Gas, respectively, equal to their BAU scenarios.

- **Reallocation of current Hydro and Pumped Hydro Storage (PHS):** India currently has an installed capacity of 4785 MW of PHS and another 1205 MW of PHS is under construction. The ability of PHS technology to absorb power during the afternoon and supply it in the evening and morning peak would provide major flexibility to the Indian power system. We have considered a maximum departure of 6200 MW in hydro generation on either side of the BAU line including running & under construction pump storage and hydro generation of state & central sector.

  More flexing of hydro generation is expected especially from state sector by introducing incentive, two-part tariff etc. Presently many states are utilizing their hydro generation for meeting their base demand as well as balancing purpose, thus optimizing their system to avoid deviation charge. Optimization of sub systems does not necessarily lead to optimization of the whole system. Therefore, tariff, regulation & grid code to be modified in such a manner that utilities shall participate willingly to optimize the whole system for their financial gain.

- **Reallocation of Gas based power:** Currently Gas plants are not being flexed to their potential. Out of a total installed base of around 25 GW, less than 6 GW of power is being scheduled on an average day. This situation is due to shortage of gas. The BAU case carries forward a similar behavior in the future. However, we anticipate that even with limited availability of gas we can run the gas based thermal capacity in a flexible manner. We have considered a maximum departure of 3000 MW in gas generation on either side of the BAU line.

The typical Gas and Hydro generation curves before and after re-allocation are shown for each of the Typical Days.

13.3.1 Step 1: Reallocation of Hydro and Gas on Lowest MTL Day

The graph on the left shows the BAU generation scenario on 27th July 2021. The generation from Hydro and Gas has been modified and the revised generation is shown on the graph on the right. MTL is found to improve from 25.73 % to 36 % with Step-I coordination.

Figure 10 BAU and Step-1 scenario comparison – Lowest MTL Day

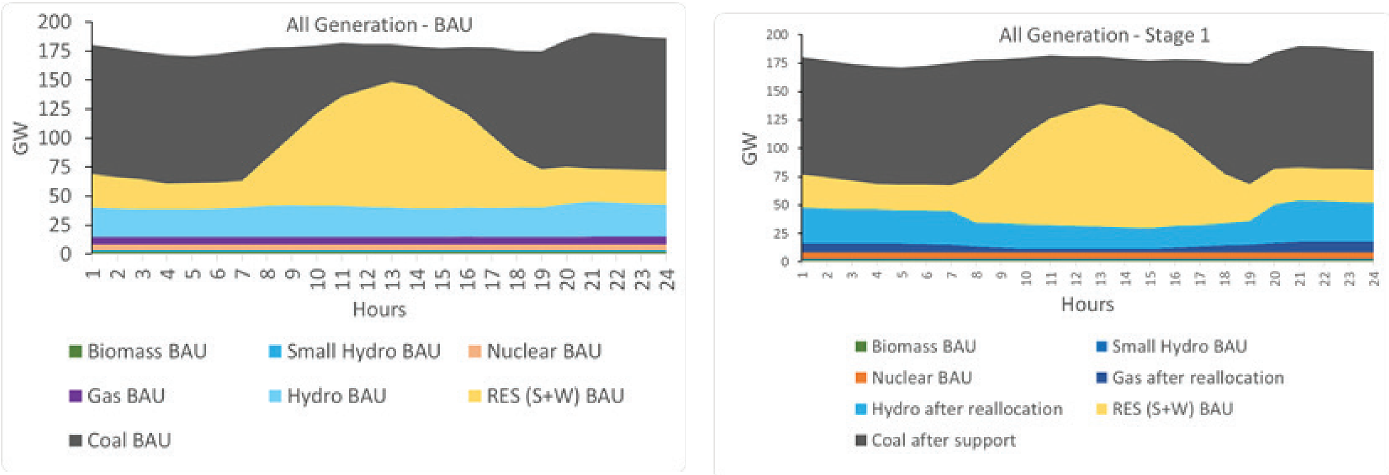
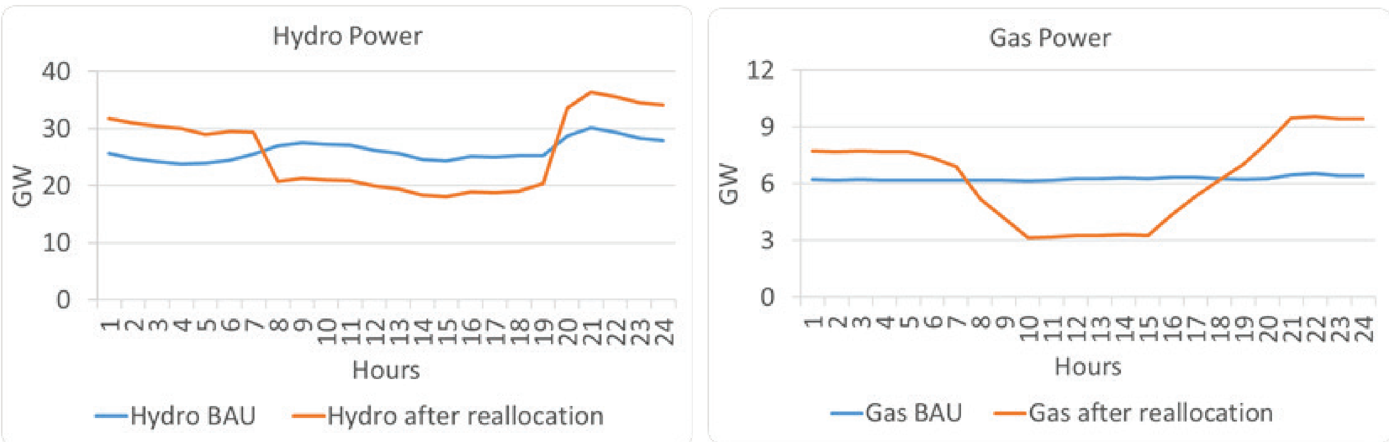


Figure 11 Hydro and Gas generation – BAU and Step - I comparison during Lowest MTL Day



13.3.2 Step I: Reallocation of Hydro and Gas on Average Monsoon Day

The average day of monsoon has been derived after superimposing 92 days of June to August months of the year,2021-22. The generation profiles after reallocation of Hydro & Gas generation have been presented below. The MTL is found to improve from 41.70 % to 52 % with Step-I coordination.

Figure 12 BAU and Step-1 scenario comparison – Average Monsoon Day

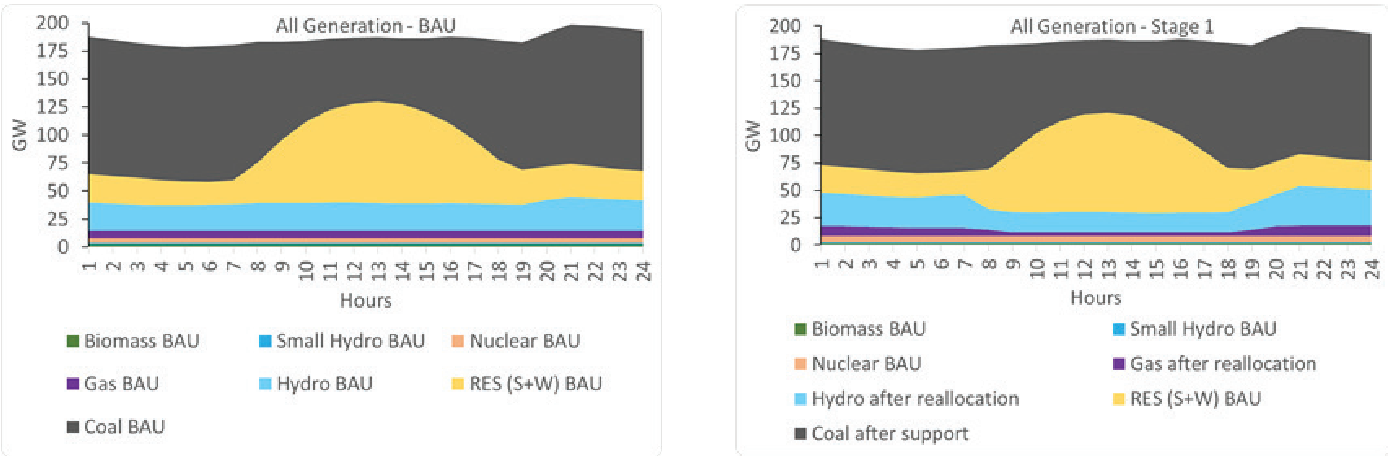
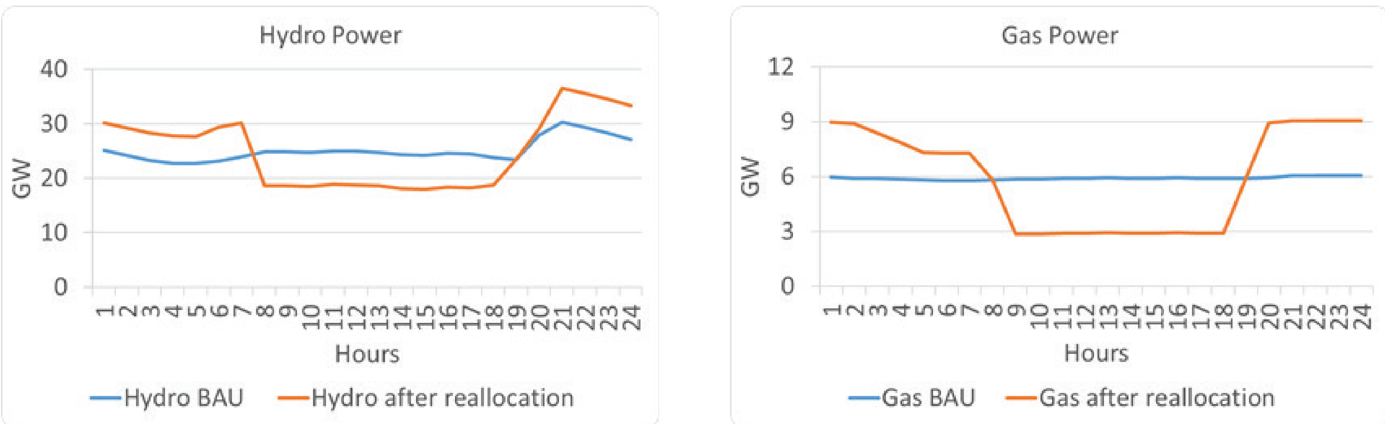


Figure 13 Hydro and Gas generation - BAU and Step 1 scenario comparison during Average Monsoon Day



13.3.3 Step I: Reallocation of Hydro and Gas on Average Non-Monsoon Day

The average non-monsoon day has been obtained after superimposing the 273 days of September to May months. The generation profiles after reallocation of Hydro & Gas generation have been presented below. The MTL is found to improve from 55 % to 65 % with Step-I coordination.

Figure 14 BAU and Step-1 scenario comparison – Average Non-Monsoon Day

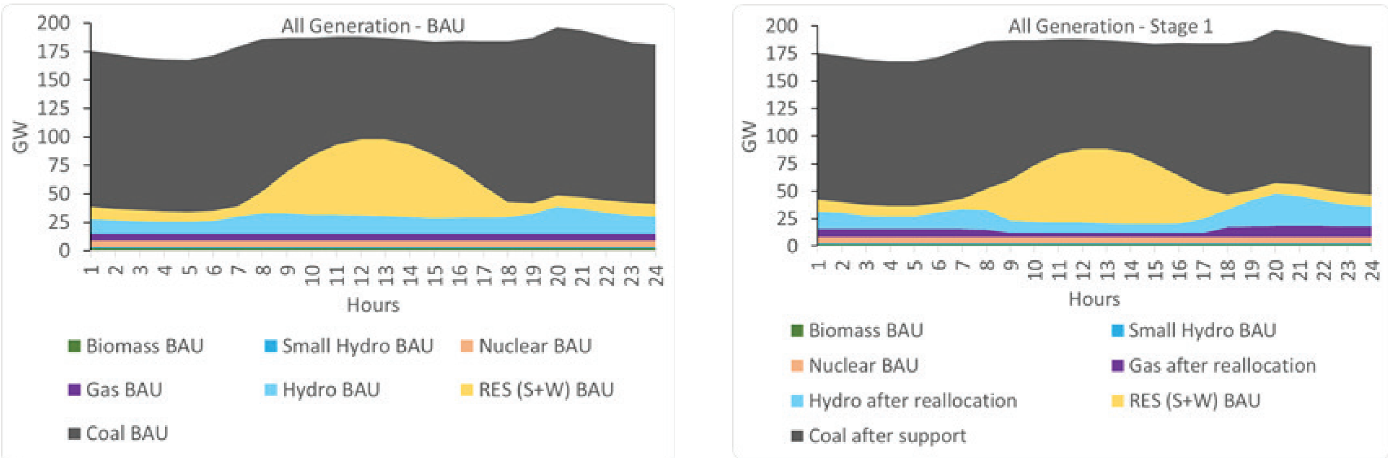
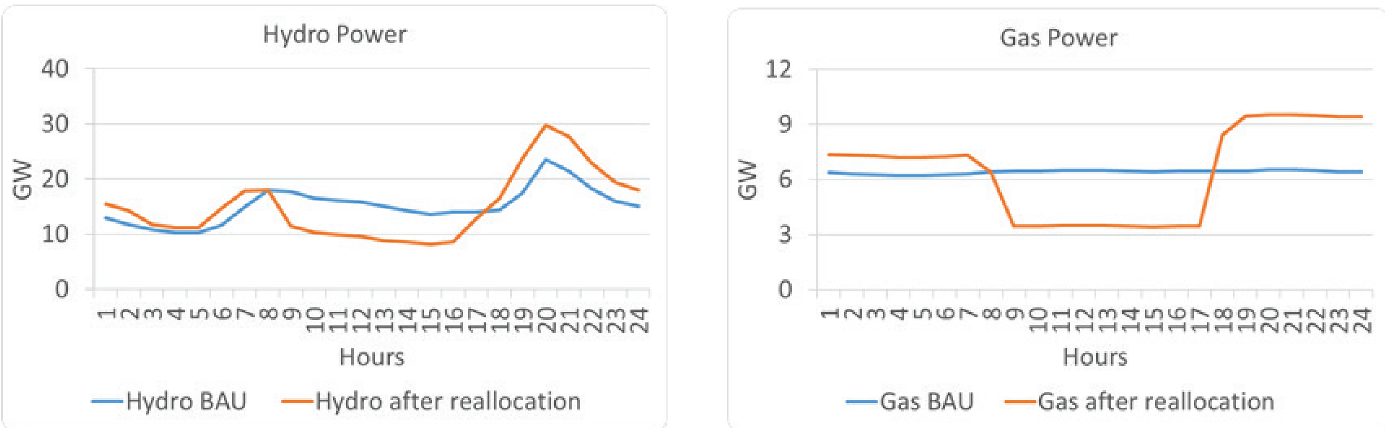


Figure 15 Hydro and Gas generation - BAU and Step 1 scenario comparison during Average Non-Monsoon Day



13.3.4 Step I: Reallocation of Hydro and Gas on Best MTL Day

The best MTL day found out in the study is 23rd October 2021. The generation profiles after reallocation of Hydro & Gas generation have been presented below. The generation from RES is remarkably low on this day at just 50 GW. This is also the period of high demand in the country. This is the reason that with just Step-I coordination the MTL of around 73 % can be obtained.

Figure 16 BAU and Step-1 scenario comparison – Best MTL Day

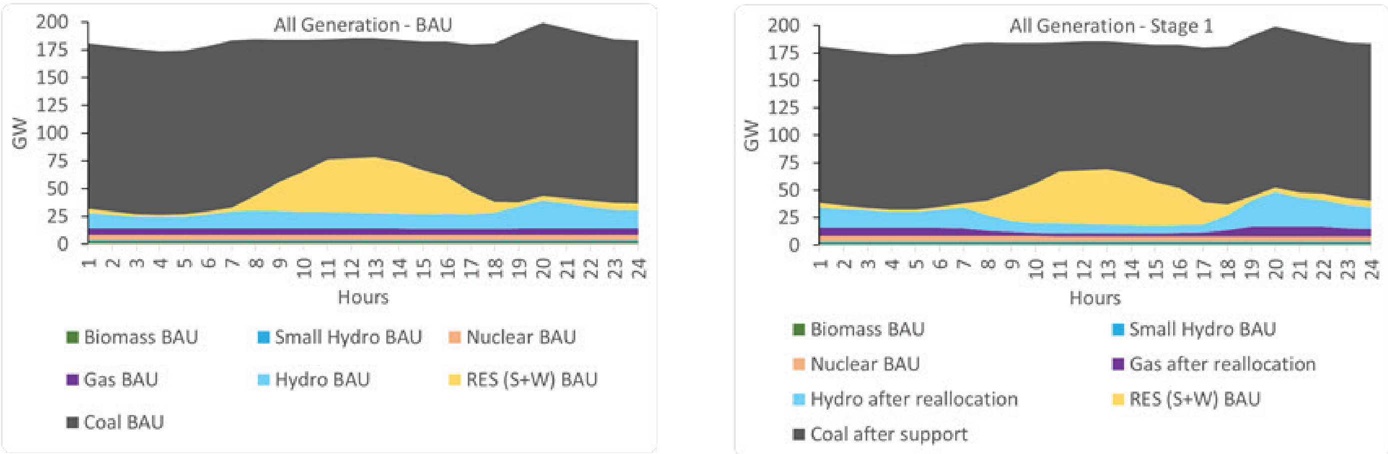
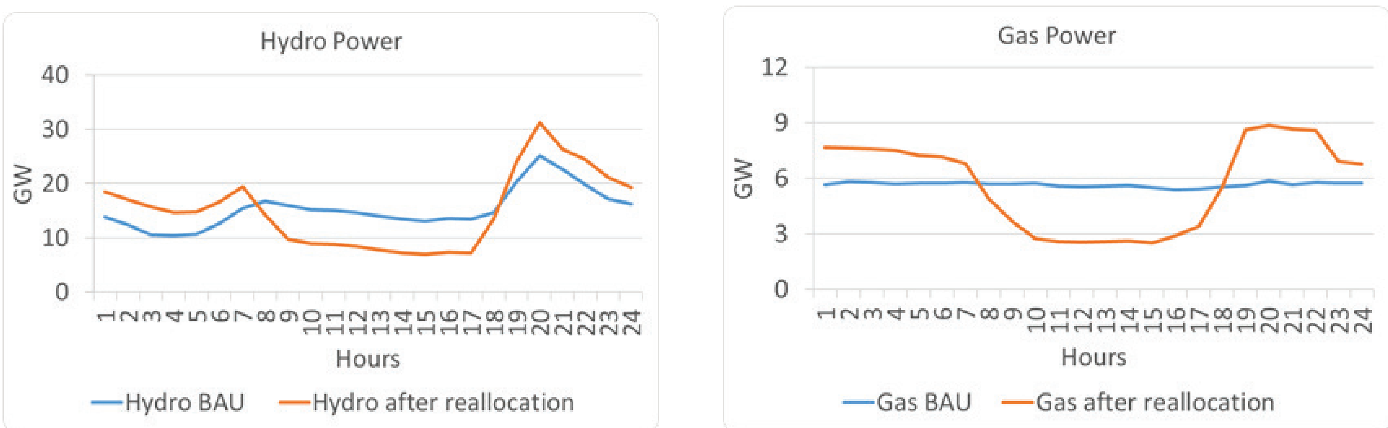


Figure 17 Hydro and Gas generation - BAU and Step 1 scenario comparison during Best MTL Day



A summary of MTL achieved after generation from Hydro and Gas have been reallocated as above is presented in the figure below.

Figure 18 Summary of MTL achieved

	Worst Case	Monsoon	Non Monsoon	Best Case
BAU: Only Coal	26	42	55	63
Stage 1: Hydro + Gas	36	52	65	73

13.4 Step II: Pump or Battery Storage or combination of both and Two Shift Operation

In order to improve the MTL of coal-fired units further, especially during monsoon period, the Step-II measures may be adopted on top of the measures of Step-I. These include the following.

1. **Pump or Battery Storage or combination of both:** In this report, we have assumed a conservative estimate of around 7000 MW of installed capacity of pump or battery storage or combination of both systems connected to the grid.
2. **Two shift operation of small, old and high ECR thermal units:** Around 10 GW of coal fired thermal capacity in the country are of unit size 151 MW or less. Most of these are more than 25 years old and have high Energy Charge Rating. The committee has proposed to run 5000 MW out of 10000 MW capacity during the monsoon months of June, July and August for six hours in the evening.

The typical Gas and Hydro generation curves before and after allocation are shown for each of these Typical Days.

13.4.1 Step II: Pump or Battery Storage and Two Shift Operation on Lowest MTL Day

The graph on the left shows the BAU generation scenario on 27th July 2021. The generation from Pump or Battery storage and Two shift operation has been introduced in addition to Step-I as per the profiles shown in the subsequent graph on the right. The MTL is found to improve from 36 % to 46 % with Step-I and Step-II coordination.

Figure 19 BAU and Step-2 scenario comparison – Lowest MTL Day

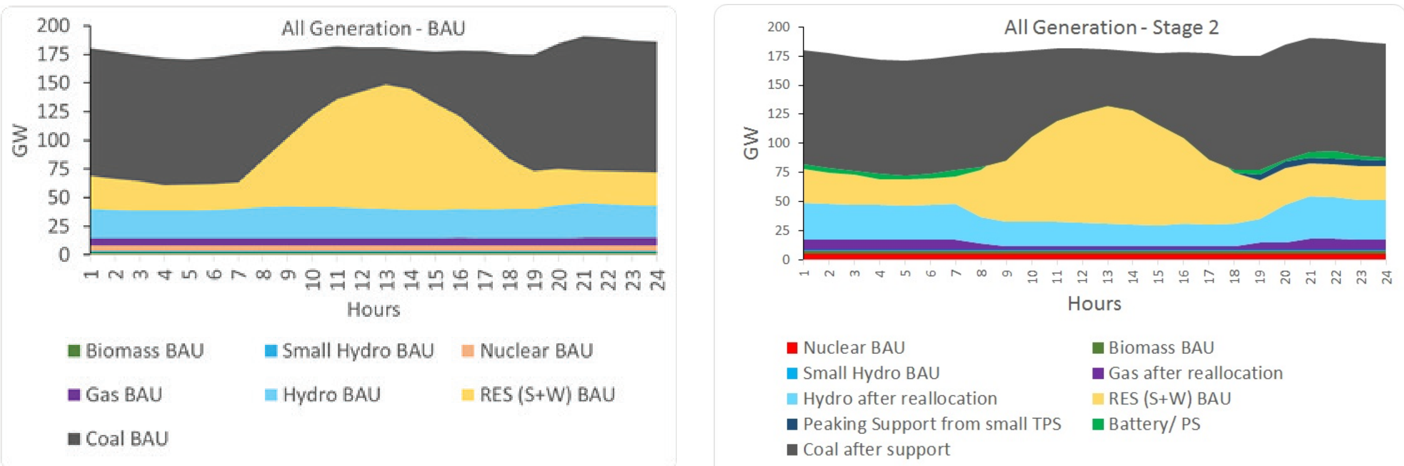
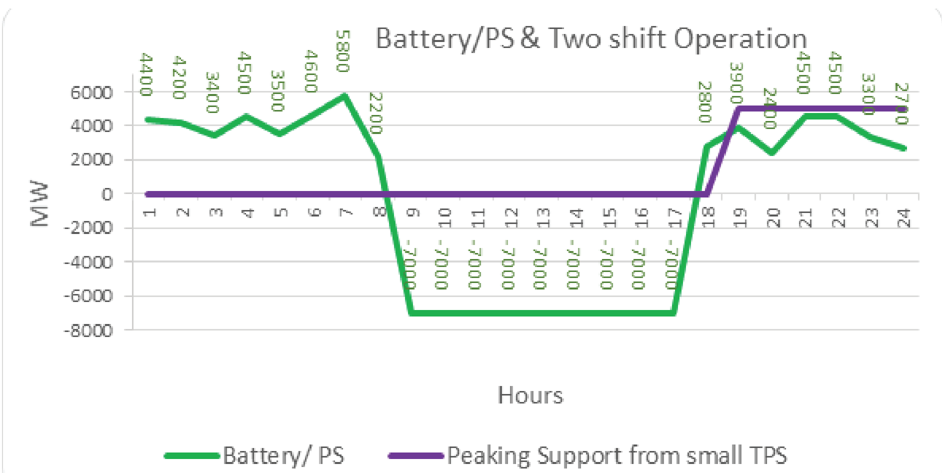


Figure 20 Battery Storage/PS & Two Shift Operation during Lowest MTL Day



13.4.2 Step II: Pump or Battery Storage and Two Shift Operation on Average Monsoon Day

The average day of monsoons has been derived after superimposing 92 days of June to August months of the year,2021-22. The generation profiles are presented below. The MTL is found to improve to 62 % with Step-I & II coordination.

Figure 21 BAU and Step-2 scenario comparison – Average Monsoon Day

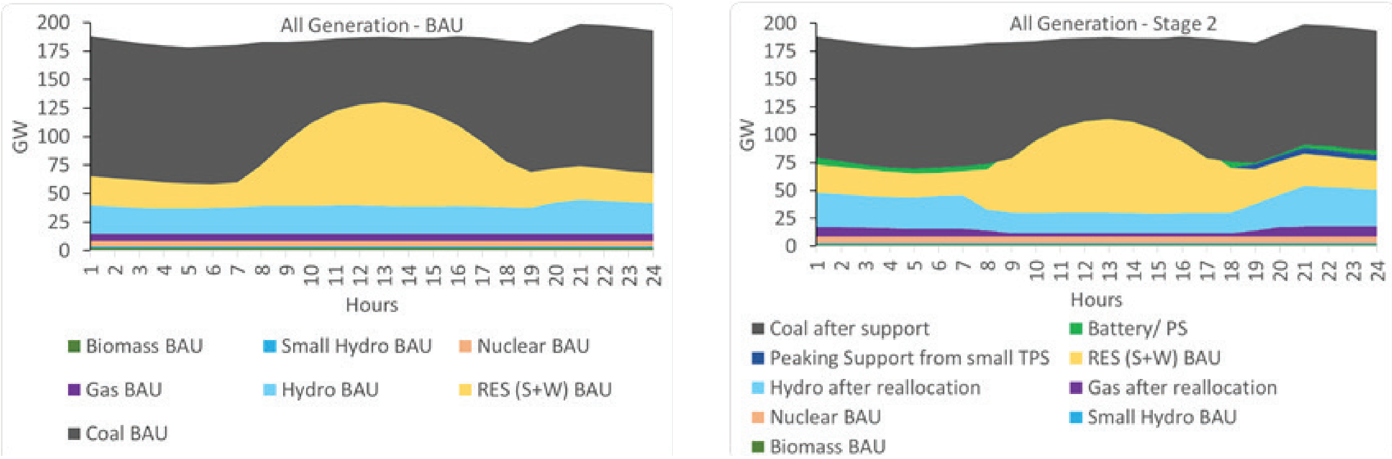
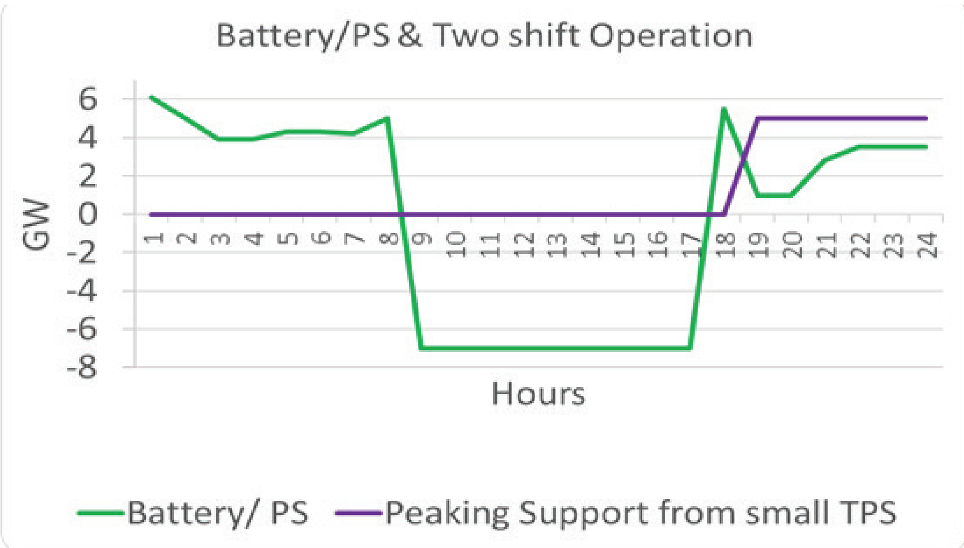


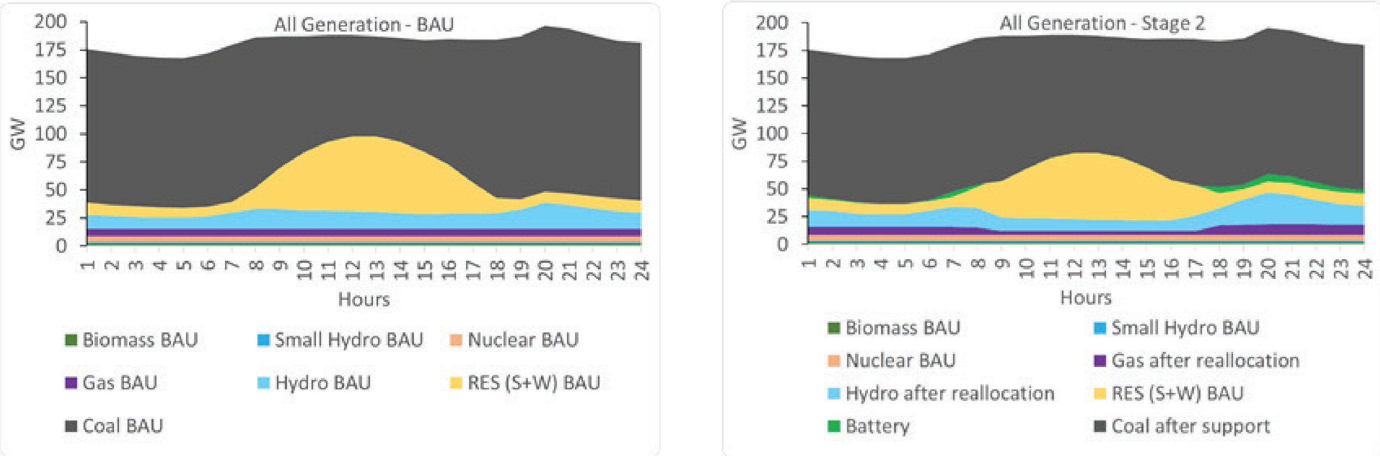
Figure 22 Battery Storage/PS & Two Shift Operation during Average MTL Day



13.4.3 Step II: Pump or Battery Storage and Two Shift Operation on Average Non-Monsoon Day

The average non-monsoon day has been obtained after superimposing the 273 days of September to May months. The generation profiles are presented below. The MTL is found to improve to 74 % with Step-I & step-II in coordination.

Figure 23 BAU and Step-2 scenario comparison – Average Non-Monsoon Day



A summary of MTL achieved after reallocation of generation from Hydro, Pump/Battery storage and Two-shift operation of gas & small coal fired units is presented in the figure below.

Figure 24 Summary of MTL achieved

	Worst Case	Monsoon	Non Monsoon	Best Case
BAU: Only Coal	26	42	55	63
Stage 1: Hydro + Gas	36	52	65	73
Stage 2: Battery + TSO	46	62	74	-

13.5 Step III: RE Curtailment

Renewable energy is a source of clean power with zero marginal cost. India, with its 900 GW of renewable energy potential, is emerging as a front-runner in installation of RE based power projects. The provisions of must-run and feed-in tariffs for RES have made the sector more viable than other fuel sources. In such a scenario, renewable energy curtailment looks like an aberration from the general policy of govt. of India. Hence, it may be emphasized that the option of RE curtailment may only be looked upon as a last resort. Issues such as Grid congestion and power evacuation may alone be considered as tenable reasons for curtailment of RE.

With the RES generation data available to us, we have attempted to demystify the issue of RE curtailment. An important conclusion drawn from the analysis is that with just 1% RE curtailment the burden on other sources to provide flexible power reduces substantially. This has been depicted in the table below for the lowest MTL day of 2021-22.

Table 13 Requirement of flexible power from other sources with 1% RE curtailment

MTL achieved (%) without support from other sources and without curtailment	RE Curtailment p.a. (%)	MTL achieved (%) without support from other sources	MTL achieved (%) with support from hydro & gas	Annual RES curtailed in Million Units (MU)	Value of RES lost p.a. @ Rs. 2.5/kWh (Rs. Crore)
25.73 %	0.01%	30%	41.07%	22	6
	0.09%	35%	46.38%	252	63
	0.38%	40%	51.48%	1035	259
	0.96%	45%	56.80%	2630	658
	2.02%	50%	61.90%	5541	1385
	3.99%	55%	67.21%	10945	2736
	7.56%	60%	71.69%	20736	5184

Capacity Utilization Factor	
CUF Solar	18.48%
CUF Wind	21.40%
CUF Solar (after 1% curtailment)	18.18%

It is inferred that 0.96% curtailment of RES on an annual basis would improve the MTL on coal-based capacity from 25.73% to 45%, in BAU scenario. Further, if Hydro & Gas participate in coordination as explained in Step-I, then the MTL can further be improved to 56.80% with curtailment of renewable generation.

One percent renewable generation curtailment leads to loss of 2630 MU of renewable energy in the year 2021-22. This in turn corresponds to a loss of Rs. 658 Crore in terms of monetary value of renewable energy at an average cost of Rs.2.5/kWh. In contrast, the MTL will be improved from 25.73% to 46% without curtailment by implementing Step-I & Step-II. Both Pump or Battery storage and two-shift operation of coal-fired unit as suggested in Step-II, are costly measures as on date. Hence, RES curtailment may be a more viable option. However, with more capacity addition of RES after 2021-22 and reduction in prices of storage technologies, the scenario is expected to change.

The table below shows the amount of RES curtailed during the Monsoon (June to August) and Non-Monsoon (September to May) Seasons.

Table 14 RES curtailment during Monsoon (June to August) and Non-Monsoon (Sept to May)

	Season	MU of RES produced	MU of RES curtailed	% of RES curtailment
1	Monsoon	100815	2555	2.53%
2	Non-Monsoon	173488	73	0.04%
3	Overall	274303	2628	0.96%

Utilization of curtailed renewable generation: If the curtailment of renewable generation is unavoidable considering the grid security & stability, then individual RE generator may utilise the excess generation in the way mentioned below:

- **Power to Gas to Power:** Surplus of RES generation can be used to generate hydrogen from water through electrolysis while oxygen generated in this process may be used suitably. As per the requirement of the system, the stored hydrogen can be used as primary fuel to generate electricity.
- **Compressed air energy storage (CAES):** CAES is another storage option that can be explored.
- **Installation of pump power plant** where water is pumped to a tank or reservoir from where the potential energy can be recovered later in a hydro turbine.

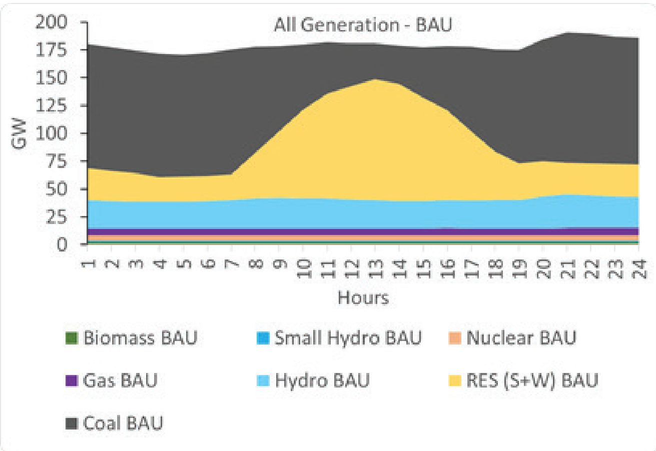
The issue may also be addressed by maintaining battery or pump storage capacity of 2.5% of daily energy production at plant level so that the stored energy can be used during peak hours.

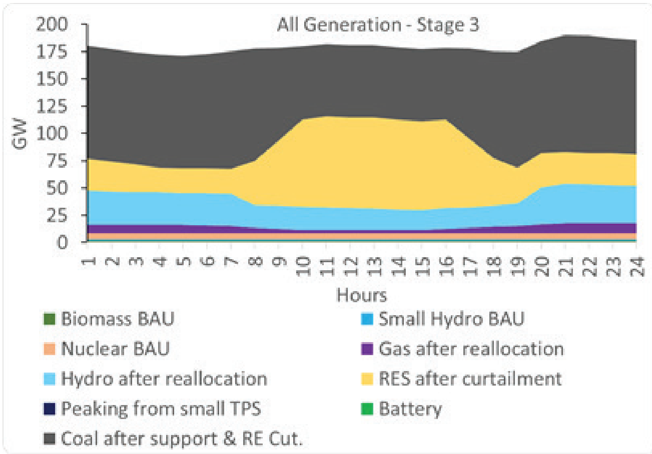
The following analysis show the generation graphs on Lowest MTL day and Average Monsoon Day after curtailment of renewable generation. In the analysis, 1% renewable generation curtailment on an annual basis has ensured that MTL does not fall below 45% even in the BAU case wherein no coordination is obtained from other fuel sources.

13.5.1 Step III: RE Curtailment on Lowest MTL Day

The graph on the left is BAU scenario on the lowest MTL day. The graph on the right shows the generation profile including Hydro & Gas reallocation as well as RES curtailment (Step-I & III). The MTL is found to improve from 36 % to 56 % with step -III coordination.

Figure 25 BAU and Step-3 scenario comparison – Lowest MTL Day

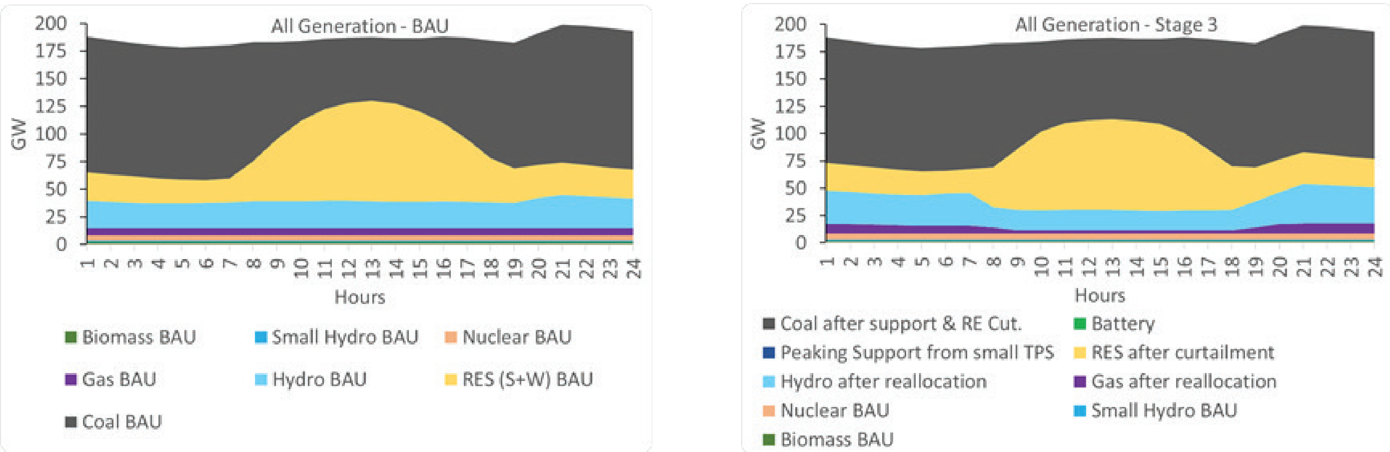




13.5.2 Step III: RE Curtailment on Average Monsoon Day

The graph on the left is BAU scenario on an average day during monsoon. The graph on the right shows the generation profile including Hydro & Gas reallocation as well as RES curtailment. The MTL is found to improve from 52 % to 59 % with step-III coordination.

Figure 26 BAU and Step-3 scenario comparison – Average Monsoon Day



13.6 Summary of the generation scenarios with different steps of coordination.

The summary of Minimum Thermal Loads (MTL) observed under the various scenarios explained above is depicted in the figure below. It is clear that flexible operation of coal-fired power plants is the need of the hour. All thermal power stations should be usually capable of operation at loads of around 45% to 55%. If preference is given to any unit (super critical) to operate at higher MTL then other units have to run at lower MTL to maintain the average MTL of grid connected units. Generation from all sources like Hydro, Gas, Pump or Battery storage and RES curtailment can come to the rescue of thermal power.

Figure 27 Summary of MTL observed during various scenarios

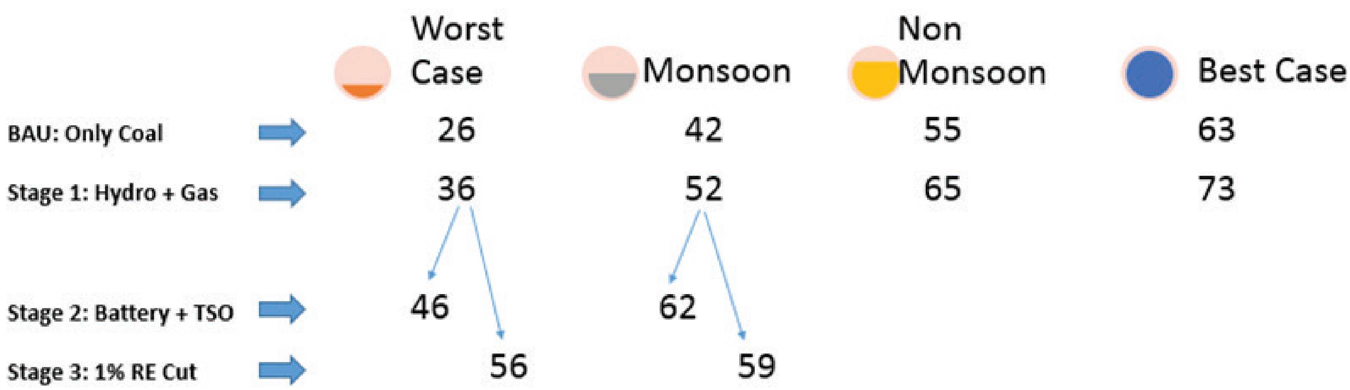
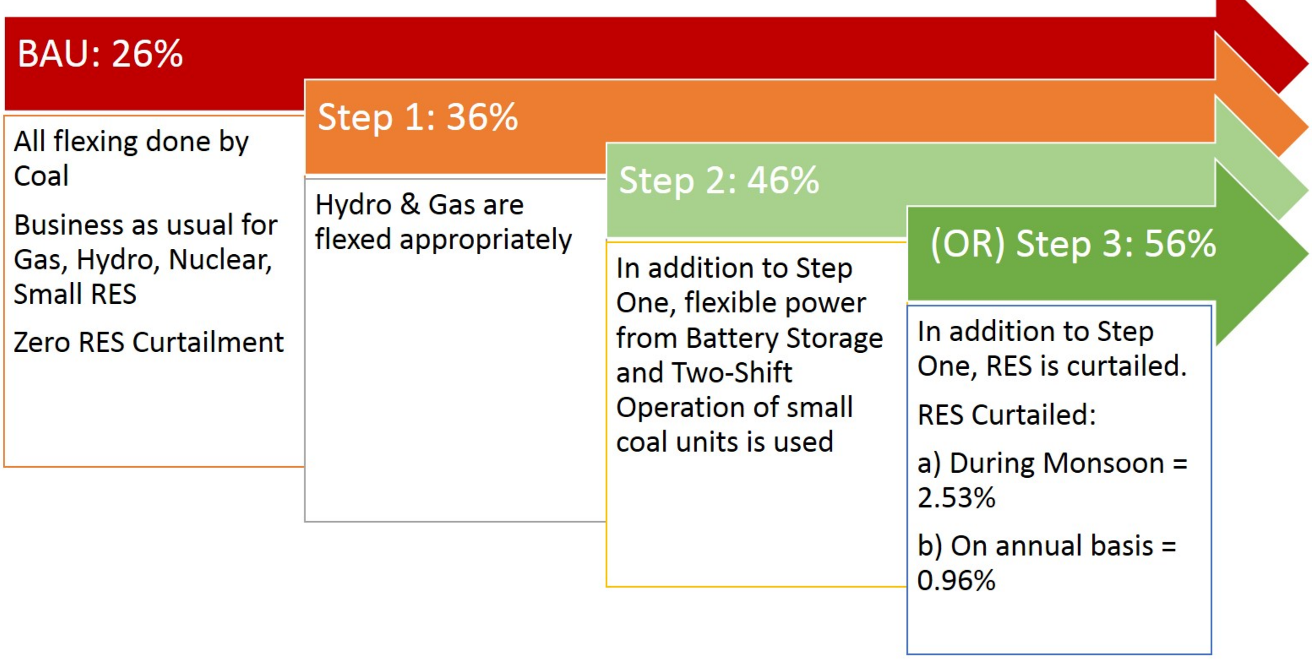


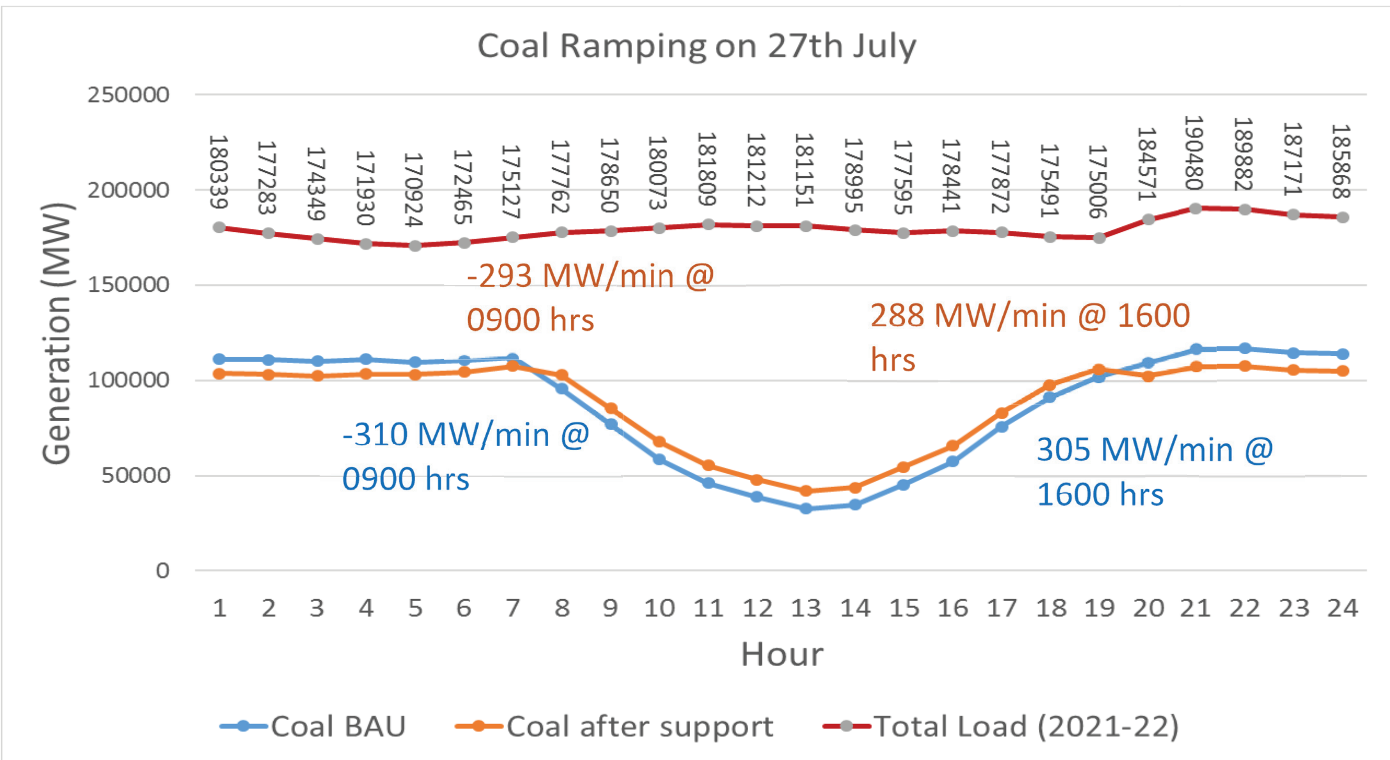
Figure 28 Graphical summary of the chapter on coordinated effort



13.7 Ramp Rate of Coal Generation on Lowest MTL Day

For the day 27th July 2021, ramp rate observed before and after contribution of flexible power from other sources is given in the following chart.

Figure 29 Contribution of flexible power from various sources



The thermal capacity of 117 GW will be synchronized on 27th July, 2021 and they have the capability to deliver ramp of 1173 MW/min., considering ramping capability of 1%/min of individual unit.

Table 15 Thermal capacity ramp rate (2021)

SN	Unit & Size (MW)	Capacity utilization	Capacity on Bar	Assumed Ramp	Ramp Rate
		%	MW	Rate (%)	(MW/Min.)
1	< 150	30	3055	1%	41
2	200/210	50	16140	1%	258
3	250 to 360	50	19303	1%	309
4	500	52	24229	1%	373
5	600 to 800	52	54564	1%	860
	Total		117291		1173

Part III: Flexible Operation of Thermal Unit

- A Study on Expenditure

14. Costs Involved in Flexing Coal-Fired Generation

Both regulated and market-based power systems can ensure appropriate investment in additional power plant flexibility measures by identifying the value of specific flexibility services and ensuring fair compensation for them. This can be accomplished in regulated market-based power systems by improving energy pricing schemes (e.g. Time of Day tariffs). Implementation of well-designed mechanisms that accurately reward generators for providing flexible generation to the grid will improve the flexibility of the generators. These remuneration mechanisms may be structured around specific services, such as ramping or start-up time, and could provide a complementary source of income for power plants that are necessary to the system but unable to maintain business-as usual profitability due to less utilization. In regulated contexts, power plant flexibility investments can be secured by allowing cost recovery of flexibility retrofits, as well as by offering financial incentives for developers to utilize highly flexible components.

The costs involved in enabling a thermal generating unit for flexible operation may be clubbed under the following heads.

1. **Capital Expenditure (CAPEX)** This is the one-time expenditure incurred in the installation of various equipment required to make the plant capable of low load operation.
2. **Operational Expenditure (OPEX)** This is the recurring cost of flexible operation due to factors such as increase in O&M cost and decrease in efficiency.

The next section gives an estimate of the costs involved in flexible operation. However, the data/ values of cost indicated therein may be treated as being indicative in nature. Actual costs involved will highly depend on the condition of a particular plant and the prevailing market scenario.

14.1 Capital Expenditure

Capital expenditure is required to meet the requirement of flexible operation mainly for the capital interventions at unit level. The number and type of interventions required would vary from plant to plant depending on the age of unit and scope of works.

NTPC has demonstrated 40% minimum load operation at unit 6 (490 MW) of Dadri TPS. As per Preliminary estimates, considering the scope of works, the implementing company (Siemens) has estimated a capital expenditure of around Rs.20 crores for implementation of measures enabling stable operation at 40% minimum load.

Similarly, an estimate of Rs. 50 crore has been provided by GE for unit 2 of Talcher TPS of NTPC to enable stable operation at 40% minimum load.

Major retrofit is not required to operate a thermal unit at 55% load. Only modification of Operational procedures along with control system tuning are required.

To operate a thermal unit below 40% load requires implementation of measures which will depend on the unit design type, size, coal quality, historical operation, maintenance, and age of the units. The accumulated fatigue/creep will depend on the historical operational duties and maintenance practices. This will provide guidance on remaining useful life of critical components, which in turn will guide the scope and extent of intervention required. The scope will also depend on the future operational flexibilisation regime the unit is expected to support i.e. low/very low load, start/stop-daily/weekly shift operation.

14.2 Operational Expenditure

The report tries to give preliminary estimates of the increase in operational expenditure due to flexible operation of the thermal units. It may be noted that the estimates provided in this report are based on studies conducted at specified plants. The actual costs involved for a particular unit will depend on the condition of the unit and the prevailing market scenario.

The increase in operational expenditure due to flexible operation can be clubbed into the following heads.
Impact of Flexible Operation:

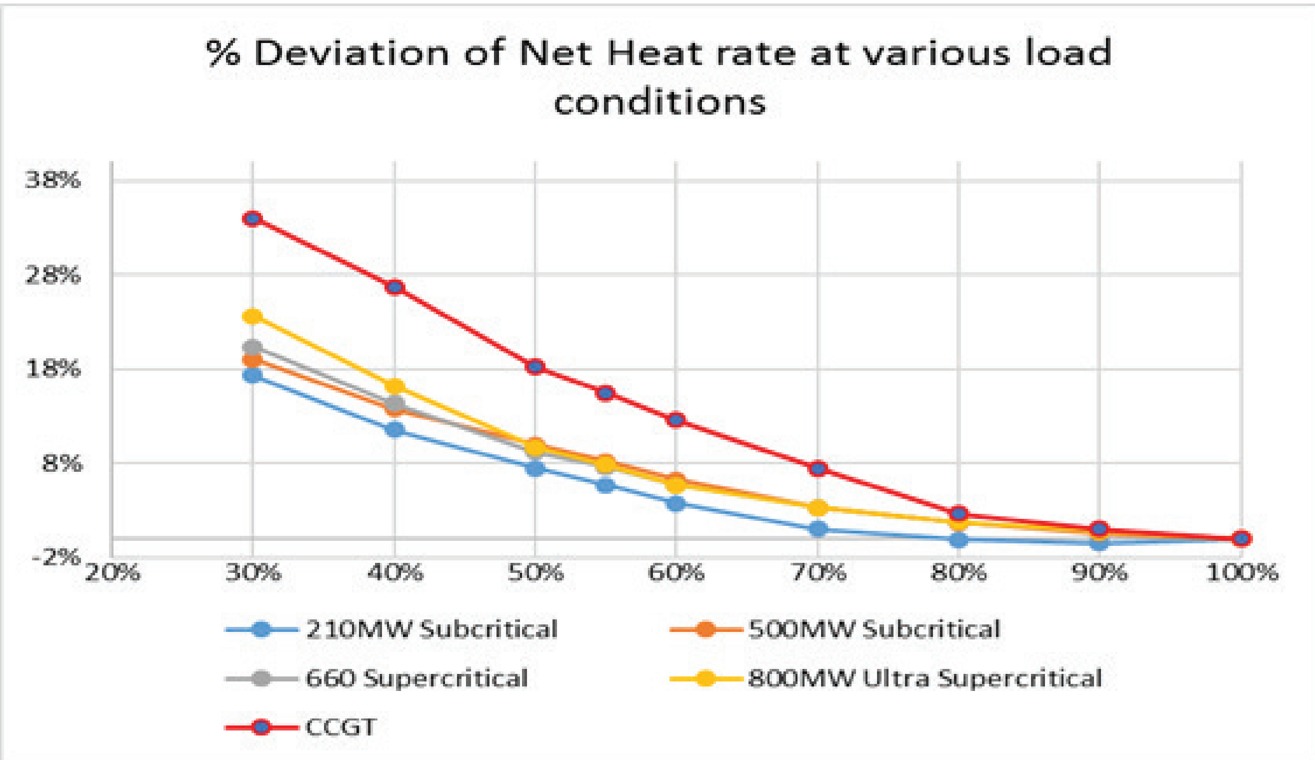
- Cost due to increase in Heat Rate and Auxiliary Power Consumption (APC).
- Cost due to increase in Operation and Maintenance (O&M) due to reduction in life of components.
- Cost due to increase in Oil consumption on account of frequent start/ stops.

Generally, units are designed to operate on base load condition and all the components are accordingly designed for certain creep life and certain fatigue life in terms of number of starts. As the operation regime changes and moves away from base load operation to load cycling operation, the component life is consumed at a faster rate.

14.2.1 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 loading of units. The estimates in this report are based on combustion engineering boiler design and GE make turbines of 200/210 MW, 500 MW and 660 MW capacity units.

Figure 30 Deviation of net heat rate at various load conditions

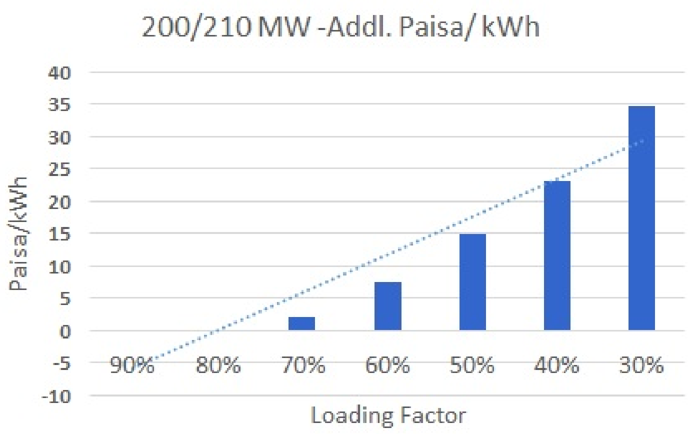


Source: NTPC based on GE make turbines of 200/210 MW, 500 MW and 660 MW capacity

For a typical 200/210 MW unit the increase in tariff due to increase in Net Heat Rate at different loading factors is given below. The base ECR has been assumed to be 200 paisa/kWh based on the average ECR of NTPC stations from April to October 2018.

Table 16 Increase in tariff due to increase in net heat rate for 200/210 MW power plant units

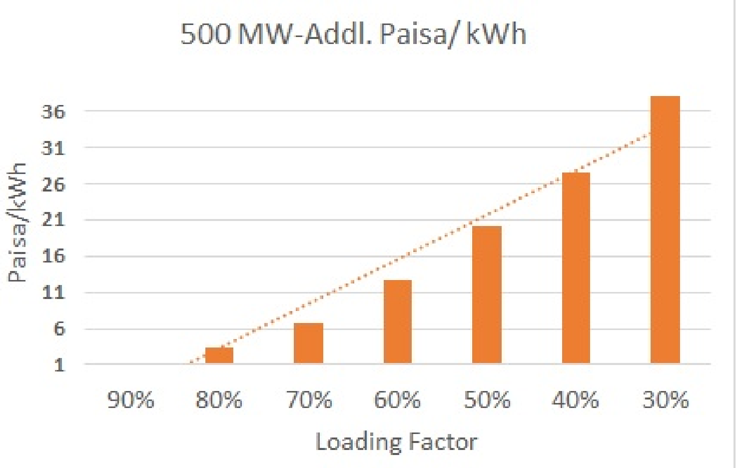
Typical 200/210 MW unit				
Sr. No.	Unit loading (%)	Increase in NHR (%)	Absolute Paisa/kWh	Addl. Paisa/kWh
1	90%	0%	200	0
2	80%	0%	200	0
3	70%	1.1%	202.1	2.1
4	60%	3.8%	207.5	7.5
5	50%	7.5%	215.0	15
6	40%	11.6%	223.2	23.2
7	30%	17.3%	234.6	34.6



Source: GE / NTPC

Table 17 Increase in tariff due to increase in net heat rate for 500 MW power plant units

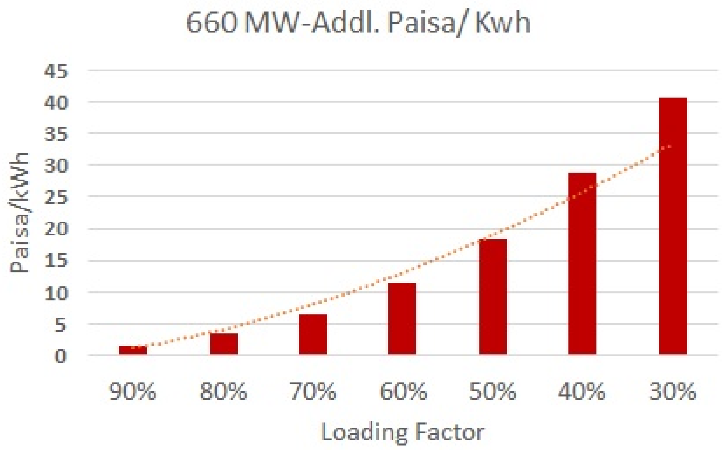
Typical 500 MW unit				
Sr. No.	Unit loading (%)	Increase in NHR (%)	Absolute Paisa/kWh	Addl. Paisa/kWh
1	90%	0.55%	201.1	1.1
2	80%	1.7%	203.4	3.4
3	70%	3.3%	206.7	6.7
4	60%	6.3%	212.6	12.6
5	50%	10.0%	220	20.0
6	40%	13.8%	227.6	27.6
7	30%	19%	238	38



Source: GE / NTPC

Table 18 Increase in tariff due to increase in net heat rate for 660 MW power plant units

Typical 660 MW unit				
Sr. No.	Unit loading (%)	Increase in NHR (%)	Absolute Paisa/kWh	Addl. Paisa/kWh
1	90%	0.8%	201.6	1.6
2	80%	1.7%	203.5	3.5
3	70%	3.3%	206.6	6.6
4	60%	5.7%	211.5	11.5
5	50%	9.2%	218.4	18.4
6	40%	14.4%	228.7	28.7
7	30%	20.4%	240.8	40.8



Source: GE / NTPC

14.2.2 Cost due to Life Consumption reflected in increased O&M cost

Flexible operation leads to a higher rate of deterioration of plant components. This is observed in increased failure rate and more frequent replacement of components. The impact on reduction in life of components increases with increase in number of start stops the unit undergoes in a year. As a result, the operation and maintenance cost is significantly higher in units operated on a daily or weekly start-stop basis.

An estimate of the increase in O&M Cost due to reduction in life of components is given in Table 19. It is based on the study conducted under the USAID's Greening the Grid(GTG)- Renewable Integration and Sustainable Energy Initiative (RISE) Program implemented by Deloitte Consulting LLP with technical support from M/s Intertek, USA at Ramagundam TPS and Jhajjar TPS of NTPC. The study was based on the ten-year historical cost data of the units (all the costs are at 2017 levels). The current level O&M costs is 28.7 Lakhs/MW for 210 MW unit and 19.22 Lakhs/MW for 500 MW unit based on the CERC normative O&M cost for year 2016-17. The incremental cost due to each event is expressed as percentage of the normative O&M costs.

Study on increased O&M cost due to life consumption on account of cyclic operation in case of super critical unit have not been carried out.

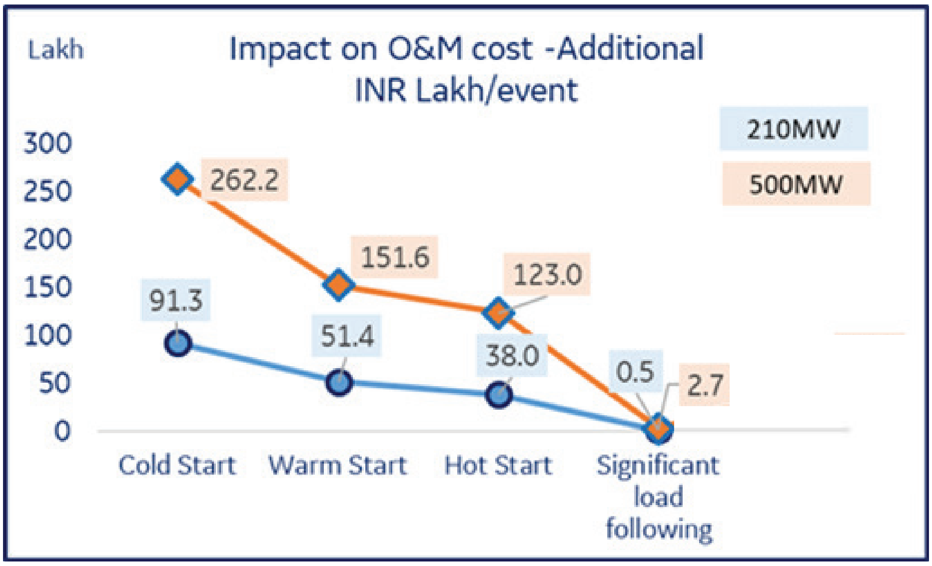
The above costs are based on the load cycling cost studies of two units of NTPC. It is anticipated that as these costs are based on the past load cycling, which has not been very severe, they are expected to rise with increase in cycling and age and condition of units.

Table 19 Increase in O&M cost due to life consumption on account of cyclic operation

MW	Event	O&M Cost (INR-Lakh)			
		Per Event	Per MW	Per MW (Current level) As allowed by CERC 2017	% Addl./Event
200	Cold Start	91.3	0.46	**28.70**	1.59%
	Warm Start	51.4	0.26		0.90%
	Hot Start	38	0.19		0.66%
	Significant load following	0.5	0.0		0.01%
500	Cold Start	262.2	0.52	**19.22**	2.73%
	Warm Start	151.6	0.30		1.58%
	Hot Start	123	0.25		1.28%
	Significant load following	2.7	0.01		0.03%

Source: Study conducted under GTG-RISE Program by M/s Intertek, at Ramagundam TPS and Jhajjar TPS of NTPC

Figure 31 Impact on O&M cost in reference to cyclic operation



Source: Study conducted under GTG-RISE Program by M/s Intertek, at Ramagundam TPS and Jhajjar TPS of NTPC

14.2.3 Cost due to Increased Oil Consumption due to frequent start/ stops.

Startup of thermal power stations requires secondary fuel support mainly in the form of Oil support (LDO). The quantity of oil consumption depends on the duration of startup. The level of oil consumption for startup has been specified in the CERC IEGC 4th & 5th amendments. During flexible operation, there may be a requirement of increased number of Cold, Warm or Hot startups as per the requirements of grid. This would lead to an additional cost to the power station. Assuming the price of oil as Rs. 45000/kl, the cost of oil consumption in case of a Cold, Warm & Hot start for a 200 MW & 500 MW unit is given in Table 20.

Table 20 Cost of oil consumption in case of a Cold, Warm, and Hot Start

Start up oil consumption calculations			
MW	**Price**	**45000**	**INR/KL**
200	Oil consumption per start (as per CERC)	KL	INR Lakh/event
	Cold	50	22.5
	Warm	30	13.5
	Hot	20	9
500	Price	45000	INR/KL
	Oil consumption per start (as per CERC)	KL	INR Lakh/event
	Cold	90	40.5
	Warm	50	22.5
	Hot	30	13.5

Source: CERC IEGC 4th & 5th amendments

14.2.4 Summary of Operational Costs

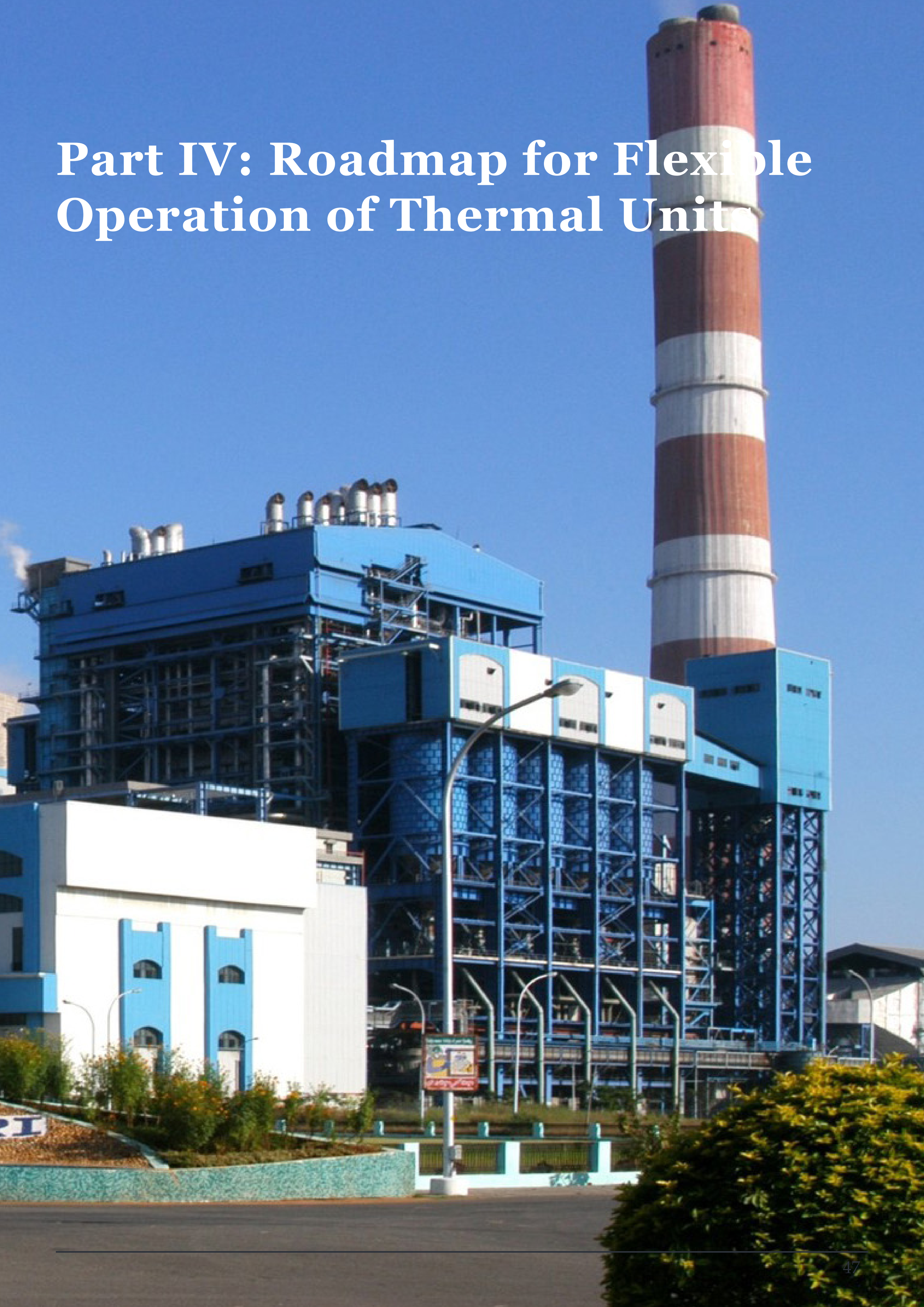
A summary of the operational costs involved in flexible operation is presented in Table 21. The overall impact in terms of per unit costs due to different modes of cyclic operations has been estimated.

The assumptions made in deriving the estimates on per unit basis are delineated in Annexure III .

Table 21 Summary of Operational Costs

			Typical 200/210 MW Unit				Typical 500 MW Unit			
			Due to HR	Add. O&M	Start-up Oil	Total	Due to HR	Add. O&M	Start up Oil	Total
Sr. No.		Unit loading %	Addl. Paisa/kWh				Addl. Paisa/kWh			
1	Minimum load with significant load followng	90%	0.0	0.0	0.0	0.0	1.1	0.0	0.0	1.3
2		80%	0.0	0.0	0.0	0.0	3.4	0.0	0.0	3.4
3		70%	2.1	3.3	0.0	5.4	6.7	7.1	0.0	13.8
4		60%	7.5	3.3	0.0	10.8	12.6	7.1	0.0	19.7
5		50%	15.0	3.3	0.0	18.3	20.0	7.1	0.0	27.2
6		40%	23.2	3.3	0.0	26.5	27.6	7.1	0.0	34.8
7		30%	34.6	3.3	0.0	38.0	38.0	7.1	0.0	45.2
	Weekly Start		23.2	60.2	14.8	98.2	27.6	69.2	10.7	107.5
	Daily Start		7.5	444.1	112.6	564.2	12.6	531.0	75.0	618.6

Part IV: Roadmap for Flexible Operation of Thermal Units



15. Introduction

To be sure, what might work best for the power system may not always be beneficial for individual power plants, which may have been built to operate round the clock. Power plants can provide different modes of flexibility. However, depending on cost structure, fuel type and plant design, power plants show large differences in their flexibility performance.

India has already achieved "One Nation, One Grid, One Frequency and on most of the days One Price in the electricity exchange". The Electricity Grid has evolved from local grid to state level grid and then to Regional grid and finally national synchronous electricity grid. Indian Electricity Grid is also connected to other countries (Bhutan, Nepal and Bangladesh) to gain international character. Now, with the constraint free robust transmission grid in place, time has come to move ahead from regional level scheduling to national level optimization in scheduling.

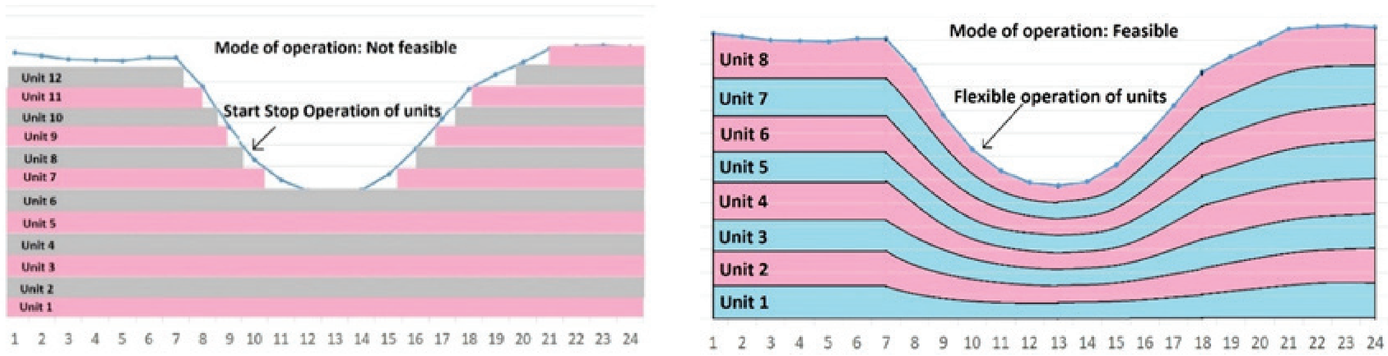
In order to maximize utilization of low-cost power, an all India level merit order is beneficial. This would not only schedule maximum power from cheaper stations but also enable optimum utilization of railway infrastructure for transportation of coal to the power stations.

Therefore, the scheduling exercise in this part of the report has been carried at national level employing an all India merit order dispatch.

16. Scheduling of Thermal Power

Methodology: Coal fired plants usually take considerable amount of time to start up due to the inherent slowness of the process of combustion and time required to achieve required steam parameters. Therefore, daily start stop operation of the entire fleet is not feasible, technically as well as financially. In other words, the scenario given in the left figure below, where in some plants are started and stopped at the requirement of grid operator while others run at full load, is not possible.

Figure 32 Mode of operation of thermal power plant



Hence, the entire day's scheduling shall be done based on the forecasted value of maximum evening load on coal-fired units during the day. In such a scenario, the units scheduled in a day would be expected to run at low loads during the hours when high solar power is available and then they would be expected to ramp up gradually when solar generation goes down and total demand picks up. An illustration is given on the right above.

Analysis

The following analysis attempts to run a mock scheduling exercise based on all India Merit Order Dispatch. The number of units scheduled from each category are calculated. Possible values of minimum load the units are expected to run at is estimated.

A total of 217 GW of thermal capacity in 2021-22 has been considered. The break up based on unit size is given below. The category TSO would be used in Two Shift operation as detailed in part II of the report.

Table 22 Break-up of thermal capacity in 2021-22

Symbol	Category	Capacity Range	Capacity	No. of units
x	Base Load	660 to 800 MW	68160	98
y	Flexible	490 to 600 MW	70770	133
z	Very Flexible	195 to 360 MW	67640	285
TSO	Two shift operation	< 151 MW	10564	110
	Total		**217134**	**626**

The scheduling of units has been done based on ECR data collected from central/ state utilities and IPPs. All India Unit-level data was collected, w.r.t. size, make of components, age, coal quality, past PLF, location, design, variable cost with respective state merit order etc. Based on the data, the analysis of technical capability data of the All India coal fleet was done to establish the capacities that can be made available for different levels/modes of flexing.

16.1 Lowest MTL day – Case study

The demand met from coal generation in the lowest MTL day is given below. The steps defined here are the same as those explained in the section 13 on coordinated effort.

Table 23 Demand met from coal generation during lowest MTL day.

Step No.	Flexibility from sources other than coal	Minimum Coal Based Generation (MW)	Maximum Coal Based Generation (MW)	Min. Coal Based Generation after considering APC (MW)	Max. Coal Based Generation after considering APC & reserve (MW)
BAU	Without support from other fuel sources	32665	116769	35896	139509
1	With support from other fuel sources	41865	107569	46005	128517
2	With Battery & Two Shift Operation	48865	98199	53698	117322
3	RE Curtailment	65658	107569	72151	128517

As per the above data, the no. of generation units expected to schedule on a given day (Lowest MTL Day) are given in the table below. In the BAU scenario, around 139 GW capacity is likely to be synchronized with the grid in the evening running at full load. They would, however, be running at loads as low as 25.73% in the afternoon. Around 307 units are expected to be scheduled during the day.

Table 24 Expected generation units to be scheduled on lowest MTL day - BAU

BAU				
Category	**Evening Load on each category based on MOD (MW)**	**No. of units on bar**	**MTL of each category as a whole**	**Afternoon Load on each category (MW)**
x	55020	79	25.73%	14157
y	52390	98	25.73%	13480
z	32320	130	25.73%	8316
Total	139730	307	25.73%	35953

In Step-I, around 272 units are expected to be scheduled including 79 units from x-category (Supercritical), 86 units from y-category (Subcritical unit size 500-600 MW) and around 107 units from z-category (Subcritical unit size 151-499 MW). The MTL of each category's units are given in table 25.

Table 25 Category-wise MTL of thermal units to be scheduled – Step I

Step - 1				
Category	**Evening Load on each category based on MOD (MW)**	**No. of units on bar**	**MTL of each category as a whole**	**Afternoon Load on each category (MW)**
x	55020	79	40.00%	22008
y	46090	86	35.00%	16132
z	27110	107	30.00%	8133
Total	128220	272	36.09%	46273

In Step-II, around 243 units are expected to be scheduled including 75 units from x-category, 78 units from y-category and around 90 units from z-category. The MTL of each category's units are given in table 26.

Table 26 Category-wise MTL of thermal units to be scheduled – Step II

Step - 2				
Category	**Evening Load on each category based on MOD (MW)**	**No. of units on bar**	**MTL of each category as a whole**	**Afternoon Load on each category (MW)**
x	52380	75	50.00%	26190
y	41890	78	44.00%	18432
z	23280	90	40.00%	9312
Total	117550	243	45.88%	53934

Further, Units having higher ECR are proposed to run at lower loads than units having lower ECR within the same category in the table below:

Table 27 Comparison of loading of units with varying ECR

Step-2					
Category	**Evening Load on each category based on MOD (MW)**	**No. of units on bar**	**Average MTL of each category as a whole**	**ECR range of the category**	**MTL range of the category**
x	52380	75	50.00%	0.84 to 2.38	45% to 55%
y	41890	78	44.00%	1.20 to 2.36	40% to 50%
z	23280	90	40.00%	1.10 to 2.30	35% to 45%
Total	117550	243	45.88%	0.84 to 2.38	

In step - III, around 272 units are expected to be scheduled including 79 units from x-category (Supercritical), 86 units from y-category (Subcritical units 500-600 MW) and around 107 units from z-category (Subcritical units 151-499 MW). However, due to RE curtailment in the afternoon hours, the minimum demand met by coal is increased which in turn improves the MTL of each category.

Table 28 Category-wise MTL of thermal units to be scheduled – Step III

Step - 3				
Category	**Evening Load on each category based on MOD (MW)**	**No. of units on bar**	**MTL of each category as a whole**	**Afternoon Load on each category (MW)**
x	55020	79	59.00%	32462
y	46090	86	56.00%	25810
z	27110	107	53.00%	14368
Total	128220	272	56.65%	72641

16.2 Average Monsoon Case

The demand met from coal generation in the average monsoon case is given below.

Table 29 Demand met from coal generation - Average Monsoon

Stage No.	Flexibility from sources other than coal	Minimum Coal Based Generation (MW)	Maximum Coal Based Generation (MW)	Min. Coal Based Generation after considering APC (MW)	Max. Coal Based Generation after considering APC & reserve (MW)
BAU	Without support from other fuel sources	57340	126477	63011	151108
1	With support from other fuel sources	66540	117277	73121	140116
2	With Battery & Two Shift Operation	73450	108921	80714	130133
3	RE Curtailment	74357	117277	81711	140116

In Business-as-usual (BAU) Step, around 337 units are expected to be scheduled including 85 units from x-category (Supercritical), 105 units from y-category (Subcritical units 500-600 MW) and around 147 units from z-category (Subcritical units 151-499 MW).

Table 30 MTL on units in BAU Step

BAU				
Category	**Evening Load on each category based on MOD (MW)**	**No. of units on bar**	**MTL of each category as a whole**	**Afternoon Load on each category (MW)**
x	59120	85	45.00%	26604
y	56090	105	41.00%	22997
z	36110	147	38.00%	13722
Total	151320	337	41.85%	63323

In step one, around 309 units are expected to be scheduled including 80 units from x-category (Supercritical), 98 units from y-category (Subcritical units 500-600 MW) and around 131 units from z-category (Subcritical units 151-499 MW).

Table 31 MTL of scheduled units in Step-I

Step - 1				
Category	**Evening Load on each category based on MOD (MW)**	**No. of units on bar**	**MTL of each category as a whole**	**Afternoon Load on each category (MW)**
x	55680	80	56.00%	31181
y	52390	98	51.00%	26719
z	32570	131	47.00%	15308
Total	140640	309	52.05%	73208

In step two, around 278 units are expected to be scheduled including 79 units from x-category (Supercritical), 89 units from y-category (Subcritical units 500-600 MW) and around 110 units from z-category (Subcritical units 151-499 MW).

Table 32 Category-wise MTL of thermal units to be scheduled – Step II

Step - 2				
Category	**Evening Load on each category based on MOD (MW)**	**No. of units on bar**	**MTL of each category as a whole**	**Afternoon Load on each category (MW)**
x	55020	79	65.00%	35763
y	47590	89	60.00%	28554
z	27730	110	60.00%	16638
Total	130340	278	62.21%	80955

In step three, around 309 units are expected to be scheduled including 80 units from x-category (Supercritical), 98 units from y-category (Subcritical units 500-600 MW) and around 131 units from z-category (Subcritical units 151-499 MW). However, due to RE curtailment in the afternoon hours, the minimum demand met by coal is increased which in turn improves the MTL of each category.

Table 33 Category-wise MTL of thermal units to be scheduled – Step III

Step - 3				
Category	**Evening Load on each category based on MOD (MW)**	**No. of units on bar**	**MTL of each category as a whole**	**Afternoon Load on each category (MW)**
x	55680	80	60.00%	33408
y	52390	98	58.00%	30386
z	32570	131	55.00%	17914
Total	140640	309	58.10%	81708

Note: The scheduling has been envisaged considering the result of pilot test and studies of thermal units which indicated that incremental cost of flexible operation decreases with decreasing unit size. Factors considered during scheduling are different sizes of units and Energy Charge Rating (ECR). Further fine tuning for optimum scheduling of various sizes of thermal units may be done using a modelling software.

17. Flexibility Measures at Plant Level

Preparation of a coal fired unit for flexible operation would require measures to be implemented at all levels of operation, maintenance and administration. Some of the measures required are listed below.

1. **Raise the awareness for flexible operation:** Provide background information about the need for flexible operation of coal-fired units. Similarly explain the impact of flexible operation on O&M of the plant and initiate training programs accordingly. The commercial impacts must also be sensitized.
2. **Check the status of the plant** and identify bottlenecks and limitations with respect to flexible operation:
   - Consult with OEMs to assess the influences of low load operation and temperature & pressure gradients on main components/ equipment.
   - Ensure smooth operation of all control loops at base load.
3. **Plan and execute test runs** to evaluate the plant flexibility potential
   - Create transparency about the plant performance with respect to normal load, start-up and cycling behavior in the current setup.
   - Identify constraints and process limitations as well as improvement potential.
4. **Optimize I&C system:** This is the most cost-effective way to enhance the flexibility of the plant. A certain level of automation is a prerequisite for tapping this potential.
   - Implementation of smooth control system in major power plant processes strengthen flexible operation; e.g. precise steam temperature control.
   - Optimization of underlying control loops, i.e. coal supply, drum level and air control, is a basic requirement and plant operators need to consider interlocks coming from logics.
5. **Implement mitigation measures** to manage the consequences of flexible / cycling operation. This includes a reassessment of all O&M procedures, with a special focus on water and steam quality, preservation and layup procedures as well as on maintenance strategies. The use of appropriate condition monitoring systems is essential.
6. **Optimize combustion:** Stable combustion is the key aspect to ensure minimum load operation. The following aspects are important.
   - Reliable flame detection for each individual burner
   - Transparency about the coal quality and composition
   - Optimization of air flow management
   - Operation with a reduced number of mills
   - Adaptation of the boiler protection system at low load operation.
7. **Optimize start-up procedures:** In order to ensure a fast and efficient start-up, plant operators should check start-up related temperature measurements and consider replacement of measuring equipments, if required. Besides automated start-up procedures, this is a prerequisite to assess admissible temperature limits and to operate with less conservative set points.
8. **Improve the plant efficiency at part load and dynamic behavior of the plant:** This refers to the measures like use of the potential of the water-steam cycle – such as frequency support by condensate stop and HP heater optimization – as well as measures to enhance the performance of important equipment and components, e.g. ID, FD and PA fans or feed water pumps.

9. **Improve the coal quality:** Better quality of coal improves the combustion process. Therefore, implement measures, such as blending & washing and online coal analysis to improve and monitor coal quality.

10. **Automate Control Procedures:** Automated operation always has advantage over manual operation. Some of the options that can be explored are:

- Automated Start of Fans and Pumps
- Automated Mill Operation
- Steam Temperature Control
- Flue Gas Temperature Control

Since each unit has a separate plant layout, equipment design, efficiency in operation practices and general condition of the machinery the interventions specific to a plant may be enumerated only after conducting a test run. A pilot test for flexible operation was conducted at unit 6 (500 MW) of Dadri TPS of NTPC. The test has successfully demonstrated operation of the unit at 40% minimum load and ramp rates of upto 3%/ min. The test procedure of the pilot test is attached at annexure-IV for reference of the generating utilities.

18. Measures to Ensure Grid Security and Stability

18.1 Automatic Generation Control (AGC) to support power system flexibility

With growing penetration of renewable energy sources, automatic controls are a must to maintain system frequency and the tie line flows as per schedule. Importance of spinning reserves in the system operation has been reiterated by the Commission in several documents and orders.

While primary frequency control is already mandated by the Indian electricity grid code on several generators, slow tertiary frequency control as an ancillary service for manually changing the schedules of thermal generators was introduced in 2016. Lack of automatic controls for balancing the system, the rapid expansion in Renewable Energy (RE) generation and the need to successfully integrate these in the grid brought out the need for automatic secondary frequency control in the Indian grid.

Almost every day it is observed that the inter-state shared generating stations have power reserves available due to non-requisition by the states. Some generators are under reserve shutdown due to less requisition of power from their respective beneficiaries. These reserves have been envisaged to be harnessed for meeting high demand ramps and for minute to minute tracking of load through Automatic Generation Control (AGC).

18.2 AGC on Solar/Wind

Considering the excellent controllability of power electronic devices and the low cost of the AGC setup, Renewable Energy (RE) resources like wind and solar need to be equipped with AGC. This would be useful for regulation in extreme dispatch scenarios like running out of secondary reserves and/or emergencies if RE is to be curtailed. Load forecast, Area Control Error (ACE) and Renewable forecast can be together used for deciding the participation of renewables under AGC for a particular time of the day. In the normal operation, the renewables would be dispatched fully. However, in cases of either a network congestion or when the entire coal fired generation is down to the technical minimum generation levels, it might be desirable to curtail RE through down regulation which can be done quickly through AGC signals. This process would also bring in transparency in RE curtailment.

18.3 Reserve Regulation Ancillary Services(RRAS)

The un-despatched surplus capacity available in the thermal & gas generating stations shall be used for RRAS Regulation 'Up' service. The RRAS Regulation 'Down' service is provided by these generating stations when they back down upto minimum load, thus acting as a tool for flexing the generation resource as per the requirement of the grid. RRAS will also help system operator to overcome critical situation like handling Low Probability High Impact Events. Thus, RRAS will help in facilitating large scale integration of renewables.

18.4 Fast Response Ancillary Services(FRAS)

Hydro generators are suitable for providing fast response and peaking support. Fast Response Ancillary Service (FRAS) from hydro stations is proposed as 'regulation service' from storage/pondage based hydro stations e.g. to handle the hour-boundary frequency spikes. . In this direction, CERC, vide order in Petition No. 07/SM/2018 (Suo-Motu) dtd. 16th July, 2018, ordered implementation of pilot project for FRAS covering all Central sector hydro generating stations which would help in gaining experience. POSOCO has been assigned the responsibility for implementing the Fast Response Ancillary Service (FRAS). All constraints declared by the hydro stations shall be honored and the total energy delivered over the day would be maintained as declared by the hydro station.

18.5 Usage of retiring power plants as synchronous condensers:

The installation of 175 GW RE capacity will cause reduction in total rotating masses (thermal generator) in the system. The stability of the transmission grid can be affected adversely in future due to reduction of rotating generating capacity in the power system. Solar PV panels have no rotating parts and no mechanical inertia. The retirement of a conventional power generation unit can create a deficit in reactive power. Therefore, it is suggested to utilize retiring thermal units as synchronous condensers for supplying reactive power as well as short circuit support.

Reactive power: Reactive power shortages are caused by a variety of factors: plant retirements, plant trips, transmission line failures and peak electricity demand. Reliable sources of reactive power, like synchronous condensers, are key to avoiding these shortages. Reactive power also supports the flow of real electrical power throughout the grid. When short-term and long-term changes in grid reactive power capacity are not balanced, the result can lead to system voltage instability, islanding, voltage collapse and, ultimately it leads to system breakdown.

Short circuit support: As the condenser is a rotating device, it can also provide short circuit support in addition to reactive power capacity. Conversion of thermal generating unit to a synchronous condenser can provide electrical system voltage support resulting in a stable source of electric power.

Converting an existing synchronous generator to a synchronous condenser requires a custom-engineered solution because each plant will have a unique design and layout. The generator, electrical, cooling and lubrication systems must be evaluated as a whole. A plant level study needs to be done for the detailed engineering on Mechanical parts, lubrication system, hydrogen cooling, exciters, prime movers and the control system (includes generator protections etc.) should be integrated with the overall plant controls to enable monitoring of the system's status. System level study may be conducted by CEA/CTU/POSOCO for the assessment of reactive power requirement in the retired generators control area and the voltage profile improvement. Finally, Regulatory support (Ancillary services on reactive power) is needed for condenser mode of operation.

19. Conclusion and Recommendations

19.1 Conclusion

The integration of 175 GW of renewable capacity (100 GW of solar and 60 GW of wind) by 2021-22, will result in 36% share of RE in the total installed capacity. there would be a need for better access to flexibility from other sources. With business as usual scenario, there would be undue pressure on coal-fired units to flex their generation to as low as 26% of the rated capacity, which they are not designed for. It is also techno-economically unviable for coal units to operate at such low loads especially with the high-ash content Indian coal. In step one, with additional peaking support from hydro and gas, the minimum loads of coal plants can be significantly increased. In step two, pump or battery storage or combination of both and two-shift operation of certain coal-fired plants are envisaged.

Finally, as a last resort, RE curtailment is explored with its corresponding impact on thermal minimum load of coal-fired units. It was inferred that 0.96% curtailment of renewable energy on an annual basis would improve the MTL of coal-based generating units from 25.73% to 45%, considering BAU participation from other fuel sources. Alternatively, provision for storage of 2.5% of daily energy production at plant level by RE generator and utilization of same during peak demand hours will strategically minimize the requirement of flexible generation. The AGC (Automatic Generation Control) for solar and hydro may also be implemented for effective grid balancing. Additionally, measures like Demand-Side Management (DSM) and robust forecasting will further reduce the difference between peak & off-peak demand. Under demand side management, as agricultural consumption is about 18% of the total energy consumption in the country, shifting of an agricultural load of around 2000 to 3000 MW from night hours to solar generation hours is expected to improve the MTL by 2 to 3%. Similar improvement is also expected in future, if e-vehicle charging load is coordinated with the time of solar generation.

Flexible operation of smaller sized thermal unit is economical than that of bigger sized units. Thus, it is proposed to run smaller size units at lower load and bigger size unit at comparatively higher load during low grid demand or high solar generation period when the lower sized unit has equal or lower ECR compared to the higher sized unit. Investment is required to implement various measures, which may vary from plant to plant, to convert a base load thermal unit into a flexible generator. Revision of tariff is essential to make profitable flexible operation of thermal units.

There is an urgent need of regulatory intervention, revision of grid code & tariff structure for supplying flexible generation into the grid from hydro, gas, thermal plant and pumped & battery storage. As thermal sector is expected to provide majority of the requirement of flexible power, they may be incentivized to operate their plants in a flexible regime and follow the best O&M practices. The central and state commisions have to work on this aspect. Regulatory intervention is also required for mandatory establishment of storage capacity at Solar and Wind plant level.

19.2 Recommendations

1. Hydro power plants are especially suitable for quick supply of flexible power. Coordination with state operated hydro plants would play an important role in re-allocation of hydro generation. Pumped storage, existing and under-construction, may be used exclusively for peaking or balancing of system on the direction of regional/ national level system operator only. To make the peak hour's generation lucrative, provision of two-part tariff and revision of grid code are suggested. Regulatory intervention is required to implement the recommendation.

2. Gas power plants have better start stop capability and need to contribute to flexible generation as much as possible. An estimate of the extent of flexible generation anticipated from Gas has been provided in the report.

3. Establishment of pump or battery storage or combination of both at strategic locations may be explored for energy storage during high solar generation period and utilizing the same during peak demand

hours or at the time of need.

4. RE curtailment or Step two measures of the report (Pump or Battery storage and Two Shift Operation) cannot be avoided in the year 2021-22, especially during the monsoon period. It is suggested that establishment of pump storage in combination of solar and/or wind plant may be explored wherever such geographical advantages are available in India. For others, mandatory establishment of battery storage of 2.5% of daily energy generation at solar or wind plants is suggested. Regulatory intervention is required to implement the same.

5. The pilot test on flexible operation of thermal power plant reveals that incremental cost of flexible operation decreases with decreasing unit size. Therefore, it is suggested to operate smaller sized units, having equal or lower ECR in comparison to a higher sized unit, at a MTL which is lower than that of the higher sized unit.

6. Among the fleet of 200 MW, 500/600 MW or 660/800 MW units, units which are efficient and have low ECR, should be given preference over other units in terms of generation schedule.

7. Traditionally most of the coal-fired units are designed to operate as base load plants. Hence, several measures need to be undertaken to make the plants capable of low load operation. From the cost point of view, it is suggested to provide revised tariff to coal-fired generators for supplying flexible generation as below.

    - Opex – based on a benchmarked costs (compensation) + markup (incentivisation).
    - Capex to be reimbursed on actual basis after examination.

8. Pilot study of thermal units for operation at low load shall be conducted before implementation of measures for flexible operation as the measures are plant specific.

9. As historically coal fired plants have been operated as base load plants, capacity building of power plant operators becomes an important measure in the changing operational regime. Therefore, training programs on thermal power plant simulator should be institutionalized focusing on areas such as plant startup and shutdown, flexible operation, operation of Distributed Control Systems (DCS), emergency situations and safety procedures.

10. Demand side management including measures targeted at domestic, agricultural, industrial and e-mobility sectors would enable more rational consumption pattern of electricity, which would facilitate integration of renewable generation. All these measures are recommended to increase power consumption during solar generation period and reduce it in evening, morning & night hours when solar generation is not available.

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Annexure 1: Data Analysis for Minimum Technical Load for Business as usual (BAU) scenario

Annexure – I

1. Minimum Thermal Load (MTL) is calculated such that all fuel sources operate as business-as-usual (BAU) and all thermal units ramp up / ramp down at the same rate simultaneously. The critical day obtained in this fashion is 27th July 2021.

2. 10% reserve has been considered. As APC deteriorates with low load operation, APC of 7% at maximum load and 9% at minimum load is considered.

Day	Total Load (2021-22)	Max RES (W+S)	Minimum Coal Demand (MW)	Maximum Coal Demand (MW)	Minimum Thermal Load (MTL)
01-Apr	192082	73165	74458	139302	49.16%
02-Apr	194439	70102	80139	141357	52.14%
03-Apr	192709	71682	75651	141000	49.35%
04-Apr	194328	73660	72786	140815	47.54%
05-Apr	191361	71878	72780	140151	47.76%
06-Apr	193765	71884	75273	142192	48.69%
07-Apr	194971	68924	81076	146234	51.00%
08-Apr	194211	70784	81432	144886	51.70%
09-Apr	194980	69683	82393	148366	51.08%
10-Apr	193482	69800	82543	147452	51.49%
11-Apr	192989	74200	78995	146120	49.73%
12-Apr	189577	70602	73670	142471	47.56%
13-Apr	189062	69080	74725	142784	48.14%
14-Apr	189788	66604	82009	146995	51.31%
15-Apr	194432	63471	86970	149962	53.34%
16-Apr	197485	66361	83486	153321	50.08%
17-Apr	192760	66220	81524	150051	49.97%
18-Apr	194552	69872	78759	148998	48.62%
19-Apr	194604	81274	65863	146917	41.23%
20-Apr	194781	69908	79145	149526	48.68%
21-Apr	198294	63698	88254	152204	53.33%
22-Apr	198717	65181	87740	149881	53.84%
23-Apr	197399	71834	81643	146238	51.35%
24-Apr	195553	72104	78396	145246	49.64%
25-Apr	196598	74277	76577	143604	49.05%
26-Apr	194715	68149	79841	144168	50.94%
27-Apr	197248	60510	90071	146945	56.38%
28-Apr	197954	68988	86026	146872	53.87%
29-Apr	199528	71503	83721	147443	52.23%
30-Apr	198499	76378	77609	145949	48.91%
01-May	194191	76343	72826	144695	46.29%
02-May	196217	78996	75377	144148	48.10%
03-May	193164	78218	71848	142912	46.24%
04-May	191111	76637	74038	142013	47.95%
05-May	194130	75836	75716	143853	48.41%

Day	Total Load (2021-22)	Max RES (W+S)	Minimum Coal Demand (MW)	Maximum Coal Demand (MW)	Minimum Thermal Load (MTL)
06-May	196940	77049	76623	146312	48.17%
07-May	198349	72691	79920	145464	50.53%
08-May	190838	68509	83756	143186	53.80%
09-May	196128	67993	83920	137457	56.15%
10-May	191906	74215	74518	139422	49.16%
11-May	193990	79441	70420	138958	46.61%
12-May	196924	75424	75231	145098	47.69%
13-May	193044	77745	72840	143680	46.63%
14-May	194699	76290	70998	145121	45.00%
15-May	193837	73526	74454	144039	47.54%
16-May	195198	78488	72963	142910	46.96%
17-May	192708	78411	70704	141576	45.93%
18-May	193562	73563	76234	139913	50.12%
19-May	193396	85806	66713	135934	45.14%
20-May	197863	86085	65143	140630	42.61%
21-May	199364	88416	65319	134032	44.82%
22-May	199811	91723	60964	134426	41.71%
23-May	196273	92496	61706	131182	43.27%
24-May	195028	87332	60624	131698	42.34%
25-May	191855	90115	61074	126539	44.39%
26-May	198715	87083	66188	137605	44.24%
27-May	198148	87249	68619	142834	44.19%
28-May	198527	90210	63715	141704	41.36%
29-May	195640	90339	59368	138550	39.41%
30-May	197113	83564	69466	140781	45.38%
31-May	193160	88519	62555	134936	42.64%
01-Jun	193438	85686	65117	137074	43.69%
02-Jun	196732	81121	75287	141243	49.03%
03-Jun	196413	72890	82703	141365	53.81%
04-Jun	199590	71587	84695	145676	53.48%
05-Jun	197510	72612	82198	149471	50.58%
06-Jun	202618	76439	81641	146260	51.34%
07-Jun	197098	76088	79071	144487	50.34%
08-Jun	201416	79859	76733	141265	49.96%
09-Jun	200369	81903	74892	135480	50.84%
10-Jun	201201	81706	76652	133852	52.67%
11-Jun	197970	72423	85601	138336	56.92%
12-Jun	194130	84964	68269	134289	46.76%
13-Jun	193112	95654	55591	126881	40.30%
14-Jun	195355	94784	51094	128200	36.66%
15-Jun	196702	95349	54018	133459	37.23%
16-Jun	202178	88225	64268	140881	41.96%
17-Jun	203173	87322	69553	140585	45.51%

Day	Total Load (2021-22)	Max RES (W+S)	Minimum Coal Demand (MW)	Maximum Coal Demand (MW)	Minimum Thermal Load (MTL)
18-Jun	202614	84205	72874	140244	47.79%
19-Jun	201605	92558	61967	139375	40.89%
20-Jun	203001	91606	62493	131382	43.75%
21-Jun	196022	94470	53682	125772	39.26%
22-Jun	199133	102839	43849	123755	32.59%
23-Jun	198817	97386	52575	123267	39.23%
24-Jun	199015	104369	45343	119298	34.96%
25-Jun	197881	105715	40589	124800	29.91%
26-Jun	199810	105670	40938	123614	30.46%
27-Jun	201470	103307	47621	120105	36.47%
28-Jun	200428	99387	49442	126912	35.83%
29-Jun	197982	99660	52560	124293	38.90%
30-Jun	205164	100115	52712	136106	35.62%
01-Jul	201723	108926	45763	126077	33.39%
02-Jul	200912	99571	49949	121804	37.72%
03-Jul	197787	106365	41241	119615	31.71%
04-Jul	202529	108484	41717	119972	31.98%
05-Jul	200939	107415	42198	121228	32.02%
06-Jul	198890	108036	41372	121007	31.45%
07-Jul	202379	105542	48929	121243	37.12%
08-Jul	203396	105614	51208	124166	37.93%
09-Jul	200979	108395	44953	122625	33.72%
10-Jul	195144	107069	41351	119427	31.85%
11-Jul	197643	105907	44181	127614	31.84%
12-Jul	196034	97533	49122	124338	36.34%
13-Jul	199099	86441	62404	126026	45.54%
14-Jul	203374	85197	66679	129603	47.32%
15-Jul	202481	93535	59353	128928	42.34%
16-Jul	199450	96111	50247	127670	36.20%
17-Jul	194534	92799	52814	121782	39.89%
18-Jul	194790	105137	41455	117802	32.37%
19-Jul	194645	108316	34071	113695	27.56%
20-Jul	196607	105000	38910	121594	29.43%
21-Jul	201041	102262	46383	124087	34.38%
22-Jul	199961	102318	45254	121877	34.15%
23-Jul	198795	102692	42854	120364	32.75%
24-Jul	196390	95438	48447	120500	36.98%
25-Jul	197300	100021	45455	122440	34.15%
26-Jul	193252	95777	47052	120800	35.83%
27-Jul	190480	108082	32665	116769	25.73%
28-Jul	195634	103845	37605	121781	28.40%
29-Jul	195959	103795	37348	115504	29.74%
30-Jul	197121	96133	45044	123157	33.64%

Day	Total Load (2021-22)	Max RES (W+S)	Minimum Coal Demand (MW)	Maximum Coal Demand (MW)	Minimum Thermal Load (MTL)
31-Jul	194280	88674	49472	120550	37.75%
01-Aug	193299	83683	55165	121710	41.69%
02-Aug	192388	82006	55089	120000	42.22%
03-Aug	196715	96844	45525	118068	35.47%
04-Aug	197621	101046	42447	119379	32.70%
05-Aug	199307	96917	45837	121903	34.59%
06-Aug	200245	95083	49456	128680	35.35%
07-Aug	198076	93943	48954	126147	35.69%
08-Aug	200568	88419	56358	129493	40.03%
09-Aug	198734	82166	61316	131961	42.74%
10-Aug	195324	82683	58766	129079	41.87%
11-Aug	199524	84733	58550	129672	41.53%
12-Aug	198791	84778	57030	127897	41.01%
13-Aug	198193	86770	53363	123910	39.61%
14-Aug	197494	88451	52265	123269	39.00%
15-Aug	189474	91355	37897	119009	29.29%
16-Aug	197298	87401	49613	128375	35.55%
17-Aug	198460	74333	64180	134579	43.86%
18-Aug	197583	71272	68873	135925	46.61%
19-Aug	202552	73332	70665	136313	47.68%
20-Aug	205697	76191	71001	138195	47.26%
21-Aug	205109	76341	70634	137765	47.16%
22-Aug	207042	80102	68184	135792	46.18%
23-Aug	205333	81469	67665	130302	47.76%
24-Aug	204332	79459	71947	137271	48.21%
25-Aug	206200	81133	71192	136195	48.08%
26-Aug	207558	81241	73373	135576	49.78%
27-Aug	206247	79963	72519	139890	47.68%
28-Aug	204781	80387	72446	140967	47.27%
29-Aug	202349	79309	71535	136752	48.11%
30-Aug	204044	81937	68284	134912	46.55%
31-Aug	201127	76659	67884	136162	45.86%
01-Sep	201308	72885	72037	139203	47.60%
02-Sep	200743	71231	75913	140082	49.84%
03-Sep	202396	68167	78251	146096	49.26%
04-Sep	196782	69252	74899	134548	51.20%
05-Sep	196116	74118	71001	135898	48.05%
06-Sep	198395	71213	74989	138689	49.73%
07-Sep	199727	62215	84931	144259	54.15%
08-Sep	205698	62986	88122	144972	55.91%
09-Sep	207876	69217	85212	144262	54.33%
10-Sep	207581	65907	88496	147602	55.15%
11-Sep	207447	67453	86681	146139	54.56%

Day	Total Load (2021-22)	Max RES (W+S)	Minimum Coal Demand (MW)	Maximum Coal Demand (MW)	Minimum Thermal Load (MTL)
12-Sep	207489	66398	90152	145859	56.85%
13-Sep	206744	67075	87638	140245	57.48%
14-Sep	204059	72454	82555	135881	55.88%
15-Sep	205562	66523	87411	136849	58.75%
16-Sep	205884	75176	79802	136430	53.80%
17-Sep	204459	72903	79224	133412	54.62%
18-Sep	202295	75959	77300	131120	54.22%
19-Sep	206725	77500	75145	140782	49.09%
20-Sep	201499	80771	70462	135875	47.70%
21-Sep	202756	70612	77678	138430	51.61%
22-Sep	204049	60028	88405	144450	56.29%
23-Sep	205573	57662	91979	150382	56.26%
24-Sep	205107	56199	94943	151101	57.79%
25-Sep	202551	58047	91014	146781	57.03%
26-Sep	207004	60481	92197	152205	55.71%
27-Sep	202795	58970	90896	150198	55.66%
28-Sep	204872	49322	104329	154821	61.98%
29-Sep	209907	56336	101333	157679	59.11%
30-Sep	208099	58379	100884	156774	59.19%
01-Oct	206818	54149	106450	159128	61.53%
02-Oct	201786	50113	103096	153627	61.72%
03-Oct	206851	54587	103380	150267	63.28%
04-Oct	208426	56998	102617	157215	60.04%
05-Oct	207997	51191	108391	159902	62.35%
06-Oct	211819	52830	107438	158274	62.44%
07-Oct	225751	52421	119610	175611	62.65%
08-Oct	209826	52232	107134	156976	62.77%
09-Oct	207095	55773	100767	155984	59.42%
10-Oct	206506	62580	94310	147712	58.73%
11-Oct	200999	54259	99127	150087	60.75%
12-Oct	201516	52215	102867	154526	61.23%
13-Oct	207067	55892	102025	158176	59.33%
14-Oct	206309	55540	99133	157085	58.05%
15-Oct	206950	54313	100833	157895	58.74%
16-Oct	205542	54661	101552	156358	59.74%
17-Oct	207902	55459	103047	160367	59.10%
18-Oct	205652	58364	98926	156765	58.04%
19-Oct	207778	53040	107146	161071	61.18%
20-Oct	210372	54643	106764	163089	60.21%
21-Oct	210259	53170	109524	161281	62.46%
22-Oct	202829	53225	104154	158037	60.62%
23-Oct	199211	50326	107338	155905	63.33%
24-Oct	200094	54255	102882	151108	62.62%

Day	Total Load (2021-22)	Max RES (W+S)	Minimum Coal Demand (MW)	Maximum Coal Demand (MW)	Minimum Thermal Load (MTL)
25-Oct	198011	54118	101336	150492	61.93%
26-Oct	200976	51862	103857	155372	61.48%
27-Oct	203569	52944	105986	158860	61.36%
28-Oct	201486	54629	103603	156700	60.81%
29-Oct	200693	52044	103833	157175	60.76%
30-Oct	194639	53000	99911	150658	61.00%
31-Oct	195762	52243	99196	148818	61.31%
01-Nov	193237	52301	100193	149084	61.81%
02-Nov	196113	48850	104433	153722	62.49%
03-Nov	201216	53496	103557	155573	61.23%
04-Nov	200234	53460	104246	155171	61.79%
05-Nov	201763	55564	102890	154243	61.36%
06-Nov	199214	54445	103335	154427	61.55%
07-Nov	200257	57873	101585	156651	59.65%
08-Nov	199075	59510	100887	152691	60.77%
09-Nov	198421	59759	99393	148259	61.66%
10-Nov	199352	62485	93678	145539	59.20%
11-Nov	195147	71101	82151	141728	53.31%
12-Nov	193719	54160	97967	149866	60.13%
13-Nov	192085	55678	96368	149407	59.33%
14-Nov	194742	67736	85228	148283	52.87%
15-Nov	192886	59715	92965	150479	56.82%
16-Nov	193583	68442	85361	151659	51.77%
17-Nov	194824	51565	104625	152619	63.05%
18-Nov	196201	67526	88136	149608	54.19%
19-Nov	196049	63475	90872	149286	55.99%
20-Nov	192115	60887	94607	148128	58.75%
21-Nov	196646	63339	93248	150438	57.01%
22-Nov	187647	61192	93784	147047	58.66%
23-Nov	194985	58105	95252	153314	57.14%
24-Nov	195339	59446	99424	153329	59.64%
25-Nov	194921	56196	98631	153415	59.13%
26-Nov	195702	60555	93701	151891	56.74%
27-Nov	191131	53776	100135	148515	62.02%
28-Nov	195814	53679	102857	152135	62.19%
29-Nov	193217	57604	97851	151306	59.48%
30-Nov	192495	61039	93941	150956	57.24%
01-Dec	193049	59522	96969	154058	57.89%
02-Dec	193052	64012	91574	154062	54.67%
03-Dec	193281	61710	92829	152390	56.03%
04-Dec	189502	65613	87970	148129	54.62%
05-Dec	194399	65683	91760	148088	56.99%
06-Dec	190157	75992	80311	142547	51.82%

Day	Total Load (2021-22)	Max RES (W+S)	Minimum Coal Demand (MW)	Maximum Coal Demand (MW)	Minimum Thermal Load (MTL)
07-Dec	193847	66088	93494	150518	57.13%
08-Dec	197050	64011	94256	153138	56.61%
09-Dec	198739	58270	103180	155841	60.90%
10-Dec	196925	63004	99329	154416	59.17%
11-Dec	194259	67807	90541	152111	54.75%
12-Dec	193097	62833	95568	153463	57.28%
13-Dec	188711	57253	99000	149861	60.76%
14-Dec	189377	65358	90594	150109	55.51%
15-Dec	193080	64681	91226	149757	56.03%
16-Dec	194808	70730	86834	149838	53.30%
17-Dec	194685	71000	87313	153498	52.32%
18-Dec	190121	62974	96542	152267	58.32%
19-Dec	195665	59613	103163	152934	62.04%
20-Dec	192755	63777	95507	151716	57.90%
21-Dec	194320	63389	97297	153708	58.22%
22-Dec	198987	65027	98531	158497	57.18%
23-Dec	198277	62216	101213	155712	59.79%
24-Dec	197100	62302	100658	154624	59.88%
25-Dec	192103	70936	89497	148450	55.45%
26-Dec	196954	73137	90594	150570	55.34%
27-Dec	193909	75176	86690	148602	53.66%
28-Dec	194866	81751	81835	147123	51.16%
29-Dec	197112	82185	82861	150421	50.67%
30-Dec	198382	72306	91261	147616	56.86%
31-Dec	196168	83154	80071	144561	50.95%
01-Jan	188664	81285	79493	140270	52.13%
02-Jan	195603	69847	92423	154627	54.98%
03-Jan	193238	67750	93097	155319	55.13%
04-Jan	194203	68932	94227	153859	56.33%
05-Jan	198368	74880	90890	159196	52.51%
06-Jan	199422	69864	96114	160059	55.23%
07-Jan	198127	69937	92329	159516	53.24%
08-Jan	195530	66135	94184	157929	54.85%
09-Jan	198083	71440	92127	158310	53.53%
10-Jan	196525	67863	94151	154291	56.13%
11-Jan	198771	70459	94307	156427	55.45%
12-Jan	201091	73286	93093	158198	54.13%
13-Jan	199162	73780	91265	159365	52.67%
14-Jan	190953	75210	84346	147283	52.67%
15-Jan	190015	76102	84285	144941	53.49%
16-Jan	194235	72916	90658	152251	54.77%
17-Jan	195873	72794	90992	155774	53.73%
18-Jan	198499	70231	95589	158527	55.46%

Day	Total Load (2021-22)	Max RES (W+S)	Minimum Coal Demand (MW)	Maximum Coal Demand (MW)	Minimum Thermal Load (MTL)
19-Jan	198605	74395	92447	157269	54.07%
20-Jan	200434	70041	95590	156614	56.14%
21-Jan	202651	71925	92329	160862	52.79%
22-Jan	198656	72001	91630	156341	53.91%
23-Jan	201187	67989	97093	154520	57.79%
24-Jan	198155	70946	94043	154883	55.85%
25-Jan	197525	76860	87087	152216	52.62%
26-Jan	189047	75485	80425	138902	53.26%
27-Jan	198222	75991	83623	150931	50.96%
28-Jan	200527	74823	89381	155283	52.94%
29-Jan	196736	64884	98126	152216	59.29%
30-Jan	200235	76228	89207	156150	52.55%
31-Jan	197073	75571	89552	154130	53.44%
01-Feb	197730	68540	95829	154304	57.12%
02-Feb	200233	74816	89455	148672	55.34%
03-Feb	200364	74701	88842	154133	53.02%
04-Feb	201622	82015	81150	149265	50.01%
05-Feb	197420	74291	87643	151585	53.18%
06-Feb	199673	73149	90292	152309	54.53%
07-Feb	197570	70974	91984	151035	56.02%
08-Feb	198077	79724	84325	151089	51.33%
09-Feb	203259	74369	88909	154026	53.09%
10-Feb	202748	79046	87072	154633	51.79%
11-Feb	200769	70990	91692	156955	53.73%
12-Feb	199066	68657	94054	157536	54.91%
13-Feb	202838	71843	93117	156985	54.56%
14-Feb	200140	65092	99622	159219	57.55%
15-Feb	199910	66734	99300	155484	58.74%
16-Feb	202369	70317	94924	157556	55.41%
17-Feb	201832	72450	92112	157855	53.67%
18-Feb	202280	69969	96513	158747	55.92%
19-Feb	200899	68198	97624	155505	57.74%
20-Feb	203094	67883	95514	157142	55.91%
21-Feb	199735	74339	87212	153380	52.30%
22-Feb	200436	73071	92201	155683	54.47%
23-Feb	205811	75230	90723	155506	53.66%
24-Feb	206484	78427	89984	153419	53.95%
25-Feb	206012	73974	93439	158868	54.10%
26-Feb	201223	68365	97219	155226	57.61%
27-Feb	205525	64942	101933	161981	57.88%
28-Feb	199774	72894	94218	153172	56.58%
01-Mar	194645	73192	84304	147682	52.51%
02-Mar	199123	74122	84126	150339	51.47%

Day	Total Load (2021-22)	Max RES (W+S)	Minimum Coal Demand (MW)	Maximum Coal Demand (MW)	Minimum Thermal Load (MTL)
03-Mar	199991	70355	92305	155407	54.63%
04-Mar	198135	67001	95481	157003	55.94%
05-Mar	193738	70476	89381	152273	53.99%
06-Mar	188377	70435	79324	144478	50.50%
07-Mar	192325	68859	88172	147063	55.15%
08-Mar	195373	64754	91865	146534	57.66%
09-Mar	199007	75316	84709	149235	52.21%
10-Mar	194368	74849	84075	144698	53.44%
11-Mar	195989	74353	83655	144223	53.35%
12-Mar	192602	70179	86341	140579	56.49%
13-Mar	185585	74684	73474	140192	48.21%
14-Mar	193897	71204	84725	143405	54.34%
15-Mar	191697	69151	84353	145626	53.28%
16-Mar	196454	65714	90988	152538	54.86%
17-Mar	198523	68859	89451	153300	53.67%
18-Mar	198752	70827	87912	154034	52.49%
19-Mar	196543	65838	94297	153523	56.49%
20-Mar	198477	68694	91356	155024	54.20%
21-Mar	201498	70917	90709	157639	52.93%
22-Mar	200848	66491	96597	155796	57.03%
23-Mar	202965	68666	96358	154126	57.50%
24-Mar	201722	70726	91413	154202	54.53%
25-Mar	206297	68780	96856	160561	55.48%
26-Mar	203421	66986	99974	157978	58.21%
27-Mar	204515	71018	94057	157033	55.09%
28-Mar	206749	70647	97170	159116	56.17%
29-Mar	202653	71733	93174	157860	54.29%
30-Mar	206216	65481	98809	160104	56.76%
31-Mar	206474	63019	103350	161301	58.93%

Annexure IB

S.No.	Day	Date	Max Total Demand	Max RES Generation	MTL	Max. Ramp Rate (MW/min)
1	Highest Demand Day	7th October 2021	225751	52421	62.65%	-216
2	Lowest Demand Day	13th March 2022	185585	74684.5	48.21%	-422
3	Highest RE Day	1st July 2021	201723	108926	33.39%	-332
4	Highest Ramp Down Day	13th March 2022	185585	74684	48.21%	-422
5	Highest Ramp Up Day	3rd Feb 2022	200364	74701	53.02%	379
6	Lowest MTL Day	27th July 2021	190480	108082	25.73%	-310

Annexure 2

Step I

Day	Time	Total Load (2021-22)	Solar BAU	Wind BAU	Nuclear BAU	Gas BAU	Biomass BAU	Small Hydro BAU	Hydro BAU	Coal BAU	Redis Hydro	Gas - Reallocation	PS New Cap Add.	Coal after support from	Gas after reallocation	Hydro after reallocati
27-Jul	00:00	180339	0	28859	5420	6241	2000	1000	25620	111199	5000	1500	1200	103499	7741	31820
27-Jul	01:00	177283	0	27063	5421	6199	2000	1000	24714	110886	5000	1500	1200	103186	7699	30914
27-Jul	02:00	174349	0	25391	5427	6220	2000	1000	24191	110120	5000	1500	1200	102420	7720	30391
27-Jul	03:00	171930	0	22295	5443	6190	2000	1000	23845	111158	5000	1500	1200	103458	7690	30045
27-Jul	04:00	170924	0	22705	5440	6180	2000	1000	24011	109588	5000	1500		103088	7680	29011
27-Jul	05:00	172465	11	22591	5445	6178	2000	1000	24542	110699	5000	1200		104499	7378	29542
27-Jul	06:00	175127	1893	21146	5445	6203	2000	1000	25568	111872	5000	700	-1200	107372	6903	29368
27-Jul	07:00	177762	18561	22029	5448	6193	2000	1000	26994	95537	-5000	-1000	-1200	102737	5193	20794
27-Jul	08:00	178650	36535	22955	5453	6180	2000	1000	27488	77038	-5000	-2000	-1200	85238	4180	21288
27-Jul	09:00	180073	52386	27396	5449	6142	2000	1000	27249	58450	-5000	-3000	-1200	67650	3142	21049
27-Jul	10:00	181809	62405	31575	5440	6190	2000	1000	27104	46095	-5000	-3000	-1200	55295	3190	20904
27-Jul	11:00	181212	68953	32738	5444	6251	2000	1000	26182	38645	-5000	-3000	-1200	47845	3251	19982
27-Jul	12:00	181151	70924	37158	5442	6265	2000	1000	25697	32665	-5000	-3000	-1200	41865	3265	19497
27-Jul	13:00	178995	67804	37372	5441	6296	2000	1000	24564	34519	-5000	-3000	-1200	43719	3296	18364
27-Jul	14:00	177595	57278	36057	5444	6283	2000	1000	24327	45205	-5000	-3000	-1200	54405	3283	18127
27-Jul	15:00	178441	44548	36459	5450	6368	2000	1000	25158	57458	-5000	-2000	-1200	65658	4368	18958
27-Jul	16:00	177872	26279	36094	5447	6339	2000	1000	24955	75757	-5000	-1000	-1200	82957	5339	18755
27-Jul	17:00	175491	9299	34586	5453	6272	2000	1000	25276	91606	-5000	-100	-1200	97906	6172	19076
27-Jul	18:00	175006	36	32997	5457	6219	2000	1000	25316	101982	-5000	800		106182	7019	20316
27-Jul	19:00	184571	0	31724	5464	6276	2000	1000	28668	109439	5000	1900		102539	8176	33668
27-Jul	20:00	190480	0	28662	5462	6465	2000	1000	30191	116700	5000	3000	1200	107500	9465	36391
27-Jul	21:00	189882	0	28695	5466	6535	2000	1000	29417	116769	5000	3000	1200	107569	9535	35617
27-Jul	22:00	187171	0	29459	5466	6419	2000	1000	28300	114527	5000	3000	1200	105327	9419	34500
27-Jul	23:00	185868	0	29100	5463	6417	2000	1000	27904	113984	5000	3000	1200	104784	9417	34104
Max		190480	70924	37372	5466	6535	2000	1000	30191	116769	5000	3000	1200	107569	9535	36391
Min		170924	0	21146	5420	6142	2000	1000	23845	32665	-5000	-3000	-1200	41865	3142	18127
MTL														**35.80%**		

Step II

Day	Time	Total Load (2021-	Solar BAU	Wind BAU	Nuclear BAU	Gas BAU	Biomass BAU	Small Hydro BAU	Hydro BAU	Coal BAU	Redis Hydro	Gas - Reallocation	PS New Cap Add.	Battery / PS	Peaking Support from	Coal after support	Gas after realloca	Hydro after realloca
27-Jul	00:00	180339	0	28859	5420	6241	2000	1000	25620	111199	5000	2500	1200	4300	0	98199	8741	31820
27-Jul	01:00	177283	0	27063	5421	6199	2000	1000	24714	110886	5000	2500	1200	4100	0	98086	8699	30914
27-Jul	02:00	174349	0	25391	5427	6220	2000	1000	24191	110120	5000	2500	1200	3300	0	98120	8720	30391
27-Jul	03:00	171930	0	22295	5443	6190	2000	1000	23845	111158	5000	3000	600	4400	0	98158	9190	29445
27-Jul	04:00	170924	0	22705	5440	6180	2000	1000	24011	109588	5000	3000		3400	0	98188	9180	29011
27-Jul	05:00	172465	11	22591	5445	6178	2000	1000	24542	110699	5000	3000		4500	0	98199	9178	29542
27-Jul	06:00	175127	1893	21146	5445	6203	2000	1000	25568	111872	5000	3000		5900	0	97972	9203	30568
27-Jul	07:00	177762	18561	22029	5448	6193	2000	1000	26994	95537	-3000	-500	-1200	2100	0	98137	5693	22794
27-Jul	08:00	178650	36535	22955	5453	6180	2000	1000	27488	77038	-5000	-3000	-1200	-7000	0	93238	3180	21288
27-Jul	09:00	180073	52386	27396	5449	6142	2000	1000	27249	58450	-5000	-3000	-1200	-7000	0	74650	3142	21049
27-Jul	10:00	181809	62405	31575	5440	6190	2000	1000	27104	46095	-5000	-3000	-1200	-7000	0	62295	3190	20904
27-Jul	11:00	181212	68953	32738	5444	6251	2000	1000	26182	38645	-5000	-3000	-1200	-7000	0	54845	3251	19982
27-Jul	12:00	181151	70924	37158	5442	6265	2000	1000	25697	32665	-5000	-3000	-1200	-7000	0	48865	3265	19497
27-Jul	13:00	178995	67804	37372	5441	6296	2000	1000	24564	34519	-5000	-3000	-1200	-7000	0	50719	3296	18364
27-Jul	14:00	177595	57278	36057	5444	6283	2000	1000	24327	45205	-5000	-3000	-1200	-7000	0	61405	3283	18127
27-Jul	15:00	178441	44548	36459	5450	6368	2000	1000	25158	57458	-5000	-3000	-1200	-7000	0	73658	3368	18958
27-Jul	16:00	177872	26279	36094	5447	6339	2000	1000	24955	75757	-5000	-3000	-1200	-7000	0	91957	3339	18755
27-Jul	17:00	175491	9299	34586	5453	6272	2000	1000	25276	91606	-5000	-3000	-1200	2700	0	98106	3272	19076
27-Jul	18:00	175006	36	32997	5457	6219	2000	1000	25316	101982	-5000			3800	5000	98182	6219	20316
27-Jul	19:00	184571	0	31724	5464	6276	2000	1000	28668	109439	4000			2300	5000	98139	6276	32668
27-Jul	20:00	190480	0	28662	5462	6465	2000	1000	30191	116700	5000	3000	1200	4400	5000	98100	9465	36391
27-Jul	21:00	189882	0	28695	5466	6535	2000	1000	29417	116769	5000	3000	1200	6400	5000	96169	9535	35617
27-Jul	22:00	187171	0	29459	5466	6419	2000	1000	28300	114527	4500	2500	1200	3200	5000	98127	8919	34000
27-Jul	23:00	185868	0	29100	5463	6417	2000	1000	27904	113984	4500	2500	1200	2900	5000	97884	8917	33604
Max		190480	70924	37372	5466	6535	2000	1000	30191	116769	5000	3000	1200	6400	5000	98199		
Min		170924	0	21146	5420	6142	2000	1000	23845	32665	-5000	-3000	-1200	-7000	0	48865		
MTL																**45.77%**		

Step III

Day	Time	Total Load (2021-22)	Solar BAU	Wind BAU	Nuclear BAU	Gas BAU	Biomass BAU	Small Hydro BAU	Hydro BAU	Coal BAU	Redis Hydro	Gas - Reallocation	PS New Cap Add.	RES Curtailed	RES after curtailment	Adjusted Coal
27-Jul	00:00	180339	0	28859	5420	6241	2000	1000	25620	111199	5000	1500	1200	0	28859	103499
27-Jul	01:00	177283	0	27063	5421	6199	2000	1000	24714	110886	5000	1500	1200	0	27063	103186
27-Jul	02:00	174349	0	25391	5427	6220	2000	1000	24191	110120	5000	1500	1200	0	25391	102420
27-Jul	03:00	171930	0	22295	5443	6190	2000	1000	23845	111158	5000	1500	1200	0	22295	103458
27-Jul	04:00	170924	0	22705	5440	6180	2000	1000	24011	109588	5000	1500		0	22705	103088
27-Jul	05:00	172465	11	22591	5445	6178	2000	1000	24542	110699	5000	1200		0	22602	104499
27-Jul	06:00	175127	1893	21146	5445	6203	2000	1000	25568	111872	5000	700	-1200	0	23039	107372
27-Jul	07:00	177762	18561	22029	5448	6193	2000	1000	26994	95537	-5000	-1000	-1200	0	40590	102737
27-Jul	08:00	178650	36535	22955	5453	6180	2000	1000	27488	77038	-5000	-2000	-1200	0	59490	85238
27-Jul	09:00	180073	52386	27396	5449	6142	2000	1000	27249	58450	-5000	-3000	-1200	0	79782	67650
27-Jul	10:00	181809	62405	31575	5440	6190	2000	1000	27104	46095	-5000	-3000	-1200	11034	82946	66329
27-Jul	11:00	181212	68953	32738	5444	6251	2000	1000	26182	38645	-5000	-3000	-1200	18484	83207	66329
27-Jul	12:00	181151	70924	37158	5442	6265	2000	1000	25697	32665	-5000	-3000	-1200	24464	83618	66329
27-Jul	13:00	178995	67804	37372	5441	6296	2000	1000	24564	34519	-5000	-3000	-1200	22610	82565	66329
27-Jul	14:00	177595	57278	36057	5444	6283	2000	1000	24327	45205	-5000	-3000	-1200	11924	81411	66329
27-Jul	15:00	178441	44548	36459	5450	6368	2000	1000	25158	57458	-5000	-2000	-1200	0	81007	65658
27-Jul	16:00	177872	26279	36094	5447	6339	2000	1000	24955	75757	-5000	-1000	-1200	0	62373	82957
27-Jul	17:00	175491	9299	34586	5453	6272	2000	1000	25276	91606	-5000	-100	-1200	0	43885	97906
27-Jul	18:00	175006	36	32997	5457	6219	2000	1000	25316	101982	-5000	800		0	33033	106182
27-Jul	19:00	184571	0	31724	5464	6276	2000	1000	28668	109439	5000	1900		0	31724	102539
27-Jul	20:00	190480	0	28662	5462	6465	2000	1000	30191	116700	5000	3000	1200	0	28662	107500
27-Jul	21:00	189882	0	28695	5466	6535	2000	1000	29417	116769	5000	3000	1200	0	28695	107569
27-Jul	22:00	187171	0	29459	5466	6419	2000	1000	28300	114527	5000	3000	1200	0	29459	105327
27-Jul	23:00	185868	0	29100	5463	6417	2000	1000	27904	113984	5000	3000	1200	0	29100	104784
Max		190480	70924	37372	5466	6535	2000	1000	30191	116769	5000	3000	1200	24464	83618	107569
Min		170924	0	21146	5420	6142	2000	1000	23845	32665	-5000	-3000	-1200	0	22295	65658
MTL																**56.14%**

Annexure 3: Assumptions

Assumptions

1. Cost due to increase in Heat Rate and Auxiliary Power Consumption (APC)

Assumptions in calculation of per unit cost are as follows.

- For Significant Load Following, the calculations are mentioned in Tables 16 to 18.
- The unit running as daily start-stop would remain either at zero load or at full load during its operation in a day of the year. As such, for Daily Start, the net heat rate deteriorates by 3.8% & 6.3% for 200 MW & 500 MW unit resp.
- The unit running as weekly start-stop would be required to flex during a day as per requirement in addition to its weekly shutdown routine. As such, for Weekly Start, the net heat rate deteriorates by 11.6% & 13.8% for 200 MW & 500 MW unit resp.
- The base ECR has been assumed to be 200 paisa/kWh based on the average ECR of NTPC stations from April to October 2018

2. Cost due to increase in Operation and Maintenance (O&M) due to reduction in life of components

Assumptions in calculation of per unit cost are as follows.

2.1 The increase in O&M cost due to load following on per unit basis is calculated as per the following formula.

$$O\&M\ Cost_{annual} = (365 - n * 7) * O\&M\ Cost_{event} * k$$

- **n** = 6, number of weeks of planned and forced outages per year.
- **k** = 2, number of significant load followings considered per day.
- **O&M Cost$_{event}$** = 0.5 INR lakhs for 200 MW and 2.7 INR lakhs for 500 MW, increase in O&M cost due to one event of significant load following as given in Table 19.
- PLF is 63% for units operating under Significant load following.

2.2 The increase in O&M cost due to Daily and Weekly Start on per unit basis is calculated as per the following formula.

$$O\&M\ Cost_{annual} = n_c * O\&M\ Cost\ Cold_{event} + n_w * O\&M\ Cost\ Warm_{event} + n_h * O\&M\ Cost\ Hot_{event}$$

- Six weeks of planned and forced outages per year.
- **Daily Start:** Total no. of starts are 81 where the ratio of cold (n_c), warm (n_w) and hot (n_h) start is 1:4:2. Units are operated for six hours in the evening during a day for three monsoon months of the year.
- **Weekly Start:** Total no. of starts are 46. All are cold starts (n_c). Units are flexed as per requirement of grid in addition to weekly shutdown. PLF is 45%.

3. Cost due to increase in Oil consumption on account of frequent start/ stops

Assumptions in calculation of per unit cost are as follows.

The increase in oil cost due to cycling on per unit basis is calculated as per the following formula.

$$Oil\ Cost_{annual} = n_c * Oil\ Cost\ Cold_{event} + n_w * Oil\ Cost\ Warm_{event} + n_h * Oil\ Cost\ Hot_{event}$$

- Six weeks of planned and forced outages per year.
- **Daily Start:** Total no. of starts are 81 where the ratio of cold (n_c), warm (n_w) and hot (n_h) start is 1:4:2. Units are operated for six hours in the evening during a day for three monsoon months of the year.
- **Weekly Start:** Total no. of starts are 46. All are cold starts (n_c). Units are flexed as per requirement of grid in addition to weekly shutdown. PLF is 45%.
- **Oil Cost$_{event}$** = As given in Table 20. Cost of oil is 45000 INR/kl.

Annexure 4: Test Procedure (Minimum Load Pilot Test at Unit6 of Dadri TPS, NTPC)

SIEMENS

Test Procedure

UNID:

Handhabung: Nur für internen Gebrauch / Handling: For internal use only

Kraftwerk/Power Plant	PKZ./Plant Code

Block/Unit	Inhaltskennzeichen/Contents Code	DCC	Zähl-Nr./Reg. No.

System/Komponente: **Coal firing Boiler 500 MW NTPC Dadri Power Plant 5/6**
System/Component

Titel: **Part load and ramp test**
Title

Appendix 0

*) Nicht zutreffendes streichen *) Delete as appropriate	Erstellt Prepared by	Erstellt/Geprüft*) Prepared/Verified by	Geprüft/Freigeg.*) Verified/Released by	Geprüft/Freigeg.*) Verified/Released by
Dienststelle Department	PTEC ME	RC IN PS PG		
Name Name	Tschetschik	Chittora		
Datum Date	08.06.2018	08.06.2018		
Unterschrift Signature				

Geändert:

Modified by:

Geprüft/Freigegeben:
Reviewed/released by:

Rev.	Name/Kurzzeichen	Dienststelle/Firma	Datum	Fachabteilung, Ibs-Leitung, Projektleitung
Index	Name/Signature	Department/Company	Date	Techn. Department, Comm. Management, Project Management

Verteiler:
Copy to:

Content:

Kraftwerk/Power Plant	PKZ./Plant Code	Block/Unit	Inhaltskennzeichen/Contents Code	DCC	Zähl-Nr./Reg. No.

1 General Description

Plant description:

Capacity Four units – 500 MWel each unit

Start of operation 2011 to 2012

Boiler: Controlled circulation with single drum, Directly fired by pulverized coal, Dry-Bottom, Radiant Reheat, Single Drum, Top Supported, Dry bottom, Manufactured by BHEL (CE Design), Tilting tangential firing Fuel Indian coal from different sources

Coal Mills: Stage 2: 10 mills;

Number of mills in operation	Six
Mill load, %	89
Air flow per mill, t/h	97.7
Air temperature inlet	307°C
Mill outlet temperature	66 to 90°C
Fineness %(through 200 mesh)	70
Burner tilt, deg.	–30 to +30

Coal fuels description:

Coal Carbon, % 31.70

Hydrogen, % 3.30

Sulfur, % 0.28

Nitrogen, % 0.83

Oxygen, % 8.54

Carbonates, % 0.30

Phosphorus, % 0.05

Moisture, % 14.00

Ash, % 41.00

HHV, Kcal/kg 3,300

For base load, the operation of six burner levels is usually sufficient. In part load the mills of burner levels B to F are used due to a more stable operation. This was discovered by trial and error. **Two adjoining mills per burner level** have to be in operation. Due to possible coal mixture inconsistency, flame stability problems have been observed.

The drum level control might cause problems. Auxiliary steam is used when “ramping up”. When ramping down, the auxiliary steam mode cannot be reached and the control is done manually. With respect to part load, the **ID fan causes no problems**, because of frequency drive. **No problems were observed for FD fans**.

Primary air fans (2 x 50 percent) are not equipped with frequency control, but with blade pitch control. The switch **from two fans to one fan in part load causes problems when one fan needs to be shut down**.

Live steam parameters 166.7 bar, 537°C;

Live steam flow 369 kg/s;

HRH temperature: Stage 2: 39.6 bar, 565°C;

Efficiency at 500 MWel: 84.85% (ASME);

Feed water inlet temperature 253 °C;

The 500 MWel units are equipped with one motor-driven und two steam-driven Boiler Feed Pumps (BFP). The plant can be operated with one steam-driven BFP up to a load of approximately 300 MWel. Load limits for the motor-driven BFP were not tested, because it is only used for the start-up procedure. Separate load extraction valves are installed with an open/close option in the minimum flow line of the boiler feed pumps.

During normal operation of the power plant units the 2 x 50 percent steam-driven BFPs are used. Usually the steam-driven BFPs are supplied by steam from an extraction line. The valves in the steam pipe to the BFPs are controlled by turbine speed (RPM). The valves open further when the speed decreases. At a certain value (when the valve is almost wide open) the steam supply is switched to a different steam source. A valve opens the auxiliary steam supply, which can be fed by the Cold Reheat line (or the auxiliary steam header, in which all four units deliver steam). The change usually occurs for unit loads below 70 percent. Especially during start-up procedure, problems were observed regarding the stability of pressure and temperature in the supply steam. For this reason, unit loads lower than 70 percent have not been tested yet.

The units are already operated in the 70 to 100 percent load range **without** problems. For a load below 70 percent two BFP have to be used in parallel. The changeover in the steam supply for the steam-driven BFPs has to be improved with respect to reliability (currently problems with stability of flow and pressure decrease).

Turbine: Nominal rating 500 MWel, Load 524.2 MWel (VWO – valves wide open), Single-flow HP turbine, double-flow IP- and LP turbine, Manufactured by BHEL – KWU design

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Cooling: Closed cycle with natural draft cooling tower

The following parameters have an influence (and limitation of partload operation):

1. Evaporator stability, ECO Stability/steaming, drum behavior
2. Combustion behavior (stability of flame, effectivity, aerodynamic, permissible emissions, burner supported fuel: e.g. oil)
3. Coal specification (mill operation diagrams)
4. Boiler outlet parameters (HP/HRH temperatures, control systems, flue gas dampers, active burning levels in operation, attemperators etc.)
5. Feed water parameters
6. Air Preheater, dew point
7. Flue gas cleaning system (effectivity)

For the possible increase of power transients the following parameters should be considered:

8. Points 1-5 mentioned above, for dynamic behavior of boiler
9. Evaluation of current life time consumption (incl. creep) of pressure part (ECO/Evaporator/Drum/SH/RH part: tubes, pipes, links, boiler internal piping, fittings, valves etc.)
10. Evaluation of the impact of increased thermal transients (pressure, temperature, massflow) on the affected boiler part.

<u>Based on previously information of customer:</u>
Is there any LH & RH side temperature difference observe?

Answer: During normal running of the Units there is not much difference between LH & RH Steam Temperature, however during abrupt change of load due to imposing or lifting of backdown or Coal interruption to the furnace due shear pin failure or overload tripping of RC Feder.

Does the Boiler operate in pure sliding pressure operation or Constant Pressure operation? Can the boiler operate purely on sliding pressure mode?

Answer: Boilers at Thermal Plant mainly operation sliding pressure mode as Pressure master control in all the Units is non-functional

The following aspects were given as the most limiting factors preventing the minimum load being reduced further:

- Flame intensity/combustion at low load if specific coal is less than **0.6**
- Less PA flow resulting in PA fan operation near stalling zone
- **Low extraction pressure resulting in BFPs changeover to ACV mode** (ACV means cold re-heat as steam source for auxiliary steam). Drum level control is not smooth when BFPs are in ACV mode
- Low feed water flow resulting in BFPs recirculation valves being open
- **High MS HP temperature, high spray and low HRH temperature**

To ensure the maximum possible reheater outlet temperature during the planned low load operation in future, the upper burner levels should be investigated, **namely mill H, J and K (stage 2)**. At low load, the deviation between actual behavior and design of HRH needs to be investigated. In particular, the interaction of the tilting burners in conjunction with the spray type (water) attemperators, especially between the re-heater heating bundles, should be thoroughly investigated and modified, if applicable.

The main challenges are

1. Combustion behavior (stability of flame, permissible emissions, active burning levels in operation)
2. Mill operation behavior. Mill operation data (coal/air temperature to burner)
3. Evaporator stability
4. ECO Stability/steaming,
5. Drum level behavior
6. Boiler internal temperature (ECO, Superheater) and temperature difference between parallel outlet pipes - equal temperature distribution
7. HP/RH attemperator behavior
8. Boiler outlet parameters (MS HP/HRH temperatures, control systems, equal temperature distribution)
9. Limitation of the flue gas/steam temperature for all relevant operational conditions according to boiler design
10. Feed water parameters
11. Air Preheater, dew point
12. Filter

2 Test targets

The test procedure includes 3 main parts:

1. Reduce Min stable load (Current Target of NTPC: 40% min load **without** hardware invest)
2. Faster load Ramp up/Ramp down between new/old min load and base load.
3. Check of sliding pressure curves based on influence for steam generator

The test target includes:

1. Boiler pre-assessment. Investigation of current situation with boiler/steam turbine. Possible evaluation of aging of equipment. Check of control system, measurement, staff skill
2. Identifying of the process limitations/restrictions (thermal, mechanical, aerodynamically, operation) during the new/old min load
3. Collecting measurement data for calibration of thermal models for boiler/steam turbine/BOP for further boiler thermodynamic analyze
4. Boiler and steam turbine curves (water/steam cycle, coal, air, flue gas) for actual new/old load Ramp up/Ramp down for life time consumption investigations (FEM-Method) and for release the new boiler/steam turbine margins. Collecting measurement data
5. Identifying of the process limitations/restrictions (thermal, mechanical) during the new/old Ramp up/Ramp down
6. First impression about feasibility of flex retrofit for this plant “Go/No-Go”
7. Definition of first measures which are needed to be implemented for this upgrade

3 Additional Measurements

No additional measurement has been planned.

4 Test Preparation

Any adjustments and control settings for the boiler/steam turbine/plant system was install, shall be finalized one day prior to the beginning of testing.

The test and possible change of control settings in order to minimize of part load and increase of steam turbine load transient between part load and base load must not conflict with normal boiler operation or operating limits. No modifications, which can have the influence to safety of boiler, are allowed during, in-between, or after Test. All of boiler / plant

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protection should be activated. If necessary the control systems should be switched on manual mode (e.g. attemperator / steam temperature control).

If necessary the test should be interrupted.

Preferred operation procedures shall include all expected operating modes of the boiler as operation with available coal with and w/o sliding pressure.

The responsible Test Engineers of Siemens have to agree that the plant operation status meets the specified load conditions and those steady-state conditions have been reached.

The grid should be informed with increased risk of plant trip/shutdown that the test will occur.

NTPC will carry out the test and operate the boiler.

The time interval between readings of test measurements will be less than or equal to 20 seconds.

The preparation should be included:

1. Check of design/operation documents/information
2. Boiler pre-assessment
3. Investigation of the current situation of the boiler/steam turbine. Investigations of problem/restrictions for static and dynamic operation and **damage of boiler elements (tubes, header, pipes, valves, burners, vessels etc.)**:
   Operating experiences full/part load for several ambient conditions, Cold/Warm start-up, shut-down and load change (problems, restrictions, hold times). Operational problems during minimal load cases of boiler
   Are boiler inspections conducted? If yes: How often? Please provide Inspection reports (assessment report) if available. Is it possible to have the measured wall thickness for pressure part of HP/RH and piping?

- If available following technical problem descriptions and perhaps solutions:
- Warning and/or trips of boiler (water/steam side, flue gas side) in the past
- Stability and steam temperature in evaporator,
- Drum level stability (water swell) during normal operation, load change, start-up
- Steaming of HP economizer
- Boiler vibration (flue gas side)
- HP Drum “carry-over” curves
- HP/RH steam temperature control (desuperheater) during start-up and operation
- Steam side corrosion
- Flue gas corrosion (high/low temperature)
- Mechanical design of HP/RH Superheater and Drum
- Safety and control valves etc.
- Problems with specific components? Components changed, improved or re-designed?

• Is there any experience with slagging, fouling or corrosion on the flue gas side?
• Is there any experience with less power performance of the boiler/steam turbine?
• Life time loss of the main components (Steam pressure part Lines, Headers…) if available
• Possible of temperature strain of flue gas in the boiler if investigated in the past,

4. Possible evaluation of the aging of the equipment
5. Check of control system, measurement, rough evaluation of test risks and test stop criterion: temperature, pressure, mass flow water/steam/coal/air/flue gas, drum level, combustion, equipment vibration etc., emissivity, optical control etc.

6. Determination, which mills to use in the test. This depends on actual coal quality and operation experience with former tests as well based on mill operation diagrams. Since probably at least two mills will be in operation, thetests will be conducted without supporting fuel (fuel oil).

5 Test Description:

5.1 Test of new stabile part load case

The test sequence:

1. The boiler should operate in baseload with 2h w/o any operation change. Then the measurements (s list below) should be recorded.
2. The boiler should operate in actual min load with 2h w/o any operation change. Then the measurements (s list below) should be recorded.
3. Stepwise decrease of actual min load at 50% to min achievable load (NTPC: 40%) every 1-2%-point, then 1,5 - 2 h stabilization of parameters and collecting of necessary data/information. If no instabilities, load can be reduced further. The control system may be operated manually if necessary.

NTPC will carry out the test and operate the boiler.

The boiler should be operated based on existing manual/design handbook and safety rules.

The boiler main operation settings (e.g. air excess ratio) should be remaining at value for actual min load. The change of values should be done if necessary (NTPC/Siemens).

If necessary the test should be interrupted if the safety of boiler system will be at risk.

Preferred operation procedures shall include all expected operating modes of the boiler as operation with available coal with and w/o sliding pressure.

The control setting of boiler systems (burner/combustion, coal milling and drying, APH, temperature and pressure control, drum level control etc.) may be out of operation/control range. If necessary the control systems should be switched on manual mode (e.g. attemperator / steam temperature control).

If necessary after each part load step the combustion should be tuned (stability, emissivity, equal steam temperature distribution – platen SH). The coal preparation system, APH etc. should also be tuned if necessary.

No modifications, which can have the influence to safety of boiler, are allowed during, in-between, or after Test. All of boiler / plant protection should be activated.

If necessary (instable operation behavior, danger of activation of boiler protection) the test should be interrupted.

Preferred operation procedures shall include all expected automatic operating modes of the boiler as operation with available coal.

Sootblower cleaning system should be operated in normal mode.

NTPC will carry out the test and operate the boiler.

It might be necessary to temporarily increase load a little bit, if instabilities are becoming too dangerous for operation. When instabilities cannot be eliminated, go back to last safe load. Depending on which instabilities occur determine whether to maybe change mills, main steam pressure, burner tilts, air to mills, air to burner etc., and repeat to lower load.

Risk evaluation:

System	Risk description and evaluation
HP Economizer system	The partial steaming of ECO may occur. The hammering may occur. These events are allowed for short time. If intensity of that will increase the test should be interrupted. The risk with damage of pipe and tubes is very low.
HP Evaporator system	The risk with damage of pipe and tubes is very low. The hammering may occur. These events are allowed for short time. If intenseness of that will increase the test should be interrupted. The drum water level may achieve high and low levels and may be instable and fluctuated. The control setting of drum level control system may be out of operation/control range. Manuel operation of drum level control system and tuning are necessary. For the test in sliding pressure operation the carry-over may occur. The long-term effect is very small. Further investigations will be necessary.
HP/RH superheater system	Material/steam temperature and temperature difference between parallel outlet pipes can increase. The risk with damage of pipe and tubes are very low. If steam temperature (as well as temperature difference) will achieve the design limit the test should be interrupted. Because the operation pressure will remain or will decrease based on sliding pressure curve the risk with creep life time consumption with temperature will not change. The attemperator control system may be instable and fluctuated. The overspray/overheating can occur. The control setting of temperature control system may be out of operation/control range. Manuel operation of attemperators control valves and tuning are necessary.

Combustion (Burner)	The min operation of burner can achieve. If necessary the burner level may switch out (preferred bottom burner level). The vibration/combustion instability, demolition of flame, increase of emission (CO, dust) may occur. These events are allowed for short time. If intenseness of that will increase the test should be interrupted. The control setting of burner control system may be out of operation/control range. Manuel operation of combustion control system and tuning are necessary. The risk with damage of burner systems is very low.
Coal preparation (Coal milling/drying)	The mils operation restrictions (vibration/instability in milling and coal/air stream, mechanical restrictions, operation behavior for part load) may occur. These events are allowed for short time. If intenseness of that will increase the test should be interrupted. Manuel operation of coal preparation control system and tuning are necessary. The control setting of mill control system may be out of operation/control range. Manuel operation of mill / coal feed control system and tuning are necessary. The min operation of mill can achieve. The stream behavior of coal/air mixture to burner may be changed and out of operation range. The aerodynamic disturbances and negative impact to combustion may occur The risk with damage of equipment is very low.
APH (Air part)	The air preheating operation restrictions (vibration/instability, mechanical restrictions of fans primary, secondary, temperature operation behavior for part load) may occur. These events are allowed for short time. If intenseness of that will increase the test should be interrupted. The control setting of air control system may be out of operation/control range. Manuel operation of air preheating control system and tuning are necessary. The risk with damage is very low.

Flue gas part (incl. filter)	The flue gas operation restrictions (vibration/instability, mechanical restrictions of fan, dewpoint, temperature operation behavior for part load) may occur. These events are allowed for short time. If intenseness of that will increase the test should be interrupted. The control setting of flue gas/filter control system may be out of operation/control range. Manuel operation and tuning are necessary. The risk with damage is very low.
HP turbine	HP inlet: margins for shaft and casing margins might be exceeded → low risk for small number of events HP exhaust temperature may increase depending on IP-valve position → low risk if HP exhaust < 400°C
IP-turbine	No additional risk identified
LP-turbine	No additional risk identified

During described test procedures following measurements have to be recorded:

1. Ambient Conditions
2. Ambient Temperature
3. Ambient Pressure
4. Relative Humiditiy
5. HP Feedwater Massflow
6. HP Feedwater Temperature
7. HP Feedwater Pressure
8. HP Eco Outlet Temperature
9. HP Drum Pressure
10. HP Drum steam temperature
11. Wall HP Drum temperature
12. HP EVAP mass flow
13. HP SH1 Outlet Temperature
14. Wall HP SH1 Outlet Temperature
15. HP SH Attemperator 1 Massflow
16. HP Platen SH Inlet Temperature
17. HP Platen SH Outlet Temperaure
18. Wall HP Platen SH Outlet Temperaure
19. HP SH Attemperator 2 Massflow
20. HP Final SH Inlet Temperature

21. HP Wall Final SH Inlet Temperature
22. HP Final SH Outlet Temperature
23. HP Wall Final SH Outlet Temperature
24. HP Final SH Outlet Pressure
25. HP Final SH Massflow
26. HP Wall Final SH Outlet Temperature before turbine
27. HP Final SH Outlet Pressure before turbine
28. Cold Reheat Massflow
29. Cold Reheat Temperature
30. Cold Reheat Temperature after turbine
31. Cold Reheat pressure after turbine
32. Cold Reheat Pressure
33. Reheat Atemperator Massflow
34. Wall Reheater Inlet Temperature
35. Wall Reheater Outlet Temperature
36. Hot Reheat Temperature
37. Hot Reheat Pressure
38. Hot Reheat Temperature before turbine
39. Hot Reheat Pressure before turbine
40. FD Fan A/B air entering Temp.
41. FD Fan A/B Air Flow

42. FD Fan B/B air entering Temp.
43. Air Temperature upstream Pulverizer A/B/C/D/E/F
44. Air Heater Combustion Air Outlet Temperature
45. Air Heater Primary Air Outlet Temperature
46. Air Ratio Combustion Chamber Outlet
47. Flue Gas temperature ECO Outlet
48. Flue Gas Temperature Air Heater Outlet
49. Air Ratio Flue Gas Air Heater Outlet
50. Pulverizer A/B/C/D/E/F Feeder (rotation per minute)
51. Coal Massflow
52. Pulverizer A/B/C/D/E/F Classifier Outlet Temperature
53. Burner Tilt Angle Burner Stage A/B/C/D/E/F
54. Oxygen in flue gas before air preheater
55. Speed of all boiler feed pumps
56. Speed of air/flue gas fans
57. Position of attemperator control valves
58. Position of HP steam bypass (incl. attemperator control valves)
59. Position of IP steam bypass (incl. attemperator control valves)
60. Position of drum blow-down valve
61. Position of feed water control valve
62. Position of steam valves (e.g. form extraction and cold reheat) which are feeding the

turbine-driven boiler feed pumps

- **Valve positions (HPV/IPV)**
- **Controller output (of active controller for main steam valve, most likely HP pressure controller)**
- **Pressure upstream HP- and IP-blading (if available)**
- **Steam turbine power output**
- **HP shaft temperature**
- **HP inlet inner casing temperature**

5.2 *Test of Last Ramp up/Ramp down between new and old min load with new and old last ramp transient*

The test sequence:

1. The boiler should operate in new achievable min load with 2h w/o any operation change. Then the measurements (s list below) should be recorded.
2. Load Ramp up/Ramp down between **new and old min load** with **old** load transient (5 MW/min). The wall temperature margins of boiler for superheater HP/RH and HP Drum (steam turbine?) may be deactivated only for the test, and then activated again. The ramps may be repeated. Collecting of necessary data/information based on list
3. Load Ramp up/Ramp down between **new and old min load** with **new** load transient (10/15 MW/min). The wall temperature margins of boiler for superheater HP/RH and HP Drum (steam turbine?) may be deactivated only for the test, and then activated again. The ramps may be repeated. Collecting of necessary data/information based on list
4. Load Ramp up/Ramp down between **new min load and baseload** with **old** load transient (5 MW/min). The wall temperature margins of boiler for superheater HP/RH and HP Drum (steam turbine?) may be deactivated only for the test, and then activated again. The ramps may be repeated. Collecting of necessary data/information based on list
5. Load Ramp up/Ramp down between **new min load and baseload** with **new** load transient (10/15 MW/min). The wall temperature margins of boiler for superheater HP/RH and HP Drum (steam turbine?) may be deactivated only for the test, and then activated again. The ramps may be repeated. Collecting of necessary data/information based on list
6. Load Ramp up/Ramp down between **new min load and baseload** with **old** load transient (5 MW/min) and **new sliding pressure curve (e.g. 40 to 70% rel. load)**. The wall temperature margins of boiler for superheater HP/RH and HP Drum and steam turbine may be deactivated only for the test, and then activated again. Sliding pressure curve should be implemented. The ramps may be repeated. Collecting of necessary data/information based on list

7. Load Ramp up/Ramp down between **new min load and baseload** with **new** load transient (10/15 MW/min) and **new sliding pressure curve (e.g. 40 to 70% rel. load)**. The wall temperature margins of boiler for superheater HP/RH and HP Drum (steam turbine?) may be deactivated only for the test, and then activated again. Sliding pressure curve should be implemented. The ramps may be repeated. Collecting of necessary data/information based on list

8. At new min load according to with new sliding pressure curve the Approach Point should be checked (in order to prevent steaming in the Economizer). If at this point of operation there still is a sufficient margin, the IP valves at the turbine could be throttled (which would increase the reheat pressure and thus the final feed water temperature) until there is no margin left and steaming in the Economizer starts

NTPC will carry out the test and operate the boiler.

The boiler should be operated based on existing manual/design handbook and safety rules.

The boiler temperature/pressure transient/gradient margins should be deactivated during the test. The margins have to be activated after the test.

The boiler main operation settings (e.g. air excess ratio) should be remaining at value for actual min load. The change of values should be done if necessary (NTPC/Siemens).

If necessary the test should be interrupted if the safety of boiler system will be at risk.

Preferred operation procedures shall include all expected operating modes of the boiler as operation with available coal with and w/o sliding pressure.

The control setting of boiler systems (burner/combustion, coal milling and drying, APH, temperature and pressure control, drum level control etc.) may be out of operation/control range. If necessary the control systems should be switched on manual mode (e.g. attemperator / steam temperature control).

If necessary after each part load step the combustion should be tuned (stability, emissivity, equal steam temperature distribution – platen SH). The coal preparation system, APH etc. should also be tuned if necessary.

No modifications, which can have the influence to safety of boiler, are allowed during, in-between, or after Test. All of boiler / plant protection should be activated.

If necessary (instable operation behavior, danger of activation of boiler protection) the test should be interrupted.

Preferred operation procedures shall include all expected automatic operating modes of the boiler as operation with available coal.

Risk evaluation:

System	Risk description and evaluation
HP Economizer system	The partial steaming of ECO may occur. The hammering may occur. These events are allowed for short time. If intensivity of that will increase the test should be interrupted. The risk with damage of pipe and tubes is very low. The increase of cycle life time fatigue consumption due to increase of load transient is marginal.

UNID:

Handhabung: Nur für internen Gebrauch / Handling: For internal use only

Kraftwerk/Power Plant	PKZ./Plant Code	Block/Unit	Inhaltskennzeichen/Contents Code	DCC	Zähl-Nr./Reg. No.

HP Evaporator system	The risk with damage of pipe and tubes is very low. The hammering may occur. These events are allowed for short time. If intenseness of that will increase the test should be interrupted. The drum water level may achieve high and low levels and may be instable and fluctuated. The control setting of drum level control system may be out of operation/control range. Manuel operation of drum level control system and tuning are necessary. The temperature/pressure margins of boiler should be deactivated. The increase of cycle life time fatigue consumption due to increase of load transient is marginal. For the test in sliding pressure operation the carry-over may occur. The long-term effect is very small. Further investigations will be necessary.
HP/RH superheater system	Material/steam temperature and temperature difference between parallel outlet pipes can increase. The risk with damage of pipe and tubes are very low. If steam temperature (as well as temperature difference) will achieve the design limit the test should be interrupted. Because the operation pressure will remain or will decrease based on sliding pressure curve the risk with creep life time consumption with temperature will not change. The attemperator control system may be instable and fluctuated. The overspray/overheating can occur. The control setting of temperature control system may be out of operation/control range. Manuel operation of attemperators control valves and tuning are necessary. The temperature/pressure margins of boiler should be deactivated. The increase of cycle life time fatigue consumption due to increase of load transient is marginal.
Combustion (Burner)	The min operation of burner can achieve. If necessary the burner level may switch out (preferred bottom burner level). The vibration/combustion instability, demolition of flame, increase of emission (CO, dust) may occur. These events are allowed for short time. If intenseness of that will increase the test should be interrupted. The control setting of burner control system may be out of operation/control range. Manuel operation of combustion control system and tuning are necessary. The risk with damage of burner systems is very low.

Coal preparation (Coal milling/drying)	The mils operation restrictions (vibration/instability in milling and coal/air stream, mechanical restrictions, operation behavior for part load) may occur. These events are allowed for short time. If intenseness of that will increase the test should be interrupted. Manuel operation of coal preparation control system and tuning are necessary. The control setting of mill control system may be out of operation/control range. Manuel operation of mill / coal feed control system and tuning are necessary. The min operation of mill can achieve. The stream behavior of coal/air mixture to burner may be changed and out of operation range. The aerodynamic disturbances and negative impact to combustion may occur The risk with damage of equipment is very low.
APH (Air part)	The air preheating operation restrictions (vibration/instability, mechanical restrictions of fans primary, secondary, temperature operation behavior for part load) may occur. These events are allowed for short time. If intenseness of that will increase the test should be interrupted. The control setting of air control system may be out of operation/control range. Manuel operation of air preheating control system and tuning are necessary. The risk with damage is very low.
Flue gas part (incl. filter)	The flue gas operation restrictions (vibration/instability, mechanical restrictions of fan, dewpoint, temperature operation behavior for part load) may occur. These events are allowed for short time. If intenseness of that will increase the test should be interrupted. The control setting of flue gas/filter control system may be out of operation/control range. Manuel operation and tuning are necessary. The risk with damage is very low.

Kraftwerk/Power Plant	PKZ./Plant Code	Block/Unit	Inhaltskennzeichen/Contents Code	DCC	Zähl-Nr./Reg. No.

HP turbine	HP inlet: margins for shaft and casing margins might be exceeded → low risk for small number of events HP exhaust temperature may increase depending on IP-valve position → low risk if HP exhaust < 400°C
IP-turbine	No additional risk identified
LP-turbine	No additional risk identified

During described test procedures following measurements have to be recorded:

1. Ambient Conditions
2. Ambient Temperature
3. Ambient Pressure
4. Relative Humiditiy

5. HP Feedwater Massflow
6. HP Feedwater Temperature
7. HP Feedwater Pressure
8. HP Eco Outlet Temperature
9. HP Drum Pressure
10. HP Drum steam temperature
11. Wall HP Drum temperature
12. HP EVAP mass flow
13. HP SH1 Outlet Temperature
14. Wall HP SH1 Outlet Temperature
15. HP SH Attemperator 1 Massflow
16. HP Platen SH Inlet Temperature
17. HP Platen SH Outlet Temperaure
18. Wall HP Platen SH Outlet Temperaure
19. HP SH Attemperator 2 Massflow
20. HP Final SH Inlet Temperature
21. HP Wall Final SH Inlet Temperature
22. HP Final SH Outlet Temperature
23. HP Wall Final SH Outlet Temperature
24. HP Final SH Outlet Pressure
25. HP Final SH Massflow

Kraftwerk/Power Plant	PKZ./Plant Code	Block/Unit	Inhaltskennzeichen/Contents Code	DCC	Zähl-Nr./Reg. No.

26. HP Wall Final SH Outlet Temperature before turbine
27. HP Final SH Outlet Pressure before turbine
28. Cold Reheat Massflow
29. Cold Reheat Temperature
30. Cold Reheat Temperature after turbine
31. Cold Reheat pressure after turbine
32. Cold Reheat Pressure
33. Reheat Atemperator Massflow
34. Wall Reheater Inlet Temperature
35. Wall Reheater Outlet Temperature
36. Hot Reheat Temperature
37. Hot Reheat Pressure
38. Hot Reheat Temperature before turbine
39. Hot Reheat Pressure before turbine
40. FD Fan A/B air entering Temp.
41. FD Fan A/B Air Flow
42. FD Fan B/B air entering Temp.
43. Air Temperature upstream Pulverizer A/B/C/D/E/F
44. Air Heater Combustion Air Outlet Temperature
45. Air Heater Primary Air Outlet Temperature
46. Air Ratio Combustion Chamber Outlet

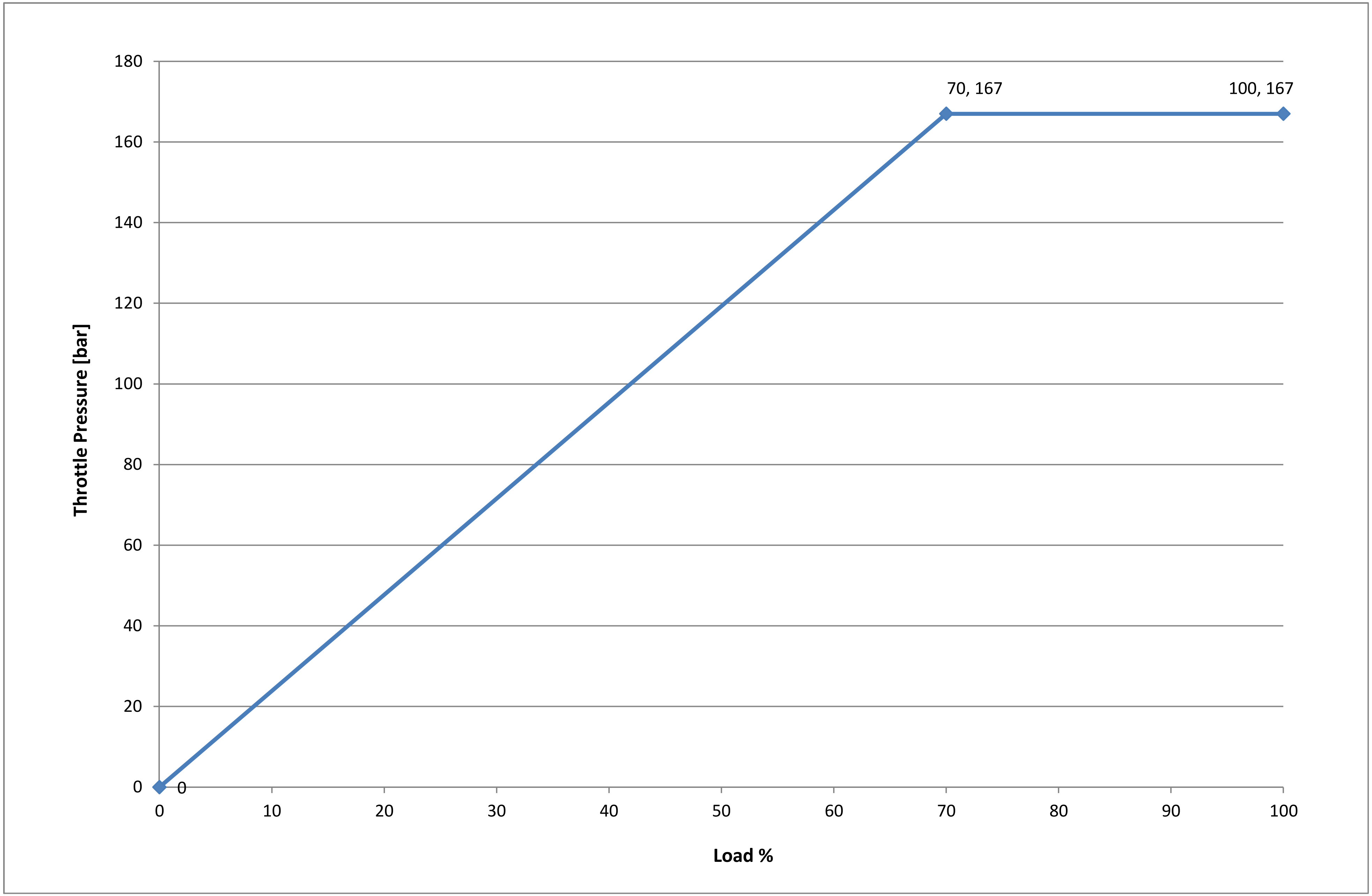
47. Flue Gas temperature ECO Outlet
48. Flue Gas Temperature Air Heater Outlet
49. Air Ratio Flue Gas Air Heater Outlet
50. Pulverizer A/B/C/D/E/F Feeder (rotation per minute)
51. Coal Massflow
52. Pulverizer A/B/C/D/E/F Classifier Outlet Temperature
53. Burner Tilt Angle Burner Stage A/B/C/D/E/F
54. Oxygen in flue gas before air preheater
55. Speed of all boiler feed pumps
56. Speed of air/flue gas fans
57. Position of attemperator control valves
58. Position of HP steam bypass (incl. attemperator control valves)
59. Position of IP steam bypass (incl. attemperator control valves)
60. Position of drum blow-down valve
61. Position of feed water control valve
62. Position of steam valves (e.g. form extraction and cold reheat) which are feeding the turbine-driven boiler feed pumps

- **Valve positions (HPV/IPV)**
- **Controller output (of active controller for main steam valve, most likely HP pressure controller)**
- **Pressure upstream HP- and IP-blading (if available)**
- **Steam turbine power output**

- **HP shaft temperature**
- **HP inlet inner casing temperature**

6 Personal:

- -Boiler Thermal Engineer (Mr. Tschetschik)
- *-optional-* Commission Engineer (NTPC)
- -I&C Engineer (NTPC)
- -Combustion Tuner (NTPC)
- -Operation Staff (NTPC)
- -ST Engineer



Throttle Pressure [bar]
180
160
140
120
100
80
60
40
20
0
70, 167
100, 167
0
0
10
20
30
40
50
60
70
80
90
100
Load %

Annexure 5: Minutes of the Meeting (MoMs) of the CEA Committee on Flexible Operation.

भारत सरकार
Government of India
विद्युत मंत्रालय
Ministry of Power
केन्द्रीय विद्युत प्राधिकरण
Central Electricity Authority
तापीय परियोजना नवीनीकरण एवं आधुनिकीकरण प्रभाग
Thermal Project Renovation & Modernization Division

Subject: Task Force Committee Report on Flexibilisation of Thermal Power Plants – 8th Feb 2018 MoM – reg.

विषय: थर्मल पावर प्लांटों के फ्लेक्सिबिलाइजेशन पर टास्क फोर्स कमेटी रिपोर्ट - 8 फरवरी 2018 बैठक के मिनट - संबंधित

Minutes of the meeting held under the chairmanship of Member (Thermal) on 8th February 2018 at 11:00 AM in Conference Room, 6th Floor, CEA, Sewa Bhawan, Sec 1, R K Puram, New Delhi to discuss the Task Force Committee Report on Flexibilisation of Thermal Power Plants is enclosed for further action.

थर्मल पावर प्लांटों की फ्लेक्सिबिलाइजेशन के लिए कार्य बल समिति की रिपोर्ट पर चर्चा हेतु सम्मेलन कक्ष, 6 वीं मंजिल, सीईए, सेवा भवन, सेक्शन 1, आरके पुरम, नई दिल्ली में 8 फरवरी, 2018 को सदस्य (थर्मल) की अध्यक्षता में आयोजित मीटिंग का कार्यवृत्त आगे की कार्रवाई के लिए संलग्न है।

Encl.: As above / **संलग्नक:** उल्लिखित

Bcmallick 12/2/2018

(B. C. Mallick) / (बी. सी. मलिक)
CE (TPRM) / सी.ई. (टी.पी.आर.एम.)

CE (GM) / CE (IRP) / CE (TPP&D) / CE (PSPA) / CE (TETD) / CE (TPM-I) / Member Secy. (NRPC) / CMD (NTPC) / CMD (POSOCO)

सं.: 2/18 / सीईए / टीपीआरएम / फ्लेक्सी. ओपी. / 2018 / 75-93 दिनांक: 12.02.2018

Copy to:-

- Member (Thermal) / Member (GO&D) / Member (PS) / Member (Planning)
- JS (Thermal), MoP
- Shri Vikram Singh, Director (GM), CEA / Shri Upendra Kumar, SE, NRPC / Shri P.E.Kamala, DD (IRP), CEA / Shri A.K.Sinha, AGM, NTPC / Shri N. Nallarasan, DGM, POSOCO

सेवा भवन ,आर.के .पुरम – 1, नई दिल्ली – 110066 टेलिफैक्स: 011-26186904 ईमेल: cetrm@yahoo.co.in वेबसाइट: www.cea.nic.in
Sewa Bhawan, R.K Puram-I, New Delhi -110066 ~~Telefax~~: 011-26186904 Email: cetrm@yahoo.co.in Website: www.cea.nic.in

Minutes of the meeting held on 8th February 2018 on Task Force Committee Report on Flexibilisation of Thermal Power Plants

Member (Thermal) welcomed the participants and informed that a Special Task Force under the Chairmanship of Director (Operations), NTPC was constituted under IGEF Sub-Group-l for enhancing the flexibilisation of existing coal-fired power plants. The demonstration of technical and economic feasibility at two reference plants of NTPC Plant (Dadri, 210 MW and Simhadri, 500MW) was carried out by VGB Power teach, Germany. He also requested members to discuss the recommendations of the committee and take a decision for implementation at least first measures which requires no investment or minimum investment.

CE (TPRM) briefly highlighted the need for flexiblisation of thermal power plants in the Indian power scenario. He stated that the target of RES capacity addition by 2022 is about 175 GW and thermal generation has to be back down with required ramp rate to accommodate the RES generation into the grid as it is clean energy. He described the present minimum load of two reference plant of NTPC are higher than the design value. Similarly, present ramp rate are also lower than the design value. So there are enough potential for improvement in terms of low load as well as ramp rate. He appraised the members about recommendations of various measures and different level of expenditure for 50%, 40% & 25% minimum load operation. He stressed the need for implementation of the Task Force Committee's recommendations in his presentation. He also explained the working of plasma ignition technology. The plasma technology has huge advantage over oil based ignition system as it leads to 100% oil saving and also enables the unit to run at loads as low as 10%.

Members present in the meeting discussed the various aspects of Task Force committee's recommendation on 50%, 40% & 25% minimum load with different level of expenditure in Indian scenario. They also discussed the findings of VGB Power Tech. during test run at Dadri and Simadri TPS of NTPC and other observations on Start-up optimization, automation, Flame detection etc. Members deliberated on the recommendation of advance unit control concept and star up optimization.

Members also discussed the existing CERC's recommendation for minimum load and the compensation mechanism for the same. The CEA's recommendation to CERC for technical minimum was 50% of rated capacity. CERC stated in the IEGC (4th Amendment)

Regulation 2015 that considering CEA's recommendation and giving some margin over the recommendation they proposed for 55% of installed Capacity/ MCR of units as technical minimum. Members finally agreed to the CERC's recommendation and decided to start with 55% minimum load operation initially as the set procedure is already available.

After detailed deliberation, members decided followings for immediate implementation.

1. 55% minimum load operation would be implemented in the six thermal units on immediate basis. Two units of NTPC and one unit each from DVC, GSECL, APGENCO, MSPGCL have been considered in this pilot test.
2. A Committee has been constituted to find out year wise quantum of flexible power (GW) & ramp rate (MW/Min.) required from thermal power plants in order to accommodate RES generation and maintain stable & secured grid. Committee will also suggest a methodology for identification of units for implementation of 55% minimum load operation on priority basis.
3. The committee is constituted with the following members:
    - Shri B.C.Mallick, CE (TPRM), CEA – Chairman
    - Shri Rajeev Kumar, Director (TPRM), CEA – Convener
    - Shri Vikram Singh, Director, GM, CEA- Member
    - Shri Upendra Kumar, SE,NRPC- Member
    - Shri A.K.Sinha, AGM, NTPC – Member
    - Shri Nallarasan, DGM,POSOCO - Member
    - Smt. P.E.Kamala, DD, IRP, CEA - member

Meeting ended with vote of thanks to the Chair.

****

List of participants.

1. Shri P. D. Siwal, Member (Thermal), CEA
2. Shri B C Mallick, Chief Engineer, TPRM, CEA
3. Shri Dinesh Chandra, Chief Engineer, GM, CEA
4. Shri M. A. K. P. Singh, MS, NRPC
5. Shri S. K. Roy Mohapatra, Chief Engineer, PSPA-II, CEA
6. Shri Praveen Gupta, Chief Engineer, IRP, CEA
7. Shri N. S. Mondal, Chief Engineer, TPPD Division, CEA
8. Shri S. K. Kassi, Director, MoP
9. Shri Rajeev Kunwar, Director, CEA
10. Shri Vikram Singh, Director, GM Division, CEA
11. Shri N. Nallarasan, DGM, POSOCO
12. Shri A K Sinha, AGM, NTPC
13. Shri Amit Kulshreshtram, AGM, NTPC
14. Shri M. M. Nazir, DD, TPRM, CEA
15. Smt. Rehana Sayeed, DD, TPRM, CEA
16. Shri Shiva Suman, DD, PSPA-I, CEA
17. Smt. Anita Saini, US (Thermal), MoP
18. Shri Prabhjot Singh Sahi, AD, TPRM, CEA
19. Shri Rohit Yadav, AD, TPRM, CEA
20. Shri Kaushik Panditrao, AD, NRPC
21. Shri N. Nallarasan, DGM, POSOCO
22. Shri A K Sinha, AGM, NTPC
23. Shri Amit Kulshreshtram, AGM, NTPC

सत्यमेव जयते

भारत सरकार
Government of India
विद्युत मंत्रालय
Ministry of Power
केन्द्रीय विद्युत प्राधिकरण
Central Electricity Authority
तापीय परियोजना नवीनीकरण एवं आधुनिकीकरण प्रभाग
Thermal Project Renovation & Modernisation Division

Subject: - **Committee formation for implementation of Flexible operation capability in coal fired thermal generating units**.

This is to inform that it was decided in the meeting held on 08.02.2018 in CEA under Chairmanship of Member(Thermal), CEA on Task Force Committee Report on Flexibilisation of Thermal Power Plants to constitute a committee to come up with recommendations and future roadmap for implementation of 55% minimum load operation in thermal power plants based on the report of the Task Force Committee Report. The committee will have representation from CEA, NTPC, POSOCO and RPC. The main agenda of the committee would be the following: -

a. Identify the quantum of flexible thermal power and ramp rate required from thermal power plants in terms of GW and MW/ min respectively, in order to maintain stable grid.
b. Suggest a methodology for identification and identify the units where the measure for 55% minimum load operation need to be implemented on priority basis.
c. Develop a road map for implementation of the measures on all India basis.

On view of the above a committee has been constituted having following members:

i. Shri B.C. Mallick (Chief Engineer, TPRM),CEA – Chairman
ii. Shri Rajeev Kumar, Director, TPRM, – Convener
iii. Shri Upendra Kumar, SE, NRPC
iv. Shri Vikram Singh, Director, GM Division
v. Shri A K Sinha, AGM, NTPC
vi. Shri N. Nallarasan, DGM, POSOCO
vii. Smt. P.E. Kamala, DD, IRP

The first meeting of the committee will be held on **16.02.2018** at **11.00 hrs** in the office of Chief Engineer, TPRM, CEA. You are requested to make it convenient to attend the above said meeting.

9/2/18

(Rajeev Kumar)
Director(TPRM)

Chief Engineer(IRP)/CE(GM)/MS(NRPC)

2/16/TPRM/CEA/2018/ 62-73 Dated: -09/02/2018

Copy to: -
1. CMD, NTPC
2. CEO, POSOCO
3. JS(Thermal), MoP
4. All members

Minutes of the 2nd meeting of the committee on Flexibilisation of Thermal Power Plants held on 16th February 2018

CE (TPRM) welcomed the participants and reviewed the agenda given to the committee viz. to find out year wise quantum of flexible power (GW) & ramp rate (MW/Min.) required from thermal power plants in order to accommodate RES generation into the grid and maintain stable & secured grid. Committee will also suggest a methodology for implementation of 55% minimum load operation on priority basis.

To identify the quantum of flexibilisation required from Thermal Power Plants, the members deliberated in detail regarding the contribution of each type of generation to the peak and off-peak demand of electricity in India for the year 2021-22 when 175 GW RES capacity will be added to the system.

It was found that the peak of RES generation generally occurred during the off-peak period of grid demand. After accounting for peak RES generation of around 95 GW in 2021-22 for installed capacity of 175 GW, around 110 GW balanced demand to be met by conventional generation, considering system off-peak demand of 205 GW.

The peak demand of country in 2021-22 as mentioned in the 19th EPS is around 225 GW. The RES contribution during that time has been taken different in different studies. The same depends on assumed capacity utilization factor (CUF) of wind. The POSOCO/ USAID considered 48 GW contribution from wind while the NEP considered 10 GW during the study. Members agreed that the high Wind CUF of around 45% assumed in POSOCO study is less probable. Therefore, it would be appropriate to take the worst scenario.

It was felt that since there is a seasonal variation in the generation from RES, e.g. high wind in monsoons etc, it would be a good option to simulate the contribution from each type of generating source for a typical day in each season or each quarter as found suitable.

Representative from IRP Division highlighted that they have simulated the power demand curve for 2021-22 considering self-designed five seasons. Further, the updated data regarding hydro and thermal generation contribution will be helpful in predicting accurate results by simulation.

CE (TPRM) suggested that after assessing the quantum of flexibilisation and ramp rate required from thermal sector next step would be the identification of thermal units for distribution of the quantum of flexible power and ramp rate. Then, we would be able to find out the percentage of minimum load operation required from thermal units during high RES penetration into the grid. AGM, NTPC highlighted that supercritical and pithead stations should be flexed as little as possible in the national interest as they produce cheap and clean power. He also suggested that the collection of unit-wise relevant data in this regard like energy charge, heat rate, coal quality etc. would be helpful in determining flexibilisation capacity of each unit.

The following was decided in the meeting:

a. IRP will come up with expected contribution from each generation technology during peak & off-peak hours during the five seasons / four quarter of the year 2021-22. Data required will be provided by CEA and POSOCO.
b. POSOCO to provide the following data to IRP Division, CEA:
    i. Contribution of hydroelectric power (in MW) to the peak demand during the daily peak and off-peak times for the four quarters of the year 2015-16, 2016-17 and 2017-18 to assess the generation characteristic of hydro plant.
    ii. Actual data for all India electricity demand (in MW, on hourly basis) for the years 2015-16, 2016-17 and 2017-18.
c. HPPI Division to provide data regarding the storage capacity / pondage etc. for the hydro power plants currently in operation or planned till 2021-22. The data will be helpful in analyzing the peaking as well as back down capabilities of the hydro capacity.
d. TPM Division to provide the following data:
    i. Current installed capacity, planned capacity addition and expected retirement capacity of all thermal power stations in India for each year from 2017-18 to 2021-22.
    ii. Current installed capacity, planned capacity addition of Supercritical thermal power stations in India for each year from 2017-18 to 2021-22.
e. Shri Rakesh Kumar, Director, HPPI, CEA is co-opted members of the committee.

Next meeting is scheduled to be held on 23.02.2018 at 11:00 hrs. in the chambers of CE(TPRM).

Meeting ended with vote of thanks to the Chair.

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List of participants.

1. Shri B C Mallick, Chief Engineer, TPRM, CEA
2. Shri Rajeev Kumar, Director, TPRM, CEA
3. Shri Rakesh Kumar, Director, HPPI, CEA
4. Smt. P. E. Kamala, DD, IRP, CEA
5. Shri Prabhjot Singh Sahi, AD, TPRM, CEA
6. Shri Vikrant Singh Dhillon, AEE, NRPC
7. Shri A K Sinha, AGM, NTPC
8. Shri Mohit Joshi, DM, POSOCO

Minutes of the 3rd meeting of the committee on Flexibilisation of Thermal Power Plants held on 23rd February 2018

1. CE (TPRM) welcomed the participants and asked the member for the progress made on the agenda viz. to find out year wise quantum of flexible power (GW) & ramp rate (MW/Min.) required from thermal power plants in order to accommodate RES generation into the grid and maintain stable & secured grid.

2. IRP division presented Total Load and Net Load curves for the five self-designed seasons for the year 2021-22. The graphs were prepared taking into account the hourly historic demand for the year 2014-15 to 2016-17 and scaling it to the 2022 demand assuming the same characteristic shape.

3. As per IRP's assessment, the peak demand occurs in the season 3 (Oct to Nov '22) and is 225751MW. However, as the peak to off-peak ratio is different for different seasons, more flexible power may be required even in a season which has second highest peak demand. Hence, it was decided that for the purpose of assessment the analysis will be conducted for each month of the year during (i) High RE generation day (Maximum Peak/Off-Peak ratio of Net Load curve), and (ii) Maximum demand day.

4. IRP stated that they have the hourly data for total power demand, RES and hydro. However, for other technologies (Gas, Nuclear, Biomass, Small Hydro) hourly data for power generated is not available. The members reached a consensus that generation from Nuclear, Biomass and Small Hydro is small and can be assumed to be constant throughout the day and year. POSOCO stated that the power generated from Gas has been erratic over the years. However, whatever data regarding historic generation from Gas is available they would share.

5. Members agreed that in the limited time that the committee has been provided, certain unplanned changes in operational aspects like rare or excess monsoon, backing down of Gas in the future, lack of capacity addition in RES are not to be consider in the study.

6. Some empirical calculations were carried out by the members considering most probable contribution from each technology during the peak off peak demand.
    a. For the season April to June, the empirical analysis revealed a ramping down requirement of 41 GW from thermal for the morning peak and a ramping up

requirement of 59 GW during the evening peak. Regarding ramp down rate (MW/min), from the curve it is clear that the ramp rate varies continuously and an hourly analysis of contribution from all type of generation will be required to find out the maximum and minimum ramp down rate required. However, the average value calculated by spreading the 41GW over a period of 6 hours comes out to be 114 MW/min. Similarly, the peak hour ramp up rate is estimated to be 59GW /5.5hr = 179 MW/min.

b. The contribution of thermal power in the evening peak demand during Season 1 (Apr-Jun) is estimated to be 137 GW. Considering that scheduled capacity is 90% of the declared capacity (DC), the DC comes out to be 152 GW. This is the capacity on bar and it is assumed that the number of units involved will be the same as those operating during the off-peak hours. The off-peak demand from thermal is 78 GW. Hence, if all thermal unit are consider together, they will be operating at 78/152 = 51 % load during the off-peak time.

These calculations are only indicative and more than the figures represent the process used to calculate minimum load on thermal units. Accurate figures will be reached when further simulations are performed.

7. Considering Declared Capacity (DC) as 90% of the peak demand (137GW) in season -1 (Apr-Jun), the DC comes out to be 152 GW. This is the capacity is on bar which means we have a reserve shutdown capacity of 152-137=15 GW which is more than the current total spinning reserves (primary, secondary and tertiary) as stipulated by CERC.
8. The regulation by CERC on reserve power states that:
"Each region should maintain secondary reserve corresponding to the largest unit size in the region and Tertiary reserves should be maintained in a de-centralized fashion by each state control area for at least 50% of the largest generating unit available in the state control area. This would mean secondary reserves of 1000 MW in Southern region; 800 MW in Western regions; 800 MW in Northern region; 660 MW in Eastern region and 363MW in north-eastern region. (total approx. 3600 MW on an All India basis). Primary reserves of 4000 MW would be maintained on an All India basis considering 4000 MW generation outage as a credible contingency."

Details of current primary, secondary, and tertiary reserves in the country are as follows.

Primary Reserves (Distributed in All India Generators)	Secondary Reserves Region wise	
4000 MW Primary Reserve to arrest the sudden frequency drop during outage of Ultra Mega Power Plant or any similar event.	Region	Reserve (in MW)
	North	800 MW
	East	660 MW
	West	800 MW
	South	1000 MW
	North East	363 MW
	Total	**3623 MW**

Tertiary Reserves at intra state level Region wise summation	
Region	**Reserve (in MW)**
North	1658 MW
East	857 MW
West	1353 MW
South	1343 MW
North East	65 MW
Total	**5218 MW**

The total spinning reserves come out to be around 12841 MW. It was decided that this figure can be used to estimate the spinning reserves in 2021-22 after a certain scaling.

9. It was decided that PSPA should be involved in the study in order to identify the transmission constraints due to flexibilisation, if any.

The following was decided in the meeting.

1. POSOCO to provide the hourly data for Gas generation for the previous three year.
2. IRP to come up with hourly contribution from each technology type for 8760 hours of the year 2021-22. IRP to calculate from the Maximum ramp rate, Flexible thermal power required, average minimum loading on thermal units from the results of the simulations in association with TPRM and GM divisions.
3. Format for getting data regarding ramping capability of the thermal units to be circulated to all utilities.
4. Smt. Rishika Sharan, Director, PSPA-II co-opted as members of the committee.

Meeting ended with vote of thanks to the Chair.

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List of participants.

1. Shri B C Mallick, Chief Engineer, TPRM, CEA
2. Shri Rajeev Kumar, Director, TPRM, CEA
3. Shri Vikram Singh, Director, GM, CEA
4. Shri Rakesh Kumar, Director, HPPI, CEA
5. Smt. P. E. Kamala, DD, IRP, CEA
6. Shri Prabhjot Singh Sahi, AD, TPRM, CEA
7. Shri Vikrant Singh Dhillon, AEE, NRPC
8. Shri A K Sinha, AGM, NTPC
9. Shri N. Nallarasan, AGM, POSOCO
10. Shri Mohit Joshi, DM, POSOCO

Minutes of the 4th meeting of the committee on Flexibilisation of Thermal Power Plants held on 5th April 2018

1. CE (TPRM) welcomed the participants to the 4th meeting of the committee on Flexibilisation of Thermal Power Plants.

2. DD, IRP submitted the simulated power demand curves for two typical days for each month of the year 2021-22 on all India basis accounting for generation from renewable sources. The two typical days correspond to the peak demand day and maximum RES integration day. Maximum Peak – Off Peak ratio is taken as a measure of maximum RES integration.

3. Director, PSPA-II, expressed that in order to identify constraints involved in power transmission due to flexible operation of thermal power plants and large-scale integration of renewables, they would require region wise data regarding anticipated generation from future installed capacity including that from renewables.

4. It was decided that region wise analysis of hourly demand and generation data including RES generation would be carried out on region-wise peak demand day and maximum RES integration day in each month to help identify the constraints in inter-region transmission of power, if any.

5. AGM, NTPC stated that unit wise data regarding capacity, make, coal quality, coal mines, ECR, current ramp rate would be helpful in assessing the flexing capability of individual power stations.

6. The following was decided in the meeting
    a. To ascertain the approximate backing down capabilities of individual plants, the state utilities would be requested to provide the plant wise data including the following.
        i. Location/State, Unit Capacity, AGE/COD Date, Boiler make, Turbine Make, Mills Type, PLF, HR, APC, Minimum Load, Ramp Rate, Coal Source(s), Grade of Coal received by Station, and ECR.
    b. The regional power committees would be requested to provide the following data to facilitate identification of transmission constraints.

i. Historic generation data of renewables (RES) on hourly basis and, if possible, at 15 mins interval for a period of one year.
ii. Location of installed capacity of all current renewable energy sources and location of anticipated RES installations by 2022.

7. Point no.5 of the last MoM may be read as follows:-
   "Members agreed that in the limited time that the committee has been provided, certain unplanned changes in operational aspects like rare or excess monsoon and backing down of Gas in the future are not to be consider in the study. Further, full capacity addition of RES i.e. 175 GW would be considered in the analysis."

Meeting ended with a vote of thanks to the Chair.

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List of participants.

1. Shri B C Mallick, Chief Engineer, TPRM, CEA
2. Shri Rajeev Kumar, Director, TPRM, CEA
3. Shri Upendra Kumar, SE, NRPC
4. Smt. Rishika Sharan, Director, PSPA-II, CEA
5. Smt. P. E. Kamala, DD, IRP, CEA
6. Shri Prabhjot Singh Sahi, AD, TPRM, CEA
7. Shri Vikrant Singh Dhillon, AEE, NRPC
8. Shri A K Sinha, AGM, NTPC
9. Shri N. Nallarasan, AGM, POSOCO

Minutes of the 5th meeting of the committee on Flexibilisation of Thermal Power Plants held on 26th April 2018

1. CE (TPRM) welcomed the participants to the 5h meeting of the committee on Flexibilisation of Thermal Power Plants.

2. CE (TPRM) presented the results of all India analysis conducted in IRP. Some of the key findings of the all India analysis are as follows:-
   a. The maximum RES integration in 2022 is 107 GW and occurs at 1100 & 1200 hrs during the summer months of June & July.
   b. The minimum generation required from coal-fired units is 33925 MW at 1100 hrs on 19th July 2022. While the maximum generation required from coal fired units is 112328 MW on the same day to meet the evening peak demand of 194645 MW at 2100 hrs.
   c. Assuming reserve capacity equal to 10% of the maximum generation required from coal fired units during the evening peak of the day, this leads to a minimum load on coal fired units of 27%.

3. Dir, PSPA – II, stated that a load flow analysis could be performed once they are provided with the regional data like demand, generation, and location of generating units including RES to assess the transmission constraints, if any.

4. Regarding regional analysis it was clarified that the regional analysis would be carried out for the days when the all India demand and RES integration is maximum, i.e. all India critical days will be simulated on regional level. A subsequent analysis may be carried out for peak demand and maximum RES integration in individual regions.

5. IRP stated that they are having most of the data for regional analysis. However, RES data is indicative in nature.

6. CE (TPRM) informed that the power plant data has so far been collected from NTPC, OPGCL, UPRVUNL and TSGENCO. Data from other utilities is awaited. However, the general trend is that utilities are stating that the minimum load which their machines can obtain is close to 70%. He proposed to run small size inflexible thermal units during peak period of the day. In addition, he suggested to utilize generation from gas during peak hours

only and to shift some of the hydro generation from off-peak to peak hours to improve minimum load operation of thermal units. Hydro power utilities should be compensated accordingly for shifting their generation so that they can easily purchase power from the grid to meet their off-peak demand.

7. The following was decided in the meeting
   a. The coal-fired units will be clubbed based on their capacity into the following four groups. Various combinations of the minimum load for each group would be tried to match minimum grid demand from coal-fired units.
      i. <= 150 MW
      ii. 200/210 MW
      iii. 500 MW
      iv. 660/800 MW
   b. Explore the possibility of utilization of thermal units (<=150 MW) during evening peak hours only.
   c. Explore the possibility of utilization of whole generation from Gas during peak hours.
   d. Lastly, shifting of a portion of hydro generation from off-peak to peak hours.

The meeting ended with a vote of thanks to the Chair.

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List of participants.

1. Shri B C Mallick, Chief Engineer, TPRM, CEA
2. Shri Rajeev Kumar, Director, TPRM, CEA
3. Smt. Rishika Sharan, Director, PSPA-II, CEA
4. Smt. P. E. Kamala, DD, IRP, CEA
5. Shri Prabhjot Singh Sahi, AD, TPRM, CEA
6. Shri N. Nallarasan, AGM, POSOCO

Minutes of the 6th meeting of the committee on Flexibilisation of Thermal Power Plants held on 12th June 2018

1. CE (TPRM) welcomed the participants to the 6th meeting of the committee on Flexibilisation of Thermal Power Plants and presented the brief findings of the interim report highlighting that in order to meet the challenge of renewable integration all fuel sources will have to contribute.
2. CE (TPRM) envisaged that hydropower is more suitable for peak load operation. Even in the scenario as on date, the intermittent power introduced by RES is being mitigated by hydro and thermal plants only. He explained that the maximum hydro generation as predicted is 29 GW at 20:00 hrs. on 25.06.2021 and minimum generation is 22 GW at 09:00 hrs on the same day. He emphasized that approximately 6000 MW additional support in peak hours can be provided by re-allocation of hydro generation from off-peak hours by introducing incentive, two-part tariff etc. specially from state sector. Thus more generation can be available during evening & morning time and less generation during day time, when Solar generation is high. This will improve the minimum load operation of thermal plant. Considering the installed capacity of storage type and pumped storage type (5.9 GW) plants out of total 60 GW installed capacity (as projected for 2021) the peak support of 35 GW seems reasonable. He also informed members that confirmation of 55% minimum load operation of thermal unit from NTPC, DVC, Gujarat & Punjab for pilot projects has been received. He requested members to discuss the matter for implementation of 55% minimum load operation of the thermal units.
3. Director, HPP&I said that the proposal of shifting 6000 MW of hydro from off peak to peak hours might turn out to be a difficult proposition due to the follow reasons: -
    a. Unwillingness of states to schedule their power generation to meet national objectives in the absence of an incentive oriented commercial mechanism
    b. Preference to irrigation and flood control over power generation in most dams.

    He, however, added that if a commercial mechanism were ensured states would be willing to come onboard.
4. Director, GM said that the CERC regulation clearly states that thermal plants should be capable of running at 55% minimum load. Hence, no relaxation may be provided to TPS in this regard. Further, in order to meet the increased RES addition this will also become a technical necessity for safe operation of Grid apart from being a regulatory mandate.
5. AGM, NTPC stated that some thermal power plants that are running on coal of GCV less than 4000 kcal/kg would find it difficult to run their stations at low loads. NTPC is exploring the use of biomass blended with coal in such cases as it has potential of raising

the calorific value and flame stability of low quality coal. He also stated that 55% minimum load operation of thermal plant will be implemented in coordination with NLDC/RLDC by providing schedule of 55 % generation. He also highlighted that confirmation from plant on running units at 55% load shall be obtained before trial run.

6. DD, PSPA-II stated that they would be able to identify the regional transmission constraint, if any, based on regional generation data to be provided by IRP.

After detailed deliberation, followings are decided in the meeting:

a) Presently 800 MW hydro re-allocation will be considered instead of 6000 MW and the committee will recommend incentives, implementation of two-part tariff, revision of grid code to attract more hydro generation during peak hours.
b) Generation of 1200 MW pump storage under construction will be added at peak hours and pumping load of 1600 MW will be added at off-peak hours.
c) Further, pump or battery storage of 3750 MW will be suggested for peak support.
d) Letter to be issued to NTPC, DVC, GSECL, APGENCO & MSPGCL asking their preparedness on 55% minimum load operation of thermal units.
e) PSPA-II division of CEA will simulate the transmission network on 25.06.2021 during integration of 108 MW RES generation to find out transmission constrain if any.

The meeting ended with a vote of thanks to the Chair.

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List of participants.

1. Shri B C Mallick, Chief Engineer, TPRM, CEA
2. Shri M. A. K. P. Singh, MS, NRPC
3. Shri Rajeev Kumar, Director, TPRM, CEA
4. Shri Rakesh Kumar, Director, HPP&I, CEA
5. Shri Vikram Singh, Director, GM, CEA
6. Smt. P. E. Kamala, DD, IRP, CEA
7. Shri Prabhjot Singh Sahi, DD, TPRM, CEA
8. Shri U. M. Rao, DD, PSPA-II, CEA
9. Shri Suyash Verma, AD, PSPA-II, CEA
10. Shri N. Nallarasan, AGM, POSOCO
11. Shri A.K.Sinha, AGM, NTPC
12. Shri Nathi Ram, Manager, NPTC

Minutes of the 7th meeting of the committee on Flexibilisation of Thermal Power Plants held on 9th July 2018

1. CE (TPRM) welcomed the participants to the 7th meeting of the committee on Flexibilisation of Thermal Power Plants and highlighted that pilot power project demonstration, identification of units, transmission constraints, and economic / commercial analysis is the next step in the study. He also congratulated NTPC for successful demonstration of 40% minimum load operation at Dadri TPS, Unit 6.
2. Regarding pilot demonstration at Dadri TPS, unit 6, NTPC was requested to share its learnings, test procedures, SOPs for guidance of the utilities.
3. An issue was raised by AGM, NTPC on operation of thermal plants equipped with FGD at reduced loads. It remains a cause of concern whether FGD equipment will be able to perform efficiently when the unit is running at low loads. In addition, upto what minimum load of the TPS the performance of FGD will be called satisfactory.
4. Members discussed the matter of low load operation of TPS highlighting that the measures to be implemented (automation etc.) for minimum load operation would require at least Rs. 10 to 15 Cr investment per unit. After detailed deliberation members agreed that the funding opportunity for implementation of minimum load operation can be explored from PSDF, as it is a matter of Grid security and stability. Further, funding option can also be explored from Coal Cess Fund as investment in this regard is enabling integration of clean energy i.e. RES directly.
5. Regarding flexibilisation from sources other than thermal:-
    a. Members expressed hope that battery storage may become viable in coming years and may be helpful in reducing the burden of RES integration on thermal power stations.
    b. Members also expressed that modifications in approach towards distribution of Gas may be required in order to employ Gas based power stations in flexible operation.
6. Members also emphasized that training of power plant personnel / operators on simulators and education on automation etc. would be essential for operation of thermal units at low load.

The meeting ended with a vote of thanks to the Chair.

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List of participants.

1. Shri B C Mallick, Chief Engineer, TPRM, CEA
2. Shri Rajeev Kumar, Director, TPRM, CEA
3. Shri Rakesh Kumar, Director, HPP&I, CEA
4. Shri Vikram Singh, Director, GM, CEA
5. Smt. P. E. Kamala, DD, IRP, CEA
6. Shri Prabhjot Singh Sahi, DD, TPRM, CEA
7. Shri N. Nallarasan, AGM, POSOCO
8. Shri A.K.Sinha, AGM, NTPC
9. Shri Nathi Ram, Manager, NPTC

Minutes of the Meeting held on 11th July, 2018 under the Chairmanship of Joint Secretary (Power) in MoP to review the progress of CEA's Task force on implementation of flexibilisation of Thermal Power Plant.

The meeting was held on 11th July, 2018 under the Chairmanship of Joint Secretary (Power), Ministry of Power in the National Power Monitoring Centre 2nd Floor, Shram Shakti Bhawan, New Delhi. List of Participants is enclosed at Annex.-A.

1. Initiating the discussions, Joint Secretary (Thermal) welcomed the participants and informed that the meeting has been convened to review the progress of CEA's Task force on implementation of flexibilisation of Thermal Power Plant.
2. Chief Engineer (TPRM), CEA informed about progress of actions taken for implementation of flexibilisation of thermal power plants based on the report submitted by IGEF Task Force. It was informed that ramp rate required for balancing needs can be catered by existing flexibility in the thermal power plants and issue to be addressed is minimum load capability of thermal power plants and economic operation of the plant at part loads.
3. CEA has identified power stations of NTPC (2 units), DVC (1 unit), GSECL (1 unit), APGENCO (1 unit) & MSPGCL (1 unit) and obtained their consent for conducting flexibility test.
4. JS (Thermal) requested that the implementation process of flexiblisation of thermal power plants needs to be expedited and following should be covered:

    a. The technical capability and economic feasibility of the power stations for the flexibilisation.

    b. Analysis of legal framework conditions and the new framework required to facilitate and incentivise flexibilisation of the thermal power stations.

    c. Assessment of total flexibilisation potential of thermal plants in India, year-wise, keeping in view the trajectory of renewables and roadmap to achieve it.

    d. Preparation of the flexibility manual for the power sector based on outcome of (a), (b) and (c) above.

The meeting ended with the vote of thanks to the Chair.

Annexure-A

Sl No.	Name	Designation and organization
1	Shri Aniruddha Kumar	Joint Secretary, MoP.................In Chair
2.	Shri S.K.Kassi	Director (Thermal), MoP
3	Shri B.C. Mallick	Chief Engneer, CEA
4	Shri Vikram Singh	Director, CEA
5	Shri Rajeev Kumar	Director, CEA
6	Shri N. Nallarasan	DGM, POSOCO
7	Ms. P.Esther Kamala	Deputy Director, CEA
8	Shri Anjan Sinha	AGM, NTPC
9	Shri Prabhjot Singh Sahi	CEA
10	Shri Nikhil Mittal	AD, MoP