DECOMMISSIONING OF COAL-BASED PLANTS IN INDIA AND ITS RAMIFICATIONS

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List of Abbreviations

ALMM	Approved list of models and manufacturers
BCD	Basic customs duty
BUs	Billion units
CCGT	Closed cycle gas turbine
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
CESC	Calcutta Electric Supply Company
CO_2	Carbon dioxide
COP	Conference of the parties
DVC	Damodar Valley Corporation
EPA	Environmental Protection Agency
FGDs	Flue gas desulphurisers
GW	Gigawatts
GWH	Gigawatt hours
IEA	International Energy Agency
KW	Kilowatts
MoEF&CC	Ministry of Environment, Forests and Climate Change
MW	Megawatts
NEP	National electricity plan
NO_X	Nitric Oxide
PLF	Plant load factor
PPA	Power purchase agreement
SCC	Specific coal consumption
SHR	Station heat rate
SO_2	Sulphur dioxide
SO_X	Sulphur Oxide
UNFCCC	United Nations Framework Convention on Climate Change

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Abstract

According to the International Energy Agency (IEA), the Indian power sector is the highest emitter of carbon dioxide (CO2). In 2021, the power sector emitted 1104 MT of CO2 which was about 45% of the total emissions. Next was the industrial sector which emitted about 762 MT of CO2. Within the industrial sector, the largest contribution was from the iron and steel industry estimated at 304 MT. India has declared its intention to become net-zero by 2070, and going by available literature, there is usually a 30-year gap between reaching peak emission levels and achieving net-zero. Going by this argument, India will probably have to peak its emissions by around 2040.

The power sector being the largest emitter of CO2 has a key role to play if India wants to achieve its target of going net-zero by 2070. This will mean that we would need to move away from coal-based generation and adopt renewable power instead, mainly wind and solar. Of course, it can be supplemented with hydro power, biomass and nuclear. This energy transition can only happen if one is able to decommission coal-based plants without any adverse effect of not being able to meet the system demand. Countries like USA, UK and Germany have been able to move away from coal. They were able to do this primarily due to availability of gas and also through a system of giving market signals coupled with strict environmental norms for coal-based generation.

The movement away from coal-based generation is not really working in the case of India for various reasons. India's proportion of coal-based generation has gone up in 2020 as compared to what it was in 2000. This is just the opposite of what has happened in USA, UK and Germany. In UK, coal-based generation today is only about 1.6% of total generation. India, unfortunately, does not have access to cheap gas and it has various other issues which are affecting the growth of hydro and nuclear power. Though India has ramped up its wind and solar generation manifold, it is still far behind if one is dreaming of replacing coal with renewable generation.

This working paper examines as to what is the ideal parameter for decommissioning of coal-based generation. Is it the age of the plant, its station heat rate (SHR) or any other parameter? It also examines whether it would be possible for India to undertake this energy transition easily so as to become net-zero by 2070.

Keywords: Coal, Decommissioning, Renewable

JEL classification: Q40, Q48

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Decommissioning of coal-based plants in India and its ramifications

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1. Background

This working paper looks into the various facets of decommissioning of coal-based generation. This energy transition phase has several ramifications especially on the lives and livelihoods of people working in the coal industry. The irony is that though phasing out of coal-based is imperative for attaining net-zero, there are benefits also if one decides to carry on with coal-based generation. The ground reality of each country differs from the others and consequently, each country has to weigh the pros and cons before deciding on the retirement of coal-based units. While section 2 gives the overview of the generation sector in India, section 3 describes the dilemma faced by countries on whether to retire coal-based units or not. In section 4, one has dealt with the issues which affect the coal sector on account of decommissioning and in section 5, the international experience of some countries who have successfully moved away from coal-based generation have been cited. Finally section 6 deals with what is the way forward as far as India is concerned.

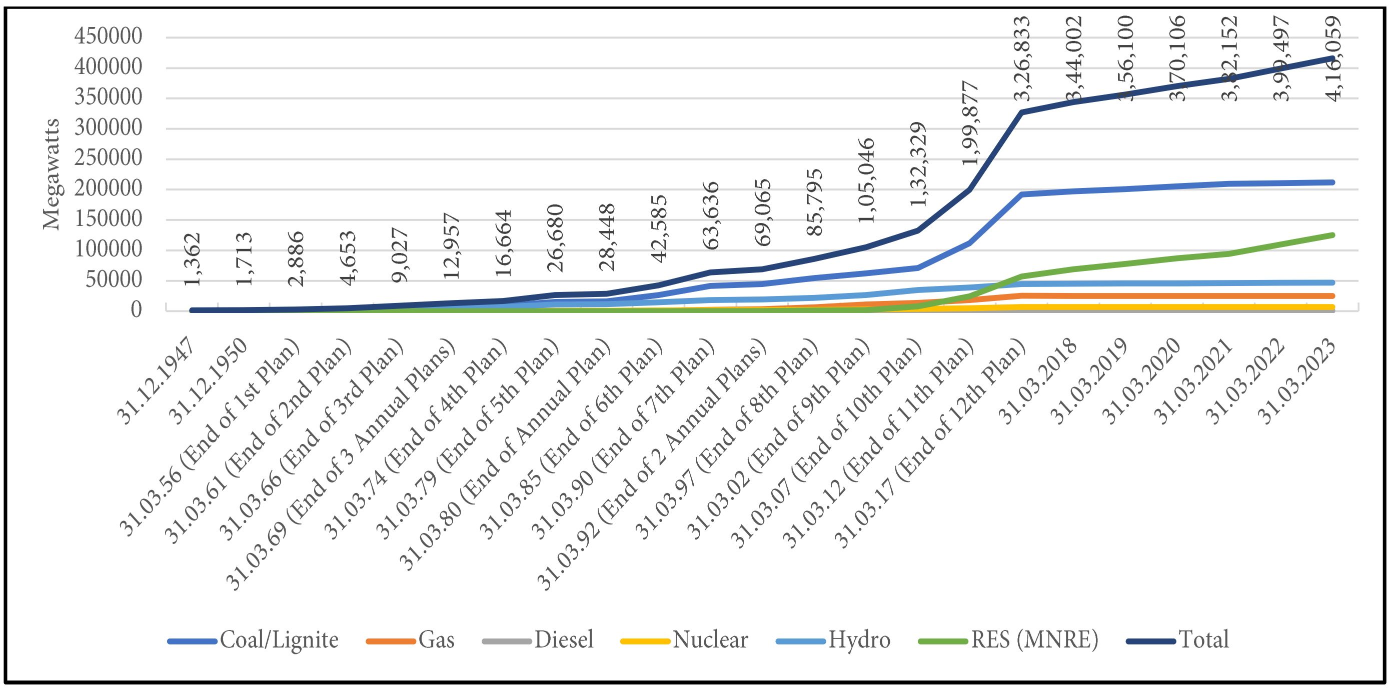
2. Overview of the generation sector in India: Some facts and figures

2.1 Growth of installed capacity since 1947

It is difficult to say when exactly the first power plant was set up in British India. There is some documentation, however, which suggests that in January 1887, Kilburn and Company secured an electric license as agents of the Indian Electric Company Limited. This company was later named as the Calcutta Electric Supply Company (CESC) and the first power generating company was established in 1899 at Kolkata (then Calcutta). There is yet another report of a diesel generating unit which was set up in Delhi in 1905. This was a private entity which was later known as the Delhi Electricity Supply and Traction Company. The first hydroelectric station in India was set up at Sivasamudram in Mysore in 1902 which was followed by a hydroelectric station for the Bombay area. What is clear is that the electricity sector was initiated in private hands as there was a lot of debate on nationalisation of the sector before the enactment of the Electric Supply Act, 1948.

The following graph **(Figure 1)** projects the growth of the generation sector (source wise) in India since 1947.

Figure 1: Growth of installed capacity in India since 1947 to 31/03/2023 (in MW)



Source: Central Electricity Authority, 2023a

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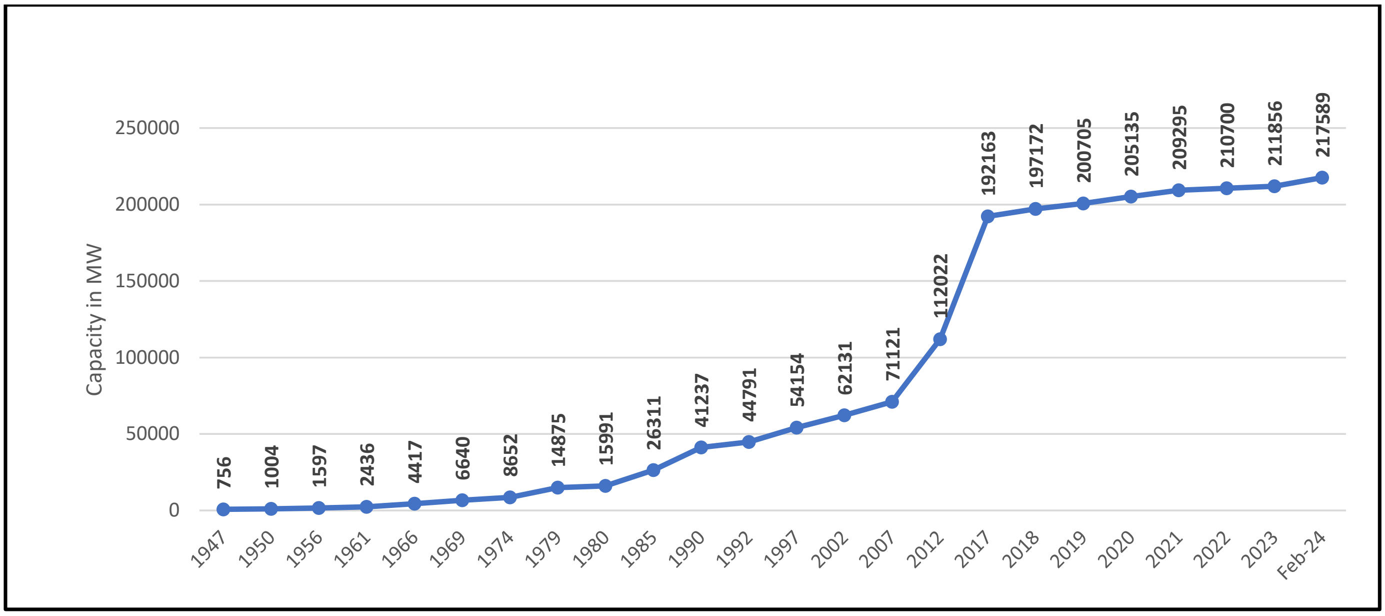
Before embarking on the actual topic under discussion, ie. decommissioning of coal-based plants, in this section the broad contours of coal-based generation in India is being laid out to give a picture of where we stand today. The parameters highlighted in this section include the growth of coal based capacity over time, their generation vis-à-vis total generation, the PLF of coal based plants, the quantum of capacity belonging to the class of super-critical technology, the distribution of coal plants based on size etc.

As on February, 2024, the total installed capacity was 434 GW and out of this, coal and lignite accounted for 217.5 GW. If one considers only coal plants, then the capacity is about 210 GW. The growth of the coal and lignite-based capacity over time can be seen in **(Figure 2).**

Figure 2: Capacity of coal and lignite-based plants from 1947 to February, 2024 (in MW)

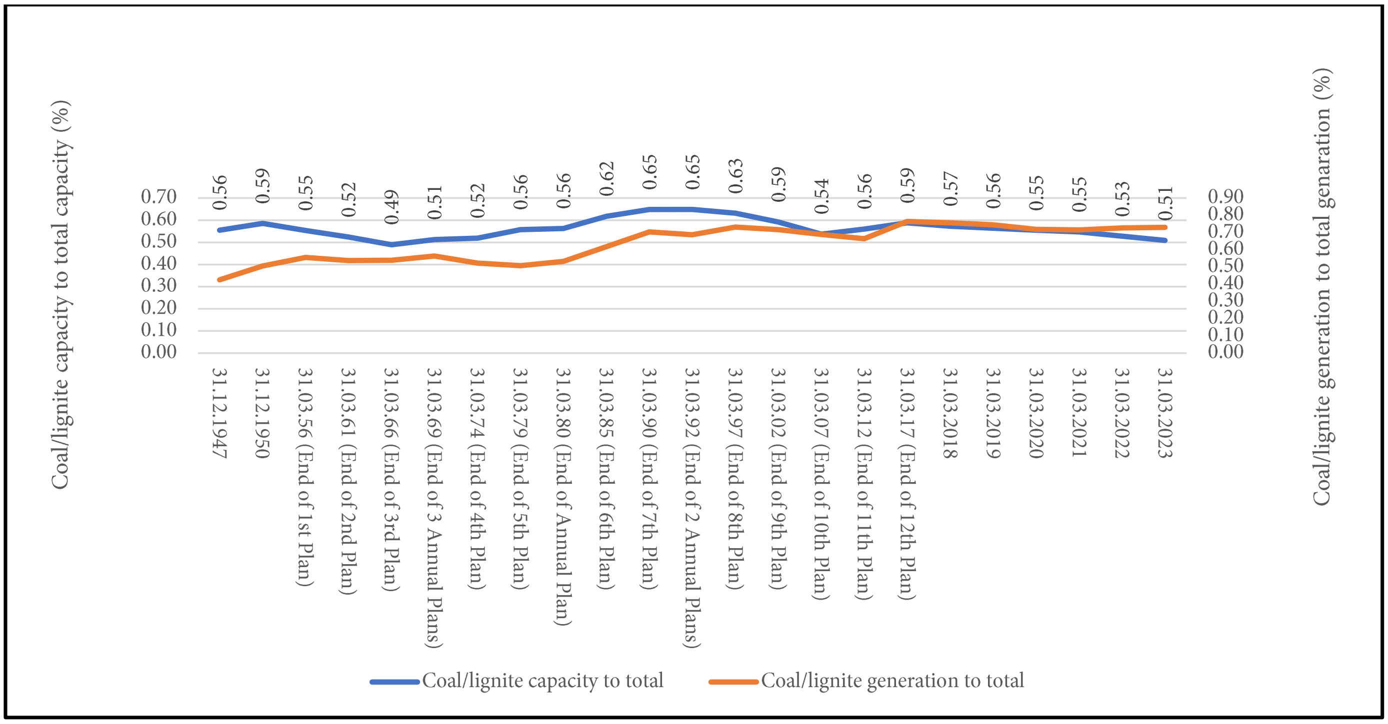


Source: (Central Electricity Authority, 2023a)

2.2 Share of coal/lignite in total installed capacity and also generation

Coal is the cheapest source of energy for us and our dependence on coal is considerable. Though there has been a small decline in the proportion of our installed capacity from coal/lignite from about 55% (in 1947) to about 50% (in 2024), it is still the largest contributor both in terms of capacity and generation **(Figure 3)**. As on March 2024, coal/lignite accounted for 50% of our capacity and 73% of generation. In fact, coal/lignite would still account for about 32% of our installed capacity in 2030 despite our push for renewable generation as highlighted by the Central Electricity Authority (Central Electricity Authority, 2023b). The report states that to meet the demand of 334.8 GW in 2030, we would need a coal capacity of 251.6 GW assuming we are able to meet our targets from other sources including nuclear, hydro, solar and wind. If we fail to do this, our need for coal-based projects would be even more.

Figure 3: Share of coal/lignite-based capacity and generation (in percentage)

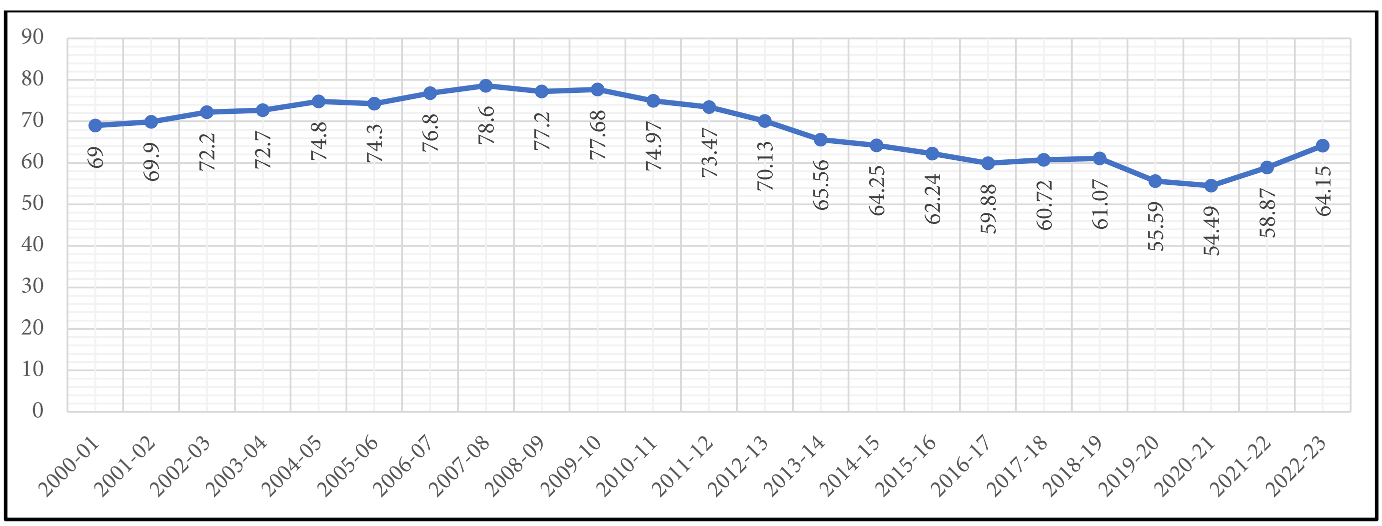


Source: (Central Electricity Authority, 2023a) and the author's construction

2.3 Plant load factor (PLF) of central, state and private sector units

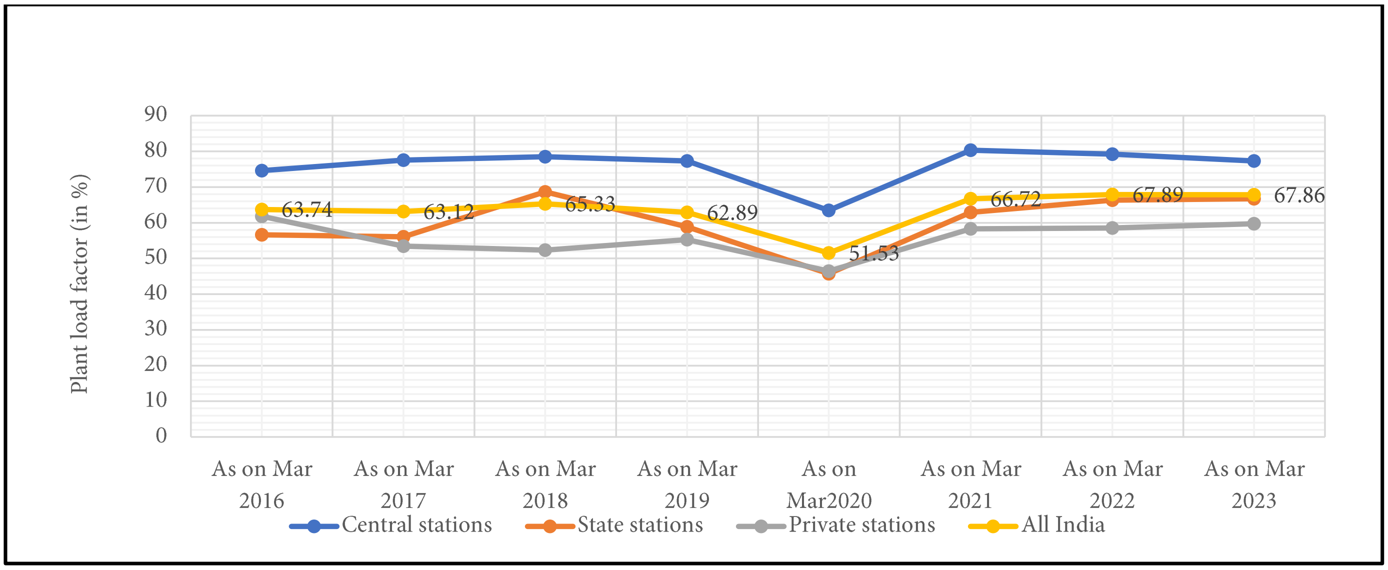
As is evident from Graph 2, the pace of installation of coal-based plants shot up around 2007 and it continued till about 2017. The main reason for this spurt was the high spot prices seen in the power exchanges and it provided the necessary market signal to developers. The banks also stopped their due diligence and provided money indiscriminately without examining whether the power plant(s) had a power purchase agreement and also a fuel linkage. More than 121,000 MW of capacity was created between 2007 and 2017 and a large number of such projects became stranded assets. Such a huge capacity led to a fall in the plant load factor (PLF) because demand failed to pick up commensurate with the increase in capacity. The rise of renewable capacity was also responsible for the fall in PLF **(Figure 4)**. There has been some improvement in PLF of late because of increase in demand, post pandemic. The PLF figures vary across plants whether they are central, state or privately owned. The central sector plants performed the best **(Figure 5).**

Figure 4: PLF of coal/lignite stations from 2000-01 to 2022-23 (in percentage)



Source: (Central Electricity Authority, 2023a)

Figure 5: Plant load factor of central, state and private plants in percentage (excluding gas-based units)



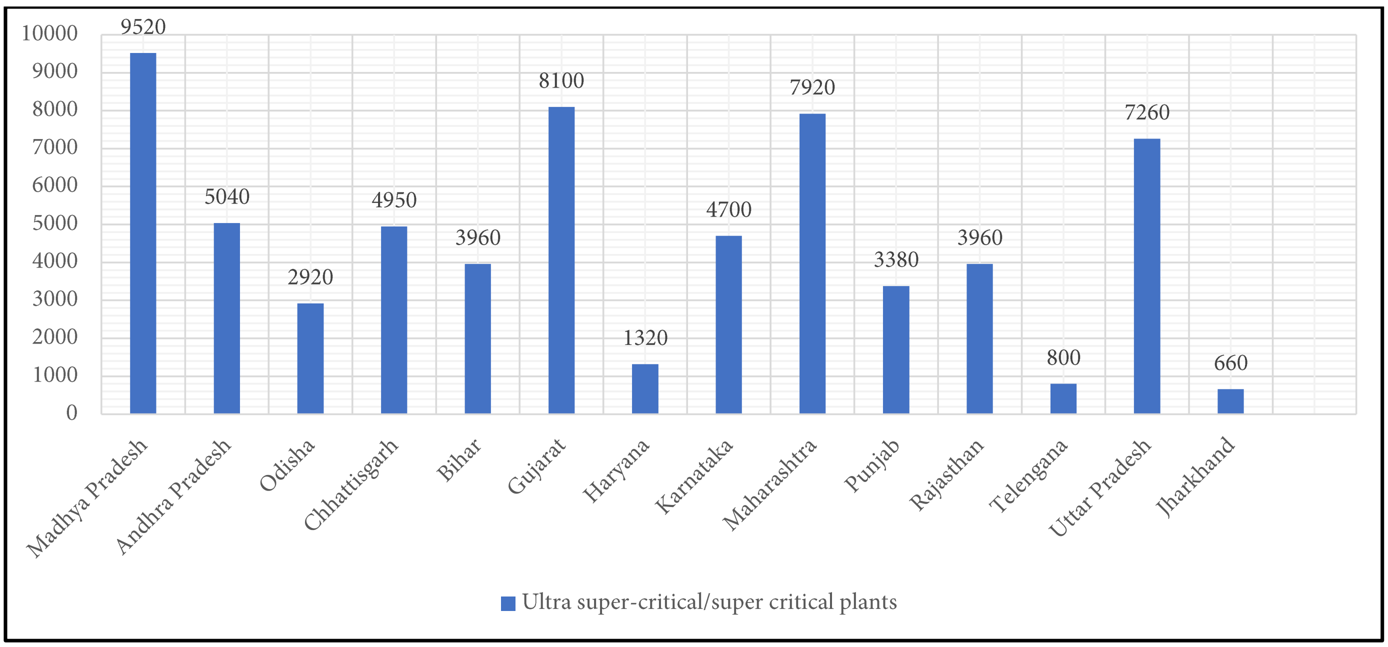
Note: Ratios indicated above are All India figures

Source: CEA's Executive Summary for various years for the month of March

2.4 Ultra super-critical/super-critical units

Out of a total coal capacity of around 210 GW, about 64.5 GW (31%) is in ultra-super critical or super critical form. The capacity of ultra super-critical is quite small and is estimated to be about 1320 MW and both the units are in Madhya Pradesh. The distribution of ultra super-critical and super-critical units across India is at **Figure 6**. A capacity of 18,850 MW is concentrated in the coal rich states, namely, Jharkhand, Odisha, Chhattisgarh, Madhya Pradesh, West Bengal and Telangana. The efficiency of the super-critical units is between 42% and 44% whereas the sub-critical units have an efficiency of ranging from 33% to 37%. The advantage of having super-critical units is that they use less coal for each unit of electricity generated which consequently means that there are less carbon footprints.

Figure 6: State-wise distribution of ultra super-critical/super critical plants (in MW)

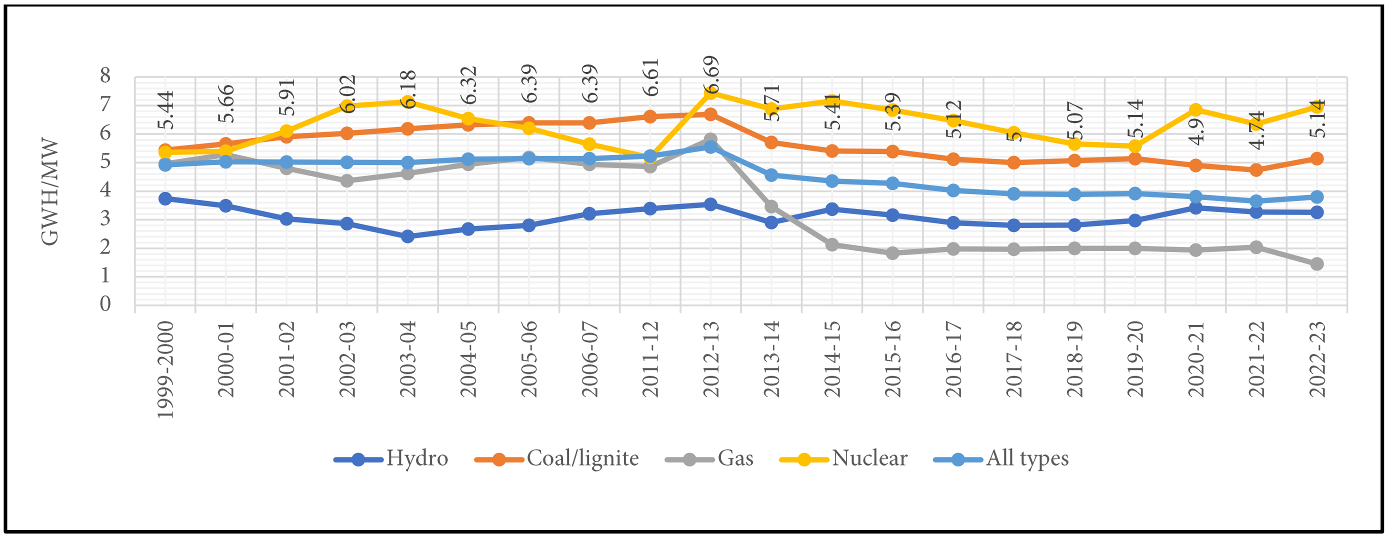


Source: Information obtained from CEA

2.5 Specific generation by utilities

Specific generation by utilities gives a measure of how much benefit we are deriving from the generating plants. Higher the PLF of the plant, higher is the ratio of GWH/MW. The PLF of a plant depends on various factors. Apart from the technical health of the plant, the PLF is a function of the scheduling that it is receiving from the utilities. If the variable cost of a plant is high, it may or not be scheduled and if it is not, its ratio of GWH/MW will fall. This ratio will also fall if the plant faces outages or is not able to declare full availability due to any other reason including lack of access to fuel. As seen from **Figure 7**, the ratio of GWH/MW for coal is second best, just below nuclear. The ratio is the best for nuclear since nuclear plants are never ramped down unless there are fuel/technical issues. They keep generating at full capacity.

Figure 7: Specific generation by utilities from 1999-00 to 2022-23 (in GWH per MW)

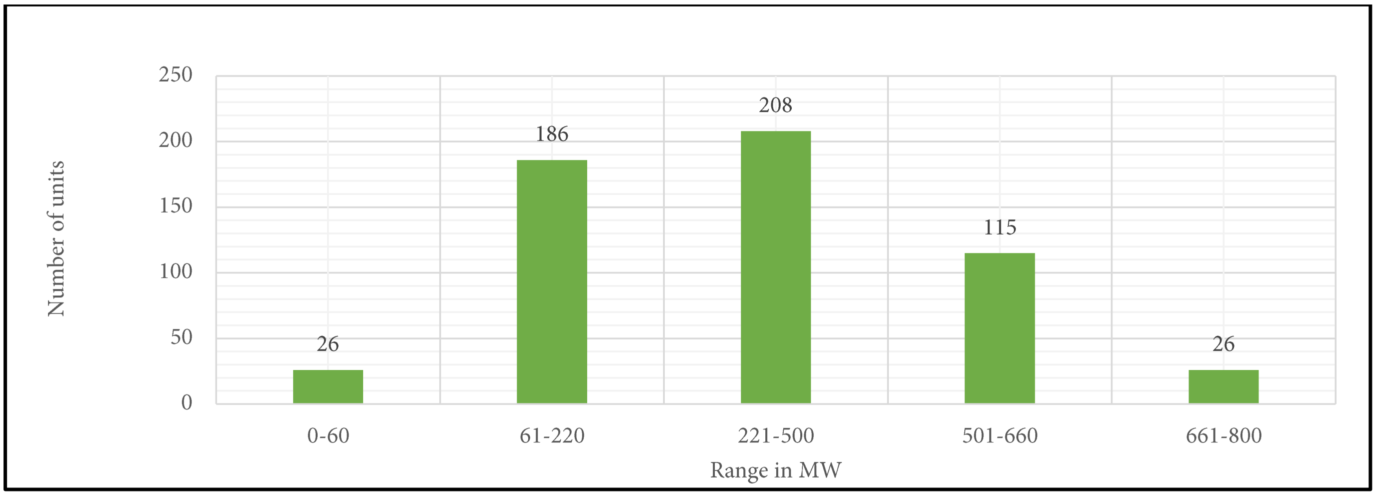


Note: The figures indicated above are for coal
Source: (Central Electricity Authority, 2023a)

2.6 The size of the coal based plants

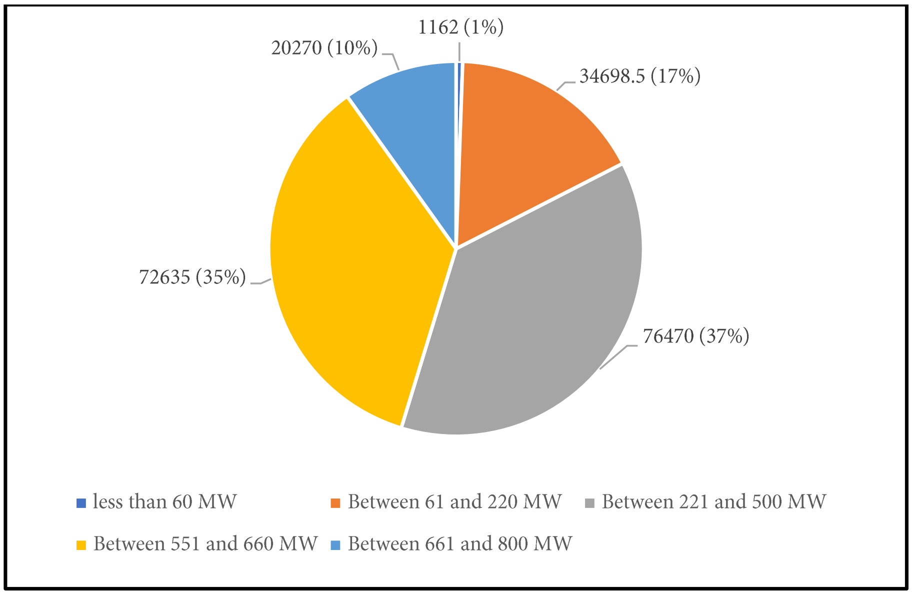
Surprisingly, there are 60 MW units still generating along with super-critical units as big as 800 MW **(Figure 8)**. The bulk of the units, however, are in the range of 221-500 MW where there are 208 units operating. Going by cumulative capacity, the maximum capacity is from units whose size is ranging from 221 to 500 MW (37%). It is closely followed by units whose size ranges from 551MW to 660 MW (35%). Details can be seen in **Figure 9**.

Figure 8: Number of units by size



Source: Information obtained from CEA

Figure 9: Total installed capacity by size of units



Note: Figures in brackets are percentage shares
Source: Information obtained from CEA

2.7 Gist of the coal sector in India

1) Coal is the primary fuel in India accounting for about 51% of the capacity (210 GW) an 73% of generation (1257 BUs).

2) CEA has estimated that coal and lignite will continue to have a capacity share of about 32% in 2030 despite a massive push towards renewable energy. Coal and lignite capacity would be 251 GW out of a total capacity of 777 GW.

3) The PLF of coal-based stations is low because of inadequate demand and because of growth in renewable capacity.

4) About 72% of the coal capacity consists of units whose size ranges from 220 MW to 800 MW. Thus, a little more than one-fourth of the capacity consists of units less than 220 MW, raising questions of efficiency.

5) Super critical units account for about 31% of the total capacity (64 GW out of 210 GW) and only about 18.8 GW is housed in the coal rich states of Jharkhand, Odisha, Chhattisgarh, Madhya Pradesh, West Bengal and Telangana.

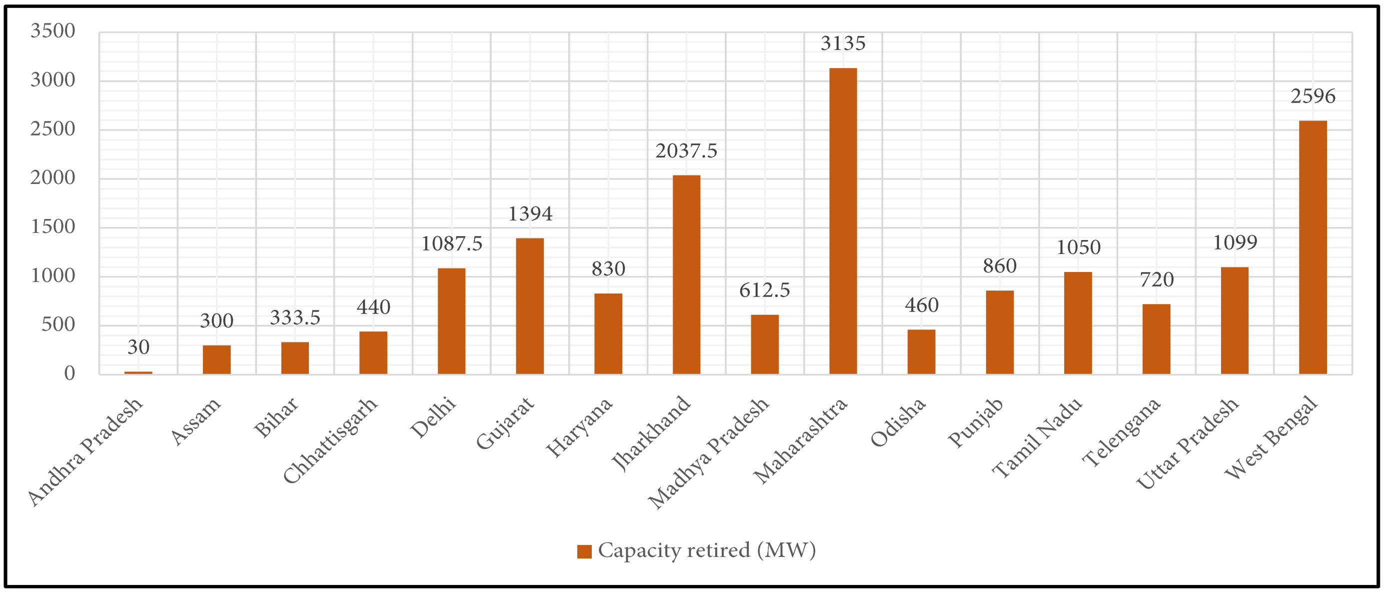
3 To retire or not to retire

3.1 Background

Going by the facts and figures indicated in the previous section, one gets a fair idea of the size of the coal fleet in India, its vintage, its efficiency etc. For the government, whether or not to retire a coal plant has always been a debateable issue. Though power is a concurrent subject, it must be made clear at the outset that the central government has no authority to order closure of any generating station belonging to the state or private sector. It's up to the states to decide whether or not to close a station. The state governments are usually loathe to close any unit because it has political ramifications largely on account of the unemployment that it creates, both upstream and downstream. Whatever has been retired till now has been done on techno-economic considerations and in a few cases, units were shut down on orders from courts of law. Examples where units were shut down on orders of the courts include the Badarpur station and the Indraprastha station in Delhi due to environmental reasons.

The central government has never cited any policy for retiring coal-based stations. The list of coal and lignite stations which have been retired from 2002 till August 2023 is given at **Annexe 1**. The decision to retire state generating stations have been taken by the states concerned and they have merely informed the CEA which then struck off the stations from its rolls. The total capacity that has been retired in respect of coal/lignite based stations is about 17,000 MW and primarily all are state generating units. The capacity of the units that have been retired ranges from 1.5 MW to 500 MW. The following graph **(Figure 10)** gives the capacities that have been retired from various states over the period 2002 till August 2023.

Figure 10: Capacity retired from 2002 to August 2023 (in MW)



Source: CEA (2023)[2]

3.2 The National Electricity Plan (2018)

It was in the National Electricity Plan (2018) that the central government for the first time indicated any criteria for retirement wherein plants more than 40 years old and/or less than 100 MW were identified for retirement. This only added up to 5.2 GW of capacity. However, in the finalised version of the National Electricity Policy (2018), the norms for retirement underwent a change and the age criteria was lowered to 25 years and further, included all those plants which did not have space to install flue gas desulphurisers (FGDs). Accordingly, a capacity of 22,716 was identified for retirement which included coal and lignite based plants. Out of 22,716 MW, 5,927 MW was treated as normal retirement as they were inefficient and 16,789 MW was due to inadequate space for FGD and on the completion of 25 years by the year 2022. In addition to this, another 25,572 MW of capacity had been identified for retirement between 2022 and 2027. To aggregate, between the years 2017 and 2027, a total capacity of 48,288 MW was planned to be retired. A complete volte-face was, however, seen when the NEP of 2023 was finalised which one shall come to later. The actual retirement which actually took place between 2017-22 has been summarised in **Table 1**. It may be seen that retirement was only 10,044 MW (Table 1E) against a target of 22,716 MW though 2995.3 MW of additional capacity was also retired which was outside the original plan in NEP 2018 (Central Electricity Authority, 2018).

Table 1: Summary of capacity retired between 2017 and 2022

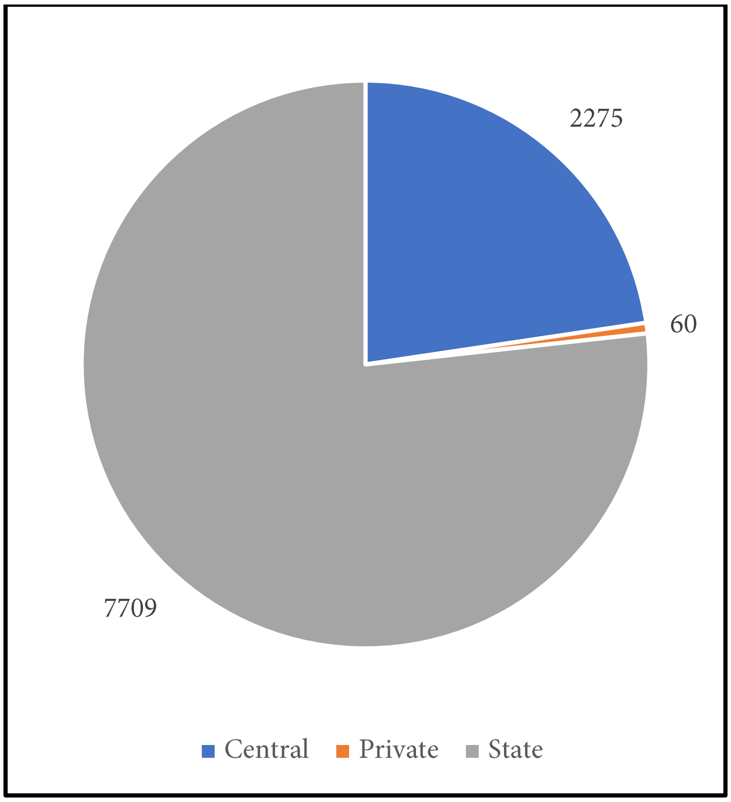
A.	Scheduled retirement during 2017-22	22690.5 MW
B.	Capacity retired due to old age between 2017-22 against 5901.5* MW envisaged in NEP 2018	4589 MW
C.	Capacity retired due to new environmental norms during 2017-22 against 16789 MW envisaged in NEP 2018	2760 MW
D.	Additional capacity retired between 2017-22 outside the retired capacity envisaged in NEP 2018	2695.3 MW
E.	Total capacity retired during the period 2017-22 (B+C+D)	10044.3 MW
F.	Capacity which did not retire but was scheduled to be retired due to old age between 2017-22 (5901.5MW-4589 MW)	1312.5 MW
G.	Capacity which did not retire but was scheduled to be retired because of new environmental norms between 2017-22 (16789 MW-2695.3 MW)	14029 MW

* This figure was mentioned as 5927 MW in the narrative in NEP 2018
Source: (Central Electricity Authority, 2023)

2 Available at: https://cea.nic.in/power-data-management-division/?lang=en. Accessed on November 1, 2023.

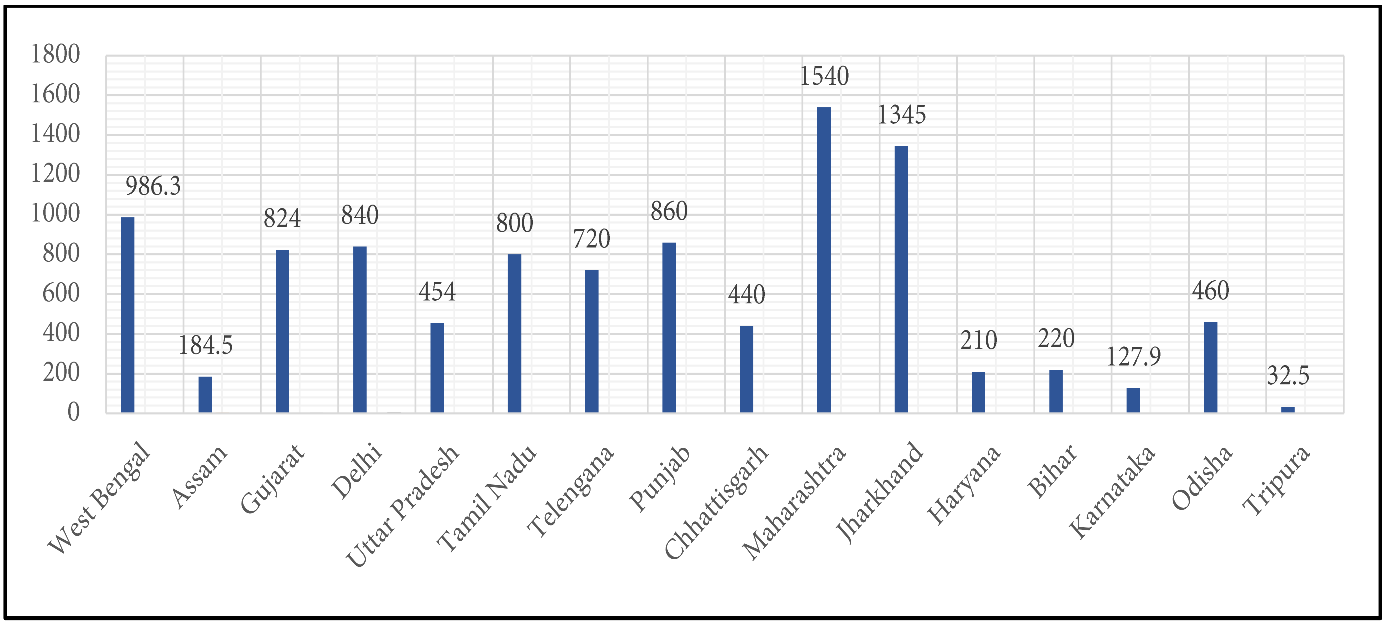
The list of coal-based plants which were retired between 2017-22 either due to old age or non-compliance of environmental norms is given in **Annexe 2.** The data has been summarised in the following graphs **(Figure 11 and Figure 12)**.

Figure 11: Capacity actually retired between 2017-22 due to inefficiency, non-compliance of new environmental norms or not originally planned for retirement (in MW)



Source: (Central Electricity Authority, 2023)

Figure 12: State wise retirement of coal/lignite/gas-based units from 2017 to 2022 (in MW)



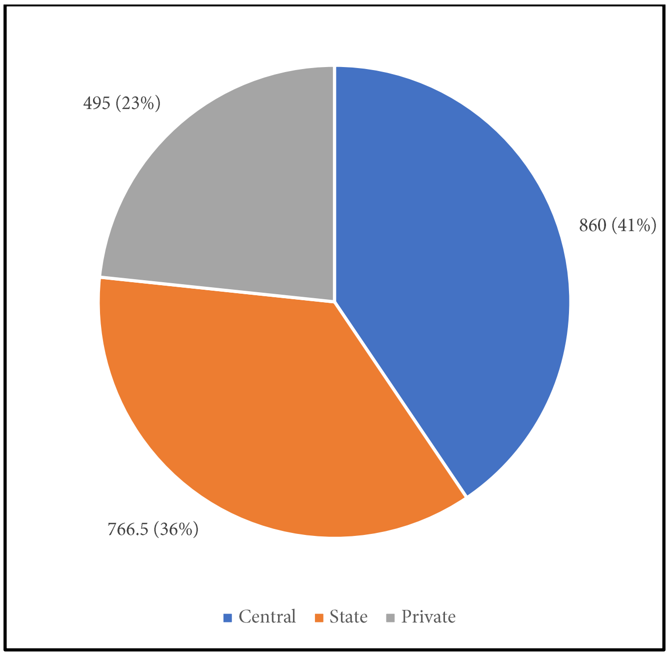
Source: (Central Electricity Authority, 2023)

3.3 National Electricity Plan 2023

As far as retirement is concerned, in the NEP 2023, there was a complete turnaround and the capacity which now would be retired from 2022-32 was brought down to 2121.5 MW. In contrast, in the NEP

2018, it was stated that between the years 2017-27, a total of capacity of 48,288 MW would be retired. What changed the situation is that the government decided to do away with the criteria of age ie. 25 years for retirement. The government opined that plants which are 25 years or more have a lot of life left in them and it would be a waste of national assets if such plants are dismantled. The fact that the Ministry of Environment, Forests and Climate Change diluted their criteria for emissions also helped in the process. The list of plants identified for retirement between 2022-32 are indicated in **Annexe 3.** The sector wise retirement that has been planned is given in **Figure 13.**

Figure 13: Capacity to be retired, sector-wise, from 2022 to 2032 (in MW)



Note: Figures in brackets are percentage shares
Source: (Central Electricity Authority, 2023)

The decision not to retire any coal-based generating station was based on an advisory issued by the CEA in January 2023. The CEA had said that given the fact that demand was growing fast, it would be advisable to run all generating stations till 2030 irrespective of their age. Not only this, the CEA had recommended that renovation and modernisation (R&M) measures be taken up wherever required and feasible so that maximum number of coal-based stations are in operation. The government also issued a directive to all domestic coal-based stations to import at least 4% to 6% of their coal requirement and blend it with domestic coal so as to keep their plants running full capacity. As of now, these instructions are valid till June 2024. Keeping coal-based stations alive till 2030 will not only help in meeting the burgeoning demand but also help in better integration of renewable generation. Of course, retirement of plants go to the back burner.

3.4 Optimal generation mix in 2030

This advice of the CEA certainly points to the fact that there is apprehension in the government whether the pace of renewable capacity addition can match the growing demand. In the optimal generation mix report (Central Electricity Authority, 2023b), it is stated that to meet the demand of 334.8 GW and 2279 BUs in 2029-30, an installed capacity of about 777 GW would be required and the contribution of each source would be as follows **(Table 2):**

Table 2: Capacity requirements (source wise) in 2029-30

Source	Capacity in MW	Percentage contribution
Hydro	53860	6.93
Small hydro	5350	0.69
Pumped storage	18986	2.44
Solar PV	292566	37.65
Wind	99895	12.85
Biomass	14500	1.87
Nuclear	15480	1.99
Coal + lignite	251683	32.38
Gas	24824	3.19
TOTAL	777144	100.0
Battery storage (MW/MWH)	41650/208250	

Source: (Central Electricity Authority, 2023b)

It is simple arithmetic that to reach such levels of renewable capacity (solar and wind), we would need to add about 40 GW each year from now to 2030. Incidentally, what we have actually added in the past couple of years on an average is only about 9 GW per year! The ability of the cash starved distribution companies to absorb such huge capacity of renewable electricity is also suspect. To top it all, some policies of the government is making renewable power more expensive, thus making the discoms' job all the more difficult. Imposition of a basic customs duty (BCD) of 40% on solar panels and modules is one example which will inhibit growth of solar power. The fact that land acquisition is cumbersome, getting access to transmission network is difficult, getting regular and timely payments from distribution companies is a dream etc. is only adding to the developers' woes.[3]

3.5 The political economy of retirement of coal-based generation plants

As already mentioned earlier, retirement of coal plants is an extremely sensitive issue and much depends on the political economy. It is neither pure economics nor technical reasons in most cases that decide whether or not to retire a plant. To understand how the political economy affects the decision to retire, one has to first understand how generation tariffs are determined.

In India, what we have is a two-part tariff structure, the fixed cost and the variable cost. The fixed cost consists of five components, namely, return on equity, depreciation, operation and maintenance, interest on loans and interest on working capital. The fixed cost is fixed by nature and is incurred by the generator irrespective of whether there is any generation. There is, however, a gradation in the manner of payment which is described in the subsequent paragraph. The variable cost is the fuel charge, namely cost of coal in the case of a coal-based station. The extent of variable cost incurred is, of course, a function of the amount generated by the power plant.

Each generating station under the Availability based tariff (ABT) regime (ie. the system that we have in India) has to declare how much it will generate the following day. Depending on that, it will be reimbursed the extent of the fixed cost. In simplified terms, if it declares that it will be able to generate 85% or more of his plant capacity (at annual level), he will fully recover his fixed cost.[4] If it declares that it will generate less, it will not receive it's full fixed cost but will get a certain percentage of the fixed cost. Ensuring the availability of fuel is the headache of the generator and if it declares that it will generate less because of lack of fuel, the generator will not receive his full fixed cost.

3 There has, however, been significant improvement in payment to generators after the introduction of late payment surcharge rules
4 There are, however, some differences in the regulations of CERC, MERC, MPERC etc., where there are different weightages given to peak and off-peak hour availability

About ninety percent of the generation capacity in India is tied in the form of power purchase agreements (PPAs). All the distribution companies have a set of PPAs which indicates that from which all plants they can draw power. The PPAs exist for the state owned generating plants and also the central owned generating plants which are also known as inter-state generating units since they supply power to more than one state. The plants of NTPC are an example of inter-state generating units. In addition to the generating units declaring a schedule for the following day, the discoms too declare a schedule for the following day declaring how much of power they would like to draw from the central generating stations. How much they will draw from the central generating stations depends on the merit order schedule. Under this principle, power is first drawn from that plant which has the cheapest variable cost before moving to the next cheapest plant and so on till the demand is met.[5]

The fact is that discoms have signed up more PPAs than they actually require. As a result of this, they are paying fixed charge for more generating units than they require. This is a legacy of the past where peak and energy shortages were in excess of ten percent. So now that the discoms have tied up excess capacity, they obviously have to choose the plants from whom they would like to draw power. In such a situation, they would obviously start from the cheapest plant and move upwards till their demand is met. Since fixed cost will have to be borne by discoms whether or not they draw power from a generating station (meaning sunk costs), the discoms will start with that generating station which has the cheapest variable cost before moving to the next.

Since there are excess PPAs tied up, there will be a few central generating plants left from whom power will not be scheduled. So far the PPA is valid, ie. it is less than 25 years old, there is no problem since fixed cost will be paid irrespective of whether they generate. Once the life of the PPA is over, then the problem starts. The discoms would not like to pay for the fixed cost anymore and they would request the Ministry of Power to release them from the burden of the PPA. Examples where discoms wanting to do away with expensive PPAs would include Dadri II unit (of NTPC) and other gas-based stations like Anta and Auriya (also of NTPC) when they complete 25 years. This has created a dilemma in the minds of the policy makers as to what to do with such plants which are no longer wanted. According to the tariff regulations of the Central Electricity Regulatory Commission (CERC), in case the discom and the generator are keen to extend the PPA beyond the life of 25 years, they are free to do so and the regulator determines the tariff. In case the variable cost is relatively low, the discoms are more than happy to extend the PPA since the fixed cost by that time reduces considerably as loans have been paid up. So for such economical plants, retirement after 25 years does not make sense. The problem is with those plants whose variable cost is high since there are no takers for such plants. The fact is that these plants are still efficient and can carry on further, maybe for another 15 years or so.

3.6 Pooling of power stations which are 25 years old

In order to keep expensive plants in use beyond the life of the PPAs, the government has devised a scheme (though not yet operational) whereby all plants which are more than 25 years old will be pooled together and the pooled tariff (both fixed and variable) will be decided by the central regulator. Generators are happy with this idea since this ensures that the fixed cost of expensive plants are still recovered beyond their life of 25 years. The central regulator, however, has to amend its tariff regulations for this purpose which has not yet been done. The net effect of all this is that the plants don't retire after 25 years as cited earlier in the NEP of 2018. So neither will the economical plants nor will the expensive plants actually retire! While devising this scheme of pooling, the government is cognizant of the fact that demand for power is going to increase manifold in the near to medium term. In fact, the highest ever peak demand of 240 GW was recorded on 1st September, 2023. By devising this scheme of pooling, the government has killed two birds with one stone. It has ensured that there is enough coal-based generating capacity available to meet the ever growing demand and it has ensured generators keep earning their fixed costs beyond their original PPA life of 25 years.

5 There have been cases where the merit order schedule has been violated and this is particularly true of renewable generators who have the status of 'must run' since their variable cost of generation is zero.

3.7 The tightening of environmental norms and installation of flue gas desulphurisation (FGDs) units

In the NEP of 2018, a capacity of 16,789 MW was identified for retirement. This capacity was identified keeping in mind that there was no space is these identified units to set up FGD units and also due to the fact that these units would complete 25 years by January, 2022. It would be useful to see what actually has happened as far as installation of FGD is concerned. It all started in December 2015 when the Ministry of Environment, Forests and Climate Change announced new environmental norms for thermal power plants. All thermal power plants were to adhere to the new norms by 2017 and the norms announced are reproduced below **(Table 3).**

Table 3: Revised environmental norms for thermal power plants announced in December 2015

Parameter	SO_X (Mg/Nm3)	NO_X (mg/NM3)	PM (mg/NM3)	Water (M3/MWH)	Mercury (Hg) (mg/NM3)
Units installed before 31/12/2003	600 (<500MW) 200 (>=500 MW)	600	100	3.5	0.03(>=500MW)
Units installed between 2004 and 2016	600 (<500MW) 200 (>=500MW)	Initial 300 Revised 450	50	3.5	0.03
Units installed after 1/1/2017	100	100	30	Initial 2.5 Revised 3	0.03

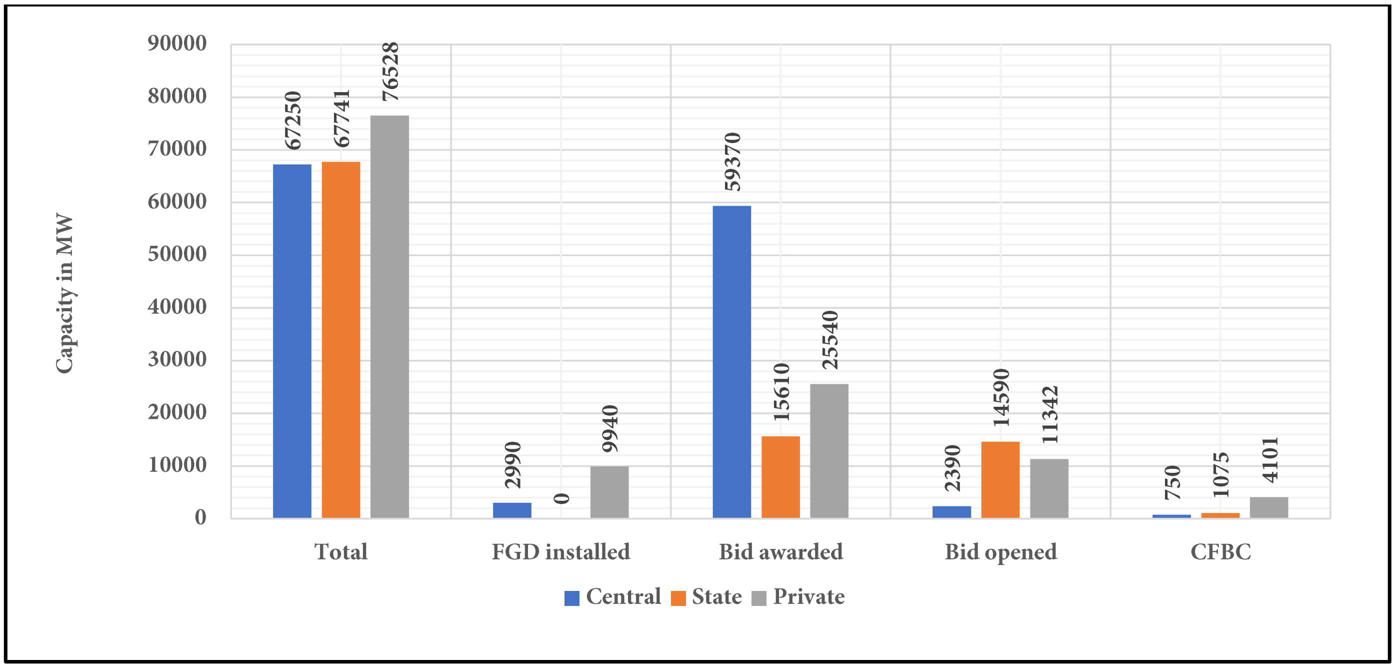
Source: (IIT Delhi, 2022)

The power sector has been slow in installation of FGDs and the deadline of 2017 was extended to December 2022 in a phased manner. The MoEF&CC issued another notification in April 2021 wherein another phased installation was notified, thus diluting the process further. All the power stations were divided into three categories, A, B and C. All plants within 10 kms radius of the national capital region or cities having a million plus population were placed in category A. The deadline for this category was December 2022. In category B, we have plants within 10 kms of critically polluted areas or non-attainable cities. Category B plants have to meet the deadline by 2023/25. All remaining plants were placed in category C and their deadline is till 2024/25. This particular notification of MoEF&CC also introduced a penalty in case the deadlines are not met. For category A, it is 20 paise/unit whereas for B and C, it is 15 paise/unit and 10 paise/unit, respectively. Apart from the three categories created, a separate category for retiring plants was also created wherein older units marked for retirement by 2025 have been exempted to meet the norms.

The amendment of April 2021 has been criticized on several grounds. The very first is that these extensions dilute the nature of the problem and exposes the masses to pollution from thermal power stations for a longer period. The categorisation of A, B and C ensures that about 44% of thermal capacity are not required to install FGD till 2024/25! The penalties which have been announced are too low and not likely to act as a deterrence. Besides, there is no logic of having graded penalties and surprisingly, the plants which have the longest timeline to install FGDs (ie. category C) have the minimum penalty.

The following graph (Figure 14) provides a bird's eye-view of actual action taken by the thermal power plants for installation of FGDs.

Figure 14: Status of installation of FGDs (sector wise) as in September 2023



Source: (IIT Delhi, 2022)[6]

How abysmal is the status of FGD installation can be seen from the above graph which shows that as far as the state sector is concerned, the progress is zero. Even in the case of the central sector, it is a poor 4.4%. The private sector seems to have performed better as it has installed FGD in almost 13% of its capacity.[7] There are several reasons for such poor implementation, some legitimate and some not so legitimate. When the revised environmental norms were notified in December 2015, a time period of only two years was given for its implementation. This is absurd since at that point of time, there were practically no manufacturers of FGD equipment domestically. So, it was impossible to cater to such a large demand if all the thermal generators actually took proactive action to install the FGD equipment. Besides, it takes about three years for installation and therefore, giving a window of two years only is inexplicable. Then there is the issue of how to recover the cost especially if the plant is not new. The cost of FGD equipment can range from Rs. 0.5 crore per MW to about Rs. 1.2 crore per MW depending upon several factors. Retrofitting is always more expensive as compared to planning installation of FGD at the drawing stage itself. On an average, this would lead to an increase in fixed cost of about 70 paise per unit. The older the plant, more difficult is to recover the cost as the time remaining for recouping the same was limited. Moreover, there would be some increase in the energy charge also because of limestone consumption etc. which could be of the order to 3 to 8 paise per unit. So plants installing the FGD equipment would suffer in terms of the merit order dispatch[8] compared to the ones who choose to ignore FGD installation. The government, however, did indicate that increase in energy charge due to FGD installation would be ignored when it comes to merit-order dispatch so that such plants are not put at a disadvantage. There were regulatory issues as well. The regulators were not very sure as to how much is the legitimate expenditure for installing FGD equipment. The job was made all the more difficult because of rising cost of equipment due to huge demand chasing limited supplies. This led to delays in awarding increase in tariff though the government had clarified that installation of FGD would be treated as change in law and considered as legitimate expense. Finally, the periodic dilution of standards and timelines also gave a signal that the government is not too particular about FGD installation. The short point being made is that due of

6 Available at: https://cea.nic.in/wp-content/uploads/tprm/2023/09/Unit_wise_FGD_implementation_status_and_summary_sheet_September_2023.pdf. Accessed on 14 November 2023.

7 The relatively better performance of the private sector in installing FGDs might be due to the fact that FGDs were mandated from the beginning and not from December 2015 when the notification was issued, examples being JSW Jaigad, plants at Mundra etc.

8 Merit order dispatch means that the plant with the cheapest variable cost is dispatched first before moving to the next plant. By this logic, the solar and wind plants should be dispatched first, since their variable cost is zero. They are, therefore called as 'must run' plants.

all these reasons, especially because of the dilution of environmental norms, retirement of plants was never a priority in the mind of the plant owners.

While on the subject of FGDs, one needs to mention about a recent study conducted by the Indian Institute of Technology, Delhi (IIT Delhi, 2022) which mentions that installation of FGDs reduce sulphur dioxide (SO2) concentration to the extent of 55% that are mostly confined to the immediate surrounding areas of the thermal power plant up to a maximum distance of 60 to 80 metres from the location of the plant. The study further recommends that FGDs should be installed in five stages, the first being from 2022-25 involving 40 plants. Subsequent to this, a study should be conducted for the next one year to confirm the benefits. The second stage would be between 2026-29 involving 49 plants and so on. The fifth and final stage would be 2033-34. The most damning statement of the study is that FGDs actually increase CO2 in the atmosphere! Every molecule of SO2 captured by the FGD releases one molecule of CO2.

3.8 What should be the criteria for retirement

There are two ways to look at this issue. One has to see as to what is our objective function? Is it to reduce the total cost of generation or is it to minimise carbon footprints? If the objective is to reduce carbon footprints, then one should weed out those plants which have a relatively higher station heat rate (SHR) including the ones whose SHR has gone up over time due to probably poor maintenance. Calculation of SHR of individual stations is an extremely tricky issue and it is not possible for regulators to do this calculation till such time the generators submit true and authentic data. In a cost-plus regime, the generators would like to see a higher SHR since this allows them higher tariffs. The regulators determine the tariff on some standardised gross SHR which are indicated in the tariff regulations. Some units, however, are allowed higher gross SHRs due to certain factors peculiar to those plants. In the latest tariff regulations of the CERC for the years 2019-2024, the SHR for 200 MW/210 MW/250 MW, is 2430 kcal per kwh. For 500 MW plants (sub-critical), the gross SHR is 2390 kcal/kwh. For higher than 500 MW plants, the gross SHR heat rate is lower by 40 kcal/kwh. For plants less than 200 MW, the gross SHR is dealt on a case-to-case basis, for example for Talcher TPS (NTPC) it is 2830 kcal/kwh. Similarly, for Bokaro TPS (DVC), it is 2700 kcal/kwh. It has been seen that the SHR of well-maintained plants rarely deteriorate over time and they continue to perform at the design heat rates. In such a situation, it is difficult to decide as to which plants should be retired. The other alternative is to retire those plants which have a high variable cost. Now high variable cost can occur due to two reasons. It can either be due to poor SHR (which is not the case of at least the centrally run stations) or it can be because the generating station is far away from the coal mine which provides it the fuel. Railway freight in India is one of the highest since the revenue earned is used to cross-subsidise passenger fares. As a result, power plants situated far away from coal mines incur a coal price which could be double (or more) than the cost at the pit head. By retiring plants which are located far away from the coal mine (and hence have a high variable cost) one runs the risk of retiring plants which otherwise have competitive SHRs. One can also witness a situation where plants with higher SHR continue to be in operation just because they are situated near the coal mine and the low coal cost masks the inefficiency of the plant.

Policy makers need to decide on the approach that should be adopted. If India wants to get to net-zero by 2070, obviously one should retire plants which have a relatively higher SHR. Age of the plant may have no bearing on the SHR. Hence retiring plants on the basis of age is not a logical course of action. Unfortunately, this is precisely what the government had proposed in the NEP 2018 when it decided to do away with plants which are more than 25 years old. This approach was subsequently shelved in the NEP of 2023.

Prayas (Energy Group), Pune has analysed the factors which need to be considered while undertaking decommissioning (Chirayil & Sreenivas, 2021). Usually, the logic given for retirement after twenty to twenty-five years is that there are significant savings and efficiency improvements (Shrimali, 2020). This, however, need not necessarily be true as pointed out by Prayas as they look into issues like variable cost savings, generation cost, reduction in coal consumption and difficulty in recovering cost of FGDs in their analysis. The study considers the case of thermal power plants (including lignite) which were commissioned on 31st of December 2000 or earlier. The coal-based capacity satisfying these conditions is 55.7 GW. Out of this, 9.1 GW has already retired. The study uses the variable cost of Rs. 2.5 per unit as a benchmark as this is the average for plants which have been commissioned post 2015. This is also the approximate cost of solar generation. Therefore, one actually needs to see how many plants are operating with a variable cost of more than Rs. 2.5 per unit and how many are beneath it. It would make little sense to retire those plants whose variable cost is less than Rs. 2.5 per unit. Fixed cost is in any case sunk cost and has to be borne whether or not the plant generates. Out of the 46.6 GW (55.7GW - 9.1GW) commissioned before 2000, about 21.6 GW had a variable cost below Rs. 2.5 per unit and about 19.7 GW had a variable cost higher than this benchmark. For about 5.3 GW, there was no data available.

It is seen that the plants which had a variable cost higher than Rs. 2.5 per unit (19.7 GW) generated about 81 BUs of electricity in FY20. So in case these plants are to be retired (because of higher than benchmark variable cost), 81 BUs need to be generated from plants which have come up post 2015. If that is done, then the PLF of the post 2015 plants goes up from 41% to 56%. Since the retired plants of 19.7 GW have an average variable cost of Rs. 3.1 per unit (and post 2015 plants have an average variable cost of Rs. 2.51 per unit), there will be a saving of about Rs. 5043 crore which is barely 2% of the annual variable cost of all coal stations in FY20. The point being made by Prayas is that the saving in variable cost through retirement is negligible.

In the next step, Prayas looks at the reduction in coal consumption. The 81 BUs generated by pre 2000 had an average specific coal consumption (SCC) of 0.696 kg per unit and the total consumption was 57 MT. The average SCC for all the coal-based plants put together is 0.612 kg per unit and based on this, the total coal consumption would be 50 MT, ie. a saving of only 7 MT. The study goes on to say that even if there is a 20% improvement in SCC, one would save only 12 MT ie. about 1.2% of the total coal consumption by India's coal-based plants.

The moot point is whether the savings in variable cost of about Rs.5000 crore can pay for the fixed cost of early retirement. The fixed cost, of course, would have come down since a part of the capital costs have already been paid. Besides, not all capital costs need to be paid, for example, operation and maintenance cost (meaning salaries) because of early retirement. Further, a part of the assets can be monetised, for example, land, dedicated transmission network.

Finally, the study looks into the case of cost recovery of installation of FGDs. The usual thinking is that older the plant, more difficult it is to recover FGD cost due to the few years that remain for its commercial operation. The impact of FGD cost can vary from 25 paise to 75 paisa (Srinivasan, et al., 2018). Out of the 46.6 GW (pre 2000), about 14.9 GW will have a cost below Rs. 4 per unit even with FGD installation given that the average power purchase cost is about Rs. 3.6 per unit without FGD. So some of the pre 2000 plants can very well recover the FGD cost contrary to the thinking that older plants will definitely not be able to recover the FGD cost. It would be pertinent to add that about 100 GW have already awarded bids for installation of FGD and they would have gone into the economics of this step.

The Prayas study concludes that it is not possible to segregate plants on the basis of one single parameter, like, age. A number of issues need to be looked into which has to be on a plant to plant basis. Further, apart from the factors already described above, one would also have to see the impact on the power flow so that there are no imbalances created in the system. Also, one can't dismiss the fact that one needs the old power stations for maintaining ancillary services and also for balancing (Singh & Tongia, 2021).

There is yet another study available which has looked into the issue of early retirement of thermal power stations (Singh & Sharma, 2021). This study looks at 130 plants with 95 GW of installed capacity representing 45% of the total capacity of 208 GW. It concludes that plant age plays a considerable role in determining the costs associated with decommissioning. The older the plant, lesser is the fixed cost. Plants which are more than 25 years old have a fixed cost relating to debt and equity of Rs. 0.24 crore per MW per year while the average for the entire sample is Rs. 0.61 crore per MW per year. It is estimated that by retiring the plants early, there is a saving in fixed cost and in the next five years, the entire cost of decommissioning can be recovered. The study encourages decommissioning of the older plants but cautions that it has to be done in stages so as to avoid imbalances. It adds that the entire process of decommissioning can be hastened by legislative action as it happened in Germany. In Germany, a terminal date was announced and coal plants were auctioned out to the person willing to take the least compensation. Developers were willing to take a haircut today rather than get next to nothing once the terminal date is reached (Wehrmann, 2020). More on the case of Germany and some other countries later have been cited in section 4.

Singh & Tongia (2021) say that going by age as far as retirement is concerned is not good enough. A similar sentiment has also been aired by Ganesan and Narayanswamy (2020) when they say that there is no direct correlation between age and coal usage. The long-term system level costs and environmental impacts need to be taken into account (Singh & Tongia, 2021). Considering the fact that more and more of renewable generation is going to be added, one would need to operate the older plants which are sub-critical in a flexible mode. Two-shift operation would be required and it is the older plants which are more suited for this purpose (Spencer, Rodrigues, Pachouri, Thakre, & Renjith, 2020). Two-shift operation for plants with high fixed cost is an expensive proposition. Older plants with very low fixed costs can operate at low plant load factor without a major impact on the cost of electricity from those plants. Besides this, though we are adding renewable generation to our kitty, coal and renewable generation are not on the same footing. Renewable power is intermittent and solar, in any case, is available only during daylight hours. If we want to retire old plants then for balancing the grid, one would need batteries which are not yet economical. In case, we want the older plants to operate in flexible mode, there are two options. The first is the relatively cheaper option where improved control and instrumentation is installed. The other option is to go in for retrofitting which is more expensive but the advantage is that it can provide for a higher degree of flexibility.

Another major issue which needs to be factored in is the installation of FGDs which is required according to the new environmental norms. The benefits of FGDs vary by location. According to a CEA study (Central Electricity Authority, 2020), SOX is concentrated in small number of clusters in states, such as, Odisha, Jharkhand, Chhattisgarh, Maharashtra, Tamil Nadu and Gujarat. There is yet another study of IIT, Kanpur which says that at distances beyond 40 kilometres, the impact of emissions is negligible. On the issue of installation of FGDs, Fernandes and Sharma (2020) argue that plants older than 20 years, if retired, can save the cost of FGDs. It may be added that FGDs have their own problems like extensive usage of water. They also cause a drop in plant efficiency and hamper two-stop operation which may be required to balance the grid.

The issue of retirement of coal-based plants was also examined by Shrimali (2020). He indicated in his study that out of the existing coal-based capacity of 196 GW, about 93 GW (47.4%) had a variable cost of generation higher than Rs.2.44 per unit which is the benchmark solar tariff. Even if one assumes that this benchmark cost will go up by about 20% because of integration with the grid, still about 48 GW (24%) of the capacity will have a cost of generation higher than Rs. 3 per unit (CEEW, 2018). Having said that, there is no doubt that cost of solar power is volatile given the fluctuations one witnesses in solar module prices, tax regimes and transaction costs (CEEW, 2016). Further, the variable cost of coal plants can be brought down by rationalising transport costs or by increasing plant load factor (Brookings, 2019). The distribution of coal plants having a relatively higher variable cost varies geographically, Uttar Pradesh (12 GW), Maharashtra (11 GW), Andhra Pradesh (9 GW), West Bengal (8.9 GW) and Tamil Nadu (7.6 GW). It is seen that the expensive coal plants are further away from the coal mines. Shrimali contends that both the fixed and variable costs can be reduced by retiring expensive coal plants. While the case of reduction of variable costs is crystal clear, in the case of fixed costs, there will be saving by moving the ownership of the asset towards a cheaper cost of capital. Eventually, what he is suggesting is that at the time of retirement, the developers and the lenders will be given a one-time payment which will be financed by the government by issue of bonds. The quantum of payment to be made would be determined through the net present value (NPV) method. The bonds would be serviced through ratepayer surcharge which basically means retail tariffs. Since government bonds are typically lower than the cost of debt or equity, there is a net saving if the plant are retired. In the example used by Shrimali, he has assumed bond rate of 8% whereas the cost of debt and equity have been taken as 9.48% and 18.97%, respectively. Of course, the savings are primarily from equity and its marginal when it comes to debt. This is because the gap between bond rates and cost of debt is much lower than the difference in cost of equity and bond rates. Shrimali acknowledges that there are issues to be tackled to make this plan successful. Just to name a few, will the demand be met reliably if certain coal plants are retired, can power purchase agreements (PPAs) be renegotiated, can distribution company liabilities be converted to bonds, how would the bonds be paid, how would coal plant workers be compensated etc.? Shrimali concludes that all these issues can be answered and opines that probably about 50 GW of capacity can be retired successfully.

4 How decommissioning affects the coal sector

In this section, we examine how coal transition adversely affects various sections of society, giving rise to the term 'just transition, implying in a way being fair to all. Incidentally, the term 'just transition' originated in the labour movements of 1970s and the 1980s where an American labour leader (Tony Mazzochi) proposed a superfund for the workers who were at the risk of losing jobs. Over time, this perspective has broadened to include environmental remediation among others (UNFCCC (COP24), 2018). Coal transition have been driven by a number of factors including decrease in domestic demand, change in relative prices of competing fuels, more stringent environmental regulations, decreased competitiveness of domestic production and productivity gains (IEA, 2022c).

To achieve the Paris goal of limiting temperature rise to 1.5 degrees centigrade, we need to cut down our coal consumption by 95%, oil by 60% and gas by 45% by 2050 compared to the consumption figures of 2019 (Joshi & Dsouza, 2023). If one only goes by the goals given in the various nationally determined contributions (NDCs), coal demand will drop only by 70%, oil and gas by 40 % by around 2050 (IEA, 2021). Focus on coal is vital since it is responsible for the highest emissions of CO2. There are some trends which have been seen globally. First, global coal demand seems to have plateaued (IEA, 2022c). Second, as of 2021, the pipeline of global coal projects have contracted by about 76% since 2016 (Littlecot, et al., 2021). 98 countries have committed to no new coal plants (Senlen, et al., 2023) though about 33 countries have proposed new plants. Third, though the Ukraine crisis has enhanced coal generation, this is expected to be temporary. Fourth, there is a strong commitment from various countries to increase generation from renewables, like, Germany will source 89% of its power from renewable sources by 2030 (Appunn, 2022). Similarly, Portugal has committed to source 80% of its power supply from renewable sources by 2026 (Goncalves, 2022).

4.1 Coal and the rest of the economy

Decommissioning of coal-based power stations is going to affect the coal sector in several ways. Coal-based plants in India are ageing fast and in fact, one-fifth of the capacity is more than 35 years old. What makes the process of decommissioning of power plants very cumbersome is the fact that there are no laws in India that mandate decommissioning and repurposing of a coal-based power plant. This is in sharp contrast to the laws laid down in respect of coal mining (Bhushan, Singh, & Chaudhari, 2022). First, a few facts and figures about the coal sector. Coal mining is primarily in the Eastern and Central parts of India, namely, Jharkhand, West Bengal, Odisha, Chhattisgarh, which account for 79% of the country's coal reserves. Coal's footprint seems to be everywhere, both spatially and temporally from large scale economic activity, small and medium enterprises, transportation etc. (Sharma , Greig, & Lant, 2021). How deeply intertwined the coal sector is with other parts of the economy can be seen by perusing the following statistics. When it comes to jobs, there are various estimates but it is largely believed that the coal sector provides direct and indirect employment to about 15 million people. Direct employment would be around 1.2 million (Pai & Zerriffi, 2021). There are a large number of informal workers in the coal sector who are mostly vulnerable having low skill, many a time they are migrants from other areas and situated at or below official poverty line (Lahiri-Dutt, 2016). Similarly, the power sector too has a huge informal labour force which could be four or five times the size of the formal labour force (Bhushan, Singh, & Chaudhari, 2022). Unfortunately, the current laws do not address the transition requirement of such informal employees engaged in the power sector. Indian laws, in any case, are not designed for large scale closure of industrial facilities. The Contract Labour (Regulation and Abolition) Act, 1970 does not speak of providing social security or reskilling unemployed labour. The Social Security Code 2020 is also not designed to deal with large scale industrial closure (Bhushan, Singh, & Chaudhari, 2022).

71% of India's electricity even today comes from coal. Coal supplies 44% of India's primary energy demand which has increased by about 33% since 2000 (IEA, 2021). Coal and lignite together contribute about 0.7% of India's gross domestic product. Coal mining and the production of coal are one of the eight core industries. Coal alone accounts for 10.3% of the weight in Index of Industrial Production (IIP) in India. From June 2020 to June 2022, coal production has received foreign direct investment (FDI) amounting to Rs. 119 crore (DPIIT, 2022).

All coal mining and coal power companies pay taxes and royalties to national, state and district governments. The Coal India Limited and the NTPC together contribute nearly 3% of the national government's total annual revenue (Athwale, Joshi, & Bhavirkar, 2019). There are 16 taxes imposed on coal including excise duty, clean energy cess, royalty, contributions to district mineral fund (DMF) etc. (Bhandari & Dwivedi, 2022). In 2020-21, CIL paid Rs. 419 billion to government including the GST compensation cess. Going at a granular level, for Jharkhand (which has the highest coal reserves in the country), taxes and royalties constitute nearly 8% of the state government revenue. The local government in Jharkhand collected nearly Rs. 800 crore under the

DMF in 2020. The coal sector is also a main revenue earner for the railways as 87% of the domestic coal is transported by them (Tongia & Gross, 2019).

4.2 Decommissioning of coal-based power stations

As already mentioned, there are several issues which crop up when coal plants are decommissioned which may also lead to closure of the associated mine(s). To begin with, one is not really sure as to how many persons are going to be adversely affected by way of loss of jobs. Many elements of the eco-system have not been quantified, for example, one does not have the figures for induced and informal jobs. The figure is, most probably, much higher than what is originally anticipated (CSIS and CIF, 2021). The most striking feature is that while the loss of jobs would be limited to the coal belt areas, the renewable generation potential which can be an alternative source of employment is located in other states, especially when it comes to wind potential. Once a coal mine is closed down, there are possibilities of diversification into other areas also like agriculture, tourism but ideally what one should take into account is the local needs, priorities, resource availability, work force skills of the local populace etc. (CSIS and CIF, 2021). It has been seen that due to lack of employment opportunities, a large number of informal coal workers are reduced to scavenging and extracting coal from discarded open cast mines for domestic use and sale in the open market (CSIS and CIF, 2021). Ironically, it seems that CIL has been making forays into other areas like solar power generation, manufacture of solar photovoltaics, aluminium smelting and surface coal gasification but the beneficiaries of such projects are not from the coal bearing areas. To give an example, all CIL solar projects are in non-coal states (CSIS and CIF, 2021).

Diversification plans ought to be discussed threadbare between the government, the coal companies and the local leaders. In fact, there are many unrepresented stakeholders who need to be included in the dialogue (CSIS and CIF, 2021). It is frequently reported that CIL does not consult its unions on how to go forward once a mine is shut down. The exclusion of the workers in the sector in the governance and decision making process has questioned the states' moral and ethical obligations (Munro, van der Horst, & Healy, 2017). The mine closure plans need to be transparent and made public. In fact, there is a need for a social dialogue for consensus building when it comes to energy transition (Molina Romo, 2022). Examples where extensive consultations have been done with stakeholders include South Africa's NEDLAC and Germany's coal commission (IEAb, 2022). Global literature on mine closure shows that closure planning is best when initiated at the start of the mining operations with committed resources, be it human, technical or financial (Bainton & Holcombe, 2018). Regulators, too, need to be strengthened so that they have sufficient enforcement capacity. India, in any case, has a poor track record of planned mine closure (Dsouza & Singhal, 2021). To consider mine closure impacts, time and financial commitments alongside national and regional political will are necessary (Roy & Schaffartzik, 2021).

The problem is that in India, there are no proper land use policies and this is where the regulatory mechanism becomes important. It is seen that power plants have been built in a mix of freehold and leasehold land using land acquisition acts (Bhushan, Singh, & Chaudhari, 2022). The government is usually the owner of the land when it comes to leasehold whereas the plant owners are different entities creating problems of coordination leading to delays. In the case of freehold land, without a clear condition to decommission, the site is likely to remain in as-it-is state. There is no government policy on how the brownfield land should be repurposed despite the fact that two-thirds of the land is either with the state or central government. In what condition the land should be while returning lease hold land has not been spelt out leading to a possibility of litigation (Bhushan, Singh, & Chaudhari, 2022).

There is evidence of community marginalisation and lack of inclusion and transparency in energy project development ((Kaur, 2022); Menon (2022); Paltasingh & Satapathy (2021)). The matter seems to be becoming more and more acute with the growth of the private sector in energy related projects. There is a certain amount of insensitivity of the private sector towards the affected persons and there is a clash of interest when it comes to accessing land, water and natural resources (Lakhanpal, 2019); (Rajvanshi, 2022). Stock (2022) has highlighted the concept of 'green grabbing' where land is captured for solar projects under the guise that the earth has to be saved from the use of fossil fuels. There are cases of land dispossession, agrarian marginalisation and abuse of rights of the original inhabitants of the land. Further, there seems to be a disproportionate impact on women and young girls as there is a reduction in women's participation in the labour force (Lahiri-Dutt, 2012). With the advent of excavation for critical minerals (in addition to coal) as the world moves towards a greener path, the alienation from peasant land is going to become all the more acute since about 70% of the critical mineral projects are on or near such land (Owen, Kemp, Lechner, & Lebre , 2022).

Large scale mining has impacted the local environment and the health of people (Pai & Carr-Wilson, 2018). One can give the example of Jharia which is famous for surface and sub-surface fires due to unsustainable mining practices and land subsidence (Saini, 2018). Coal mining has led to surface and groundwater water pollution and have also disrupted the water table which has led to drinking water shortage (Priyadarshini, 2012). In India, there is no stipulation which mandates a clean-up and remediation after the plant is decommissioned. The Environment Impact Assessment (EIA) of 2006 is silent on the subject of decommissioning. So is the case with the Forest Conservation Act 1980 under which forest land is diverted to set up coal-based power plants. Even the Air and Water Acts are silent and give decommissioning a complete miss. However, if a coal plant is actually to be decommissioned, several consents are required from different authorities. New permits are required under Hazardous Waste Rules and Construction and Demolition Waste Rules. Further, for repurposing, consent would be required under the Air and Water Acts. A new environmental clearance will be required depending on the type of repurposing proposed. Change in land use activity will require a forest clearance also (Bhushan, Singh, & Chaudhari, 2022) etc.

Availability of finances is crucial to decommissioning. Unfortunately, decommissioning costs are not a part of the project cost. Decommissioning cost is not a part of liability and therefore, not reported. It is usually believed that that the salvage value of 10 percent will be enough to take care of the cost of decommissioning but this is clearly far from actual requirement. Unless adequate finance is available with the generation companies, they are likely to leave the project site in as-it-is condition (Bhushan, Singh, & Chaudhari, 2022).

There are three key elements of energy transition, namely, environmental rehabilitation, economic diversification and stakeholder mapping (CSIS and CIF, 2021). Proper rehabilitation, however, is made difficult due to lack of enforcement and compliance and further, there is no legal framework. Compensation rates are also fixed on a normative basis and not site specific. Apart from that there are cases of legacy environmental degradation from a large number of abandoned mines. The regulatory framework for reclamation and closure of mines is convoluted (CSIS and CIF, 2021). Needless to say, an unplanned, unjust energy transition can impact the entire coal ecosystem by taking away jobs, cutting government revenues, lowering railway revenue etc.

5. International experience

5.1 Overview

More and more of coal-based capacity is being retired globally and the pace is increasing. According to the Global Energy Monitor platform, about 460 GW of coal-based capacity has been retired since 2000. The following table **(Table 4)** gives details of capacity that has been retired during the period 2000 to 2023(H1).

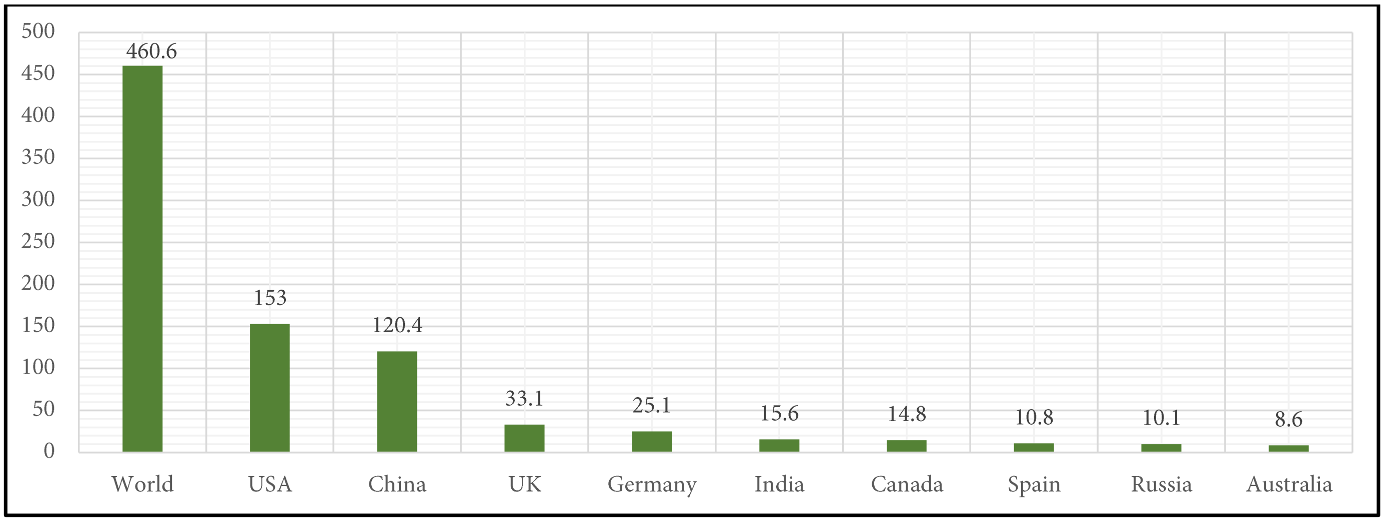
Table 4: Coal capacities retired globally from 2000 to 2023(H1) (in GW)

Years	Capacity
2000-2005	20.5
2006-2010	59.7
2011-2015	121.8
2016-2020	181.4
2021-2023 (H1)	77.1

Source: Global Energy Monitor

60% of the retired capacity is in USA and China, 7% is in UK, 6% in Germany. and 2% in Canada. Some of the leading countries who have decommissioned coal-based capacities during the period 2000 to 2023(H1) are indicated in the following graph **(Figure 15)**.

Figure 15: Coal capacity decommissioned in the world from select countries from 2000 to 2023(H1) (in GW)



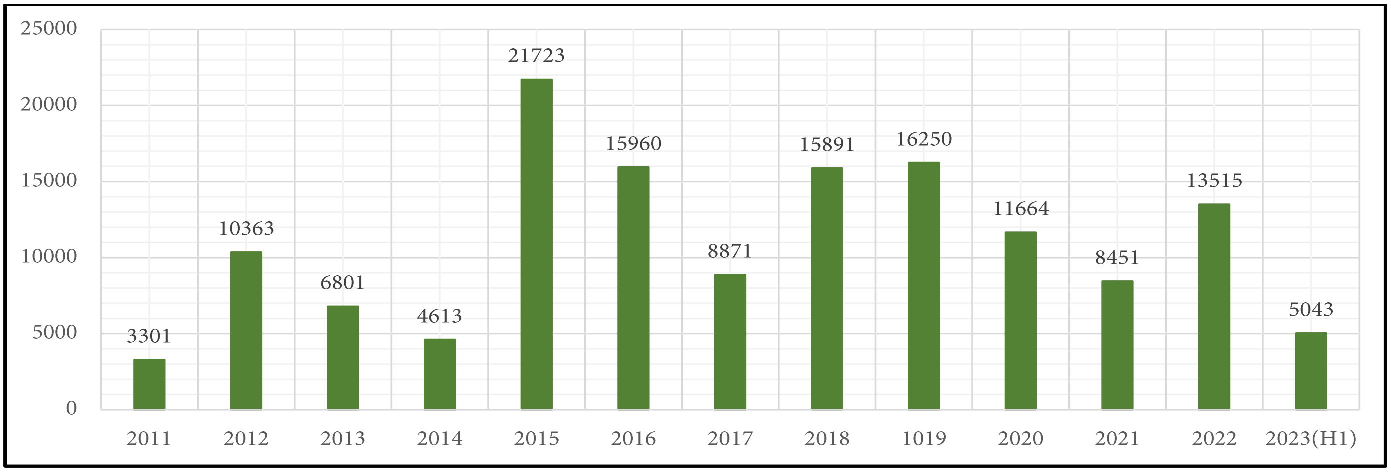
Source: Global Energy Monitor

While closure of plants in USA and China is because of techno-economic considerations, in Europe, it's because of climate change issues. Globally, it has been seen that decommissioned plants are just left standing because of the costs involved and also because of the strong legal requirements in most countries. Some of the brownfield sites have been converted into natural gas or biomass plants and in some cases, they have been converted to office space, shopping areas etc. Ideally, they should be converted into some other energy related project (like solar or battery storage) since they have an existing transmission network (Bhushan, Singh, & Chaudhari, 2022). The following paragraphs give a brief description of the decommissioning process in USA, the UK and Germany.

5.2 United States of America

The average annual decommissioned capacity between 2001-2010 was 1046 MW which increased to 11,543 MW in the last decade. The year wise decommissioning of coal plants from 2011 to 2023(H1) is given in Figure 16. This large decommissioning was aided through competition from natural gas and renewable energy sources (US Energy Information Administration, 2022). Besides, there was strengthening of environmental protection regulations also in the country and the plant owners decided to close down inefficient plants rather than invest in technology to meet the revised environmental norms (Bhushan, Singh, & Chaudhari, 2022). Some plants, of course, closed down voluntarily because of carbon emissions. There were hurdles faced in decommissioning since there was a lack of experience in doing this job. Some plant owners sold off their plants in 'as-it-is' condition since they did not know how to proceed with this (Leagre, 2018). Similar to many other countries, in USA too, decommissioning is not firmly regulated in terms of specific procedures. The Environmental Protection Agency (EPA) has only prepared factsheets which are not mandatory. Remediation activities at decommissioned sites are guided by relevant laws on air pollution control, water discharge, hazardous waste storage etc. (Bhushan, Singh, & Chaudhari, 2022).

Figure 16: Retirement of coal plants in USA from 2011 to 2023(H1) in MW



Source: Global Energy Monitor, October 2023

There are costs associated with decommissioning and how this entire process is financed depends on the type of market one is operating in which again varies from state to state in USA. In regulated markets, the plant owners can recover costs from the consumers subject to approval by the regulatory authorities. The consumers, however, are not expected to pay for any 'clean-up' operation that may be required and moreover, in some decommissioning costs are only allowed if the plans are made well in advance (Bhushan, Singh, & Chaudhari, 2022). In contrast, in an open market system, the operators build the cost of decommissioning in the tariff itself and public listed companies are required to report these costs to the US Securities and Exchange Commission (Bhushan, Singh, & Chaudhari, 2022). Besides this, there are other funding options that are available separately financed by the federal government, the state governments and local bodies. The fact that energy transition is going to affect workers is acknowledged and well recognised. Various legislative measures have been taken up, for example, the federal government's Infrastructure Investments and Jobs Act, 2021. Other states which have passed their own legislations include Pennsylvania, Colorado, Illinois and Massachusetts.

5.3 United Kingdom

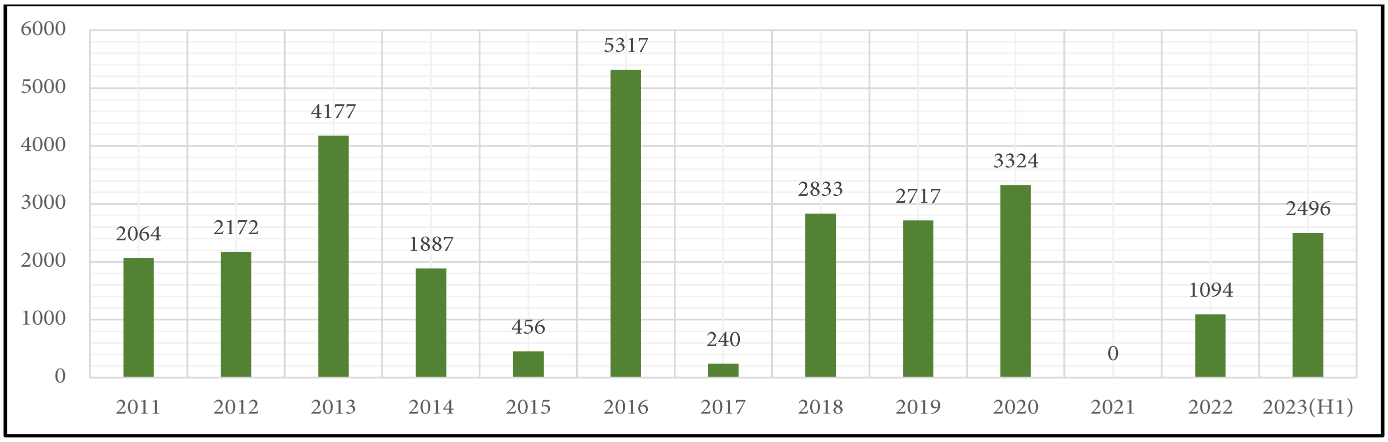
Coal provided 97% of electricity in UK in 1950 and by the 1980s, it had reduced to about 70%. By 2016, it had come down to about 8%. Not only that, in 2016, there were periods without coal in UK's electricity mix. In April, 2017, UK saw its first 24-hour period without coal. The current record for UK to be free of coal generation is 76 hours (Littlecot, Burrows, & Skillings, 2018).

The UK government issued a white paper in 2002 which acknowledged the challenge of climate change. In any case, the government had been pursuing a policy of closing down coal mines since the 1990s because of issues other than climate change, mainly political. The availability of cheap gas aided the process, popularly known as the 'dash for gas'. By 2000, most of the power plants in UK had completed 30 years and they had to compete with the new combined cycle gas turbines (CCGTs). The price of gas, however, was volatile and an increase in gas prices was unusually high between 2002 and 2009 which led to extensions in the life of existing coal plants rather than investments in CCGTs.

In 2015, the UK government took the decision that coal plants would be phased out by 2025[9]. Prior to this, the government had passed the Climate Change Act in 2008 committing to reduce greenhouse gas emissions by 80% by 2050 compared to the 1990 figure. The government also introduced regulations for mandatory use of carbon capture and storage for all new coal plants, increased carbon prices, introduced stricter pollution control and offered enhanced incentives for renewable energy (Bhushan, Singh, & Chaudhari, 2022). On the issue of carbon pricing, it may be added that the UK added a carbon price support in 2013 since the carbon price determined after the first two phases (2005 to 2007 and 2008 to 2012) was too low (Littlecot, Burrows, & Skillings, 2018).

9 This has brought forward to 1st October, 2024

Figure 17: Retirement of coal plants in the UK from 2011 to 2023 (H1) in MW



Source: Global Energy Monitor, October 2023

Decline in coal generation resulted from a mix of market drivers and regulatory interventions. They were not really pre-planned but this combination of policies led to the exit of coal. The year wise retirement of coal plants from 2011 to 2023(H1) is at Figure 17. Successive UK governments increased the cost of CO2 emissions and this was combined with stricter EU pollution norms. Introduction of pollution control and carbon pricing have served to work as push factors, leading to closure of non-compliant ageing units. In contrast, availability of subsidies for biomass co-firing and conversion has been a pull factor. Availability of capacity market payments have also worked as a pull factor which encouraged plants to continue longer (Littlecot, Burrows, & Skillings, 2018). Exit of coal was also hastened by the fact that there was a decrease in demand for electricity and simultaneously, a growth in renewable generation (Gillich, Hufendik, & Klempp, 2020). Exiting coal-based plants also had its own hiccups as most of the plant owners preferred to carry on generation till it became uneconomical rather than convert their plant to something else. Conversion of coal plants to alternative fuels was not common amongst plant owners though there are some exceptions like Drax which converted their coal-based units to renewable generation (See box on Drax power station).

Some of the decommissioned plants have been converted into biomass and natural gas plants but majority of them have actually been closed down (Littlecot, Burrows, & Skillings, 2018). Redevelopment is encouraged and all brownfield sites are assessed by environmentalists. According to the Environmental Protection Act 1990, after remediation, land should not be determined as contaminated.

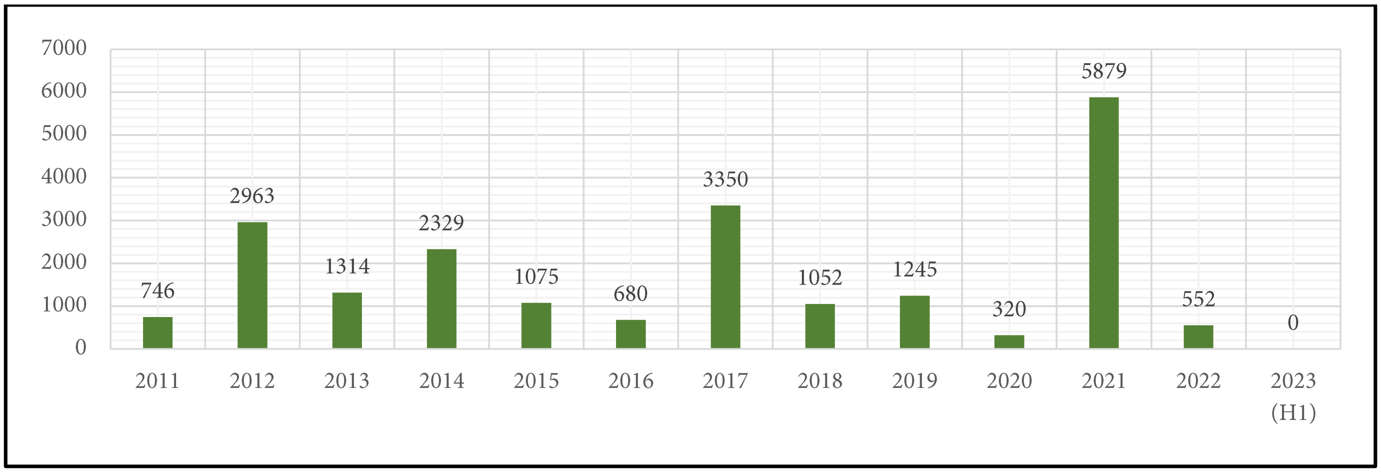
Box: The case of Drax power station

Drax power stations were built in two phases, each stage containing three 660 MW turbines. The first phase was completed in 1974 and the second in 1986. With 4 GW of capacity, it was the largest coal fired station in the UK. Over time, when its domestic mines closed down, it started importing coal. The power station was upgraded in 1988 and also in 1995 with the installation of flue gas desulphurisers (FGDs). Drax submitted plans to build two facilities to operate along with the coal stations. In 2009, the company submitted plans for a 300 MW dedicated biomass (crushed wood pellets) plant. Simultaneously, the Drax group continued to invest in the original coal stations as to enhance their efficiency. The group also launched a research and development program, exploring the viability of using alternate fuels in coal boilers. Locally sourced biomass had been mixed with coal at low levels from 2003. Later on, the company decided to convert three coal units to 100% biomass. The first two units were commissioned in 2013 and 2014 and the third was commissioned in 2016. The company was able to source biomass at large volumes (over 2 million tonnes per unit annually). Part of the biomass supply was sourced from the US and by 2017, about 60% of the biomass was coming from there. By 2018, Drax had decided to convert their fourth unit to biomass. Drax now has only two coal-based units which could be converted to gas since the government has announced exit from coal by 2025. Drax was able to successfully convert to biomass from coal because of the support it could avail from different schemes of the government, for example, the renewable obligation subsidy/certificate scheme and the contract for difference feed-in tariff, as and when the scheme(s) existed (Littlecot, Burrows, & Skillings, 2018).

5.4 Germany

In August, 2020, the German parliament enacted the Coal Exit Act which stated that coal capacity would be reduced to 30 GW by 2022 and to 17 GW by 2030. Further, coal would be completely phased out by 2038. In order to do this, the government would rely on auctions whereby coal/lignite plant owners would be offered compensation to retire their plants without living the entire plant life. Coal phase down can either be market-based or through administrative action. A market-based approach is always considered to be more efficient (Hermann, et al., 2017). However, the administratively determined path has the advantage of deciding the energy mix though in such cases, there would be claims for compensation. The way out is auctions since this removes information asymmetry between the operators and the regulator (Hermann, et al., 2017). The German law allows for making payments to operators for setting off loss of potential profits. Plants which voluntarily exit between 2020 and 2026 can compete for auction payments. From 2027, the authorities can order decommissioning without any compensation. In case of unsubscribed auctions, the mandatory mechanism would commence from 2024. However, plants which are considered necessary for the stability of the system are exempt. Also, smaller plants ie. less than 150 MW capacity may be allowed to decommission till 2030. Further, plants which have undertaken major investments between 2010 and 2019 can push back decommissioning by 12 to 36 months. The first auction was held in December 2020 for shutting down 4.8 GW of coal capacity. The second round of auction was held in August 2021 for phasing out an additional 1.5 GW. In all, seven auctions have been held between 2020 and 2023 (Tiedemann & Muller-Hansen, 2023). The year wise retirement of coal plants from 2011 to 2023(H1) is in **Figure 18.**

Figure 18: Retirement of coal plants in Germany from 2011 to 2023 (H1) in MW



Source: Global Energy Monitor, 2023

The amount of compensation would be a function of profits forgone by not selling electricity for the remaining life of the plant. For auctions to be successful, it requires oversubscription and low level of market concentration (Hermann, et al., 2017). The auction which are being held are pay-as-bid auction with a disclosed ceiling price and the ceiling price is lowered for every successive auction. The ceiling price fell from 165 euros per KW in the first round to about 89 euros per KW in the seventh round. This clearly brings out that there is a premium in deciding to retire early. In any case, the threat of administrative retirement encourages older plants to participate in the auctions early. The phasing out of nearly 10 GW of coal fired capacity cost the German taxpayer approximately 700 million euros. There is criticism in certain quarters that the auctions created windfall profits to the plant operators (Gillich, Hufendik, & Klempp, 2020). This policy also reduced about 300 million tonnes of CO2 if the generation would be replaced by the current German fleet. It may, however, be added that the auction did not lead to retirement of the most efficient plants and the carbon intensity of the remaining plants are 2% higher (Hermann, et al., 2017).

Similar to many other countries, the decommissioned sites have been converted to natural gas or biomass projects and in some cases, they have been converted to data centres, industrial parks etc (Bhushan, Singh, & Chaudhari, 2022). Remediation has not really been an issue in Germany as the government has been ensuring minimising contamination and pollution during the operation stage itself. In any case, in Germany, remediation liability is strictly enforced. Germany, incidentally, has a strong social security code which provides unemployment protection, pension system, health insurance etc. Laid off power sector workers under the age of 58 years are provided continued health and retirement benefits during phases of unemployment. Separate benefits are available for workers above 58 years of age (Kruppe & Lang, 2018). Labour laws in Germany are very strong and support just transition.

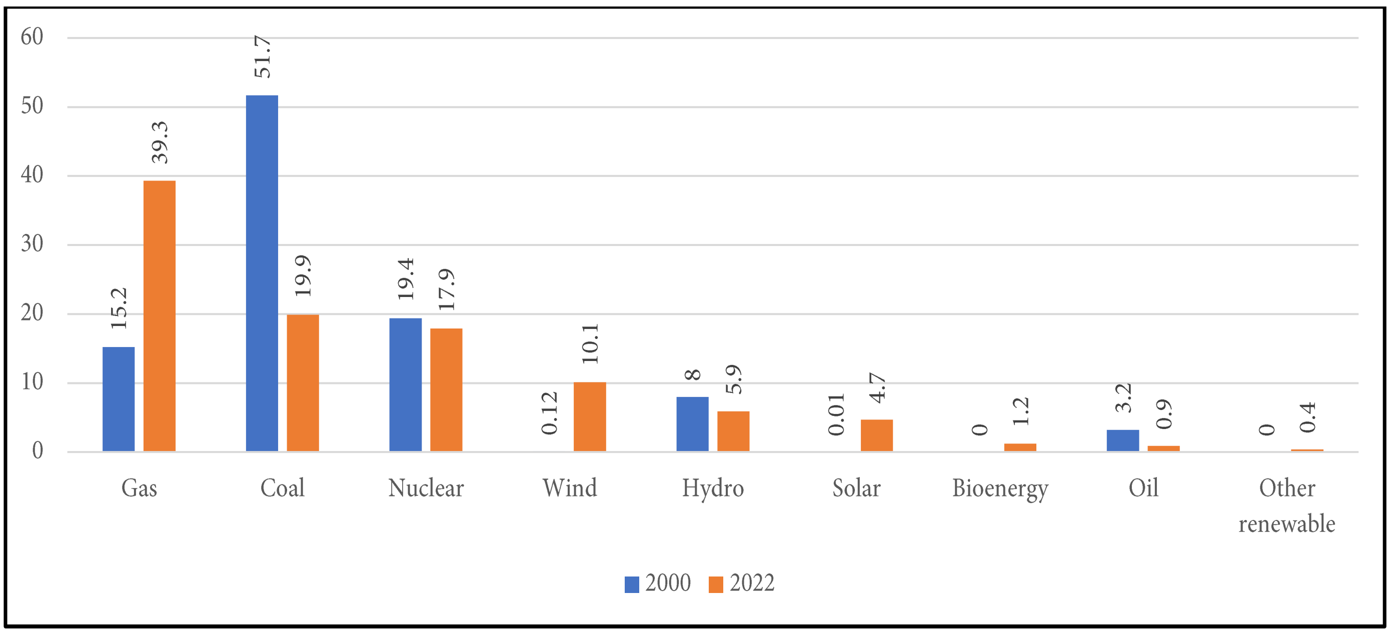
6. The way forward for India

At the cost of repetition, it may be mentioned that prior to the NEP, 2018, there was no policy for retirement of generating stations. Stations were retired on account of techno-economic considerations. This policy of 25 years was, however, short-lived because in the latest NEP of 2023, this norm was done away with. Consequently, the capacity earmarked for retirement dropped from about 48,000 MW to about 2,100 MW. Several reasons have been put forth as to why this condition of 25 years does not make sense and objectively speaking, it is very difficult to dispute them. Undoubtedly, a coal/lignite plant can operate for may be 40 years and vintage plants may have a variable cost even lower than today's solar/wind based generation. Besides, continuing operation of coal-based plants will obviate the need for any kind of storage, including batteries which is not competitive today. Moreover, vintage coal plants will help in providing cheaper ancillary services as compared to new plants with a high fixed cost. All the pointers seem to suggest that there is merit in not retiring old coal plants.

6.1 Why countries like USA, UK and Germany were successful in retiring coal plants

So how did countries like the USA, UK and Germany successfully move away from coal? The answer lies in the adoption of gas-based generation since gas was available in sufficient quantity.[10] It was also supplemented by other forms of renewable generation. The electricity mix of these three countries and also India in the years 2000 and 2022 are given in **Figures 19, 20, 21 and 22.**

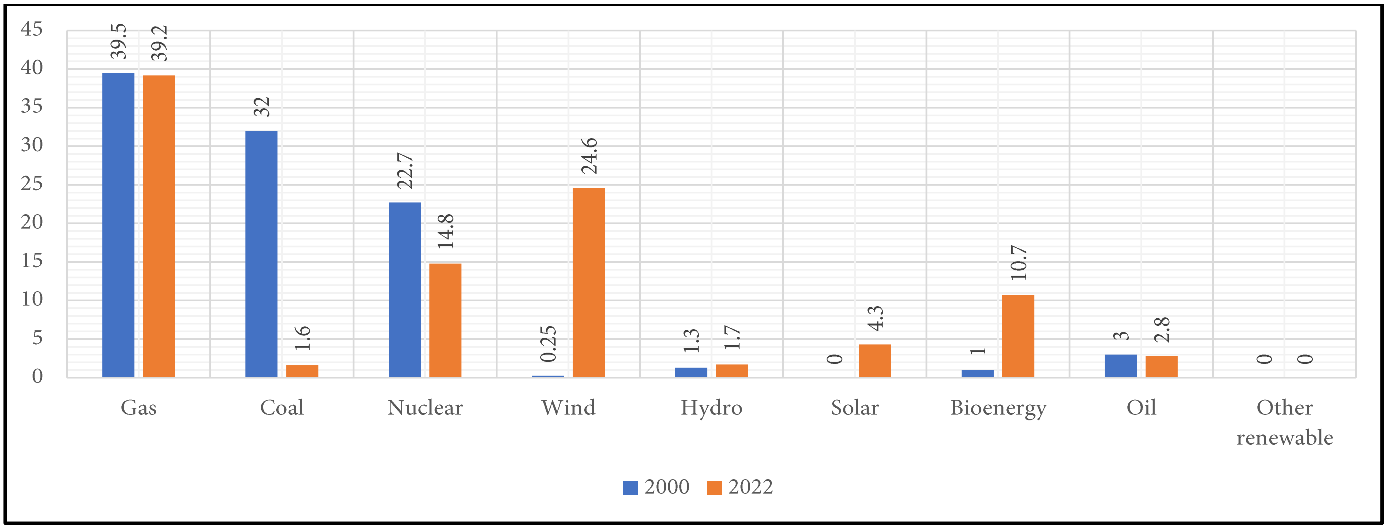
Figure 19: Electricity mix in USA in 2000 and 2020 (in percentage)



Source: (https://ourworldindata.org/electricity-mix)

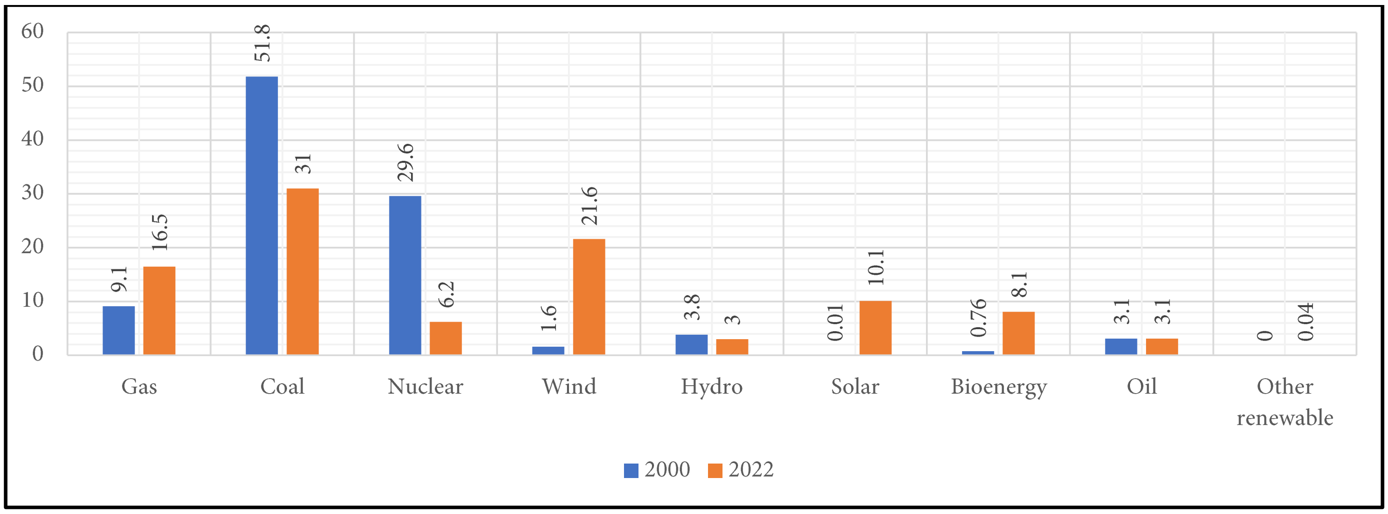
10 Another reason as to why the developed nations were able to move away from coal was due to the fact that their demand had plateaued in contrast to the case of developing economies, including India where demand is still growing.

Figure 20: Electricity mix in UK in 2000 and 2020 (in percentage)



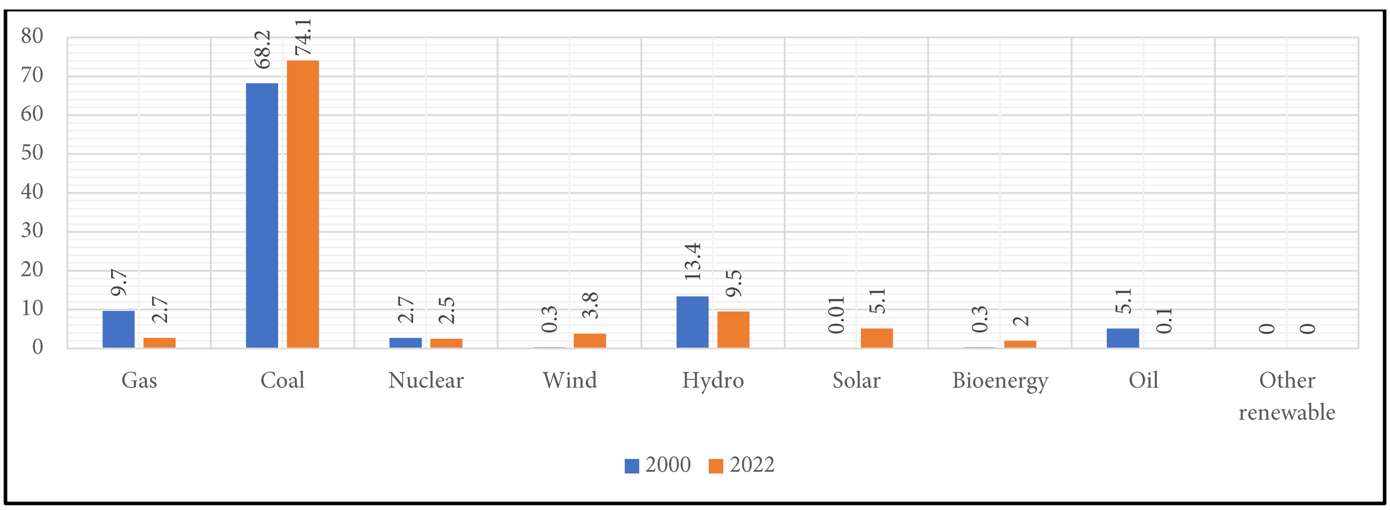
Source: (https://ourworldindata.org/electricity-mix)

Figure 21: Electricity mix in Germany in 2000 and 2020 (in percentage)



Source: (https://ourworldindata.org/electricity-mix)

Figure 22: Electricity mix in India in 2000 and 2020 (in percentage)



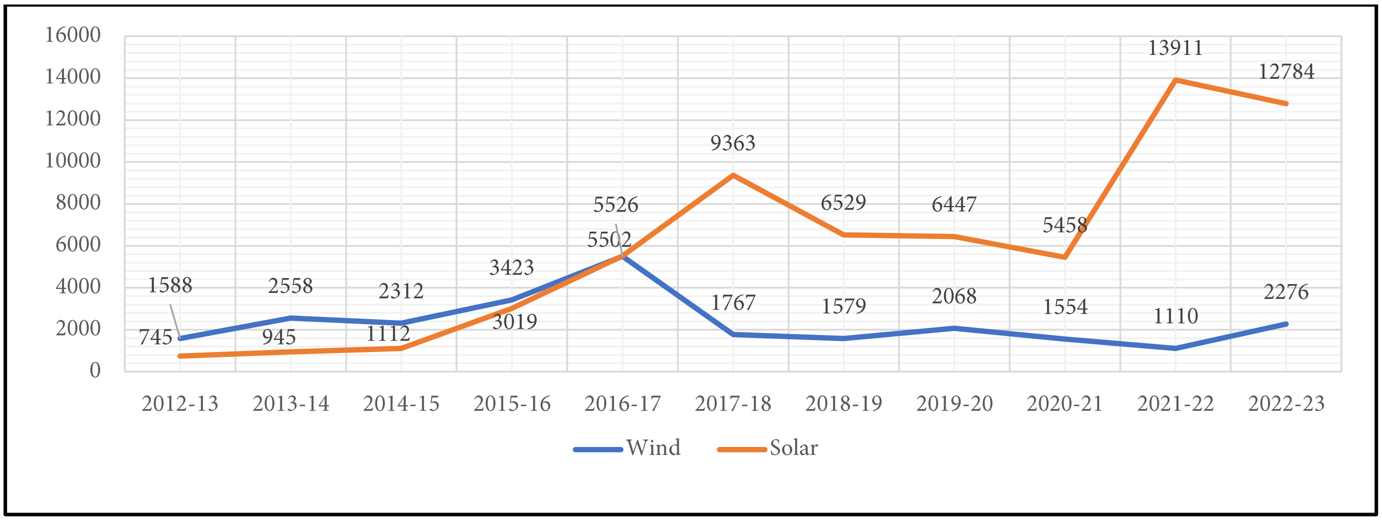
Source: (https://ourworldindata.org/electricity-mix)

As far as UK is concerned, the adoption of gas for electricity generation started much earlier than 2000 in their 'dash for gas' era. The drop in the use of coal for electricity generation is dramatic which has been compensated by a big increase in generation from renewable sources, especially wind and bioenergy. When it comes to USA, there has been a surge in the use of gas and wind based power with a corresponding drop in the use of coal. In Germany also, the use of gas, wind, solar and bioenergy has played a useful role in bringing down the share of coal-based generation. In contrast, in India there has actually been an increase in use of coal in 2022 vis-à-vis 2000 though there has been an increase in generation from solar and wind but not as dramatic as in the other three countries. Further, in the case of India, gas-based generation has actually gone down because of lack of domestic supply of gas coupled with high international prices which makes gas-based generation unviable. Consequently, gas-based plants are being utilised only to the extent of 25% or even less.

6.2 The Indian case

Since India does not have access to cheap gas, one will have to rely on other sources of electricity to meet our demand. By saying other sources, one means other than coal. India's capacity growth for solar and wind may look good because we started from a very small base. However, if one actually looks at India's growth in solar and wind capacity compared to what we need actually need if we want to restrict use of fossil fuels for electricity generation, one realises that there is a long way to go. The CEA's optimal mix report (Central Electricity Authority, 2023b) has projected that we need to have about 392 GW of capacity from solar and wind by 2030. This means that between now and 2030, we need to add fresh capacity to the tune of 276 GW from solar and wind put together. What we have actually achieved in the past 10 years or so (116 GW) is not only much less but erratic **(Figure 23)**.

Figure 23: Year wise capacity addition for wind and solar generation from 2012-13 to 2022-23 (in MW)



Source: (Central Electricity Authority, 2023a)

Our policies have not been very helpful either. The imposition of BCD, introduction of an approved list of models and manufacturers (ALMM) (though kept in abeyance for two years ie. till March 2024 before being made applicable again), cumbersome land acquisition process, poor financial condition of discoms etc. are going to stunt our growth further. Problems afflicting the solar roof top sector are different, such as, lack of awareness, high interest rates with no innovative financing, small consumers not being able to provide collateral, people not willing to give rooftop space, poor after sales service etc. It may be added that it is in the case of solar rooftops that we have fared poorly as compared to say solar parks. Wind based generation has its own set of problems which includes problems of availability of land, lack of transmission infrastructure (which is applicable in the case of solar too), introduction of reverse bidding process, dramatic fall in solar tariffs etc. Sites which have good wind potential have already been taken up but, unfortunately, have low capacity turbines installed thus leading to wastage. India's performance on the hydro front is also problematic. The hydro sector is facing issues of resettlement and rehabilitation, inter-state disputes on sharing of water, environmental problems, law and order issues etc. As a consequence, only about 1000 MW of new hydro capacity has been set up in the last 10 years. Further, our pumped storage operational capacity is only about 4,000 MW. On the nuclear front, we only have about 7,000 MW of capacity despite being in this business for quite long. In such a scenario, India has no choice but to continue with coal-based capacity, at least for the next decade or two.

The complexity of the power sector in India is much more when compared to USA, UK or Germany. In India, power is a concurrent subject meaning that both the central government and the state governments can legislate though, of course, no state law can run contrary to the central law. Moreover, there is demarcation of the domain of the centre and the states. While the centre is responsible for inter-state generation and transmission, the states are responsible for their own state generation and intra-state transmission and also distribution. There are, however, cases of overstepping as the centre has on a couple of occasions framed regulations on distribution which is purely a state subject. Just to give an example of the complexity, while targets are set by the centre (as in the CEA's optimal generation mix report), the actual implementation is done by the states and there is little coordination between the two. Unless we address the issues mentioned in the previous paragraph, our growth in renewables will be stymied, forcing us to continue with coal-based generation. Coming to easing out of coal-based generation, the only way to guide the coal plant operators to move towards renewables is through market signals as was done in USA, UK and Germany. In India, giving market signals to fossil based plants is a little difficult because a major share of the capacity is in the public sector. Out of a total coal-based capacity of 205 GW, about 132 GW lies in the public sector, centre and states put together. The average age of the public sector plants is also higher than the private sector. The figures are 17.8 years and 14.6 years, respectively. The public sector, as we all know, may not be amenable to market signals since there are various other considerations which have to be taken into account and which border on political economy. The most crucial factor for any state is employment and if coal-based plants are retired, it will have a direct impact on employment.[11]

It is not just market signals which worked in USA, UK and Germany. As we have seen, regulatory and administrative fiat also played an important role. We have seen that in these countries, environmental norms for coal-based generation were made more strict over time. The plant operators kept investing in technology in order to meet the new environmental norms till such time it made economic sense. Beyond a point, it was more meaningful to move away from generation completely or pursue some other renewable source of generation. In the case of Germany, we also saw how a Damocles sword was kept hanging on the plant operators. The operators had no choice but to opt for an auction (the sooner the better) or not get any compensation at all once the administrative fiat is exercised by the government. In India, we did introduce new environmental norms in 2015 but instead of tightening them over time, we in fact diluted them. Going by the latest notification of 2021, plants which are identified for retirement need not set up FGDs at all! Now with the government's decision of retiring only about 2,121 MW of capacity during the period 2022-32, one does not know what view will be taken by the MoEF&CC.

If one were to put the entire narrative of section 5 in the form of points for a better understanding, it would be as follows:

1) India needs a total capacity of about 777 GW by 2030 to meet its projected peak demand of about 334.8 GW. This demand has been estimated by the 20th Electric Power Survey (EPS).

2) The CEA has estimated on the basis of its cost-optimisation model that the break-up of this capacity of 777 GW would include about 292 GW of solar and about 100 GW of wind. It would also require about 251 GW of coal and lignite plants.

3) The present coal and lignite capacity is about 217 GW, so almost 40 GW need to be added in the next 7 years or so.

4) India needs to add about 276 GW of wind and solar between now and 2030 (since the solar and wind capacity as on September 2023 is 116 GW) which is about 40 GW per year whereas what has actually been added is only 9 GW per year if one takes the last 10 years average and

11 Besides, by not retiring their own generating stations, the states retain control over generation and dependence on central generators is somewhat reduced.

10.7 GW if one takes the last 5 years average.

5) The deficit in wind and solar (which is very likely) can only be met by coal-based generation in the interregnum since India has limited growth potential for hydro (including PSP), gas and nuclear.

6) If we retire coal-based generation after completion of 25 years, India is likely to face a huge peak and energy deficit as about 48,000 MW of capacity will be written off by 2027.

7) In any case, it is difficult to zero in on what should be the criteria for retirement unless, of course, the techno-economics of the plant in question is abysmal. The fact is that several vintage coal-based plants have a lower variable cost compared to solar and wind based generation and in any case, since they have a lower fixed cost, they are a better candidate for ancillary services and also for balancing the grid.

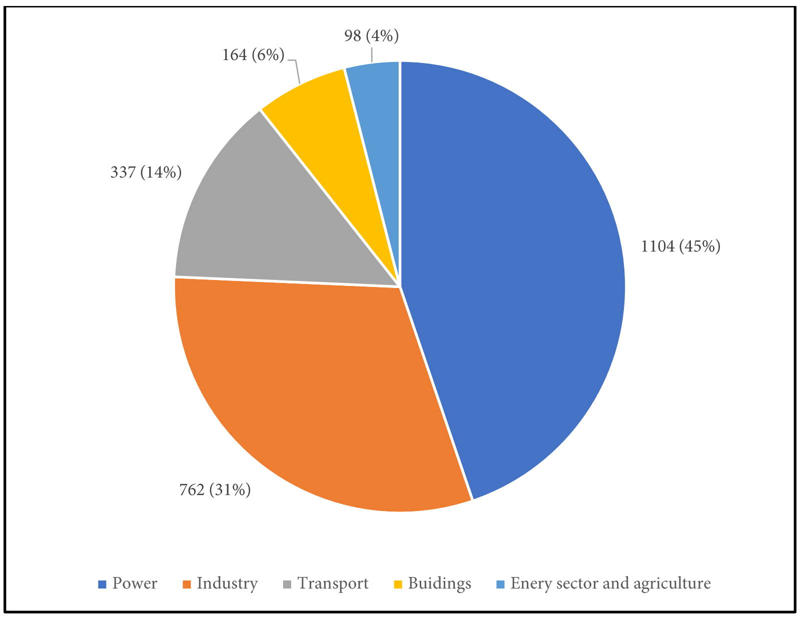
8) The policy of providing market signals and prescription of stiffer environmental regulations are unlikely to work as a major part of the coal-based generation is in the public sector (about 64%) where the criteria for operation is not based on economic but political considerations.

9) The way generation tariffs rare determined in India, there is an incentive not to retire coal-based generation but to keep them running till such time there are techno-economic considerations. The fact that environmental norms have been diluted over time encouraged coal-based plants not to retire. The government, in any case, has openly stated that no retirements should be considered, at least till 2030.

10) Power being a concurrent subject, both the central government and the state governments have to move in tandem which is not really happening. The states need to address the issues on the ground to encourage investments in to renewable sources otherwise phasing down of coal will be difficult. The centre, in any case, has no mandate to order closure of coal based plants belonging to the states.

It is quite clear that India is not in a position to retire its coal plants as it will find it difficult to meet the burgeoning demand. This will, however, have an impact on India's ambition of becoming net-zero by 2070. Power sector is the biggest emitter of carbon emissions when seen on a sectoral basis **(Figure 24)**.

Figure 24: India's sectoral carbon emissions in 2021 (in MT)



Note: Figures in brackets are percentage shares
Source: International Energy Agency (2019)[12]

12 Available at: https://www.iea.org/data-and-statistics/charts/CO2-emissions-from-the-indian-energy-sector-2019. Accessed on November 4, 2023.

In order to become net-zero by 2070, India will probably have to peak its emissions by around 2040. The Indian government has already declared its policy of keeping all coal stations running at least till 2030. This, in a way, is a tacit admission that India will not be able to add to solar and wind capacities to the extent indicated in the optimal mix report of the CEA. One may recall that during COP27 (2022), India had called for a phasing down of coal-based (and other fossil fuels) generation rather than phasing out. Instead, the current policy of the government seems to aim at maximising coal-based generation.

Coming to the question of decommissioning of coal-based plants, what could be the possible solution as far as India is concerned. The first solution is to devise policies which will actually promote growth of renewable generation. We need to address the issues referred to in this report. The problem is today the entire risk of setting up a renewable projects is being taken by the developers. Starting with land acquisition to getting regular payments from discoms, the entire onus is on developers. The government has to ensure that it shares the risk because otherwise, the requisite investments will not come. The second solution is to devise a national policy for which a body of experts need to be constituted. This body should include representation from power engineers, economists, load dispatchers and regulators. This expert body will have to identify plants which can be decommissioned on the basis of their economics, their carbon emissions, and other factors like grid stability etc. This is not all. This plan will have to be discussed with the states so that it has the approval of all stakeholders. A possible forum to do this is the Power Ministers' Conference which is held every year.

So in a nutshell, when it comes to phasing out (or down) our coal-based generation, the task is arduous and requires out-of-the-box thinking. More importantly, the centre and the states have to be on the same page.

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ANNEXE 1

List of coal and lignite power stations retired from 2002 to 2023

Sl. No.	Name of Station/Plant	State	Fuel	Retired (MW)	Retired on
1	Panki,Uttar Pradesh	Uttar Pradesh	Coal	32	Mar.06
2	Bokaro,DVC	Jharkhand	Coal	75	Mar.06
3	Mullazore,West Bengal	West Bengal	Coal	120	Mar.06
4	Nellore,Andhra Pradesh	Andhra Pradesh	Coal	30	Mar.07
5	Bokaro,DVC	Jharkhand	Coal	172.5	31.02.06
6	Harduaganj,Uttar Pradesh	Uttar Pradesh	Coal	110	Feb.07
7	Bandel TPS	West Bengal	Coal	90	2006-07
8	Dhuvaran TPS	Gujarat	Coal	254	Apr,2007
9	Bongaigaon TPS	Assam	Coal	240	Mar,2008
10	Patna (Karbigha)TPS	Bihar	Coal	13.5	Mar,2008
11	Harduaganj T P S	Uttar Pradesh	Coal	110	Jun,2008
12	Amarkantak T P S	Madhya Pradesh	Coal	60	Sep,2008
13	Obra T P S	Uttar Pradesh	Coal	150	Sep,2008
14	Faridabad T P S	Haryana	Coal	60	21.01.2009
15	Faridabad T P S	Haryana	Coal	60	23.03.2010
16	I P TPS	Delhi	Coal	247.5	23.03.2010
17	Chandrapura TPS	West Bengal	Coal	360	03.09.2010
18	Faridabad T P S	Haryana	Coal	60	03.09.2010
19	Dhuvaran TPS	Gujarat	Coal	220	Feb,2011
20	Bhusawal TPS	Maharashtra	Coal	50	03.06.2011
21	Paras T P S	Maharashtra	Coal	55	Jun,2011
22	Parli T P S	Maharashtra	Coal	40	Jun,2011
23	Barauni T P S	Bihar	Coal	100	Mar,2012
24	Harduaganj T P S	Uttar Pradesh	Coal	55	27.03.2012
25	DPL Thermal Power Station	West Bengal	Coal	60	23.05.2012
26	Obra Thermal Power Station	Uttar Pradesh	Coal	94	12.06.2012
27	Nasik Thermal Power Station	Maharashtra	Coal	250	12.06.2012
28	Satpura Thermal Power Station	Madhya Pradesh	Coal	62.5	22.01.2013
29	Satpura Thermal Power Station	Madhya Pradesh	Coal	62.5	May.2013
30	Satpura Thermal Power Station	Madhya Pradesh	Coal	125	March.2014
31	Satpura Thermal Power Station	Madhya Pradesh	Coal	62.5	July,2014
32	Amarkantak TPS	Madhya Pradesh	Coal	240	04.03.2016
33	New Cossipore TPS	West Bengal	Coal	160	04.04.2016
34	Panipat TPS	Haryana	Coal	440	12.04.2016
35	Koradi TPS	Maharashtra	Coal	420	02.08.2016
36	CHANDRAPUR(MAH) STPS	Maharashtra	Coal	420	21.10.2016
37	PARLI TPS	Maharashtra	Coal	210	21.10.2016
38	DURGAPUR TPS	West Bengal	Coal	130	21.10.2016
39	PATRATU TPS	Jharkhand	Coal	315	21.12.2016
40	SANTALDIH TPS	West Bengal	Coal	480	21.12.2016
41	GANDHI NAGAR TPS	Gujarat	Coal	240	12.01.2017
42	ENNORE TPS	Tamil Nadu	Coal	110	12.01.2017
43	CHANDRAPURA(DVC) TPS	Jharkhand	Coal	130	17.01.2017
44	TROMBAY TPS	Maharashtra	Coal	150	08.02.2017
45	DPL TPS	West Bengal	Coal	220	20.02.2017
46	ENNORE TPS	Tamil Nadu	Coal	340	31.03.2017
47	Koradi TPS	Maharashtra	Coal	200	24.04.2017
48	CHANDRAPUR(ASSAM)	Assam	Coal	60	18.08.2017

49	UKAI TPS	Gujarat	Coal	240	18.08.2017
50	SIKKA REP. TPS	Gujarat	Coal	240	18.08.2017
51	HARDUAGANJ TPS	Uttar Pradesh	Coal	60	18.08.2017
52	OBRA TPS	Uttar Pradesh	Coal	90	18.08.2017
53	BHUSAWAL TPS	Maharashtra	Coal	210	31.08.2017
54	CHINAKURI TPS	West Bengal	Coal	30	31.08.2017
55	Dishergarh TPS	West Bengal	Coal	18	31.08.2017
56	Seebpore TPS	West Bengal	Coal	8.375	31.08.2017
57	CHANDRAPURA(DVC) TPS	Jharkhand	Coal	130	04.09.2017
58	BOKARO `B` TPS	Jharkhand	Coal	420	04.09.2017
59	PATRATU TPS	Jharkhand	Coal	455	23.11.2017
60	PANKI TPS	Uttar Pradesh	Coal	210	16.03.2018
61	OBRA TPS	Uttar Pradesh	Coal	94	03.04.2018
62	BANDEL TPS	West Bengal	Coal	120	20.04.2018
63	BHATINDA TPS	Punjab	Coal	440	31.08.2018
64	ROPAR TPS	Punjab	Coal	420	31.08.2018
65	Badarpur TPS	Delhi	Coal	705	30.10.2018
66	Neyveli TPS-I	Tamil Nadu	Lignite	100	06.02.2019
67	Kothagudem TPS	Telangana	Coal	300	19.03.2019
68	Korba-II	Chhattisgarh	Coal	200	13.08.2019
69	Trombay TPS	Maharashtra	Coal	500	12.09.2019
70	Sabarmati (C Station)	Gujarat	Coal	60	13.09.2019
71	Rajghat TPS	Delhi	Coal	135	23.09.2019
72	Parli TPS	Maharashtra	Coal	420	23.01.2020
73	D.P.L. TPS	West Bengal	Coal	110	28.01.2020
74	Kothagudem TPS	Telangana	Coal	60	03.03.2020
75	Chandrapura(DVC) TPS	Jharkhand	Coal	130	19.03.2020
76	Kothagudem TPS	Telangana	Coal	120	30.03.2020
77	Kothagudem TPS	Telangana	Coal	240	31.03.2020
78	Neyveli TPS-I	Tamil Nadu	Lignite	150	31.03.2020
79	Panipat TPS	Haryana	Coal	210	31.03.2020
80	Neyveli TPS-I	Tamil Nadu	Lignite	200	08.07.2020
81	Neyveli TPS-I	Tamil Nadu	Lignite	50	30.07.2020
82	Neyveli TPS-I	Tamil Nadu	Lignite	50	28.09.2020
83	Neyveli TPS-I	Tamil Nadu	Lignite	50	30.09.2020
84	Korba-III	Chhattisgarh	Coal	240	01.01.2021
85	Kutch Lig. TPS	Gujarat	Lignite	140	22.01.2021
86	BOKARO `B` TPS	Jharkhand	Coal	210	01.04.2021
87	TALCHER (OLD) TPS	Odisha	Coal	460	01.04.2021
88	Koradi TPS	Maharashtra	Coal	210	02.09.2021
89	MUZAFFARPUR TPS	Bihar	Coal	220	31.01.2022
90	Bandel TPS	West Bengal	Coal	60	28.03.2022
91	Kolaghat TPS	West Bengal	Coal	420	28.03.2022
92	OBRA TPS	Uttar Pradesh	Coal	94	13.10.2022
93	DURGAPUR TPS	West Bengal	Coal	210	19.12.2022
TOTAL				**16985.3**	

ANNEXE 2

List of projects retired due to age, non-compliance of environmental norms and not originally planned in NEP 2018

List of projects retired due to age criteria

S.NO.	NAME OF THE UTILITY	SECTOR	STATE	CAPACITY (MW)
1	DPL	State sector	West Bengal	220
2	ASEB	State sector	Assam	60
3	GSECL	State sector	Gujarat	120
4	GSECL	State sector	Gujarat	240
5	IPGCL	State sector	Delhi	135
6	UPRVUNL	State sector	Uttar Oradesh	60
7	UPRVUNL	State sector	Uttar pradesh	94
8	NLC	State sector	Tamil Nadu	600
9	TSGENCO	State sector	Telenga	720
10	PSPCL	State sector	Punjab	220
11	CSPGCL	State sector	Chhattisgarh	200
12	UPRVUNL	State sector	Uttar Pradesh	90
13	UPRVUNL	State sector	Uttar Pradesh	210
14	PSPCL	State sector	Punjab	420
15	MSPGCL	State sector	Maharashtra	200
16	PVUNL	State sector	Jharkhand	455
17	BADARPUR TPS	Central sector	Delhi	285
18	Chandrapur TPS	Central sector	Jharkhand	260
	TOTAL			**4,589**

List of projects retired due to non-compliance of new environmental norms

S. NO.	NAME OF PROJECT	SECTOR	STATE	TOTAL CAPACITY (MW)
1	BOKARO \`B\` TPS	Central sector	Jharkhand	630
2	TALCHER (OLD) TPS	Central sector	Odisha	460
3	BANDEL TPS	State sector	West Bengal	180
4	BADARPUR TPS	Central sector	Delhi	420
5	PANIPAT TPS	State sector	Haryana	210
6	GND TPS(BHATINDA)	State sector	Punjab	220
7	KORBA-III	State sector	Chhattisgarh	240
8	SIKKA REP. TPS	State sector	Gujarat	120
9	SABARMATI	Private sector	Gujarat	60
10	MUZAFFARPUR TPS	Central sector	Bihar	220
	TOTAL			**2760**

List of projects retired but not originally envisaged in NEP 2018

S. NO.	NAME OF PROJECT	SECTOR	STATE	TOTAL CAPACITY (MW)
1	DISHENGARH	State sector	West Bengal	18
2	SEEBPORE TPS	State sector	West Bengal	8.375
3	NAMRUP CCPP	State sector	Assam	55
4	LAKWA GT	State sector	Assam	45
5	CHINAKURI TPS	State sector	West Bengal	30
6	KUTCH LIGNITE	State sector	Gujarat	140
7	BARAMURA	State sector	Tripura	16.5
8	ROKHIA	State sector	Tripura	16
9	D.P.L. TPS	State sector	West Bengal	110
10	PARLI TPS	State sector	Maharashtra	420
11	TROMBAY TPS	State sector	Maharashtra	500
12	YELHANKA DG	State sector	Karnataka	127.92
13	BASIN BRIDGE DG	State sector	Tamil Nadu	200
14	BHUSAWAL TPS	State sector	Maharashtra	210
15	UTRAN CCPP	State sector	Gujarat	144
16	KORADI TPS	State sector	Maharashtra	210
17	ADAMTILA CCPP	State sector	Assam	9
18	BASKHANDI	State sector	Assam	15.5
19	KOLAGHAT TPS	State sector	West Bengal	420
	TOTAL			**2,695**
		GRAND TOTAL		**10,044**

ANNEXE 3

List of plants earmarked for retirement from 2022 to 2032

S.NO	NAME OF PROJECT	STATE	SECTOR	ORGANISATION	TOTAL CAPACITY (MW)
1	BARAUNI TPS U6,7	BIHAR	CENTRAL SECTOR	NTPC	210
2	TANDA TPS U1-4	UTTAR PRADESH	CENTRAL SECTOR	NTPC	440
3	DURGAPUR TPS UNIT 4*	WEST BENGAL	CENTRAL SECTOR	DVC	210
4	RAMAGUNDEM-B TPS U2	TELANGANA	STATE SECTOR	TSGENCO	62.5
5	OBRA TPS*	UTTAR PARDESH	STATE SECTOR	UPRVUNL	94
6	BANDEL U2	WEST BENGAL	STATE SECTOR	WBPDC	60
7	PARICHHA TPS UNIT 1,2	UTTAR PARDESH	STATE SECTOR	UPRVUNL	220
8	KOTA TPS UNIT 1-2	RAJASTHAN	STATE SECTOR	RRVUNL	220
9	HARDUAGANJ TPS UNIT 7	UTTAR PRADESH	STATE SECTOR	UPRVUNL	110
10	GEPL TPP PH-I UNIT 1,2	MAHARASHTRA	PRIVATE SECTOR	GEPL	120
11	SALORA TPP U1	CHHATTISGARH	PRIVATE SECTOR	VVL	135
12	TITAGARH TPS UNIT 1-4	WEST BENGAL	PRIVATE SECTOR	CESC	240
TOTAL					**2121.5**

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