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Coal Power's Trilemma

Variable Cost, Efficiency and Financial Solvency

Karthik Ganesan and Danwant Narayanaswamy

Report | July 2021

Around 65% of the total coal power generation capacity as of March 2020 was installed in the previous ten-year period.

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"The first step to India's energy transition in the power sector must be to improve the efficiency of generation in the thermal fleet. The current focus on lowering variable costs, with all the distortions that currently exist, needs to be reviewed and stress should be laid on minimising environmental fallouts."

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Danwant is a Research Analyst at The Council. He is currently working on devising short-term policies on thermal power generation. Prior to the current role, Danwant worked on estimating the cost of meeting air pollution standards in the coal-fired electricity sector in association with the International Institute for Sustainable Development. He is an Energy and Environmental Engineering graduate from Tamil Nadu Agricultural University, Coimbatore.

"Enhancing the efficiency of the Indian coal fleet by optimising the resource utilisation will help the power sector in achieving the triple bottom line—by avoiding pollution-related morbidity and mortality (people), reduced emissions (planet), and improved discom finances (profit)."

There is a need to improve data transparency, as we assess the performance of our thermal fleet and prioritise action to decarbonise electricity generation.

Image: iStock

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Acronyms

APTEL	Appellate Tribunal for Electricity
AT&C	aggregate technical and commercial
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
CO_2	carbon dioxide
CPCB	Central Pollution Control Board
ER	eastern region
FGD	flue gas desulphuriser
FY	financial year
GDP	gross domestic product
GHG	greenhouse gas
GW	giga watt
INR	Indian rupee
ISGS	Inter-state generating stations
kcal	kilo calorie
KPI	key performance indicators
kWh	kilo-watt hour
Mcal	mega calorie
MERIT	Merit Order Despatch of Electricity for Rejuvenation of Income and Transparency
MoD	merit order dispatch
MoEFCC	Ministry of Environment, Forest, and Climate Change
MoP	Ministry of Power
MT	million tonnes
MU	million units
MW	mega watt
NEP	*National Electricity Plan*
NER	north-eastern region
NIT	notice inviting tender
NO_x	nitrogen oxides
NPA	non-performing asset
NR	northern region
PFC	Power Finance Corporation
PLF	plant load factor
PM2.5	particulate matter
POSOCO	Power System Operation Corporation
PPA	power purchase agreement
PRAAPTI	Payment Ratification And Analysis in Power procurement for bringing Transparency In Invoicing of generators
PTI	Press Trust of India
RE	renewable energy
SERC	State Electricity Regulatory Commission
SEVA	Coal India Limited Koyla Grahak Seva
SHR	station heat rate
SO_x	sulphur oxides
SR	southern region
USD	US Dollar
WR	western region

Variable costs of electricity generation from coal-based plants are distorted by fuel costs, fuel supply contracts and lop-sided fuel availability.

Executive summary

It was a ‘lost-decade’ (2010–2020) for coal-based power generation in India. There was much promise at the beginning of the decade and generation capacity was added at a breakneck pace. Eventually, low economic growth and poor growth in power demand ended up bankrupting the sector that was already teetering on the brink. Today, non-performing assets (NPAs) abound in the sector and recovery of dues is a challenge throughout the value chain. We are at crossroad, where at the global stage, India is contemplating its net-zero emissions timelines, while the only strategy presented thus far has been increasing the installed capacity base of renewable energy (RE).

Older plants outcompete younger ones in fixed and variable costs

What about our thermal fleet then? The timelines for compliance with pollution norms have been repeatedly stretched, with plants now being asked to present affidavits of retirement deadlines, if they have any, and benefit from a more lenient treatment. While air pollution legislation has been given prominence, soil and water pollution emanating from millions of tons of ash pile up still goes unnoticed. The COVID-19 pandemic has also dented demand growth and many assets, which are in advanced stages on construction, are in a grip of uncertainty. Alongside, a new market-based economic dispatch (MBED) mechanism for procuring bulk power has been proposed to begin in April 2022. By dispatching power through a central clearing mechanism, MBED aims to reduce power procurement costs by INR 12,000 crore (MoP, 2021). All these developments point to an undercurrent of a storm brewing in the sector, and it is at this moment we ask the question—Can India rethink how it manages its coal-based power generation fleet from here on?

Reviewing the thermal setup

We began this study with an examination of the performance—thermal, financial, and operational—of nearly 194 GW of coal-based generation capacity over the course of 30 months leading up to the start of the COVID-19 pandemic in India. We explored how assets are being utilised and segment them by vintage and ownership. We observed that older plants are generating a disproportionate share of electricity and, unsurprisingly, private sector plants bear the brunt of under-utilisation challenge the sector is facing. When exploring the cost distribution of plants, we find that not only do older plants have low fixed costs but they also have low variable costs and outcompete younger plants in the merit order stack. Even in cases where plants incurring low variable costs are available, plants with higher variable costs are dispatched as they are contracted and preferred by utilities, given their lock-in clause in the contracts. The net impact of the current strategy of utilisation of assets is that the thermal efficiency of the generation fleet in India is an abysmal 29.7 per cent, which in turn points to regulators being lax about such poor technical performance.

Given the inefficient operations of the thermal fleet, we wanted to assess what exactly determines power plant efficiency and the variable costs of generation. Towards this end, we carried out a parametric regression assessment of these two metrics. We find that age, plant load factor (PLF), and the average size of units in a plant play an important role in determining how efficient a plant is. In the case of variable costs, we find that it is largely driven by the cost of delivered coal and to a lesser extent by operational characteristics of a plant such as station heat rate (SHR) and auxiliary consumption. These reinforce the theory that newer vintage plants, if operated more consistently, would yield better outcomes to achieve system efficiency and possibly also lower variable costs. This in turn implies better environmental outcomes—lower greenhouse gas (GHG) emissions, reduced output of criteria pollutants, or lesser quantity of ash generated. But the financial implications of this proposition remain to be seen.

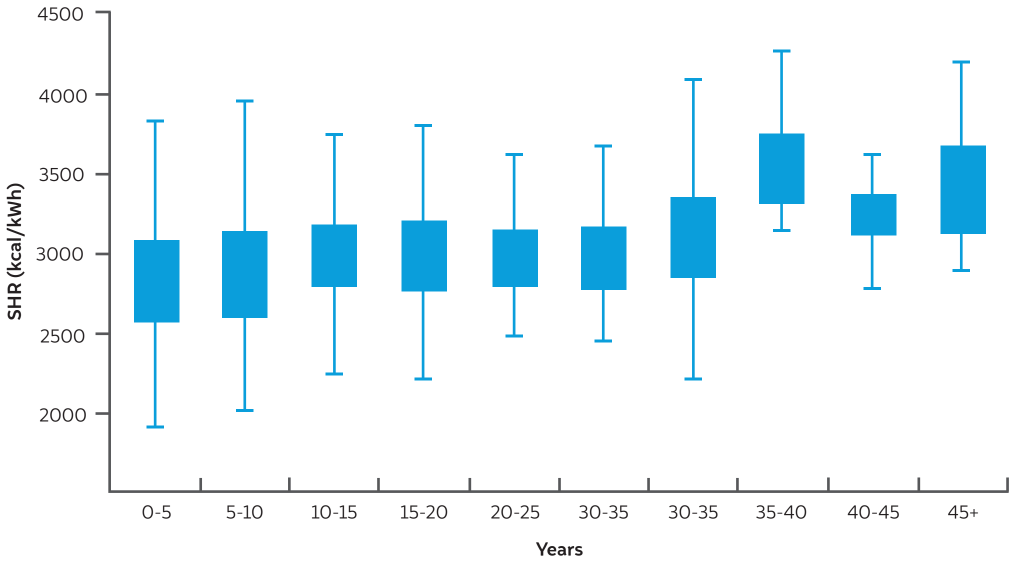


Figure ES1
Younger plants use lesser thermal energy to generate electricity

Source: Authors' analysis based on CEA monthly coal statements, monthly generation reports and coal grades data from SEVA

Our approach to determining the criteria for dispatch

In a bid to conceive of a system where efficiency is rewarded, we demonstrate an approach to dispatch power, based on an efficiency merit order and not the one based on stated variable costs. We chose efficiency as the criterion for dispatch because variable costs are distorted by fuel costs and fuel supply contracts, among others. The order based on variable costs does not mirror efficiency, as evident in our descriptive assessment of the system. As a first step in our approach, we assign higher PLFs to newer vintages, which is inherently a logical step—from operational and financial standpoints of the system. We order plants in an increasing order of estimated SHR, based on the parametric function we established in the first step. Generation schedules are assigned to plants at a daily resolution level, without factoring in spatial and temporal constraints in the movement of power but only providing for the energy demanded in a day. This is a significant limitation, but it is important to understand the nature of unconstrained opportunities existing in the Indian thermal fleet. If the proposed efficiency-based dispatch is employed, the Indian coal fleet would be able to cater to the average energy demanded from it (over the assessment period) at an improved thermal efficiency of 6 per cent over the baseline (the current scenario in action). This implies that the generation efficiency goes up to 31.6 per cent. As a corollary, we find that the reassignment results in an annual saving of nearly 42 MT of coal and a concomitant reduction in GHG and criteria pollutant emissions. The overall fleet also operates at a higher overall PLF of 78 per cent, with significant room for providing more generation should the system require it.

Outcome of our assessment: a more efficient and lower cost generation mix

We have structured an efficient generation mix, but does it financially make sense? The drivers of overall variable costs are delivered cost of coal, SHR, auxiliary consumption, unit size and age. In our assessment, we find that the delivered cost of coal in the reassigned scenario increases the overall cost of generation, as 20 per cent of the pit-head plants do not generate in the reassigned scenario. However, plants consume less energy, operate at a higher load factor, and as a result there are significant savings on variable costs of generation. The total savings on variable costs in this reassigned scenario amounts to INR 8,944 crore. Against the overall cost of power procurement by discoms, this is a small fraction, though significant enough to give much needed breathing room for their finances.

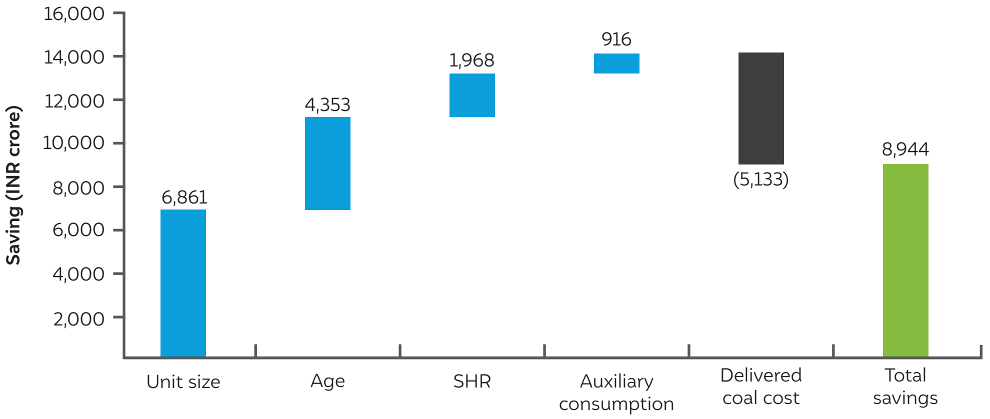


Figure ES2
Most of the savings in the reassigned scenario is attributable to improved efficiency

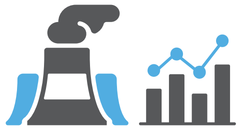
Source: Authors' analysis

As a key outcome, we find that nearly 50 GW of capacity could be deemed as surplus to the requirements of the system, for the energy demand it caters to. Even when considering power delivered, the retained generation capacity could provide for the quantum of peak power required (143 GW in the analysis period) from the thermal fleet. We propose that 30 GW of the surplus capacity, which represents the older and some of the least efficient assets, be taken up for accelerated decommissioning as these have been identified in the *National Electricity Plan* (2018) for decommissioning during the course of this decade (2021-2030). Each passing year of delay increases the burden on us with a higher electricity bill and more air, water, and soil pollution to manage. It also results in a one-time saving of INR 10,200 crore in avoided pollution-control retrofits, which would otherwise be needed should some of these plants continue to operate. Nearly 20 GW of capacity can be considered for moth-balling and based on a more rigorous assessment, it can be decided where they would be called upon to generate if contingencies are likely to arise. We also observe that the system has significant slack, outside of this assessed stock of plants, to manage contingencies and demand growth over the course of this decade. With nearly 36 GW of thermal power in various stages of construction, we find that meeting the electricity and power demand in later years of this decade should not be a matter for concern. Given some key limitations in terms of the spatial and temporal resolution in our study, there is a need to carry out a more rigorous assessment of the opportunities identified in this study. Equally, there is a need to assess electricity demand over the course of this decade and the prospects of RE materialising to the extent that it is currently anticipated in existing studies, in order to conclusively decide on decommissioning and its benefits.

Giving life to an illusion: how do we realise this opportunity?

The key contribution of our assessment has been clearly defining the performance metrics of the current thermal fleet in India in terms of both technical and financial aspects. As the data was hitherto not available easily in the public domain, it was compiled patiently and put together diligently for the purposes of the analysis. With data at our disposal, we propose a simple yet powerful way of viewing an alternative dispatch system. Some may consider the assessment incomplete as a result of the limitations stated earlier. However, in the planning horizon, the right set of policies and incentives can very much bring the outcomes envisaged in this study to life.

Despite the simplicity of our conclusions, the proposed reassignment of generation in favour of more efficient plants is far less likely to be operationalised. The Indian power system is mired in a rigid set of bilateral contracts for supply and taking away one to replace with another cannot be easily done. Our approach would leave the states with far lesser control on their sources of power, as many state-owned power generation stations are candidates for decommissioning. Given the challenges of payments for power procured and the broader political economy wielding 'power' over 'owned' generation assets, such a proposition is anathema to most actors. However, the future of the power system even as envisaged in recent white papers from the central regulator is moving towards a market-based system and does not bet on a bilateral scheduling between generators and discoms. Our proposed approach results in cost savings when viewed as a whole, but individual states are likely to see it only in terms of more costs and less flexibility for their operations.



Retiring inefficient assets will create headroom for new investment focusing on the long-term

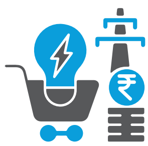
We have two main recommendations for the Ministry of Power (MoP) and relevant actors as they look to establish the framework for MBED. First, we urge them to **establish a set of key performance indicators (KPIs) for the thermal generation fleet, among which environmental footprint associated (as represented by thermal efficiency) with thermal power generation should be accorded priority.** Individual legislations on water and criteria pollutants continue to languish, but bringing thermal efficiency to the centre of the debate could lower the costs. And second, we reiterate **the need for consensus-building among states, in dialogue with central actors, to embrace the notion of a unified market. That the proposed MBED (starting in April 2022) is being carried out in two phases (MoP, 2021) is an indicator of uncertainty in the process**. Beyond the implementation framework, we propose that **an entity such a National Electricity Council be set up to oversee the concerns of states and central entities and allow for a seamless transition to the concept of 'one nation, one market'.** The challenges of this transition go well beyond the technical domain and must address the needs of state electricity utilities and key entities like Coal India Limited and Indian Railways, and what the future holds for them.

As stated earlier, despite the financial savings being relatively small, our proposed approach to prioritise efficiency opens up a window of opportunity to de-stress generation assets in the sector. By clearing out the stock of inefficient assets, we create fresh breathing room and make a case for more investment in the sector—in RE, energy storage, system upgrades, among others. With the sword of surplus not hanging over the sector anymore, cash flows for stressed assets could improve and, as a result, financial institutions saddled with NPAs could be relieved of their burden. Having gone past this preliminary hurdle, the power sector needs to address some critical issues before it, as it prepares for the larger energy transition.

1. Introduction


Image: iStock

A country's economic development is synonymous with its growth in power demand. The projection of a USD 5 trillion gross domestic product (GDP) by 2024 (PTI, 2019a) has also set the expectation that India's power demand is set to escalate multifold in the next decade. The last decade (2010–2020) generated much hype but did not live up to that promise. Electricity consumption across the economy increased by a mere 55 per cent between FY 2010 and FY 2020 (MoP, 2020). The Central Electricity Authority (CEA), starting with the 13th Electric Power Survey, has consistently overestimated the peak power demand and overall electricity demand in the economy (Josey, Mandal, & Dixit, 2017). The supposedly prudent and shrewd private sector in India did itself no favours by buying into that narrative, without any checks of its own. The surplus generation capacity that the power sector achieved has been well documented (Josey, Mandal, & Dixit, 2017; Parray & Tongia, 2019; Josey, Dixit, Chitnis, & Gambhir, 2018; IEA, 2020). This resulted in the creation of a large number of generation assets, largely coal-based and more efficient, in many cases being available on call, but not being requisitioned. Equally, the supply of coal to some of the newly built plants was also in doubt, because development of new coal mining areas did not keep pace with the increased demand.



Continuous overestimation of power demand in the past has led to surplus coal generation capacity

Many of the new assets were created primarily because power distribution companies (public and private discoms) indiscriminately signed power purchase agreements (PPA) based on a projected power demand that was not assessed well (Josey, Mandal, & Dixit, 2017). Signing PPAs implies that discoms are saddled with contracts that require them to honour the fixed cost payments due to the plants, irrespective of them supplying power, as dictated by the two-part tariff regime, which has been practiced in India since the 1980s. The indiscriminate signing of PPAs thus pushed up the overall cost of power purchase for discoms in recent years. In FY19, the total value of power sold to discoms was to the tune of INR 5,62,000 crore (USD 76.54 billion). In the same year, the total revenues that discoms managed to recover from their consumers was INR 4,87,000 crore (USD 66.33 billion) (PFC, 2020). The biggest challenge for the power sector is its revenues not covering even the cost of electricity procured. If the operating expenses of discoms (salaries, pensions, maintaining distribution assets, financing costs, and so forth) of INR 1,60,000 crore (USD 21.79 billion) are considered, we see the wide gap between revenues from the sale of electricity and the costs of providing electricity (PFC, 2020).

Financial solvency remains the holy grail for the power sector and is key to the country's economic prospects

Only a financially solvent utility would be able to address the energy needs of the poor and the aspiring class with rising incomes, as well as competitively supply electricity to Indian industry. Despite generous public support—through grants and interest rate subventions—discoms were staring at annual losses to the tune of INR 27,000 crore in FY 2019 (PTI, 2019b), depriving them of their ability to cater to any of these segments effectively. As a result of their poor financial health, discoms remain as debtors to generation companies. The total dues owed by discoms to power producers stands at INR 90,026 crore at the end of February 2021 (PRAAPTI, n.d.) and, by some accounts, this figure could be even higher (Rajasekhar & Tongia, 2020).

In literature documenting the policy failures leading to the financial woes of discoms, the most frequently discussed issues pertain to the cross-subsidized tariff structure for domestic and agriculture consumers, poor metering, billing and collection inefficiencies, and high aggregate technical and commercial (AT&C) losses in the operations of utilities (Dubash & Rajan, 2001; Tongia, 2003; Das et al. 2019; Aggarwal et al. 2020; Rajasekhar & Tongia, 2020). However, there is one other factor that often flies under the radar, that is, power purchase cost. Studies acknowledge that power purchase costs account for about 75–80 per cent of total cost of power supply incurred by a discom (Bharadwaj, Ganesan, & Kuldeep, 2017; Josey et al. 2018; Aggarwal et al. 2020). However, power purchase cost is often treated as a rigid variable in the assessment of discom operations, because oftentimes discoms purchase power through long-term contracts that have to be honoured. An important option for discoms to reduce their power purchase cost is in the margin—through better management of variable costs. This, in turn, depends on how well the merit order dispatch (MoD) principles are followed. Discoms failing to rigorously follow MoD principles is the primary reason for them incurring a high-power purchasing cost. An assessment in the case of Uttar Pradesh finds that that low-cost generation stations are not utilised to their fullest potential. The reasons cited for this range from transmission constraints to coal availability, to plant availability, and even system requirements such as maintaining voltage in the sub-transmission system (Aggarwal et al. 2020).

While coal-based technologies for power plants have evolved with time, the adoption of efficient technologies in the Indian power system has certainly been lagging. The importance of efficiency in driving down costs has been completely ignored in the operation of coal-based power systems in India. The sub-critical pulverised coal technology has been the workhorse of the power system with significant domestic supply capability (Chikkatur & Sagar, 2007). The first super-critical plant in India was commissioned only in 2012 and the first (and possibly the only) ultrasuper critical power plant was commissioned in 2019 (ETEnergyWorld, 2019). Out of 205 GW capacity of coal/lignite plants in India, 93 GW has been added since April 2012 (CEA, 2020a; CEA, 2015). A bulk of this capacity uses sub-critical technology (CEA, 2018). Furthermore, there have been only a few critical assessments of the efficiency of coal-based generation assets in the Indian system (Chitnis, et al., 2018) and their effectiveness has been limited, as evident from the current state of the system. Barring the documentation of thermal performance, which has also been sporadic and which presents aggregated views on thermal efficiency of stations, a transparent depiction of factors driving the efficiency is not available.

As the debate around net-zero emissions and India's commitment to reducing overall greenhouse gas (GHG) emissions from energy use intensifies, the development of power sector in the next two decades would play a critical role in determining the pace of the country's progress. Coal used in the power sector contributes nearly 40 per cent of the GHG emissions arising from the use of fossil fuels in the Indian economy (MoEFCC, 2018; GHG

Platform India, n.d.). Another significant imperative that involves coal burning is its impact on the optimum ambient air quality, as envisioned under the *National Clean Air Programme*. Combustion of coal in power plants contributes to 13 per cent of the ambient particulate matter (PM2.5) at a national level and accounts for a much higher share of PM2.5 in peninsular India and other pockets (Cropper et al. 2021). It is estimated that 112,000 deaths annually are attributable to air-borne pollution from existing and planned coal power plants in India (Cropper et al. 2021). In order to curb the emissions from coal power plants, the Ministry of Environment, Forest, and Climate Change (MoEFCC) notified stringent emission norms in December 2015 for various pollutants and set a deadline of December 2017 for adherence to these norms. The deadline was first extended to 2022 and, in the most recent notification in March 2021, the deadline for installing retrofits to control for SO_x and NO_x emissions have been pushed to 2025. It would have taken a full decade for plants to comply, if at all the power generators do (MoEFCC, 2015; CPCB, 2017; MoEFCC, 2021). In addition, more than a billion tons of pond ash has built up over decades and millions of tons of ash generated each year polluted the soil and water in the vicinity of these plants (CEA, 2020b). Seventeen major incidents of pollution resulting from improper ash handling and breaching of storage structures occurred in FY21 and adds to the burden of local communities (Kumar et al. 2021).

13% of the ambient PM2.5 pollution in India is attributable to power plant emissions

The issue of retrofitting of plants gave rise to the important debate of retirement of thermal assets. Many of the 166 GW of plants identified for pollution control retrofits were also indicated to be retired within this decade (by 2027), under the *National Electricity Plan* (NEP) (CEA, 2018) as it was deemed that it would not make commercial sense to retrofit them. In a study published in 2019 (Garg et al. 2019), we found that nearly 39 GW of capacity, which was indicated for retirement by 2027, would cost the system INR 14,300 crore in retrofits. At the fleet level, the health benefits of retrofitting and continuing the plant operations far outweigh the cost of retrofitting the plants in the longer run (Srinivasan, et al., 2018). But from a financial perspective, plant owners and regulators may show an unwillingness to resort to retrofitting. The latest notification, delaying the retrofit timelines to 2025, also allow plants that submit an affidavit that they would be retiring to continue operating with relatively small penalties, which would go up should they continue to operate beyond the timeline specified in the affidavit (MoEFCC, 2021).

Under the NEP, the CEA has proposed a phase-out plan with timelines for coal power plants in two tranches—22,715.5 MW by 2022 based on age and emission norms compliance and 25,572 MW by 2027 based on age as a criterion (CEA, 2018)—without really specifying if these plants can continue to operate beyond the specified timelines.[1] We establish in this study that many plants continue to operate well beyond the age limits specified in the NEP for plants to be retired. Many question age as a criterion, as older plants are still technically able to generate and provide competitive generation. However, there is dissonance in arguments made over the financial viability of pollution control retrofits that express doubt over continuing 'older' plants. It is then necessary to arrive at an objective and meaningful criteria through which the decommissioning plan should be pursued. This must take into account medium-term and long-term needs of the system and public health, and must necessarily result in cost savings and efficiency improvements for the power system.

The environmental fall outs of fly-ash generated in power plants has been overlooked

The Indian power system is still in its growth phase and our dependence on coal-based generation is likely to rise over the course of this decade. However, even in such a system, it is important to assess opportunities to reduce dependence on coal. We have laid out the imperatives for such an effort, but the evidence that efficiency improvements in the system are indeed possible is what needs to be presented. We set out to find such opportunities to reduce the carbon intensity of India's coal-based generation and the additional benefits, if any, that emerge from such an exercise.

1 Nearly 4.4 GW of capacity out of this 48 GW has already been decommissioned as of 2018.

Objective

Given this background to the thermal generation fleet in India, in this study, we set out to assess the following:

1. How are thermal power plants utilised and what are the different ways of characterising their utilisation?
2. How efficient is the generation fleet and what are the drivers of efficiency and of variable costs of generation?
3. What opportunities exist for improving the efficiency of the thermal fleet?
4. Is an efficient fleet cost-effective and what implications does it have for phase-out (mothballing or decommissioning) of thermal assets?

2. Methodology and data

Image: iStock

The methodology we use to assess plant performance begins with a descriptive assessment of plant capacities, generation, and variable costs of generation segmented by age and ownership of plants. We then attempt a regression-based parametric representation of plant efficiency, proxied by the station heat rate (SHR), as a function of average unit size in the plant, plant load factor (PLF), vintage (proxied by age), and the share of imported coal. In a second parametric representation, we attempt is to capture variable costs of generation as a function of delivered coal price, vintage, average unit size, auxiliary consumption and SHR (Equations 1 and 2).

$$\textbf{SHR = Constant +B1*Age+ B2*Average\_Unit size + B3*PLF+ B4*Import share ...... (1)}$$

$$\textbf{Variable cost = Constant + B1*SHR+ B2*Delivered coal price+ B3*Age + B4*Average\_Unit size + B5* Auxiliary consumption ...... (2)}$$

It is important to explain the choice of independent variables in this assessment. Some researchers contend that PLF is an outcome metric and in some sense may have a two-way causal relationship with SHR and variable cost. However, in theory, SHR is not considered in the way plants are dispatched today and plant loading is independent of any efficiency considerations. Equally in the case of variable cost, we see that mechanisms such as ancillary services compensate plants for flexible operation, which inherently suggests that PLF (a more aggregated metric) has an impact on the plant's variable costs. We also would like to reiterate that we pursue a regression analysis not for establishing causal relations but also for establishing a predictive expression with which we can predict the dependent variables under different counterfactual scenarios.

We propose a counterfactual where plants are dispatched based on efficiency and not variable cost

Further, and as the most important step, we propose a reallocation of thermal (coal) generation across stations. The reallocation assumes that the share of generation coming from other sources such as lignite, renewable energy (RE), hydro, gas, and nuclear remain untouched, that is, geographically and temporally they continue to deliver as much as they did in our study period. The reallocation of coal generation presents a counterfactual where power is dispatched from stations by using efficiency of generation to accord priority in a 'new merit-order'. Efficiency is represented by the estimated SHRs for stations. With the established parametric representation of SHR, we now determine SHR for the efficiency-based reallocation scenario.

SHR is estimated based on (exogenous) differential plant load factors that inherently give a leg-up to newer vintage plants. This was a logical step (and also corroborated in the parametric estimation) that newer plants far outperform older plants on efficiency (ceteris paribus). Also, this is an inherent and a necessary bias (towards newer plants) to ensure financially remunerative operations for newer plants that are yet to pay off much of their costs. This would go a long way in addressing the financial stress in the banking system by preventing newer plants from becoming non-performing assets (NPAs). Assigning higher operational hours (implicitly reducing the start–stop operations of plants) to newer plants further improves the overall system efficiency. The reassignment process is iterative and maximises utilisation based on a stack of plants ordered by efficiency, so as to fulfil the average generation requirement from coal-fired power plants over the analysis period.

Predictor equations for SHR and VC are used to assess the cost of generation in the reassigned scenario

The analysis considers plant operations over a 30-month period, starting from September 2017 to February 2020. Overall, as part of the assessment, ***we investigated 194 GW[2] of plant capacity that was operational and generating between September 2017 and February 2020***. The highest resolution data available on generation was at the daily level but given that coal consumption could only be assessed at a monthly level (CEA, n.d.), we resorted to assessing all metrics at a monthly level. The highest resolution available in generation was at the plant unit level, but again coal consumption was more consistently available at the plant level (in some cases, stages of power plants) and hence we have considered this aggregated level as appropriate (typically through capacity weighting to arrive at plant-level metrics). ***Coal consumption was then converted into energy consumption, based on the delivered grade of coal to each power plant in each of these months*** (SEVA, n.d.). The conversion to energy units is critical, as physical units of specific coal consumption can be misleading in describing the plant efficiency. The variation in delivered calorific values across plants is presented in the Annexure (Figure A2). The first parametric estimation of SHR effectively uses 30 months of data across 129 thermal power plants, which amounts to 170 GW in generation capacity.

For the parametrisation of variable cost, the delivered coal price was estimated for all the plants using the supplied coal grades, mode, and distance of coal transportation data sets obtained from Coal India Limited Koyla Grahak Seva (SEVA) (SEVA, n.d.) and CEA daily coal supply reports (CEA, n.d.) respectively. We assumed rail tariffs for all transportation to non-pithead plants, given that a large share of coal transport is carried over rail for large segments and the costs of merry-go-round were used for pithead plants. The variable generation costs of plants, while available at a high daily resolution (MERIT, n.d.), were averaged to represent variable costs at a monthly resolution over the entire period in order to create a panel dataset across the 30 months.

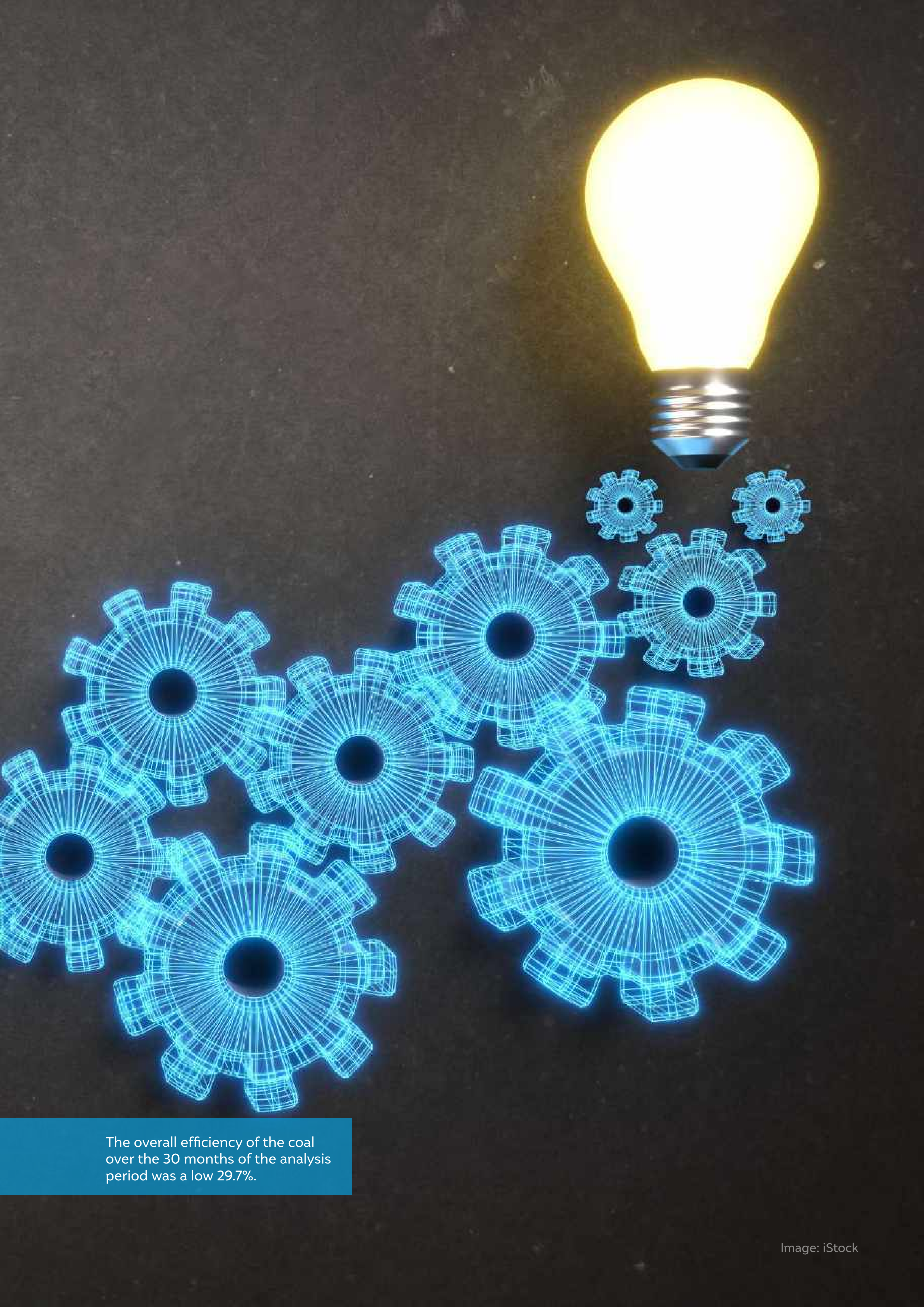
Using this parametrised expression for variable costs, we evaluate the cumulative variable cost of generation in the original generation mix and the reassigned generation mix, to determine overall savings in variable costs associated with the generation. We attribute the total variable costs saving to the various components that we assess as being significant determinants of variable costs.

Finally, given that the allocation process does not factor in operational constraints that requires a more detailed assessment (higher time resolution and network constraints), we provide a high-level view of the changes to regional and state generation mix. In addition, we also assess the sufficiency of the generation capacity that is 'retained' in the model in catering to the needs of the system over the course of this decade.

2 We do not consider the lignite-based generation capacity of 6 GW and a further 6 GW of coal-based capacity that was in early stages of commissioning and 4 GW capacity that was not generating at all in this period.

Methodology flowchart

Source: Authors' compilation



The overall efficiency of the coal over the 30 months of the analysis period was a low 29.7%.

Image: iStock

3. Descriptive results and corollaries

In this section we discuss the descriptive findings of the assessment of the performance of the coal-based power plants. The assessment considers all plants that were operational in the 30-month period from September 2017 to February 2020. Nearly 194 GW of capacity is considered in the assessment. Following the descriptive assessment, we present the parametric representation of station heat rate (SHR) and variable costs (VC), which will then be used in assessing physical and financial performance for the reassigned generation mix, in the subsequent section.

3.1 How are thermal power plants utilised?

Figure 1 illustrates the significant increase in power generation capacity. India has witnessed a huge capacity addition between 2010 and 2020. Nearly 65 per cent of the capacity as of March 2020 was installed in the previous ten-year period. We also note that 39 GW of capacity has been operating well past the economic life assumptions used in the determining the tariffs and returns on investment (CERC, 2014). Table 1 shows that half of the coal assets installed in the past decade have been done by the private sector. The remaining half of the installed capacity was equally shared between the central and state governments.

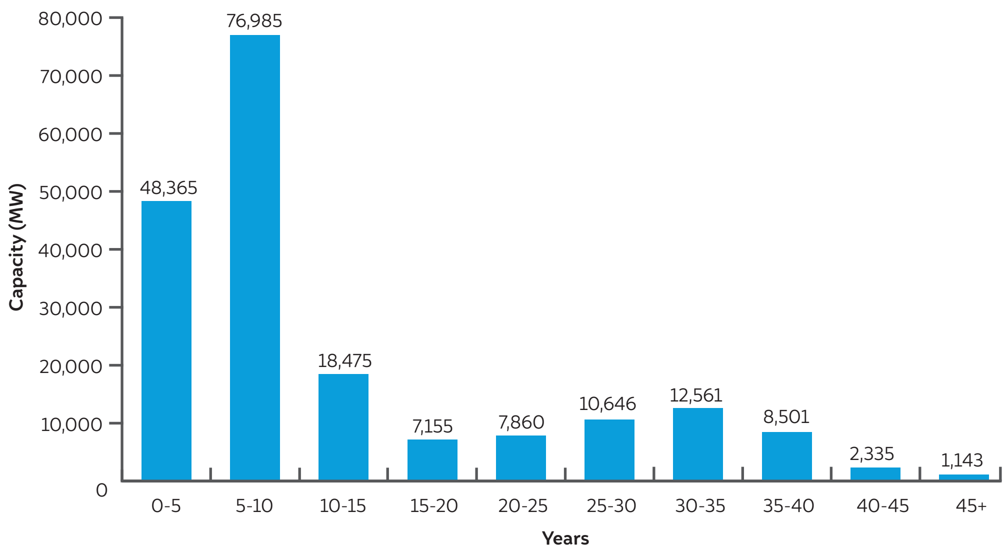


Figure 1
More than 125 GW of coal-based generation has been commissioned in the last ten years

Source: Authors' analysis from CEA daily generation reports

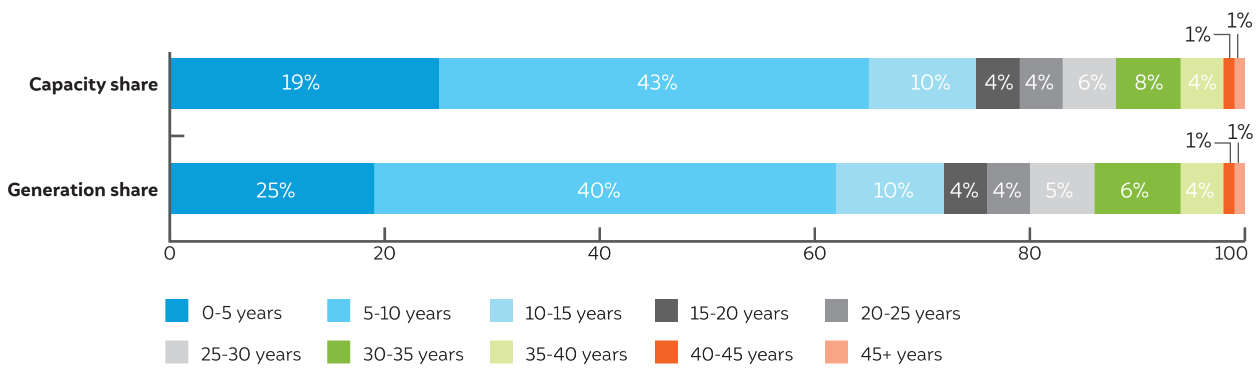
Table 1 Private sector investments have been the major driver of capacity addition in the last decade

Age group	Central sector (%)	Private sector (%)	State sector (%)	Total (%)
0–5 years	8	9	8	25
5–10 years	8	24	8	40
10–15 years	3	2	4	10
15–20 years	2	0.1	1	4
20–25 years	1	0.4	2	4
25–30 years	2	0.3	3	5
30–35 years	4	0.1	3	6
35–40 years	1	0.3	3	4
40–45 years	0	0.1	1	1
45+ years	0.2	0	0.4	1
Total	**30**	**36**	**34**	**100**

Source: Authors' analysis of CEA monthly installed capacity reports

It would be expected that newer plants being more efficient should be generating a higher share of the electricity in the system (as compared to their capacity share), as there would be economic gains from efficient generation. However, Figure 2 shows that the plants less than 10 years of age contribute a lower share to the total generation (62 per cent) than to installed capacity (65 per cent). Concomitantly, older plants contribute a disproportionately larger share of the generation as is clear from the illustration. As we show, it is contracting and other factors that determine this, and not efficiency.

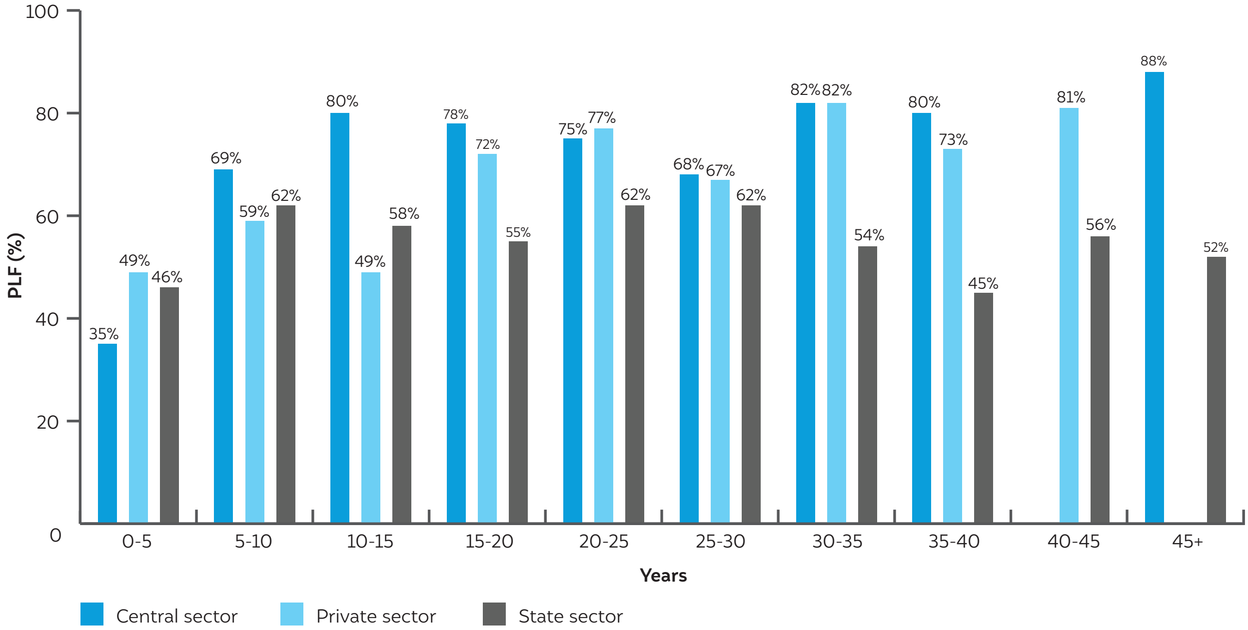
Figure 2 Generation share of young plants are lesser than their respective capacity shares



Source: Authors' analysis from CEA daily generation reports

In order to understand which segment of the plants are utilised poorly, we calculated a weighted average PLF for each category. Figure 3 indicates that the new plants have had very low PLF in the range of 40–60 per cent, while the older plants had high PLFs ranging between 75 and 85 per cent. On the whole, the state plants have been utilized less across age categories. The overall utilisation of the thermal fleet during the assessment period stood at a low of 58.5 per cent. This is clearly much lower than the envisioned PLFs for profitable operations of thermal assets.

Figure 3 State-owned plants show consistent under-utilisation across age groups



Source: Authors' analysis from CEA daily generation reports[3]

3.2 How efficient is the generating fleet of thermal power plants?

There is no consistent recording of data on the efficiency of thermal power plants at a high temporal resolution. What is available is an aggregate annualised metric, reported in tariff petitions filed by power plants and in an irregular CEA publication (with a lag of two years or more) that goes by the name 'Annual Thermal Performance Review'. Neither of these are useful to actually arrive at determinants of efficiency as many factors change over the course of a year and cannot be seen in aggregate. We set out to gather data on SHR at a higher temporal resolution. We accomplished it primarily by superimposing monthly coal consumption with the coal quality delivered, and then converting it to an efficiency metric by accounting for the electricity generated in each month.

The overall efficiency of the thermal operating fleet over the 30-month period stood at a paltry 29.7 per cent as per our calculations. The corresponding SHR was 2,898 kcal/kWh. This is particularly worrying as the improvement in the aggregate heat rate of the fleet over the years has not been commensurate with the pace of improvement in technology. This is not to say that plants did not operate more efficiently at all. A total of 29 plants exhibited an overall efficiency of more than 37 per cent (an SHR lower than 2,300 kcal/kWh) across many months in the analysis period. The median age of these plants was just a little over five years. Clearly, there are plants that are capable of performing more efficiently if the operations and circumstances allow them to.

The parametric estimation of determinants of SHR (kcal/kWh) was done through a panel regression with the independent variables being plant characteristics such as average unit size (MW), the average age of units (years), ownership (state or private, with central as the base), plant PLF (%), and share of imported coal in supply (%). We explored other variables such as measures of variability in (daily) plant loading, as theory suggests that deviation from base-load operation decreases plant efficiency. The daily variation

3 No plants in the central-owned/40–45 years category and private-owned/45+ years category is currently functioning. Also, the total capacity in 15–20, 20–25, 25–30, 30–35, 35–40 and 40–45 age groups of private sector and 45+ group of state and central sectors are insignificant (less than 1 GW).

in loading did not seem to have any relationship with SHR. We present the results of the panel regression below.

shr_kcalkwh	Coef.	Std. Err.	z	P>|z|	[95% Conf.	Interval]
avg_unitcapacity	-.9257423*	.1175411	-7.88	0.000	-1.156119	-.6953658
plf	-330.5712*	24.58023	-13.45	0.000	-378.7476	-282.3948
age_baseline	7.640537*	2.240974	3.41	0.001	3.248308	12.03277
ownership_code						
Private Sector	-23.88326	63.81838	-0.37	0.708	-148.965	101.1985
State Sector	-73.21475	61.39452	-1.19	0.233	-193.5458	47.1163
import_share	225.4556*	92.20298	2.45	0.014	44.74112	406.1701
_cons	3417.812	80.99265	42.20	0.000	3259.069	3576.555

Figure 4
Age, unit capacity, and PLF are key determinants of SHR

Source: Author's Analysis

*Note: * indicates significant at 95 per cent confidence level*

The assessment in Figure 4 suggests that younger plants and large unit sizes have a beneficial impact on SHR. A detailed plot on how SHR varies with age can be seen in Figure A1 of the annexure. Ceteris paribus, a 660 MW unit, in comparison to a 300 MW unit, will have a heat rate lower by 300 kcal/kWh. Given that super-critical units are also identified beyond a capacity threshold, they are alone not useful in explaining the variation and correlated with the average capacity metric. Similarly, a 10-year-old plant will have a heat rate that is 75 kcal/kWh lower than a 20-year-old plant. An improvement in PLF by 20 per cent (in absolute terms) improves the heat rate by 65 kcal/kWh. Clearly, the most significant impact is made by unit size, and newer vintage plants are of an increasingly higher size, as would be expected with technology development.

3.3 Categorisation of the variable cost of coal plants

While the common perception is that older plants are cheaper because their fixed costs are paid for (discussed later in Section 4.2), what we see is that older plants are also often cheaper on a variable cost basis (Figure 5). On account of their lower generation efficiency, it would be expected that their cost of generation at the margin would be higher, but that is not the case. The variability, indicated in Figure 5, states that the age does not have clear implications for variable cost, given other factors at play.

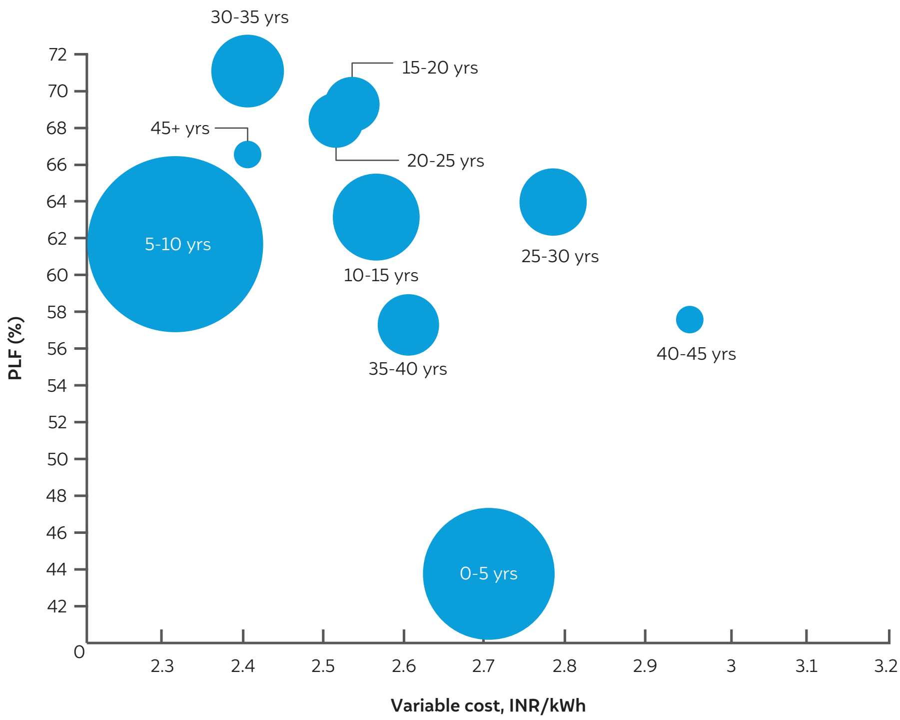


Figure 5
Despite having low variable cost, the PLF of 5- to 10-year group is low

Source: Authors' adaptation from CEA daily generation reports and Merit Order Despatch of Electricity for Rejuvenation of Income and Transparency (MERIT) state-wise daily summary data

Note: The bubble size represents the capacity share of each age group

Even in situations where younger plants, in line with efficiency arguments, have lower variable costs, we find that they are utilised to a lesser extent. How do we explain this? Discoms schedule power from the contracted generators based on the merit order dispatch (MoD) stack. Theory dictates that the generator with the lowest variable cost is dispatched first followed by the next lowest, and the iterative process continues until the energy or power demand is met, subject to technical constraints such as ramp rates and network capacity. The low PLF of certain plants (or vintages) should then reflect their (high) variable costs, indicating they are dispatched to a lesser extent. Interestingly, we see (Figure 5) that plants in the 5- to 10-year age group, which account for 40 per cent of the capacity share, despite having the lowest variable cost, have a lower PLF, compared to plants in the 20- to 35-year group. Similarly, plants in the 0–5 years bucket, despite having a lower variable cost than some of the oldest plants, operated at plant load that was 20 per cent lower. These two observations can be explained by the fact that plants that are contracted (either entirely or partially) are dispatched *only* to the extent they are contracted, as per the MoD. The uncontracted capacity either is typically treated as merchant power and sold on the exchange or through other mechanisms. They contribute to just about 10 per cent of the total procurement of electricity in the country (CERC, 2020). A significant share of capacity of newer plants remains to be contracted and, as a result, they don't get dispatched often.

3.3.1 What determines variable cost of generation at a plant?

On investigating the relationship between the variable cost and delivered cost of coal[4] (Figure 6), we found a high correlation between the two parameters. As expected, to a large extent, the delivered price of energy (INR/Mcal) is what determines the variable cost of electricity. This delivered cost of coal is largely a function of whether plants source coal from nearby mines or far away mines. Rail freight accounts for between 30 and 40 per cent of the delivered cost of coal (Kamboj & Tongia, 2018).

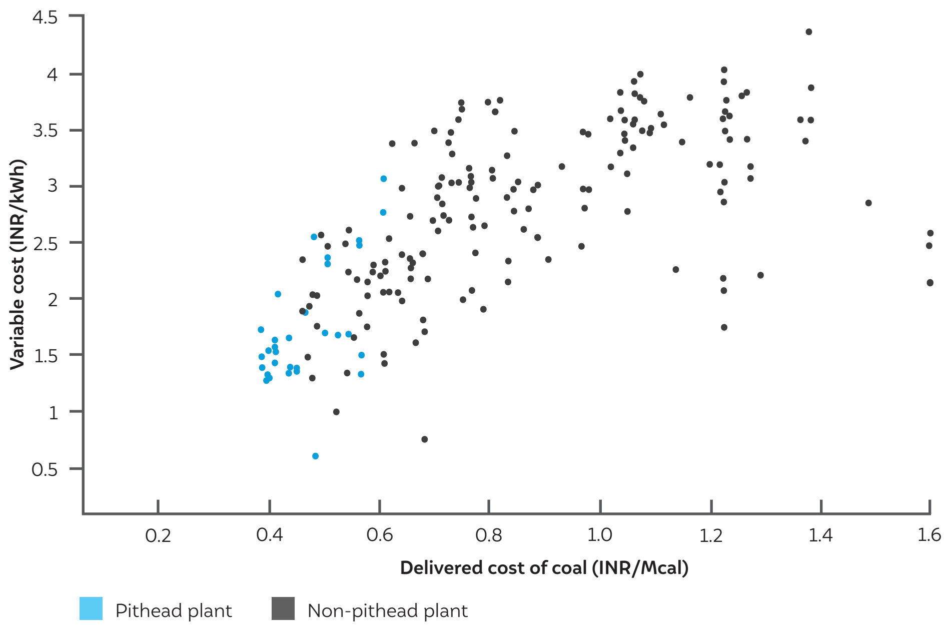


Figure 6
Variable cost of generation is driven to a large extent by delivered cost of coal

Source: Authors' analysis based on compilations from various generation tariff orders

However, in order to understand the determinants of variable cost (INR/kWh) more clearly, we carried out a linear regression-based assessment by considering independent variables such as auxiliary consumption (%), SHR (kcal/kWh), delivered coal price (INR/Mcal), average unit size (MW), and plant age (years). The results of the regression are presented in

4 Delivered cost of coal = Coal price (INR/ kg) / Gross calorific value of coal (kcal/kg).

Figure 7. We carried out this assessment for all the plants that have contracted capacity in part or full. Merchant generators are not considered in this calculation.

wtd_vc	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
shr_kcalkwh	.0001025*	.0000282	3.64	0.000	.0000473	.0001578
del_energy_cost	1.890785*	.0334197	56.58	0.000	1.825259	1.956312
age_baseline	.0074045*	.0012114	6.11	0.000	.0050293	.0097797
avg_unitcapacity	-.0006019*	.0000934	-6.44	0.000	-.0007851	-.0004188
aux_cons	2.827044*	.8023347	3.52	0.000	1.253896	4.400191
_cons	.6517435	.1273899	5.12	0.000	.4019686	.9015184

Figure 7
Other than coal price, age, unit size, SHR and auxiliary consumption were significant determinants of tariff

Source: Author's analysis

*Note: * represents variables that are significant at the 95 per cent confidence level.*

We observed that coal price has the most significant impact on the variable cost of electricity. The average delivered coal prices were at INR 0.74/Mcal. A 0.1 INR/Mcal decrease in coal price would reduce the variable cost by 0.19 INR/kWh, which is a substantial change. A 1 per cent decrease in auxiliary consumption would lower the variable cost by 0.03 INR/kWh. Similarly, replacing a 200 MW unit by 500 MW unit in the energy mix would cut down the variable cost by 0.12 INR/kWh. Running young and efficient plants too reduces the variable costs.

Given the significant upside associated with low-cost coal, we investigated the distribution of coal prices for various vintages of plants (Figure 8). We find that the plants of youngest vintage face a significant burden of high-priced coal and, as explained earlier, given their low levels of contracting, they face a double whammy of not being desirable even in an exchange or in merchant mode.

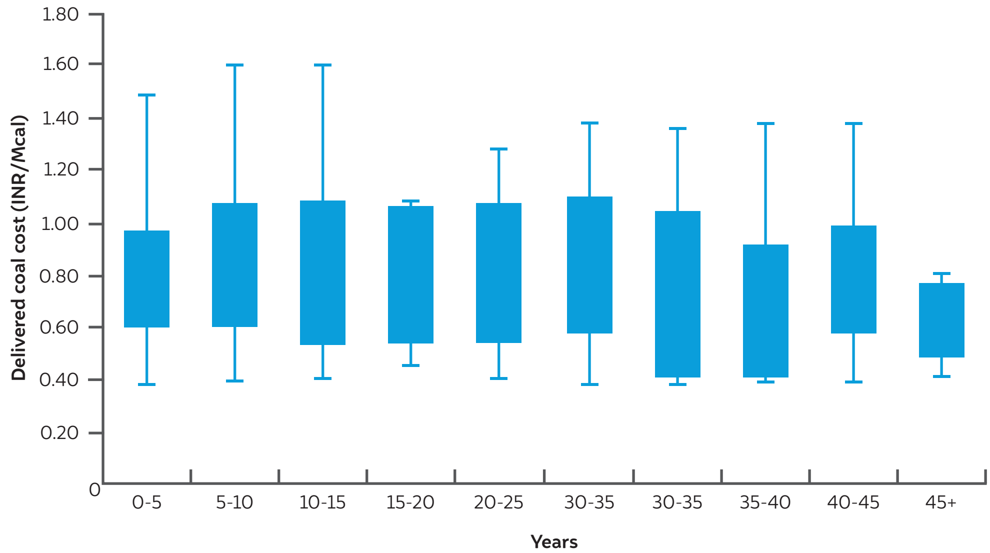


Figure 8
Plants between 30 and 40 years of age access the cheapest coal

Source: Author's analysis based on multiple tariff orders of generation companies

3.4 How does auxiliary consumption vary with vintage?

Another important implication of vintage in operational outcomes is the useful amount of energy that is actually available for commercial sale. Older plants have a higher auxiliary consumption, that is, power consumption within the plant itself (Figure 9). The same amount of energy, to be sold by a newer plant, would effectively require lesser generation to be undertaken, as more of the generated power will be available for sale. This in turn will reduce the amount of coal to be fired to generate electricity to that extent.

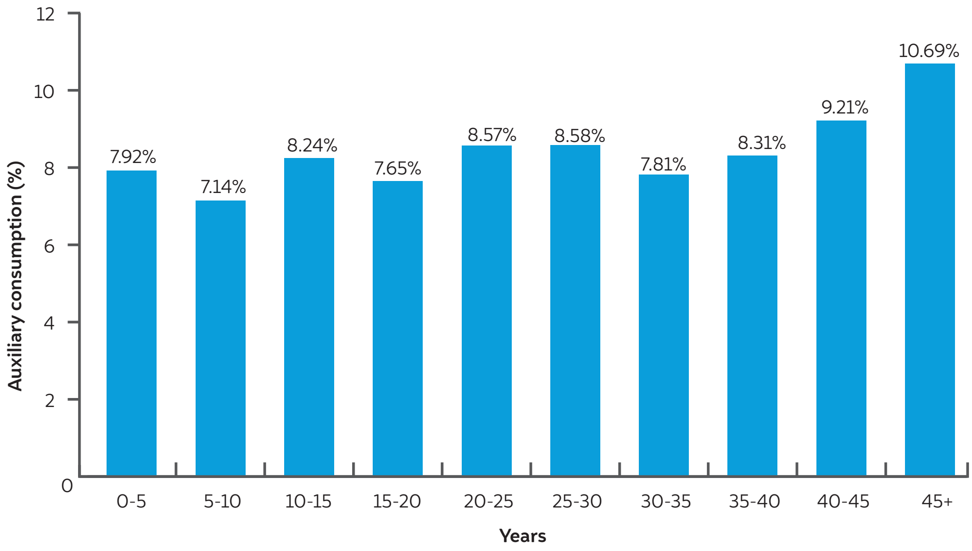
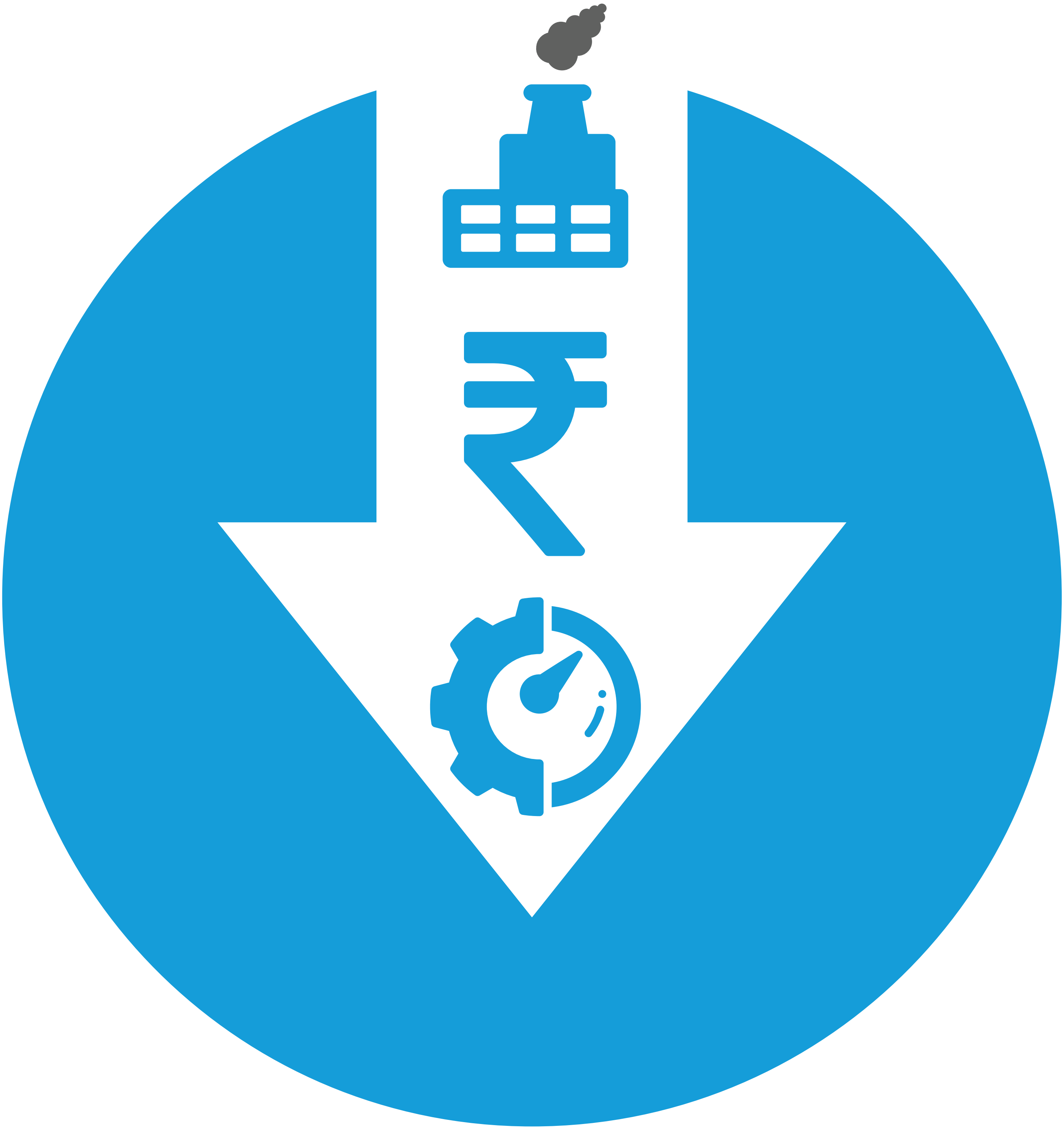


Figure 9
Older plants consume a high percentage of power produced for its own operation

Source: Authors' analysis based on compilations from various generation tariff orders



Improving the efficiency of the coal fleet by 6%, would reduce the CO_2 emissions by ~ 42 MT.

4. Results of generation reassignment and impacts

As illustrated in the previous chapter, there are quite a few distortions in the way the power system is structured, giving rise to a thermal generation profile that is inefficient (as measured by the SHR), wasteful, and possibly proving to be expensive for the discoms and end-consumers. We demonstrate a high-level reassignment of generation across assets in a bid to improve efficiency and examine if such a reassignment leads to overall reduction in cost of power procurement.

50 GW of coal-based capacity is potentially surplus to our needs

To do this, we determine the SHR for all generation stations in the mix based by assigning a graded PLF to plants—highest for newest vintage to lowest for the oldest vintage plants (as explained in Chapter 2). The target PLFs are laid out in Table A1 of the Annexure. The parametric equation derived earlier to represent SHR is used in estimating SHR across plants. Given that they capture the typical operation of the power plant, there is significant slack in the PLFs to cater to a higher demand and leave some slack for considerations of peak demand or contingencies. The average daily generation requirement (median generation is about the same) over the 30-month period is considered for the reassignment. For the period September 2017 to February 2020, the average daily generation was 2,722 MU. We order the plants based on their evaluated SHR and assign generation to the plants, until their target PLFs are met. The generation then spills over to the next plant and then to the next iteratively until the entire generation need is met by the stack of plants. The generation stack will differ from the actual generation stack, as the dispatch criteria invoked in this exercise is generation efficiency and not variable cost or any other criteria.

We assess the individual variable cost of generation for plants by including the appropriate parameters into the parametric equation describing the variable costs (Equation 2, Chapter 2). We then evaluate the total variable cost of generating electricity, by summing up the individual generation cost of each dispatched plant in the efficiency stack order.

In our assessment, we have determined that nearly **50 GW of thermal generation capacity** is surplus to the requirements of daily average generation needs of the system in the 30-month period and are not called on to generate any electricity. Even while catering to the current demand, the requisitioned fleet is operating at an aggregate PLF of 78.9 per cent. The PLF of the generating thermal fleet was at 58.5 per cent in the base case, as explained already. The vintage profile of the plants retained in the generation stack and rendered surplus is as indicated in Table 2.

Age group	Total capacity (MW)	Surplus capacity (MW)	% Rendered surplus
0–5 years	48,365	605	1%
5–10 years	76,983	5168	7%
10–15 years	18,475	8885	48%
15–20 years	7155	3155	44%
20–25 years	7860	5860	75%
25–30 years	10,646	7146	67%
30–35 years	12,561	7561	60%
35–40 years	8501	8501	100%
40–45 years	2335	2335	100%
45+ years	1142.5	1142.5	100%
Total	1,94,024	50,359 (26,686)	26%

Table 2
Much of the older capacity is deemed surplus to the needs of the system in the analysis period

Source: Author's analysis
Note: The ones indicated in red are older than 25 years, the economic life of plants as per CERC

The plants that have been identified as surplus to the needs of the system are listed in the annexure (Table A7). A discussion on their future prospects is provided later in Section 4.3.

We now focus on the implications of this reassignment on the overall efficiency of the generation fleet, coal savings, the overall cost of generation, the need for retrofitting with pollution control technologies, the regional and state-wise change in thermal generation profile, the ramping up capacity of thermal fleet, and finally, on the ability of the retained fleet to support future demand.

4.1 Implications for efficiency, coal consumption, and variable cost of generation

On reassignment, we find an overall improvement in efficiency, in relative terms, of about 6 per cent. The SHR of the fleet as a whole would improve from 2,898 kcal/kWh to 2,719 kcal/kWh. This translates into an absolute improvement in the efficiency of generation from 29.7 per cent to 31.6 per cent. This is a logical and expected outcome, as plants are now being dispatched based on an efficiency stack order and not a variable cost stack order. Many older (by age) plants that are low on efficiency are not requisitioned any more.

This is expected, because of the overall improvement in efficiency and how it bears a linear relationship with energy input (expressed in kcal). The total reduction in coal consumption stands at 42 MT (6 per cent reduction) of coal. Figure 10 shows that plants that are over 30 years of age consume over 104 MT of coal annually. As most of these plants are not requisitioned in our reassignment, they contribute to a large extent to the savings on coal.

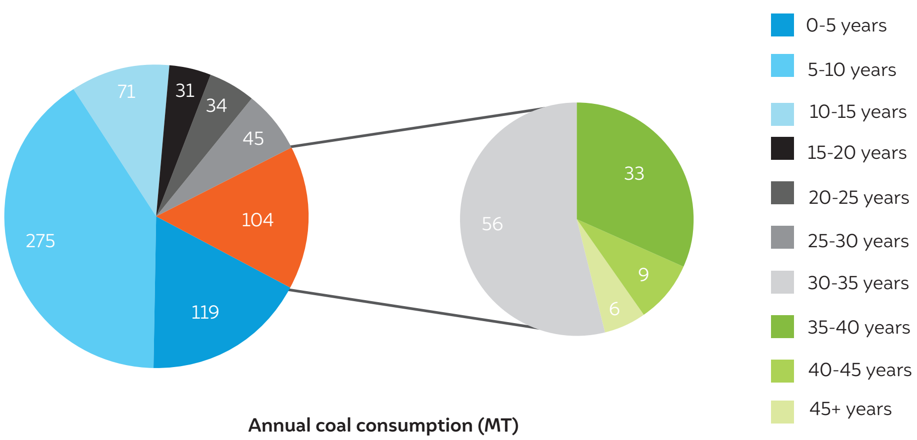


Figure 10
In the base case, 15 per cent of total annual coal requirement comes from plants over 30 years of age

Source: Authors' analysis based on CEA monthly coal statement

How does savings on coal contribute to variable costs? We further evaluate the variable cost savings by computing the difference between total cost of generation in the actual scenario and the reassigned scenario. To do this, we use the parametric estimation equations we arrived at, as described in Chapters 2 and 3. We rewrite the expression representing variable costs (Equation 2, Chapter 2) as follows:

Variable cost = Constant + B1*SHR+ B2*Delivered coal price+ B3*Age +B4*Unit size+ B5* auxiliary consumption ...... (2)

Delta_variable cost = Delta_SHR + Delta_Delivered Coal Price + Delta_Age + Delta_Unit size + Delta_auxiliary consumption ...... (3)

In catering to our current level of demand, 42 MT of coal can be saved by improving efficiency of generation

In order to assess the difference in total variable cost of generation in each scenario, and the contribution from the various determinant (significant) factors, we rejig Equation 2 to the form of Equation 3. In Equation 3, the total quantum of generation from each plant in each scenario is already factored in. From this equation, we find that the contribution of efficiency as represented by the SHR term is INR 1,968 crore. Other variables like age and unit size, which are also the determinants of SHR (as shown in Equation 1, Chapter 2), contribute around INR 11,214 crore.

The impact of delivered coal price is negative, as expected, as the price of coal to new plants in the efficient stack is higher than in the base case. The loss as a result of increase in the delivered price of coal is INR 5,133 crore. The reassigned fleet also has a significantly lower auxiliary consumption, as many of the older plants are not generating as much anymore. The savings associated with improved auxiliary consumption performance of the fleet amounts to INR 916 crore. As per our assessment, the total variable cost savings were evaluated to be INR 8,944 crore. The formulation of the parametric representation of variable cost can be rethought by collecting more data and further disaggregation, which might shift the balance of contribution of different factors.

4.2 Implications for investment in pollution retrofits

For continued operation of plants, beyond their economic life, they need to comply with environmental norms, specifically for pollutant emissions such as sulphur oxides (SO_x), nitrogen oxides (NO_x), and particulate matter (PM). As per the norms laid out for power plants in the 2015 notification by the MoEFCC (MoEFCC, 2015), nearly 166 GW worth of capacity was identified as needing to install pollution control retrofits, specifically flue gas desulphurisation systems (FGD) to control for SO_x. This has been an issue of major contention, as plants have been slow to comply with the norms. This situation was further aggravated by state electricity regulatory commissions (SERCs) showing a lax attitude and uncertainty in implementing (in letter and spirit) the 'change in law' provision that this notification brought in. Even those plants that have desired to be in compliance and began the process in earnest were ensnared in process and legal bottlenecks (APTEL, 2020).

The delivered coal price of the reassigned fleet is higher than the base case, as the coal transportation distance increases

At the core of the morass, that is the retrofitting process for compliance, is the unwillingness of actors across the board to invest and allow for investments to be recouped from the customer. It is deemed to be a burden on a consumer base that is already unwilling to pay for electricity service provision (PFC, 2020; Aggarwal & Ganesan, 2020; Banga, 2018). The most recent notification from MoEFCC (MoEFCC, 2021), allowing for a further delay in retrofits till 2025 is a further indication of the unwillingness of policymakers to push the plants for compliance and the lax implementation regime. However, given the implications for human health, of continued emissions from power plants, it is imperative that a middle ground will have to be found for ways to efficiently and expeditiously install retrofits.

In a 2019 study, we found that 39 GW of capacity, which was indicated for retirement by 2027, would cost the system INR 14,300 crore in retrofits for reining in SO_x emissions (Garg et al. 2019). An assessment of the plants that were deemed surplus to the needs, in this study, suggested that nearly 35 GW of capacity of the identified surplus 50 GW was part of the CEA notification to meet the new emissions standards. Of this 35 GW, only 1.5 GW complies with the emissions norms and has installed flue gas desulphuriser (FGD) systems. The remaining plants are at various stages of the process (of compliance) while a bulk of the plants (more than 60 per cent) are yet to issue any formal tender to a potential contractor. Details of the various stages at which plants are in the process of installing retrofits is indicated in Table A9 in the Annexure.

More than INR 10,000 crore in savings from avoided pollution control retrofits, in favour of early decommissioning

We find that if this 33.5 GW worth of plants are deemed surplus, the costs involved in retrofitting these plants can be considered as a saving, though it is a one-off saving. The total cost of retrofitting these plants was estimated to be INR 10,250 crore, based on the same methodology used in Garg et. al (2019). The savings are primarily from avoiding retrofits for FGD in these non-operational plants.

4.3 Overall implications of reassigning the generation mix

Our assessment finds that the reassigned generation mix provides for the same demand as in the base/actual scenario, with INR 8,944 crore lower variable cost. A significant portion of this savings is attributable to the savings from avoided coal consumption, on account of higher energy efficiency of the system. The reassignment prevents nearly 42 MT of coal from being unnecessarily consumed annually and also proportionately reduces the GHG and criteria pollutant emissions and generation of fly ash. Additionally, we find that one-time savings of INR 10,250 crore in avoided pollution retrofit costs can also be made. This of course does not capture the recurring benefits of avoided variable costs in pollution abatement from these plants that are deemed surplus.

In earlier sections (and indeed throughout the report) we refer to the reassigned scenario (based on an efficient stack) and to plants that are deemed surplus to the requirements of the reassigned scenario. However, we have stopped short of commenting on what happens to these plants that are deemed surplus. The plants that are not dispatching in the reassigned scenario will continue to service the debt obligations, have fixed operation and maintenance (O&M) expenditure of plants (including salaries for staff), and general up-keep of the facility. These costs will remain the same in the actual and reassigned scenario. The CEA, in the *National Electricity Plan* (2018), has specified a clear timeline for decommissioning coal-based assets to the extent of 42 GW by 2027. We find that 30 GW of capacity that has been identified as surplus in our analysis also finds place in the CEA's assessment for decommissioning by 2027. **This 30 GW of capacity must necessarily be considered for accelerated decommissioning**, possibly before the CEA timelines to realise savings explained before. Additional savings could be realised from decommissioning these plants, through sound financial engineering, which captures the value of reducing risks from future cash-flow challenges for these assets if they are decommissioned now than later.

A further 20 GW of capacity that we have identified as surplus in our analysis primarily consists of plants that are younger than 25 years (as of February 2020). There is clearly a use case for these plants, though they were deemed surplus to the needs of the system based on efficiency considerations. For these plants, a **temporary moth-balling could be considered** and they would not be requisitioned or considered in the MoD stack by load dispatch centres, unless and until there is a clear need for this capacity to come online. Again, given that fixed cost payments will continue to be made to these facilities, we expect that the general up-keep of the facility will be possible and the plants will be able to come online, with sufficient notice and preparations.

4.4 Implications for technical operations of the grid

As assessed earlier, the main outcome of the reassignment was to designate a set of plants as being surplus to the needs of the system catering to the 'average energy demand' over the last 30-month period. In the process, nearly 50 GW worth of generation capacity was designated as being surplus (some to be decommissioned and some moth-balled, as detailed above). The overall PLF of the generating fleet increased by nearly 20 per cent in the process as expected. However, given that the reassignment did not really consider any network-related constraints, we make an assessment using high-level metrics to understand some key implications of such a reassignment exercise.

In the reassigned scenerio, the overall PLF improves to 79% from the baseline of 59%

A critical assessment is to see how the generation profile changes across the different regions of the country. We find that the Southern region would show a significant increase in overall generation by almost 11 per cent in the reassignment scenario. Concomitantly, the Eastern and Northern regions are expected to record a decrease in generation by 9 per cent and 6 per cent, respectively. The Western region would see a marginal increase of 3 per cent in generation (Table A3). While these changes in regional generation throw up concerns over the ability to move power between the regions, we see that over the course of the last 30 months, the individual regions have generated much larger amounts of thermal energy and also contributed a much larger thermal share to the grid than in the reassigned scenario (Table A8). At the day-level resolution, we see that these changes do not pose an operational challenge to the grid. However, the reassignment needs to be investigated at a higher temporal resolution to assess if such a shift in regional distribution of generation is likely to disrupt the system.

While regional considerations are important in system operations, from the perspective of individual discoms and states, exercising control over generation sources is perceived to be important. As there is a significant decrease in operational capacity (required) in the reassigned scenario, states across the board would see a reduction in their generation base. Nearly 60 per cent of the reduction in capacity in the reassigned scenario is attributed to the state-owned plants. Clearly, these plants were most inefficient in the stack and did not get requisitioned. In states like West Bengal and Rajasthan, this is most pronounced with more than 40 per cent decrease in overall installed capacity. Most states would witness a decrease in capacity between 20 and 30 per cent. However, states like Odisha, Haryana, Madhya Pradesh, and Assam are likely to experience lower levels of change (<20 per cent) to their capacity base. Further, state-owned plants are also likely to witness a 23 per cent reduction in generation from the base scenario. States such as Jharkhand, Chhattisgarh, Gujarat, Tamil Nadu, and Punjab may even experience a 40 per cent reduction in the generation from state-owned plants. Given that overall generation must remain constant across both scenarios (as they serve the same demand), for most states, the loss in generation from state-owned plants is made good by increased generation from private sector plants (Table A5). States like West Bengal would encounter a significant erosion (31 per cent) of overall generation within the state boundary, while Karnataka would notice a drastic rise in power generation (85 per cent). Barring these exceptions, overall generation changes within state boundaries are within ±20 per cent (Table A4).

Generation in the Southern region increases by nearly 11%, but a high level assessment does not suggest operational challenges from this

Over and above the split in generation across different regions, states, and ownership types, it is also important to address if some important attributes like system ramping capabilities change significantly as a result of this reassignment and consequent moth-balling of capacity. With the non-availability of many older units, it is expected that ramping capacity would decrease, as older units have published (and theoretical?) ramping rates that are higher than units of a newer vintage. We find that at the national and regional level, the ramping capacity changes may see a perceptible dip of nearly 26 per cent. At the national level, the ramping (up and down) capacity drops from 1,600 MW/min to 1,200 MW/ min

(Table A2). High temporal resolution dispatch data (15-minute time block) is available only for centrally owned inter-state generating stations (ISGS). We analysed the operations of the ISGS stations that are deemed surplus in our reassignment (~7.5 GW) and found that 3.5 GW of this capacity is used for ramping during peak hours to cater the peak demand[5]. The list of ISGS plants can be found in Table A10 of the annexure. However, it is worth mentioning that, for the most part, the observed peak ramping rates of the system over the last operational year saw the thermal fleet utilising only a fraction (5 per cent) of this ramping capacity (MERIT, n.d.). Importantly, most state-owned plants also do not contribute significantly to the ramping needs of the system presently and as a result, even in a reassigned scenario, we do not foresee a paradigm shift in the way the system ramping would be managed.

The discussion on ramping then brings us to the important question of what about contribution of thermal assets to the peak demand in the country? It is well known that, given the absence of 'peaker plants', we rely on our thermal coal plants to cater to the peak demand for several months. The demand surges typically during the evening and night hours and RE is not able to provide the matching supply. The system we are left with, in the reassigned scenario, has a total operational coal capacity of 143 GW. The actual peak contribution of thermal power plants, in the assessment period, is 140 GW. This clearly suggests that at the peak, the coal generation fleet has little slack to cater to any further increases in peak demand. However, the capacity considered in this assessment excluded nearly 6 GW of lignite-based capacity and 5.7 GW of coal assets that were in the early stages of commissioning over the assessment period. This again suggests that system would be able to cater to the peak load

4.5 Implications for supply and adequacy in future years (2020–2030)

The final aspect of our evaluation is to assess how much of the demand in the later years of this decade will the retained plants be able to cater to? Here we consider future demand projections as envisioned in the NEP (CEA, 2018) and the CEA's Optimal Generation Mix Study for 2030 (CEA, 2019). As proposed earlier in this chapter, we envision that of the 50 GW of capacity identified as surplus, 30 GW must be primed for decommissioning at the earliest, while 20 GW of generation capacity is of a newer vintage that might still be beneficial to the system from an operations perspective or to cater to sudden (or gradual) growth in demand. While assessing system adequacy in catering to the overall demand (not necessarily from a network operations perspective), the retained fleet of 143 GW of capacity will be considered, in tandem with the proposed moth-balled capacity (20 GW) and any new capacity that will be added online from February 2020.

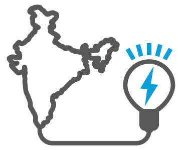
While theoretical ramping capacity (MW/min) sees a dip of 26%, only 3.5 GW of capacity that is actually used for ramping purposes is shelved in the reassigned scenario

On new capacity that is under construction, we rely on existing data from CEA on the status of such plants. The latest report available suggests that a total capacity of 60 GW is under construction as of February 2020 (CEA, 2021). Of this 60 GW, specific timelines for construction and commissioning (acknowledging delays) have been proposed only for 36 GW of capacity. The construction of remaining 24 GW of capacity is either on hold, the assets are stressed, or there is uncertainty about the future progress of the construction or commissioning.

5 The ISGS dispatch data is available in the public domain only from June 2020. Hence, the analysis was done for the period January – February 2021 and does not overlap with the analysis period (September 2017 – February 2020).

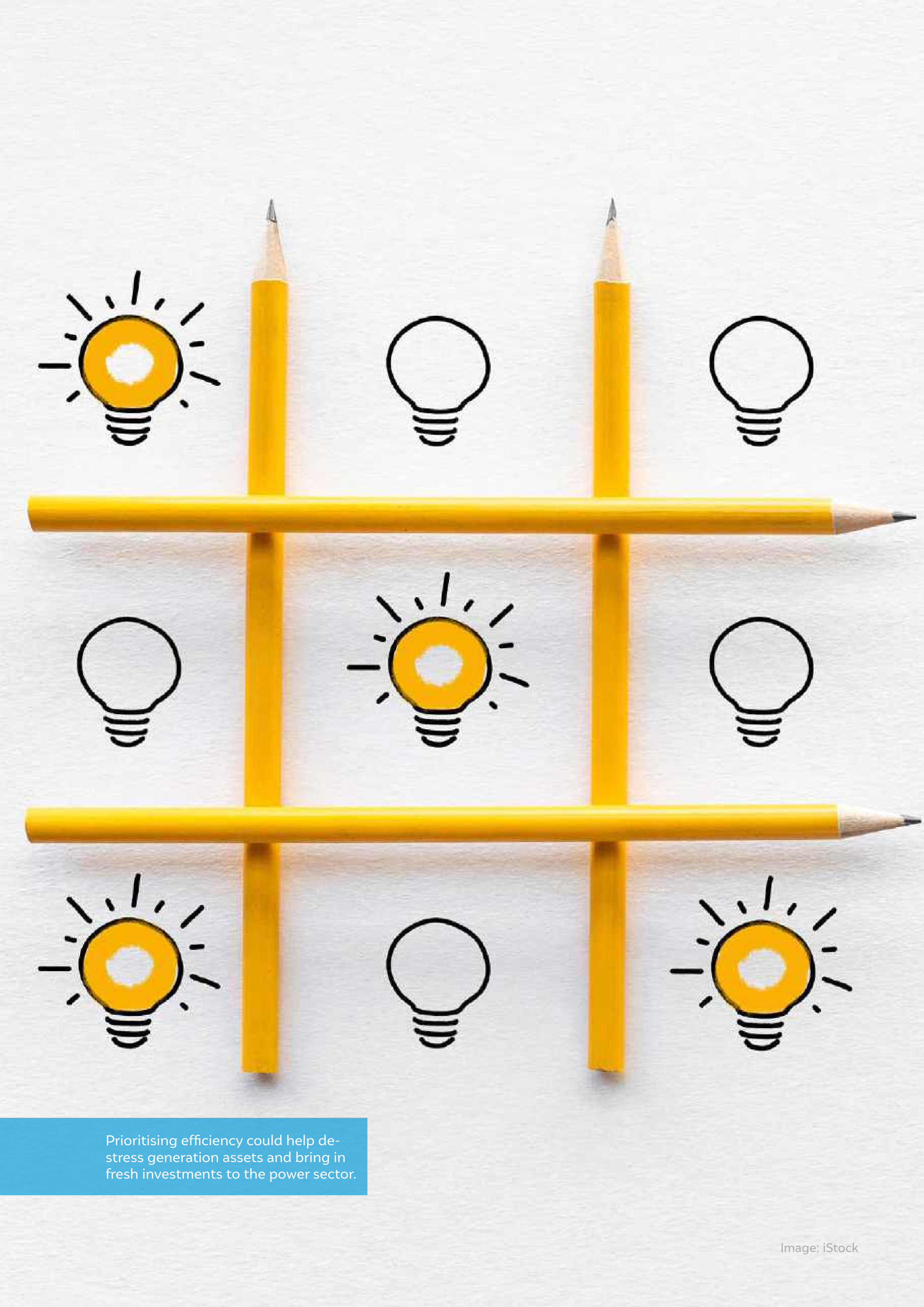
As mentioned earlier, in addition to the 143 GW of capacity retained in the analysis, there is an additional 12 GW of lignite and coal-based capacity (existing) that was not considered in the assessment. In total, we forecast 175 GW[6] of capacity as *potentially* available to supply to the system, through the rest of this decade, excluding any new capacity that might come on board from the projects under construction.

As per existing projections made in recent studies by the CEA, the share of coal in overall generation reduces from 68 per cent in 2022 to 62 per cent in 2027 and 58 per cent in 2030. In absolute terms, the generation from coal is expected to rise over the years. We find that, even by just considering the active 143 GW and moth-balled capacity (of 20 GW), the generation from this limited coal fleet is able to provide for 108 per cent of the average supply expected from all-coal assets in 2022 and 77 per cent of the supply expected from all-coal assets in 2030. If we consider days when the demand from coal is at its peak (winters and late monsoon period), we find that this limited coal fleet is able to provide 91 per cent of the peak supply expected from all-coal in 2022 and 66 per cent of the peak-supply expected from all-coal in 2030 (Table A6). With significant capacity of coal going to be made available to the system in the later years of the decade, we assess that the retained fleet is able to contribute disproportionately to the needs of the system. Experts are sceptical that the aggressive roll-out of 450 GW of RE by 2030 may not happen as the economy in the post-COVID scenario is likely to experience some teething issues, deflating some of the growth potential for all sources of energy generation. Equally, it can be expected that a sluggish economic growth would also dent the electricity demand as well in such a scenario. It is also more likely that the under-construction coal assets would see the light of day (given the significant resources already expended) at the expense of new RE capacity, the costs of which may not be justified (notwithstanding climate commitments). Under the various scenarios that could pan out in future, as explained, we are confident that the retained coal capacity would be sufficient and would contribute more than its fair share to the supply that would be expected from all coal assets over the course of this coming decade.



The retained thermal capacity and new generation capacity on boarded in this decade is sufficient to meet projected electricity demand

6 143 GW retained from the original starting point of 194 GW + 12 GW of capacity not considered in the assessment + 20 GW of capacity that is moth-balled (from the 194 GW).



Prioritising efficiency could help de-stress generation assets and bring in fresh investments to the power sector.

Image: iStock

5. Conclusions and recommendations

In this important study, we set out to examine the composition of the thermal (coal-based) generating fleet currently in use in the Indian power system, propose possible efficiency improvements, and the resulting financial and economic benefits from such improvements. We proposed a novel parametric estimation-based approach to characterise the efficiency of the thermal fleet and its variable cost structure. The parametrised functions further helped propose a dispatch stack that was based on energy efficiency of electricity generation and the costs associated with such a dispatch stack.

A reassigned scenario yields variable costs savings of ~INR 9000 crore a year

We found that at the aggregate level, an efficiency-based dispatch stack makes 50 GW of generation capacity redundant and surplus to the needs of serving the average demand over the analysis period (September 2017 to February 2020). The overall PLF of the fleet improves drastically from 59 to 78 per cent. The efficiency of the overall dispatch, in the reassigned scenario, is higher by about 6 per cent and the overall SHR falls to 2,719 kcal/kWh. In other words, the efficiency of the fleet improves from 29.7 to 31.6 per cent. A direct consequence of this efficiency improvement is that the overall coal consumption associated with generation drops (almost proportionately) and results in a coal savings of 42 MT of coal annually, on a base of 679 MT. This would translate to CO_2 emissions savings of to the tune of 42 MT annually and significant reduction in criteria pollutant loading as well. The financial implications of this efficiency-based reassignment of generation resulted in annual savings of INR 8,944 crore, primarily driven by avoided coal use in generation and savings in auxiliary consumption. There is also an opportunity for a one-time saving of INR 10,250 crore in avoided retrofit costs for plants that are part of the efficient generation stack.

On the critical question of what we propose to do with the identified surplus capacity, we arrived at a two-pronged solution. Around 30 GW of capacity, which overlaps with the plants identified in the NEP for retirement by 2027, must be considered for accelerated decommissioning, given the economic and environmental benefits associated with them not requiring to generate power. Each passing year of delay in letting them continue to generate implies that the system becomes more expensive and emission-intensive as a whole. Based on the financial solutions that we can come up with, decommissioning could also result in savings of the fixed cost outlays over the course of the remaining (contractual) life of these assets. For 20 GW of capacity that represents plants of a newer vintage and not identified for retirement in the NEP, we propose a temporary moth-balling of these facilities. Given that fixed cost payments are contractual obligations and must be made, we envision that these facilities will continue to be available for the system should the need arise. Given the uncertainty in demand outlook post-COVID and the trajectory of RE growth over the course of the decade (despite the aggressive target of 450 GW by 2030), the availability of these plants, over and above those that are under construction, provides a cushion for operational contingencies and supply adequacy. In the worst-case scenario, if they were to remain idle for the rest of their lives, it would still be a beneficial outcome, for the end-consumers and discoms, as they are anyway inefficient and the system is better off relying on other plants.

While the reassignment exercise did not consider any operational constraints associated with the grid, we performed an evaluation using high-level metrics that gave a glimpse of the operational disruptions that the reassignment exercise could pose. The slack in the system is obviously lower, with the fleet PLF going up to 78 per cent, which would require more efficient coordination on part of the system operator. State-owned generation assets account for 60 per cent of the capacity that is rendered surplus. The system is now more reliant on private sector plants and, as a result, the cushion of payment delays to state-owned plants that currently prevails would drastically come down. The impact of reassignment on states is uneven, with significant capacity reduction in West Bengal and Rajasthan. In generation terms, West Bengal is likely to experience a significant decline in overall generation of more than 40 per cent and Karnataka would witness a rise in generation by 85 per cent. The change in generation mix to a younger fleet also means that technical ramping capacity is also reduced. Given that the system today uses only a fraction of the capacity that is available in surplus, we conclude that this is not a significant barrier to the overhaul of the generation mix.

The NEP also identifies these 30 GW of capacity for decommissioning by 2027. This must be accelerated to realise these savings

On the two important questions of adequacy of such a system to cater to peak demand and for supply in the future years, we find a significant slack in the system by way of the additional capacity that we have not considered in the analysis—lignite plants (6 GW), newly commissioned coal-based capacity (5.7 GW), and plants under construction that are likely to come on board in this decade (36 GW). Over and above these capacity additions, the option to moth-ball 20 GW of capacity provides a ready breathing space for the system, should the need arise. However, rigorous assessment of the demand over the coming years and planning for operational dispatch bottlenecks would help ascertain the extent to which these redundancies would have to be made use of in case of an unexpected surge in demand.

The main takeaway from this exercise is that a unified electricity market, which treats the entire country as one dispatch region, is a desirable one. We echo the recommendations of Central Electricity Regulatory Commission (CERC) discussion paper on the redesigning of the day-ahead market for electricity and a focus on a shift to market-based economic dispatch (MBED) and move away from bilateral scheduling of generation (CERC, 2018). As India attempts to make a shift towards MBED, the need to assess efficient assets becomes even more important and the culling of surplus assets is implicit in the process. However, for this to happen, there is a fundamental change that is needed—the sanctity of variable costs in the Indian power system must be questioned. Given the distortions in the fuel market, lop-sided fuel availability and the unequal bargaining power of various actors in the system, we are unable to have a system where the lowest cost system is also the most efficient in terms of thermal efficiency.

Despite the increase in consumption of coal, this approach helps rein in coal dependence and eases financial pressure on the system

India has made ambitious commitments to reduce GHG emissions on account of global agreements and the health emergency that our population faces on account of sustained levels of air pollution, to which thermal power plants contribute significantly, imply that it is in our interest to reduce coal use, in every way possible. While India's reliance on coal is likely to continue and rise over the course of this decade, there is a need to examine the opportunities that exist in the power sector today to rein in wasteful coal use. The overall generation efficiency of the fleet currently points to a lack of emphasis on efficiency, despite the power sector being strongly regulated with clear requirements for adhering to design efficiency standards.

The overall financial savings associated with the reassignment exercise (in ‘000s of crore) is paltry when compared with the annual expenditure on procurement of electricity (in the ‘00000s of crore). However, what is crucial and has ramifications for the system as a whole is the ability to breathe new life into the system by decommissioning and moth-balling inefficient assets and giving new life to efficient but stranded assets that can then provide for relief to the banking system, by creating cash flows for stranded assets and slowly but surely resolving the NPA issue. The surplus capacity issue in the Indian system is likely to persist over the course of this decade and this exercise must be taken up officially. More temporally resolved data needs to be used to detail the challenges in achieving the outcomes outlined. Enabling a financially solvent power system can help in moving the power sector to the next step to address more pressing issues of energy transition.

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Annexure

Table A1 Target PLFs assigned to the units in the reassigned scenario

Age group	Target PLF in reassigned scenario (%)
0–5 years	85
5–10 years	85
10–15 years	80
15–20 years	75
20–25 years	70
25–30 years	65
30–35 years	60
35–40 years	55
40-45 years	55
45+ years	55

Source: Authors' analysis

Table A2 The system becomes less flexible in the reallocated scenario losing out on 26 per cent of the ramping capabilities

Region	Actual scenario		Reassigned scenario	
	Ramp up (MW/min)	Ramp down (MW/min)	Ramp up (MW/min)	Ramp down (MW/min)
Eastern Region (ER)	289	279	207	199
North-Eastern Region (NER)	1	1	1	1
Northern Region (NR)	408	363	289	257
Southern Region (SR)	311	322	231	239
Western Region (WR)	648	656	494	501
Total	1657	1621	1223	1198

Source: Authors' analysis based on the POSOCO report on ramping capabilities of coal-fired generation in India

Table A3 Southern region generates 11 per cent more in the reallocated scenario

Region	Actual scenario (MU)	Reassigned scenario (MU)	Difference from actual (%)
SR	496	548	11
NR	570	535	–6
ER	488	444	–9
WR	1158	1188	3
NER	11	9	–16

Source: Authors' analysis based on CEA daily generation reports

Table A4 Daily average generation by states in the actual and reallocated scenario

State	Total capacity—actual scenario (MW)	Actual generation (MU)	Total capacity—reassigned scenario (MW)	Reassigned generation (MU)	Difference in generation from actual scenario (%)
Andhra Pradesh	11,290	156	8380	168	7
Assam	750	11	750	9	–16
Bihar	6040	95	4675	85	–10
Chhattisgarh	22,723	315	18,430	352	12
Gujarat	14,692	213	9800	200	–6
Haryana	5540	61	4620	88	44
Jharkhand	4460	73	3090	58	–20
Karnataka	9480	77	7150	143	85
Madhya Pradesh	20,490	333	17,260	338	1
Maharashtra	23,115	297	16,320	299	0
Odisha	9450	120	8570	163	36
Punjab	5680	68	3920	75	12
Rajasthan	7580	110	4340	84	–23
Tamil Nadu	9220	123	6700	137	11
Telangana	7422.5	139	5600	100	–28
Uttar Pradesh	22,455	331	16,360	287	–13
West Bengal	13,636	199	7700	136	–31
Total	194,023.5	2722	143,665	2723	

Source: Authors' analysis based on CEA daily generation reports

Table A5 Private plants' share increase in the reassigned generation mix

Ownership	Actual scenario (MU)	Reassigned Scenario (MU)	Difference from actual (%)
Central sector	901	868	–4
State sector	872	673	–23
Private sector	949	1182	25

Source: Authors' analysis based on CEA daily generation reports

Table A6 Share of future demand met by retained assets in comparison to all demand from coal-based generation

Year	Average daily demand (MU)	Share of coal (%)	Average demand from coal (MU)	Demand from coal on peak days (MU)	Supply from retained fleet (MU)	Share of average demand met (%)	Share of demand on peak day met (%)
FY 2022	4290	68	2917	3443	3157	108	92
FY 2027	5608	62	3477	4103	2982	86	73
FY 2030	6370	58	3695	4360	2875	78	66

Source: Authors' analysis based on optimal generation mix by 2029–30, National Electricity Plan 2018 and CEA daily generation reports

Table A7 Plants deemed as surplus in the reallocation scenario

Plants to be decommissioned:

Unit ID	State	Ownership	Age	Capacity (MW)	PLF (%)
BAKRESWAR TPS1	West Bengal	State sector	11	210	79
BAKRESWAR TPS2	West Bengal	State sector	21	210	79
BAKRESWAR TPS3	West Bengal	State sector	20	210	74
BAKRESWAR TPS4	West Bengal	State sector	19	210	80
BAKRESWAR TPS5	West Bengal	State sector	12	210	75
BANDEL TPS1	West Bengal	State sector	55	60	36
BANDEL TPS2	West Bengal	State sector	55	60	37
BANDEL TPS5	West Bengal	State sector	38	210	48
BARAUNI TPS7	Bihar	Central sector	3	110	6
BOKARO B TPS3	Jharkhand	Central sector	27	210	22
DR. N TATA RAO TPS1	Andhra Pradesh	State sector	41	210	56
DR. N TATA RAO TPS2	Andhra Pradesh	State sector	40	210	63
DR. N TATA RAO TPS3	Andhra Pradesh	State sector	31	210	75
DR. N TATA RAO TPS4	Andhra Pradesh	State sector	30	210	78
DR. N TATA RAO TPS5	Andhra Pradesh	State sector	26	210	77
DR. N TATA RAO TPS6	Andhra Pradesh	State sector	25	210	76
DURGAPUR TPS4	West Bengal	Central sector	38	220	41
HARDUAGANJ TPS7	Uttar Pradesh	State sector	42	105	21
KORBA-II2	Chhattisgarh	State sector	53	50	1
KORBA-II3	Chhattisgarh	State sector	52	50	31
KORBA-II4	Chhattisgarh	State sector	52	50	26
KORBA-III1	Chhattisgarh	State sector	44	120	64
KORBA-III2	Chhattisgarh	State sector	39	120	62
KORBA-WEST TPS1	Chhattisgarh	State sector	37	210	68
KORBA-WEST TPS2	Chhattisgarh	State sector	36	210	73
KORBA-WEST TPS3	Chhattisgarh	State sector	35	210	65
KORBA-WEST TPS4	Chhattisgarh	State sector	34	210	75
KOTA TPS1	Rajasthan	State sector	37	110	41
KOTA TPS2	Rajasthan	State sector	37	110	57
KOTA TPS3	Rajasthan	State sector	32	210	68
KOTA TPS4	Rajasthan	State sector	31	210	69
KOTA TPS5	Rajasthan	State sector	26	210	71
KOTHAGUDEM NEW TPS10	Telangana	State sector	22	250	86
KOTHAGUDEM NEW TPS9	Telangana	State sector	23	250	86
KOTHAGUDEM TPS1	Telangana	State sector	54	60	70
KOTHAGUDEM TPS2	Telangana	State sector	53	60	73
KOTHAGUDEM TPS4	Telangana	State sector	53	60	76
KOTHAGUDEM TPS5	Telangana	State sector	46	120	67

Unit ID	State	Ownership	Age	Capacity (MW)	PLF (%)
KOTHAGUDEM TPS6	Telangana	State sector	45	120	51
KOTHAGUDEM TPS7	Telangana	State sector	43	120	62
KOTHAGUDEM TPS8	Telangana	State sector	42	120	50
METTUR TPS1	Tamil Nadu	State sector	33	210	62
METTUR TPS2	Tamil Nadu	State sector	32	210	71
METTUR TPS3	Tamil Nadu	State sector	31	210	73
METTUR TPS4	Tamil Nadu	State sector	30	210	74
MUZAFFARPUR TPS1	Bihar	Central sector	7	110	44
MUZAFFARPUR TPS2	Bihar	Central sector	6	110	33
NORTH CHENNAI TPS1	Tamil Nadu	State sector	16	210	64
NORTH CHENNAI TPS2	Tamil Nadu	State sector	16	210	72
NORTH CHENNAI TPS3	Tamil Nadu	State sector	24	210	72
OBRA TPS1	Uttar Pradesh	State sector	53	50	128
PANIPAT TPS5	Haryana	State sector	31	210	5
PARICHHA TPS2	Uttar Pradesh	State sector	35	110	22
RAICHUR TPS1	Karnataka	State sector	35	210	44
RAICHUR TPS2	Karnataka	State sector	34	210	46
RAICHUR TPS3	Karnataka	State sector	29	210	58
RAICHUR TPS4	Karnataka	State sector	26	210	78
RAICHUR TPS5	Karnataka	State sector	21	210	72
RAICHUR TPS6	Karnataka	State sector	21	210	61
RAICHUR TPS7	Karnataka	State sector	17	210	48
RAMAGUNDEM - B TPS1	Telangana	State sector	49	62.5	10
ROPAR TPS3	Punjab	State sector	32	210	18
ROPAR TPS4	Punjab	State sector	31	210	18
ROPAR TPS5	Punjab	State sector	28	210	22
ROPAR TPS6	Punjab	State sector	27	210	24
SATPURA TPS6	Madhya Pradesh	State sector	41	200	48
SATPURA TPS7	Madhya Pradesh	State sector	40	210	40
SATPURA TPS8	Madhya Pradesh	State sector	37	210	50
SATPURA TPS9	Madhya Pradesh	State sector	36	210	31
TALCHER (OLD) TPS1	Odisha	Central sector	49	60	92
TALCHER (OLD) TPS2	Odisha	Central sector	49	60	96
TALCHER (OLD) TPS3	Odisha	Central sector	48	60	91
TALCHER (OLD) TPS4	Odisha	Central sector	48	60	88
TALCHER (OLD) TPS5	Odisha	Central sector	47	110	80
TALCHER (OLD) TPS6	Odisha	Central sector	47	110	88
TANDA STPS1	Uttar Pradesh	Central sector	32	110	67
TANDA STPS2	Uttar Pradesh	Central sector	31	110	66
TANDA STPS3	Uttar Pradesh	Central sector	30	110	65
TANDA STPS4	Uttar Pradesh	Central sector	22	110	66

Unit ID	State	Ownership	Age	Capacity (MW)	PLF (%)
TENUGHAT TPS1	Jharkhand	State sector	24	210	52
TENUGHAT TPS2	Jharkhand	State sector	23	210	62
TUTICORIN TPS1	Tamil Nadu	State sector	41	210	48
TUTICORIN TPS2	Tamil Nadu	State sector	39	210	64
TUTICORIN TPS3	Tamil Nadu	State sector	38	210	64
TUTICORIN TPS4	Tamil Nadu	State sector	28	210	64
TUTICORIN TPS5	Tamil Nadu	State sector	29	210	62
ANPARA TPS1	Uttar Pradesh	State sector	34	210	81
ANPARA TPS2	Uttar Pradesh	State sector	33	210	77
ANPARA TPS3	Uttar Pradesh	State sector	32	210	83
BHUSAWAL TPS3	Maharashtra	State sector	38	210	12
CHANDRAPUR STPS3	Maharashtra	State sector	35	210	41
CHANDRAPUR STPS4	Maharashtra	State sector	34	210	45
DADRI (NCTPP)1	Uttar Pradesh	Central sector	28	210	48
DADRI (NCTPP)2	Uttar Pradesh	Central sector	27	210	45
DADRI (NCTPP)3	Uttar Pradesh	Central sector	27	210	52
DADRI (NCTPP)4	Uttar Pradesh	Central sector	26	210	57
FARAKKA STPS1	West Bengal	Central sector	34	200	78
FARAKKA STPS2	West Bengal	Central sector	33	200	79
FARAKKA STPS3	West Bengal	Central sector	33	200	76
GANDHI NAGAR TPS3	Gujarat	State sector	30	210	50
GANDHI NAGAR TPS4	Gujarat	State sector	29	210	48
IB VALLEY TPS1	Odisha	State sector	26	210	76
IB VALLEY TPS2	Odisha	State sector	25	210	76
KAHALGAON TPS1	Bihar	Central sector	28	210	78
KAHALGAON TPS2	Bihar	Central sector	26	210	81
KAHALGAON TPS3	Bihar	Central sector	25	210	83
KAHALGAON TPS4	Bihar	Central sector	24	210	83
KHAPARKHEDA TPS1	Maharashtra	State sector	31	210	39
KHAPARKHEDA TPS2	Maharashtra	State sector	30	210	54
KOLAGHAT TPS1	West Bengal	State sector	27	210	17
KOLAGHAT TPS2	West Bengal	State sector	30	210	46
KOLAGHAT TPS3	West Bengal	State sector	34	210	1
KOLAGHAT TPS4	West Bengal	State sector	36	210	48
KOLAGHAT TPS5	West Bengal	State sector	26	210	56
KOLAGHAT TPS6	West Bengal	State sector	29	210	51
KORADI TPS6	Maharashtra	State sector	38	210	16
KORADI TPS7	Maharashtra	State sector	37	210	9
KORBA STPS1	Chhattisgarh	Central sector	37	200	88
KORBA STPS2	Chhattisgarh	Central sector	37	200	86
KORBA STPS3	Chhattisgarh	Central sector	36	200	92

Unit ID	State	Ownership	Age	Capacity (MW)	PLF (%)
MEJIA TPS1	West Bengal	Central sector	24	210	60
MEJIA TPS2	West Bengal	Central sector	23	210	51
NASIK TPS3	Maharashtra	State sector	41	210	43
NASIK TPS4	Maharashtra	State sector	40	210	56
NASIK TPS5	Maharashtra	State sector	39	210	36
OBRA TPS10	Uttar Pradesh	State sector	41	200	63
OBRA TPS11	Uttar Pradesh	State sector	42	200	72
OBRA TPS12	Uttar Pradesh	State sector	39	200	1
OBRA TPS13	Uttar Pradesh	State sector	38	200	8
OBRA TPS9	Uttar Pradesh	State sector	40	200	66
RAMAGUNDEM STPS1	Telangana	Central sector	37	200	77
RAMAGUNDEM STPS2	Telangana	Central sector	36	200	81
RAMAGUNDEM STPS3	Telangana	Central sector	35	200	85
RAYALSEEMA TPS1	Andhra Pradesh	State sector	26	210	63
RAYALSEEMA TPS2	Andhra Pradesh	State sector	25	210	54
SABARMATI (D-F STATIONS) TPP1	Gujarat	Private sector	42	120	81
SABARMATI (D-F STATIONS) TPP2	Gujarat	Private sector	35	121	82
SABARMATI (D-F STATIONS) TPP3	Gujarat	Private sector	32	121	82
SANJAY GANDHI TPS1	Madhya Pradesh	State sector	27	210	62
SANJAY GANDHI TPS2	Madhya Pradesh	State sector	27	210	56
SINGRAULI STPS1	Uttar Pradesh	Central sector	38	200	82
SINGRAULI STPS2	Uttar Pradesh	Central sector	38	200	86
SINGRAULI STPS3	Uttar Pradesh	Central sector	37	200	82
SINGRAULI STPS4	Uttar Pradesh	Central sector	37	200	86
SINGRAULI STPS5	Uttar Pradesh	Central sector	36	200	79
SOUTHERN REPL. TPS1	West Bengal	Private sector	29	68	22
SOUTHERN REPL. TPS2	West Bengal	Private sector	30	68	30
UKAI TPS3	Gujarat	State sector	41	200	66
UKAI TPS4	Gujarat	State sector	41	200	73
UKAI TPS5	Gujarat	State sector	35	210	67
UNCHAHAR STPS1	Uttar Pradesh	Central sector	32	210	66
UNCHAHAR STPS2	Uttar Pradesh	Central sector	31	210	69
VINDHYACHAL STPS1	Madhya Pradesh	Central sector	33	210	95
VINDHYACHAL STPS2	Madhya Pradesh	Central sector	32	210	89
VINDHYACHAL STPS3	Madhya Pradesh	Central sector	31	210	90
VINDHYACHAL STPS4	Madhya Pradesh	Central sector	30	210	86
VINDHYACHAL STPS5	Madhya Pradesh	Central sector	30	210	85
VINDHYACHAL STPS6	Madhya Pradesh	Central sector	29	210	85
WANAKBORI TPS1	Gujarat	State sector	38	210	42

Unit ID	State	Ownership	Age	Capacity (MW)	PLF (%)
WANAKBORI TPS2	Gujarat	State sector	37	210	44
WANAKBORI TPS3	Gujarat	State sector	36	210	68
WANAKBORI TPS4	Gujarat	State sector	34	210	60
WANAKBORI TPS5	Gujarat	State sector	34	210	57
WANAKBORI TPS6	Gujarat	State sector	33	210	58
Total				**29,775.5**	

Plants to be temporarily mothballed

Unit ID	State	Ownership	Age	Capacity (MW)	PLF (%)
AMARKANTAK TPS3	Madhya Pradesh	State sector	12	210	91
BARKHERA TPS1	Uttar Pradesh	Private sector	9	45	17
BARKHERA TPS2	Uttar Pradesh	Private sector	8	45	14
BELA TPS1	Maharashtra	Private sector	7	270	3
BHILAI TPS1	Chhattisgarh	Central sector	12	250	74
BHILAI TPS2	Chhattisgarh	Central sector	11	250	76
BUDGE BUDGE TPS1	West Bengal	Private sector	23	250	90
BUDGE BUDGE TPS2	West Bengal	Private sector	21	250	84
BUDGE BUDGE TPS3	West Bengal	Private sector	11	250	93
CHAKABURA TPP2	Chhattisgarh	Private sector	6	30	90
CHANDRAPURA(DVC)7	Jharkhand	Central sector	11	250	83
CHANDRAPURA(DVC)8	Jharkhand	Central sector	10	250	80
CHHABRA TPS1	Rajasthan	State sector	11	250	86
CHHABRA TPS2	Rajasthan	State sector	10	250	80
GH TPS (LEH.MOH.)3	Punjab	State sector	12	250	30
DSPM TPS1	Chhattisgarh	State sector	13	250	88
DSPM TPS2	Chhattisgarh	State sector	12	250	90
GANDHI NAGAR TPS5	Gujarat	State sector	22	210	73
GH TPS (LEH.MOH.)1	Punjab	State sector	22	210	22
GH TPS (LEH.MOH.)2	Punjab	State sector	22	210	23
GH TPS (LEH.MOH.)4	Punjab	State sector	12	250	22
JOJOBERA TPS2	Jharkhand	Private sector	19	120	72
JOJOBERA TPS3	Jharkhand	Private sector	18	120	72
JSW RATNAGIRI TPP1	Maharashtra	Private sector	10	300	84
JSW RATNAGIRI TPP2	Maharashtra	Private sector	9	300	65
JSW RATNAGIRI TPP3	Maharashtra	Private sector	9	300	74
JSW RATNAGIRI TPP4	Maharashtra	Private sector	9	300	75
KASAIPALLI TPP1	Chhattisgarh	Private sector	8	135	79
KASAIPALLI TPP2	Chhattisgarh	Private sector	8	135	72
KHAMBARKHERA TPS1	Uttar Pradesh	Private sector	9	45	13
KHAMBARKHERA TPS2	Uttar Pradesh	Private sector	9	45	14

Unit ID	State	Ownership	Age	Capacity (MW)	PLF (%)
KHAPARKHEDA TPS3	Maharashtra	State sector	20	210	54
KHAPARKHEDA TPS4	Maharashtra	State sector	19	210	63
KOTA TPS6	Rajasthan	State sector	17	195	83
KOTA TPS7	Rajasthan	State sector	11	195	87
KUNDARKI TPS1	Uttar Pradesh	Private sector	8	45	21
KUNDARKI TPS2	Uttar Pradesh	Private sector	8	45	18
MAQSOODPUR TPS1	Uttar Pradesh	Private sector	9	45	15
MAQSOODPUR TPS2	Uttar Pradesh	Private sector	8	45	14
MEJIA TPS3	West Bengal	Central sector	22	210	56
MEJIA TPS4	West Bengal	Central sector	16	210	59
MEJIA TPS5	West Bengal	Central sector	13	250	64
MEJIA TPS6	West Bengal	Central sector	13	250	72
MUNDRA TPS1	Gujarat	Private sector	11	330	67
MUNDRA TPS2	Gujarat	Private sector	10	330	73
MUNDRA TPS3	Gujarat	Private sector	10	330	72
MUNDRA TPS4	Gujarat	Private sector	9	330	72
MUZAFFARPUR TPS3	Bihar	Central sector	5	195	60
NIWARI TPP1	Madhya Pradesh	Private sector	6	45	35
NIWARI TPP2	Madhya Pradesh	Private sector	0.843	45	1
OP JINDAL TPS1	Chhattisgarh	Private sector	13	250	21
OP JINDAL TPS2	Chhattisgarh	Private sector	12	250	12
OP JINDAL TPS3	Chhattisgarh	Private sector	12	250	50
OP JINDAL TPS4	Chhattisgarh	Private sector	12	250	46
PANIPAT TPS6	Haryana	State sector	19	210	12
PANIPAT TPS7	Haryana	State sector	16	250	54
PANIPAT TPS8	Haryana	State sector	15	250	57
PARAS TPS3	Maharashtra	State sector	13	250	53
PARAS TPS4	Maharashtra	State sector	10	250	73
PARICHHA TPS3	Uttar Pradesh	State sector	14	210	62
PARICHHA TPS4	Uttar Pradesh	State sector	13	210	64
PARLI TPS6	Maharashtra	State sector	13	250	41
PARLI TPS7	Maharashtra	State sector	10	250	35
RATIJA TPS1	Chhattisgarh	Private sector	7	50	80
RATIJA TPS2	Chhattisgarh	Private sector	4	50	92
RAYALSEEMA TPS3	Andhra Pradesh	State sector	13	210	58
RAYALSEEMA TPS4	Andhra Pradesh	State sector	13	210	66
RAYALSEEMA TPS5	Andhra Pradesh	State sector	9	210	53
SANJAY GANDHI TPS3	Madhya Pradesh	State sector	21	210	52
SANJAY GANDHI TPS4	Madhya Pradesh	State sector	21	210	66
SANTALDIH TPS5	West Bengal	State sector	11	250	75

Unit ID	State	Ownership	Age	Capacity (MW)	PLF (%)
SHIRPUR TPP1	Maharashtra	Private sector	3	150	0
SIKKA REP. TPS3	Gujarat	State sector	5	250	65
SIKKA REP. TPS4	Gujarat	State sector	5	250	61
SIMHAPURI TPS2	Andhra Pradesh	Private sector	8	150	1
SIMHAPURI TPS3	Andhra Pradesh	Private sector	6	150	2
SURATGARH TPS1	Rajasthan	State sector	22	250	59
SURATGARH TPS2	Rajasthan	State sector	20	250	42
SURATGARH TPS3	Rajasthan	State sector	19	250	45
SURATGARH TPS4	Rajasthan	State sector	18	250	51
SURATGARH TPS5	Rajasthan	State sector	17	250	47
SURATGARH TPS6	Rajasthan	State sector	11	250	40
SVPL TPP1	Chhattisgarh	Private sector	8	63	20
THAMMINAPATNAM TPS1	Andhra Pradesh	Private sector	8	150	3
THAMMINAPATNAM TPS2	Andhra Pradesh	Private sector	8	150	5
TORANGALLU TPS(SBU-I)1	Karnataka	Private sector	21	130	78
TORANGALLU TPS(SBU-I)2	Karnataka	Private sector	21	130	37
TORANGALLU TPS(SBU-II)3	Karnataka	Private sector	11	300	60
TORANGALLU TPS(SBU-II)4	Karnataka	Private sector	11	300	24
TROMBAY TPS8	Maharashtra	Private sector	11	250	79
UNCHAHAR STPS3	Uttar Pradesh	Central sector	21	210	68
UNCHAHAR STPS4	Uttar Pradesh	Central sector	21	210	71
UNCHAHAR STPS5	Uttar Pradesh	Central sector	14	210	69
UTRAULA TPS1	Uttar Pradesh	Private sector	8	45	19
UTRAULA TPS2	Uttar Pradesh	Private sector	8	45	18
WANAKBORI TPS7	Gujarat	State sector	21	210	77
WARDHA WARORA TPP2	Maharashtra	Private sector	10	135	4
WARDHA WARORA TPP3	Maharashtra	Private sector	9	135	28
WARDHA WARORA TPP4	Maharashtra	Private sector	9	135	29
Total				**19583**	

Table A8 Coal plants have contributed to much larger share at a regional level in the 30-month period than the estimated generation in reassigned scenario

Over the 30-month period:

Thermal generation	Eastern region	North-Eastern region	Norther region	Southern region	Western region
Maximum share (MU)	22% (610)	1% (17)	27% (686)	25% (684)	46% (1301)
Minimum share (MU)	13% (386)	0% (0)	16% (418)	14% (342)	36% (1057)

Reassigned scenario:

Thermal generation	Easter region	North-Eastern region	Northern region	Southern region	Western region
Base share (MU)	18% (487)	0.4% (11)	21% (570)	18% (495)	43% (1158)
Reassigned share (MU)	16% (443)	0.3% (9)	20% (534)	20% (548)	44% (1188)

Source: Authors' analysis based on CEA daily generation reports

Table A9 Majority of the capacity deemed surplus are at the early stage of FGD installation

FGD status	Capacity
Feasibility study started	1,410
Feasibility study completed	10,226
Tender specifications made	3,020
NIT issued	6,982
Bid opened	4,270
Bid awarded	8,380
Retendering	920
FGD commissioned	840

Source: Authors' analysis based on quarterly summary of FGD implementation status—February 2021

Table A10 Around 3.5 GW ISGS capacity providing flexibility during peak demand hours are deemed surplus in the reassigned scenario

Unit ID	Capacity (MW)	Utilisation
BHILAI TPS1	250	Baseload
BHILAI TPS2	250	Baseload
DADRI (NCTPP)1	210	Ramping
DADRI (NCTPP)2	210	Ramping
DADRI (NCTPP)3	210	Ramping
DADRI (NCTPP)4	210	Ramping
FARAKKA STPS1	200	Ramping
FARAKKA STPS2	200	Ramping
FARAKKA STPS3	200	Ramping
KAHALGAON TPS1	210	Ramping
KAHALGAON TPS2	210	Ramping
KAHALGAON TPS3	210	Ramping
KAHALGAON TPS4	210	Ramping
KORBA STPS1	200	Baseload
KORBA STPS2	200	Baseload
KORBA STPS3	200	Baseload
MUZAFFARPUR TPS3	195	Ramping
RAMAGUNDEM STPS1	200	Baseload
RAMAGUNDEM STPS2	200	Baseload
RAMAGUNDEM STPS3	200	Baseload
SINGRAULI STPS1	200	Baseload

Unit ID	Capacity (MW)	Utilisation
SINGRAULI STPS2	200	Baseload
SINGRAULI STPS3	200	Baseload
SINGRAULI STPS4	200	Baseload
SINGRAULI STPS5	200	Baseload
UNCHAHAR STPS1	210	Ramping
UNCHAHAR STPS2	210	Ramping
UNCHAHAR STPS3	210	Ramping
UNCHAHAR STPS4	210	Ramping
UNCHAHAR STPS5	210	Ramping
VINDHYACHAL STPS1	210	Baseload
VINDHYACHAL STPS2	210	Baseload
VINDHYACHAL STPS3	210	Baseload
VINDHYACHAL STPS4	210	Baseload
VINDHYACHAL STPS5	210	Baseload
VINDHYACHAL STPS6	210	Baseload

Source: Authors' analysis

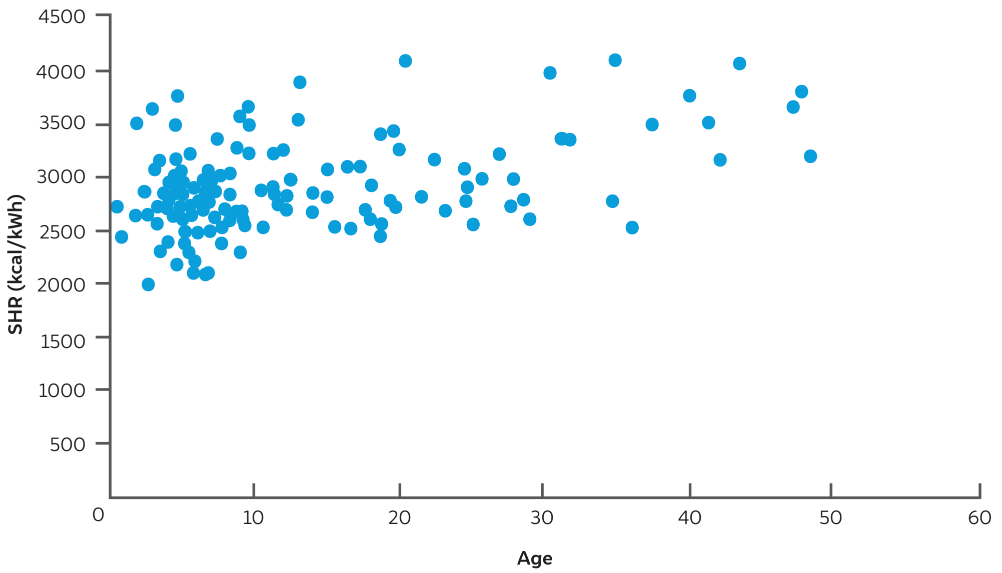

Figure A1
Older plants are likely to spend more energy per unit operation

Source: Authors' analysis based on supplied coal grades, monthly generation data and monthly coal statement report from SEVA and CEA respectively

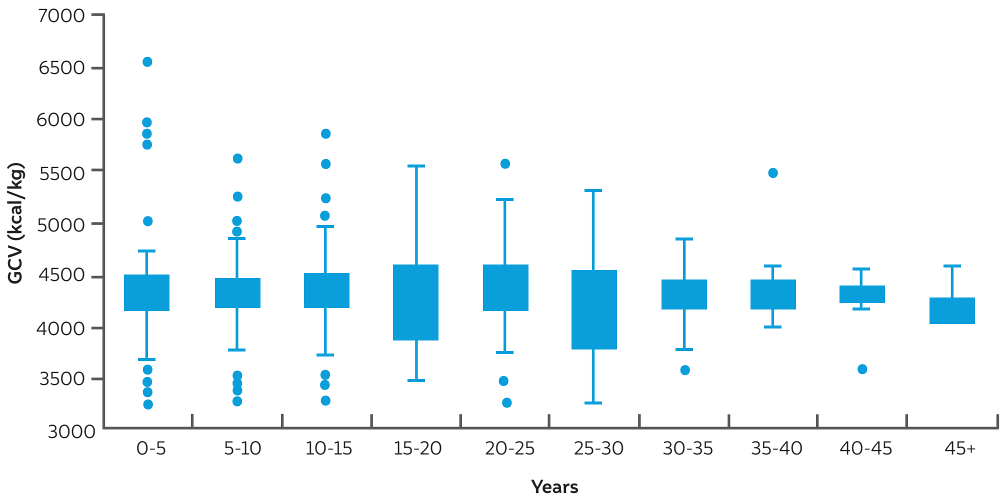

Figure A2
There is a significant distribution in coal quality, though the median is consistent across vintages

Source: Authors' analysis based on SEVA data

The remaining coal generation capacity after decommissioning 30 GW, could cater to 108% and 77% of the average supply expected from coal in 2022 and 2030 respectively.

Image: iStock

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