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Mapping Costs for Early Coal Decommissioning in India

Vaibhav Pratap Singh and Nikhil Sharma

Report | July 2021

The transition away from coal could help reduce India's GHG emissions. Still, a pacing up of this transition through mechanisms like decommissioning will free up capital locked in these assets and help finance a rapid buildup of RE and storage.

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ceew.in

Suggested citation: Singh, Vaibhav Pratap, and Nikhil Sharma. 2021. *Mapping Costs for Early Coal Decommissioning in India*. New Delhi: Council on Energy, Environment and Water.

Cover image: iStock.

Peer reviewers: David Elzinga, Senior Energy Specialist & Pradeep Tharakan, Principal Energy Specialist from Asian Development Bank; Michael Ward, Senior Consultant, Climate Investment Fund; Kartikeya Singh, Senior Associate (Non-resident) Centre for Strategic and International Studies; Ashish Fernandes, CEO & Lead Analyst, Climate Risk Horizon; Madhura Joshi, Senior Associate & Maria Pastukhova, Senior Policy Advisor from E3G; Nikit Abhyankar, Scientist, Lawrence Berkley Lab; Casey Ho, Special Assistant to The Chairman & Donald Perry Kanak, Chairman from Prudential Insurance Growth Markets; Kanika Chawla, Programme Manager, SE4ALL; Bharath Jairaj, Director, Energy, World Resource Institute; Arjun Dutt, Programme Lead, and Prateek Aggarwal, Programme Associate from Council on Energy Environment and Water.

Publication team: Alina Sen (CEEW), The Clean Copy, Twig Designs, and Friends Digital.

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The CEEW Centre for Energy Finance (CEEW-CEF) is an initiative of the Council on Energy, Environment and Water (CEEW), one of Asia's leading think tanks.

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The need for enabling an efficient and timely energy transition is growing in emerging economies. In response, CEEW-CEF focuses on developing fit-for-purpose market-responsive financial products. A robust energy transition requires deep markets, which need continuous monitoring, support, and course correction. By designing financial solutions and providing near-real-time analysis of current and emerging clean energy markets, CEEW-CEF builds confidence and coherence among key actors, reduces information asymmetry, and bridges the financial gap.

Financing the energy transition in emerging economies

The clean energy transition is gaining momentum across the world with cumulative renewable energy installation crossing 1000 GW in 2018. Several emerging markets see renewable energy markets of significant scale. However, these markets are young and prone to challenges that could inhibit or reverse recent advances. Emerging economies lack well-functioning markets. That makes investment in clean technologies risky and prevents capital from flowing from where it is in surplus to regions where it is most needed. CEEW-CEF addresses the urgent need for increasing the flow and affordability of private capital into clean energy markets in emerging economies.

CEEW-CEF's focus: analysis and solutions

CEEW-CEF has a twin focus on markets and solutions. CEEW-CEF's market analysis covers energy transition–related sectors on both the supply side (solar, wind, energy storage) and demand-side (electric vehicles, distributed renewable energy applications). It creates open-source data sets, salient and timely analysis, and market trend studies.

CEEW-CEF's solution-focused work will enable the flow of new and more affordable capital into clean energy sectors. These solutions will be designed to address specific market risks that block capital flows. These will include designing, implementation support, and evaluation of policy instruments, insurance products, and incubation funds.

CEEW-CEF was launched in July 2019 in the presence of HE Mr Dharmendra Pradhan and H.E. Dr Fatih Birol at Energy Horizons.

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Acknowledgments

We would like to thank SED Fund for their support to carry out the study.

We would like to thank Gagan Sidhu, Director, CEEW Centre for Energy Finance, for his support and guidance in working on the report. His inputs on the methodology were extremely valuable and improved the projections in the report.

We thank our reviewers – David Elzinga, Pradeep Tharakan (Asian Development Bank), Michael Ward (Climate Investment Fund), Kartikeya Singh (Centre for Strategic and International Studies), Ashish Fernandes (Climate Risk Horizon), Arjun Dutt, Prateek Aggarwal (Council on Energy, Environment and Water), Madhura Joshi, Maria Pastukhova (E3G), Nikit Abhyankar (Lawrence Berkley Lab), Casey Ho, Donald Perry kanak (Prudential Insurance Growth Markets), Kanika Chawla(SE4ALL), Bharath Jairaj (World Resource Institute) for their critical reviews and comments which helped in refining the report and the investment model presented in the report.

We thank our colleagues particularly Dhruv Warrior (CEEW-CEF), Sangeeth Raja (CEEW-CEF) and Danwant Narayanswamy (CEEW) for their help in research. Lastly, we would like to thank the Outreach Team at CEEW for helping us design and publish the report.

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"Adding more renewables, improving efficiency and getting a large part of the coal-based capacity offline will be central to the world keeping the under 2°C hopes alive. Decommissioning pathways adopted by the countries will be a key determinant of how we achieve this decarbonisation, and the costs associated both economic and social will be central to its implementation."

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"Falling and competitive renewable energy tariffs have started to make electricity buyers (discoms) rethink legacy coal power purchase agreements (PPAs). Estimating the cost required to decommission these plants and designing a suitable mechanism for a just transition is crucial to India's energy transition."

This report has been prepared with support and guidance from Gagan Sidhu, Director, CEEW Centre for Energy Finance, and exhaustive research help by Dhruv Warior, Research Analyst, CEEW-CEF, Sangeeth Raju, former intern, CEEW-CEF and Danwant Narayanswamy, Research Analyst, CEEW.

An early decommissioning, on average, could help save 23% on capacity charges.
This could help reduce the power bills of the end consumers.

Image: iStock

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Acronyms

PPA	power purchase agreement
RE	renewable energy
CAPEX	capital expenditure
O&M	operation and maintenance
DISCOM	distribution company
PV	present value
PLF	plant load factor
CUF	capacity utilisation factor
ROE	return on equity
WACC	weighted average cost of capital
O&M	operation and management
INR	Indian rupee
USD	US dollar
MW	megawatt
GW	gigawatt
Kcal	kilo calorie
GHG	greenhouse gas
OECD	Organisation for Economic Co-operation and Development
RBI	Reserve Bank of India
CEA	Central Electricity Authority
NEP	National Electricity Plan
NPA	non-performing asset

The equity payout worth 29% of the total costs of an early decommissioning will be the prime driver to reduce transition costs.

Image: Unsplash

Executive summary

To stop the further acceleration of climate change, the world needs to transition to clean energy sources. To realise this transition, the countries world over need to direct considerable investment flows to decarbonisation activities; as per OECD estimates, the world needs USD 6.9 trillion (INR 5.04 crore crore) annually to meet its 2030 nationally determined contribution targets alone (OECD 2018)[1]. Given that developing countries have limited economic resources, prioritising the decarbonisation efforts basis the impacts is needed.

Electricity is India's largest decarbonisation opportunity

In India, the electricity sector accounts for 40 per cent of all greenhouse gas (GHG) emissions in the country (as of 2016) and thus presents one such decarbonisation pathway (MOEFCC 2021). Recognising this need, India has set a target of achieving 450 GW of renewable energy (RE) by 2030 (over 4.5 times the current installed capacity). However, due to the build-up of coal-based assets over the last two decades, India also has around 10 per cent (208 GW) of the world's installed coal capacity (MOP 2021). Though coal supplies over 70 per cent of the total electricity in the country, these coal-based assets are a significant contributor to the total GHG emissions by the electricity sector. Under the National Electricity Plan (NEP) 2018, the Central Electricity Authority (CEA) has identified over 25 GW of excess coal-based capacity for retirement by 2027.

> Decarbonising of India's electricity sector, which contributes 40% of the emissions will drive India's clean energy transition. Increased RE penetration and decommissioning coal-based assets will be central to it.

India's coal powered assets with a large share of inefficient plants are underutilised

However, the retirement process continues to be slow, even for the list of earlier identified plants. The slow retirement of old inefficient assets combined with low demand growth, improving RE economics, and increasing penetration has resulted in a high share of inefficient plants in the system, putting pressure on the coal assets with system-wide low utilisation (Lolla 2021; Zeniewski and Singh 2021). Presently, India's coal assets are significantly underutilised (53 per cent in FY21) compared to at the start of the decade (above 70 per cent in FY11). The slower than anticipated growth of power demand and, of late, the increasing contribution of renewables drive this underutilisation. Low utilisation also poses a risk to the financial sector—as of September 2020, 11 per cent of Indian power sector loans were classified as non-performing assets (NPAs), and most of these were loans extended to coal-based assets.[2]

Decommissioning assets to solve for underutilisation and improved efficiency mix

To improve the coal plant mix towards new and efficient plants and accommodate the transition from coal-based assets to RE technologies, the country can opt for early decommissioning of some excess coal capacity. The economically draining capacity, which is pollution-intensive and whose absence would not adversely affect the regional demand-supply balance are ideal for piloting this solution, as already identified by the CEA under NEP, 2018. Such a step could help prepare for decommissioning other assets that may continue to function until RE technologies become viable in line with India's decarbonisation goals. In addition, this move could help improve utilisation rates and reduce the financial stress on the banking system by ensuring improved cash flows for coal assets. This step is also crucial because, as multiple sectors work towards decarbonisation, they

1. In the entire report, we have used the following conversion rate: INR 73 = USD 1.
2. According to the Reserve Bank of India (RBI), in September 2020, 18 per cent of the loans extended by Indian scheduled commercial banks were to the power sector. Of these, 11 per cent were classified as non-performing assets (NPAs), most of which were loans extended to coal-based assets

will increasingly rely on electricity rather than fossil fuels. This step can also help unlock the capital in coal-based assets to finance India's RE transition.

The costs, drivers and savings of an early decommissioning

As a first step to ascertain the costs associated with such a process, we looked at 130 plants (see Table 4) with 95 GW of installed capacity, representing 45 per cent of the total 208 GW of installed coal capacity in the country.[3] In the absence of plant-level financials, we used tariff orders of the individual plants to calculate the costs associated as per the methodology discussed later. The calculations allowed us to uncover the payables towards equity and debt holders and the workforce in the face of transition.

1. Based on the analysis, amortising the total cost associated with decommissioning would lead to an average yearly cost INR 0.37 crore/MW/year (USD 50,550/MW/year) for decommissioning a plant a year earlier than envisaged; this represents savings of around **23 per cent over the annual capacity charges**.
2. We find that decommissioning the 130 plants today would cost between **INR 2.31 lakh crore (USD 32 billion) and INR 3.50 lakh crore (USD 48 billion), including payouts to promoters and debt holders.[4] These costs, on average, are between INR 2.3 crore/MW (USD 0.33 million/MW) and INR 3.7 crore/MW (USD 0.51 million/MW)**.
3. Payouts to the workforce contribute another **INR 57,490 crore (USD 7.8 billion) to the cost. On average, workforce-related payouts for early decommissioning add INR 0.61 crore/MW (USD 0.08 million/MW)**.
4. The reduced payouts towards capacity charges, especially under the cost heads of 'O&M (operation and maintenance)' and 'other' charges in the event of early decommissioning, could help save INR 1.24 lakh crore (USD 17 billion) for the 130 plants.
5. On average, an annual saving of INR 0.11 crore/MW/year (USD 15,450/MW/year) is potentially possible through early decommissioning of the sample.[5]
6. Decommissioning the asset today, on average, will allow a **capital unlocking of equity and debt worth INR 1.3 crore/MW (USD 0.17 million/MW) and INR 2.4 crore/MW (USD 0.33 million/MW) each**.

> **On an average, decommissioning will help save 23% in fixed-cost payments for a discom.**

Given the scale of the task at hand, multiple complexities may arise, including challenges in balancing the regional power supply and demand and adapting grid infrastructure. Thus, the decommissioning process needs to be split into multiple stages to address these technical constraints and to optimise the viability of decommissioning financially. Therefore, in addition to a plant-level economic assessment of each of the 130 units, we have categorised them based on age, variable costs of power, station heat rate, etc., to understand the relationship of cost to these parameters. These benchmarks could help establish the most financially prudent path to early decommissioning among several different pathways, including those not analysed in the report.

Based on the criteria of age (one of the preferred criteria for decommissioning coal assets the world over), the assessments produced the following significant findings. For plants above 25 years of age, the assumed remaining life of the contract is five years. We estimate the average annual cost of decommissioning (including debt, equity, and workforce-related payouts) for these plants to be INR 0.2 crore/MW/year (USD 26,320/MW/year). For the 47 plants that meet these criteria, with an aggregate capacity of 35 GW and an average age of 34 years, it would cost INR 21,474 crore (USD 2.9 billion) to pay off the debt and equity holders; workforce payouts would contribute another INR 11,700 crore (USD 1.6 billion). It would cost a total of INR 33,170 crore (USD 4.5 billion) to decommission these plants early and pay the stakeholders for the five-year worth of

3. We considered 130 plants for analysis based on the available data, i.e., where we had access to tariff orders that we could use as per the chosen methodology to calculate the cost of early decommissioning or retirement. It is essential to point out that by estimating these costs, we do not endorse that these plants undertake a decommissioning process.
4. We derived the upper and lower bounds for the costs under the assumption of maximum and zero equity payouts.
5. The savings of 23 per cent will accrue to distribution companies (DISCOMs) that have contracted these capacities. Additionally, the cost of retrofitting these plants to reduce pollution could also be saved; these costs would otherwise by be borne discoms and thereby by the end consumers.

> **Equity with a 29% contribution to the costs of decommissioning will drive the lowering of costs.**

contract value.[6] However, the avoided portion of the annual payouts worth INR 7,550 crore to these assets, primarily operations and maintenance, and working capital amount to INR 37,750 crore (USD 5.2 billion). That is an early decommissioning could be paid for itself over the next five to six years.

Equity will be the primary driver to lower decommissioning costs

Interestingly, there is significant scope to reduce high equity-related payouts worth 29 per cent of the total cost of decommissioning the 95 GW capacity analysed. As is visible in Germany's latest rounds of auctions to decommission its coal assets provide evidence of how a law on phasing out coal, coal-based generation, and the auction mechanism can help reduce the costs associated with decommissioning—particularly the payouts due to equity holders—to 40 per cent of the auction caps (Wehrmann 2020).

Research and mapping of options, fallouts and process to drive the eventual uptake of decommissioning

For its next steps, India would need to ascertain how to remove coal assets from the grid through decommissioning, mothballing, or repurposing for storage or RE.[7] All these and other options need careful assessment to choose the right option viable for different sets of plants. Another essential step in the process is mapping the potential fallouts, significantly impacting the workforce, and building strategies to make the transition just for all the concerned stakeholders. Ensuring a smooth transition, especially for the people in the workforce, a mix of strategies would be needed, including voluntary retirement schemes (as used in nationalised banks in India when the core banking solution was introduced in the 1990's) and retraining and absorbing workers into alternative jobs.

Adequate compensation must be paid to coal mine owners and workers for the early closure of existing contracts to supply coal.[8] This is important since electricity generation is one of the most significant drivers of coal demand in India and directly employs close to 5 lakh people (IEA 2020). However, the process would need further deliberations as residents of over 50 districts, across 13 states in India are reliant to a varying degree on the coal based activities to earn a livelihood and transition will impact that (Sandeep Pai and Hishman Zerrefi 2021). Otherwise, by continuously delaying the process, the country may be stuck with excess coal capacity that would continue hurting financiers as has been the case with the power sector's NPAs, which may ultimately delay RE growth by locking in the much needed capital.

An optimum decommissioning to reduce the consumer bills

Based on the economics of the decision, we found that decommissioning may not be a viable option for most of the new plants but make sense for a number of the older plants above 20 years, as shown later in the analysis. The age, when combined with the variable cost factor, we found that around 16 GW of the 95GW could be feasibly retired at almost 40 per cent of the yearly costs at INR 0.15 crore/MW/year (USD 19,960 / MW/year) vs INR 0.37 crore/MW/year (USD 50,550/MW/year) of the sample analysed. Decommissioning these plants would be a cost-efficient way of decarbonising the power sector as the payouts are lesser, and discoms can save on the high variable costs associated with purchasing power from these generators.

> **An optimum mix of plants to decommission could help reduce the decommissioning to only 40% of the average costs at INR 0.15 crore/MW.**

6. For plants less than 25 years of age, we estimate the contract period to be 25 years (the standard length of the contract in long-term power purchase agreements [PPAs] with DISCOMs) minus the age of the plant in April 2020.
7. Mothballing – refers to closing the unit and preserving the equipment's for a long time so as to keep plants safeguarded against damages and also save on fixed O&M costs of the plant. The plant can be bought online after a period of notice to get it operational and produce electricity.
8. The impact on coal mines, railways, and others that depend on coal-based power producers for a large part of their revenue warrant due consideration in transition plans. A just transition must be informed by careful assessments of the payouts and processes as well as consultations and dialogues while assuring some social protection to stakeholders.

1. Introduction: a call for just transition

India and the world at large are undergoing a clean energy transition. The growth of coal-based generation, the source of 40 per cent of the world's supply, has plateaued (IEA 2020). In India, coal contributes around 70 per cent to the country's energy mix, but, after a continuous period of growth since 2003, its growth has plateaued in the last few years (IEA 2020; MOSPI 2021). The drivers for this stagnation are the lower than anticipated growth in power demand coupled with substantial renewable energy (RE; solar and wind, primarily) commitments and market activity in recent years. With every passing year, the improving economics of RE, e.g., solar tariffs less than INR 2/unit (as discovered in the 2020 auctions), i.e., noticeably below the average variable cost of power from coal, add to the pressure on coal-based electricity generation.

> **Early decommissioning of the mapped 95 GW could help unlock USD 32 billion of debt or around 19% of the FIs exposure towards the power sector in FY20.**

As a result, coal-based power plants in the country are currently suffering from overcapacity (the average utilisation of plants is only 53 per cent in FY21, i.e., below the technical minimum for many of the plants), resulting in back downs and dampened spot market prices (MOP 2021; IEA 2020). This has led to a rapid decline in investor interest in coal-based generation and a build-up of non-performing assets (NPAs) for banks that funded them.[9]

Existing long-term contracts for coal power with built-in capacity charges (also called 'fixed charges') add to the burden of already loss-making electricity distribution companies (discoms). This has implications that go beyond coal-based power. If the trend of NPA build-up in the sector continues, it has the potential to slow the addition of RE capacity to the grid in the long run by limiting the availability of credit to the sector.

As a first step, India needs to establish the costs associated with decommissioning coal plants and then choose a suitable mechanism to retire these assets. Insights from countries like Germany, which are ahead of the curve, would be valuable. Finally, the last step would be decommissioning, mothballing, or repurposing the identified units. A well-considered transition would allow the country to meet its emissions targets, manage the unrequired coal capacity, and permit banks and promoters to transition away from coal. Further, the workforce should be allowed to transition to new jobs and provided adequate payouts to make this transition just for all the stakeholders, along with compensating and finding transition pathways for the sectors like coal mining and railways that may be impacted by the shift.[10]

The transition away from coal could free up debt investments (including earnings) worth INR 2.4 crore/ MW in India. In terms of potential the exercise for the 130 plants analysed turns up to INR 2.3 lakh crore (USD 32 billion), or roughly 19 per cent of the entire banking sector exposure towards the power sector worth INR 12.3 lakh crore (USD 168 billion) in 2020[11]. This unlocking of capital could allow a furthering of the transition by incrementally financing the RE, storage and other technologies. Also, as shown later, the mapping based on parameters like higher variable costs (above INR 2.1/ unit) and age above 20 years could help reduce discom bills and the old excess capacity in the system. As expected, we find decommissioning based on economics newer plants may not cut due to higher costs associated with them. While the older plants, which have paid off a large part of the debt related liabilities and have a higher variable cost, could be considered for a pilot. Such a step, if technically feasible, could reduce the cost of transition, benefit the discoms - reduce their cost of power purchase by lowering the variable costs of power and create a track record of such a facility for future decommissioning.

> **Optimised decommissioning has the potential to reduce the cost of electricity to consumers by reducing the cost of power purchase for discoms.**

This study deals with the first step—ascertaining the cost of early decommissioning of existing assets. It also reviews the experiences of countries like Germany and South Africa, which are already engaged in decommissioning some of their coal-based capacities. For this study, we analysed 130 plants in India with a cumulative capacity of 95 GW, which forms over 45 per cent of the country's total installed coal capacity (both hard coal and lignite or soft coal) of 208 GW (MOP 2021).[12]

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9. In India, the poor performance of coal-based assets is already visible in the financial sector's power portfolio. Indian banks are facing NPA rates of around 12 per cent (as of September 2020) of the total power sector exposure, primarily due to the poor performance of coal assets.

10. A just transition to a lower-carbon pathway, requires the assessment of payouts and processes, as well as consultations and dialogues with those impacted. Further, the direct and indirect workforce would need social protection. Also, any fallouts arising out from other sectors' dependence on the revenue from supplying coal to power producers like coal mining companies, railways, and others will have to be accounted for.

11. Credit from banks – USD 77 billion (RBI 2020); credit from NBFCs includes only Power Finance Corporation at USD 47 billion (PFC 2020) and REC at USD 44 billion (REC 2020) as these are the dominant NBFC lenders to the power sector.

12. We considered 130 plants for analysis based on the available data, i.e., we included units for which we had access to tariff orders based on which we could calculate the cost of early decommissioning or retirement. Note that by estimating costs, we do not endorse that plants undertake a decommissioning process.

2. Methodology

Long-term power purchase agreements (PPA) present a challenge to the rapid decommissioning or mothballing of the world's thermal capacity (IEA 2020). These contracts run into multiple decades and usually have a two-part tariff structure comprising guaranteed capacity payments ('capacity charges') and variable payments ('energy charges') due to generators. Capacity charges account for debt, equity, and other fixed payouts; these charges usually have six components (Table 1). Energy charges primarily include the fuel costs (coal and a few other costs) of running the plant. The cost of early decommissioning needs to reflect the present value (PV) of the debt, equity, and other payouts under PPA contracts. A challenge in conducting such calculations is the unavailability of plant-level financial data. In the study, we have used the tariff orders to bypass (as explained in box 1) the lack of availability of financial study by analysing the following cost heads in Table 1.

Table 1 Cost heads (capacity charges)

No.	Cost heads (capacity charges)	Purpose/end-use	Comments
1.	Return on equity (ROE)	Ensures returns to both the promoters and debt providers	ROE can help determine the upper and lower bounds of payouts—in the event of early decommissioning—corresponding to maximum and zero equity payouts, respectively.
2.	Interest on the capital loan		Fixed outflow towards project loans.
3.	Depreciation	Captures degradation of the plant value (usually the regulator assumes a value of 5.28% to capture the loan repayment factor)	In case the capital loan persists, the contracted depreciation value captures the principal repayment due towards it. Otherwise, this is used as a proxy to capture the asset's value that is used up in a year.
4.	Interest on working capital loans	Operational costs	Not required to be paid if the plant is decommissioned early.
5.	O&M costs	Includes payouts to the workforce and other fixed O&M expenses	Except for workforce-related expenses, all others need no payment in the event of early decommissioning.
6.	Other costs	Sometimes includes the cost of secondary fuel	Not required to be paid if the plant is decommissioned early.

Source: CEEW-CEF analysis using a typical two-part tariff order

BOX 1 Tariff orders

Although the capacity charges specified in PPAs are usually constant, it is possible to revise these based on tariff orders passed annually by state or central electricity regulators, under whose jurisdiction plants operate or supply power. The revisions, if any, capture the costs of upgrading and retrofitting plants as well as making changes in the capital stack, etc. The PV of the applicable cost heads (see Table 1) for the remainder of the PPA, thus, serves as a good proxy for the cost of retiring these contracts in case of early decommissioning. The tariff orders are readily available in the public domain but not the PPA's.

We used tariff orders to determine the total capacity charge and the breakup of cost heads.[13] Further, for plants below 25 years of age, we calculate the payable capacity charges for the remaining life assuming an initial contract tenor of 25 years. For older plants, the assumed contract tenor is five years. Discounting the payable portion of the capacity charges by the weighted average cost of capital (WACC), we arrived at the PV of the payable charges (derived using the debt-to-equity ratio calculated using the debt and equity rates provided in the tariff orders).

Following on from this, the costs associated with decommissioning may be represented as = (1) + (2) + (3) + (4). In case the capital debt has been paid off, depreciation is used to capture the salvage value of the plant and is subtracted from the decommissioning costs.[14]

1. The PV of the ROE (as per the tariff order, an equity share is usually 30 per cent of the CAPEX [capital expenditure] or actual as per capital stack, whichever is lower) for the next x years.
2. The PV of the interest on the capital loan (as per the tariff order, assuming it remains the same for x years).
3. The PV of depreciation costs (as per the tariff order, assuming it remains constant over x years for the assumed CUF in the contract). For plants with no capital loan, the depreciation is subtracted from the payout values.
4. The PV of workforce-related expenses (assumed at a standard rate of INR 0.1 crore/MW derived from NTPC's annual report FY19) is captured separately (NTPC 2019).

A discount on the ROE basis of the return expectation on being upfront can result in additional savings for discoms if they pay capacity charges upfront versus staggered payments as per the contract.[15]

3. Cost of decommissioning the assets

We applied the methodology to 130 plants (see Table 3). The following findings are most significant:

1. Amortising the total costs associated with decommissioning, the analysis shows that the average yearly cost of decommissioning a plant earlier than envisaged is INR 0.37 crore/MW/year (USD 50,550/MW/year), which is a saving of around 23 per cent over the annual capacity charges.[16]
2. We found that decommissioning the 130 plants today will cost between INR 2.31 lakh crore (USD 32 billion) and INR 3.50 lakh crore (USD 48 billion) to payout the promoters and debt holders in these projects.[17]
   a. The above costs, on average, are between INR 2.3 crore/MW (USD 0.33 million/MW) to INR 3.7 crore/MW (USD 0.51 million/MW).
3. Payouts towards the workforce contribute another INR 57,490 crore (USD 7.8 billion) to these costs.
   a. On average, the workforce-related payouts in case of early decommissioning add INR 0.61 crore/MW (USD 0.08 million/MW) for the analysed plants.
4. The reduced payouts towards components of capacity charges, especially 'O&M charges' and 'other charges' in the event of early decommissioning, could help save INR 1.24 lakh crore (USD 17 billion).
   a. On average, annual savings of INR 0.11 crore/MW/year (USD 15,450/MW/Year) could potentially be made through an early decommissioning for the sample of analysed plants.

It is essential to point out that estimating costs does not amount to an endorsement to undertake the decommissioning of these plants. Cost estimation is but one of several variables that need consideration for any decision to decommission a plant early.

13. A tariff order captures annual capacity payments due to a project or unit for keeping the contracted capacity available for dispatch. These orders usually provide a breakup of capacity charges under the various cost heads and the rationale behind these charges.
14. The depreciation cost head as per the tariff order is a normative value as per the regulator's recommendations. Its value may differ from the depreciation amount on the balance sheet and, thus, the eventual salvage value of the plant and the land.
15. To better calculate the minimum acceptable payouts for these projects, we removed the ROE-related component from the fixed payouts and discounted it to the present value.
16. Across the report, we have used an INR/USD conversion factor of 73 INR = 1USD.
17. The upper and lower bounds of the costs have been derived under the assumption of maximum and zero equity payouts.

ROE – a driver to lower the decommissioning costs

As per our analysis, one of the most significant contributors to decommissioning costs is ROE—INR 1.09 lakh crore (USD 15 billion) or around 29 per cent of the total costs (inclusive of workforce-related payments). Using a well-designed framework to decommission these assets early, ROE-related payouts and, thereby, the cost of early decommissioning can be reduced. In Germany, in the latest round of auctions to take coal assets off the market, plant owners bid an average price of EUR 66,000/MW; however, it would cost EUR 1,65,000/MW to decommission the assets. The lower price was possible due to many factors, including a law mandating the retirement of all coal-based assets in phases by 2038. Because of these market realities, plant owners were willing to accept lower returns on their investments rather than wait and receive lower compensation, face uncertainty later, or both (Wehrmann 2020).

Workforce payouts - the costs of just transition

Another significant cost driver contributing 14 per cent to the total payouts for early decommissioning is workforce-related payments. A well-designed mechanism that works to reduce payouts due to the workforce, in a just manner, could allow for further lowering the costs of the entire early decommissioning process.

Parameters for assessing different decarbonisation pathways

Decommissioning is likely to occur in stages and be implemented over multiple years; based on the regional supply and demand, technical considerations and other parameters such as age, costs, etc. We provide a breakdown of the costs and benchmarks according to parameters such as age, station heat rate, and variable costs. Such benchmark averages facilitate an understanding of the economics of decommissioning, especially for plants with limited data, and help in assessing different decarbonisation pathways.

> **Benchmarked averages according to parameters like age, efficiency etc., are central to assessing decommissioning pathways.**

These cost breakdowns also allow for an improved decision making using the economic and operational parameter (like the plant load factor (PLF)) based categorisation linking economic impact understanding of varied transition pathways. The PLF captures the *plant's/unit's utilisation* in prior years and reveals the importance of meeting the energy demand from the energy system's perspective. Other factors, like the station heat rate, help us understand the plant's efficiency and its impacts on the environment. Segregation of the variable charges helps in identifying plants under long-term PPAs that are suited for early retirement from the electricity buyers' perspective.

A) Categorisation of plants based on age

Plants above 25 years of age

As per our analysis, plant age plays a considerable role in determining the costs associated with decommissioning. Our sample included 47 plants over 25 years of age with an aggregate capacity of 35 GW and an average age of 34 years. We assumed the average remaining contract life for this set of plants at five years. We observed the following findings while estimating the costs of decommissioning these plants:[18]

1. The average annual cost associated with decommissioning an older plant a year early (including debt, equity, and workforce-related payouts) is INR 0.2 crore/MW/year (USD 26,320/MW/year).

2. If decommissioned in 2021, payouts to promoters and financiers would total INR 21,474 crore (USD 2.9 billion), i.e., an average of INR 0.6 crore/MW (USD 84,450/MW). The equity-related portion, at the rate of INR 0.42 crore/MW (USD 56,940/MW), would contribute INR 14,480 crore (USD 1.98 billion) to the total.

18. For plants above 25 years of age, the assumed remaining life of the contract is 5 years. For the remaining plants, it is assumed at 25 years (the standard length of the contract under long-term PPAs with the distribution companies) minus the age of the plant in April 2020.

3. The costs are lower than average due to two factors:
    - The lower annual capacity charges (only including debt and equity payouts) for these plants, which stand at INR 0.24 crore/MW/year (USD 33,300/MW/year), while the average for the entire sample of analysed plants is INR 0.61 crore/MW/year (USD 83,750/MW/year). These reduced charges are possible because of low initial investment costs compared to newer plants and also since a majority of their debt-related obligations have already been paid in the earlier period of their operations.
    - We assumed that the average remaining contract life for these plants was five years, while the average remaining contract life for the entire sample was 12 years, thereby reducing the total payout costs for the current set of plants.
4. The workforce-related payouts add INR 11,700 crore (USD 1.6 billion) to the transition costs, i.e., INR 0.38 crore/MW (USD 51,830/MW) for five years.

Given the significant workforce-related payouts of decommissioning older plants, at 38 per cent of the total cost, early decommissioning would need to consider various measures to reduce these. Thus, measures- like the voluntary retirement schemes and retraining the workforce to help them transition to other jobs etc., along with negotiations and stakeholder engagements, are essential to manage the costs of transitioning and reduce potential fallouts.

Plants below 25 years of age

For plants below 25 years of age, i.e., 83 units in our sample with an aggregate capacity of 60 GW and an average age of 10 years, these are the significant costs related to an early decommissioning:

1. The average annual costs (including debt, equity, and workforce-related payouts) of decommissioning such plants early is INR 0.4 crore/MW/year (USD 55,400/MW/year).
2. If decommissioned today, payouts to promoters and financiers would be worth INR 3,29,000 crore (USD 45 billion), with equity-related payouts contributing around INR 1,06,250 crore (USD 14.6 billion) to the total.
3. For these plants, the average payout to the workforce (in today's cost) would amount to INR 44,860 crore (USD 6.1 billion), i.e., an average payout of INR 0.74 crore/MW (USD 0.1 million/MW) for 15 years.
4. For every MW of capacity considered, the debt and equity–related payouts are prohibitively high, at INR 5.5 crore/MW (USD 0.75 million/MW), with the ROE cost head comprising INR 1.8 crore/MW. Following are the two major contributors to the higher costs:
    - **Expensive plants and higher pending debt obligations**: Most new plants were built at a higher per MW cost than older plants. They also have higher pending debt-related payouts in terms of both interest and principal compared to older plants. The combined effect of these factors is visible in the higher annual capacity charges (debt and equity payouts alone) of INR 0.83 crore/MW/year(USD 0.11 million/MW/year). For comparison, the average debt and equity payouts for the entire sample was INR 0.61 crore/MW/year (USD 0.08/MW/year).
    - **Longer contract tenors**: We assumed the average remaining contract life for these plants to be 15 years; the average remaining contract life for the entire sample was estimated to be 12 years and thus payouts are considered for longer tenure's.

From an economic perspective, the above two factors make newer plants less suitable for decommissioning. Once the debt-related payouts for these plants are completed, such plants could become suitable for early decommissioning.

To better understand how plants of varying ages would fare, we consider the relationship of average characteristics to age in Table 2. For instance, we look at average cost elements for plants in 10-year age bands as well as that for all the plants.

Table 2 Financial and operational parameters favourable to early decommissioning, according to age bands

Plant age (average values in years) <10 10–20 20–30 30–40 >40	Capacity analysed (MW)	Average age (years)	The assumed remaining life of the contract (years)	Debt and equity payouts (INR crore/ MW)	Payouts towards equity (INR crore/ MW)	Workforce payouts (in INR crore/ MW)	Average variable cost (INR/ unit)	Average annual PLF (%)
Plants with age < 10 y	40,860	6	19	6.87	1.98	0.81	2.08	60
Plants with 10Y < age < 20Y	16,605	14	11	2.84	1.37	0.69	1.7	61
Plants with 20Y < age < 30Y	12,375	25	5	0.78	0.55	0.55	2.05	55
Plants with 30Y <age < 40Y	20,718	33	5	0.54	0.37	0.40	1.95	69
Plants with age > 40Y	4,209	46	5	0.42	0.25	0.38	2.29	39
Average/ total for all the capacity considered	**94,767**	**18**	**12**	**3.7**	**1.26**	**0.61**	**2.01**	**61**

Source: CEEW-CEF analysis

Note: The green boxes (parameters) represent favourable values for decommissioning vs the average benchmarks of the sample.

B) Categorisation of plants based on station heat rate (above and below 2,450 Kcal)

There were 72 plants with a station heat rate above 2,450 Kcal and an average age of 24 years; 2,450 Kcal is the amount of heat required to produce a unit of electricity and is considered a proxy for efficiency. With an operational tenor of 9 years on average and a cumulative capacity of 36 GW, these plants would encounter the following decommissioning costs:

1. The average annual cost (including debt, equity, and workforce-related payouts) of decommissioning a plant early is INR 0.3 crore/MW/year (USD 39,125/ MW/year).
2. Decommissioning these plants would cost INR 47,690–75,750 crore (USD 6.5–10.4 billion).
   - On average, payouts to debt and equity holders add between INR 1.3–2.1 crore/MW (USD 0.18–0.29 million/MW) and INR 2.1 crore/MW (USD 0.29 million/MW) to the total.
   - The lower cost for plants with a higher heat rate is because most are old and a large share of their debt-related obligations have already been paid off.
3. The workforce-related payouts for these plants would add another INR 18,160 crore (USD 2.5 billion) or INR 0.5 crore/MW to the early decommissioning costs.

Table 3 lists the various costs associated with early decommissioning of plants with a station heat rate above and below 2,450 Kcal and how they correspond to the average cost and operational parameters of the sample.

Table 3 **Financial and operational parameters of plants, according to station heat rate, favourable for an early decommissioning**

Plant heat rate (average values) Below 2,450 Kcal Above 2,450 Kcal	Capacity analysed (MWs)	Average age (years)	The assumed remaining life of the contract (years)	Debt and equity payouts (INR crore/ MW)	Payouts towards ROE (INR crore/ MW)	Workforce payouts (INR crore/ MW)	Average variable cost (INR/ Unit)	Average annual PLF (%)
Plants with a heat rate below 2,450	58,550	12	15	4.69	1.55	0.67	2.21	61
Plants with heat rate above 2,450	36,217	24	9	2.09	0.77	0.50	1.86	62
Total/average for all the plants	**94,767**	**18**	**12**	**3.70**	**1.26**	**0.61**	**2.01**	**61**

Source: CEEW-CEF analysis

Note: The green boxes (parameters) capture favourable values for decommissioning vs the average benchmarks of the sample.

C) Categorisation of plants based on decommissioning and variable power costs

Our calculations of the average cost of early decommissioning along with the other financial and operational parameters help us establish benchmarks and can be used to derive the approximate cost of decommissioning the country's coal-powered assets early. However, for a deeper understanding of the cost of early decommissioning, we have summarised the plant-level results in Table 4 (Annexure). The table includes parameters like age, variable charges, station heat rate, and cost parameters related to capacity charges.

As evident in Table 4, there are 24 plants with an aggregate capacity of 16.7 GW that have variable charges above INR 2.01/unit (this is an average of the variable costs) and a total cost of early decommissioning below INR 1.03 crore/MW (this is the average cost of decommissioning for plants above 25 years of age).

1. The average annual cost (including debt, equity, and workforce-related payouts) of decommissioning a plant in this category early is INR 0.15 crore/MW/ year (USD 19,960/MW/year).
2. The total payouts for early decommissioning plants in this category are INR 11,530 crore (USD 1.6 billion), i.e., an average of INR 0.69 crore/MW, including workforce-related payouts.
3. Equity-related payouts contribute 35 per cent, or INR 4,080 crore (USD 560 million), i.e., INR 0.24 crore/MW. These could be used as a driver to reduce the eventual costs of an early decommissioning by mechanisms to reduce the equity related payouts like as in the case of Germany. They can help reduce the eventual costs of an early decommissioning.
4. Workforce-related payouts stand at INR 1,400 crore (USD 192 million), i.e., an average of INR 0.08 crore/ MW.

As these plants offer low early decommissioning costs as well as high variable charges, they would be the best candidates for early decommissioning. Decommissioning these plants would be a cost-efficient way of decarbonising the power sector as the payouts are lesser and discoms can save on the high variable costs associated with purchasing power from these generators.[19]

Another insight from Table 4 is that many plants aged 20 years or older, due to the lower costs of

19. For these plants, a technical analysis would be important, as it would provide an understanding of their importance to the power supply, grid, and discoms in their respective states.

early decommissioning and their high variable costs (which cause economic pressure on discoms), would be relatively easy to decommission. This is primarily because many older plants have completed, or are nearing the end of, their debt-related payouts. Workforce-related costs are also comparatively manageable for these plants; this lowers early decommissioning costs.

Table 4 gives several other insights like for which plants equity-related payments would be defining factor, the workforce-related payouts, and thus what decommissioning mechanisms could prove effective based on the costs and operational characteristics of the individual plants considered.

4. How is the world decommissioning coal-powered assets?

After ascertaining the costs and drivers of retiring coal-based plants in India, we looked at two countries leading the decarbonisation of power generation globally. Germany and South Africa still rely on coal for a substantial share of their energy mixes, but they are ahead of India in their decommissioning journeys. Understanding their experiences is essential to designing a mechanism that suits India's needs and facilitates a just transition for all stakeholders.

A) GERMANY

'Pay-to-close' coal exit law: Fiscal funding for an accelerated coal-based plant shutdown and a transition of communities in Germany

Germany has a comprehensive phased plan to retire coal-based plants and associated coal-producing assets. The country has allocated a budget of EUR 49 billion (USD 59 billion) to compensate various stakeholders, including the workforce, for transitioning away from coal by 2038 (Parkin, Jennen, and Donahue 2020).

Coal phase-out act

In July 2020, the German Parliament passed a coal exit law following 18 months of deliberation by a multi-stakeholder coal exit commission that recommended ending all coal-fired power generation by 2038. The law sets out clear roadmaps for the phaseout of lignite and hard coal power plants, ensuring that the closure of lignite power plants will not adversely affect Germany's mining region economy, communities, and workers. Germany shut down its last hard coal mine in 2018; therefore, its power plants rely on imported coal for power generation.

> Germany has budgeted EUR 49 billion (USD 59 billion) to compensate shutting down of all coal-based power plants and coal mines by 2038.

Our study has the following limitations:

1) It does not cover the costs associated with compensating sectors dependent on supplying coal to these plants; for instance, coal mine operators, railways, the workforce employed in these sectors, and others.
2) The study does not account for the costs of choices associated with decommissioning, such as repurposing the plants for storage, RE, and RE + storage.
3) It uses nominal depreciation values derived from tariff orders, which may deviate from the actual salvage value of a plant.
4) The study does not consider the cost of the upgrades that several plants will need to undertake to meet new emissions norms. Accounting for these costs would render early decommissioning more favourable to keeping the plants operational.

The coal exit law prescribes the following timeline (Wettengel 2020):

- **Phase 1**: Retire 7.8 GW of hard coal and 6.1 GW of lignite assets by 2022, out of the existing capacities of 22.8 GW of hard coal and 21.1 GW of lignite capacity in 2019.
- **Phase 2**: Retire 7 GW of hard coal and 6 GW of lignite-powered assets by 2030 to have 8 GW of hard coal and 9 GW of lignite capacities operational.
- **Phase 3**: Retire the remaining coal-fired capacities by the end of 2038.

As a part of this process, three reviews will be done in 2026, 2029, and 2032 to determine whether the phaseout can be completed by 2035 instead.

Pay-to-close mechanism

The German Government has proposed a compensation mechanism to shut down coal plants. Under this mechanism, lignite operators and the government shall have contracts with a mutually agreed-upon compensation and shutdown schedule. The compensation amount will be determined via a series of auctions between 2020 and 2024 for the hard coal capacity phaseout.

Lignite plants

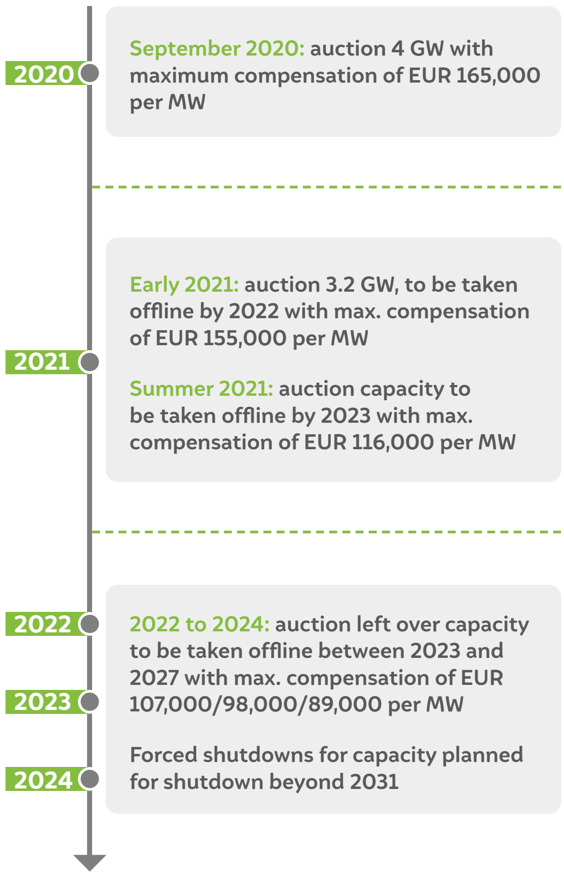
The four lignite operators in Germany (RWE, LEAG, Saale Energie, and EnBW) have agreed to compensation of around EUR 4.35 billion (USD 5.22 billion or INR 38,110 crore) for a total capacity phaseout of 21.1 GW.[20] This compensation would not change in case operators shut down plants earlier than the scheduled dates. The German Government has allocated structural aid of EUR 14 billion (USD 16.8 billion or INR 1.2 lakh crore) to support mine workers, in addition to EUR 26 billion (USD 31.2 billion or INR 2.3 lakh crore) funding for infrastructure development in the affected regions (Wettengel 2020).

Hard coal plants

A part of the 22.2 GW of hard coal capacity is scheduled for phaseout through auctions organised by the Federal Network Agency until 2027. In these auctions, coal operators can propose to retire certain capacities and demand the appropriate amount of money (EUR/MW of capacity). The auction has a cap on the maximum compensation offered (EUR/MW) which reduces over subsequent auctions (Figure 1). This creates an incentive for hard coal operators to participate in earlier tenders. In the first phase of the auctions, which concluded in December 2020, 4.78 GW of capacity was auctioned instead of the planned 4 GW, with an average compensation of EUR 66,000/MW, well below the planned maximum of EUR 1,65,000/MW.

The law stipulates a forced shutdown of hard coal plants based on their age should the auctions not yield positive results. In addition, it foresees forced shutdowns occurring between 2027 and 2038.

Figure 1 Germany's hard coal capacity to be taken offline by 2027 as per the following schedule



Source: Clean Energy Wire and Energy Central

20. EUR 1 = USD 1.20.

Key enablers of the transition

- Auctioning at a later stage for hard coal plants, which are grid critical.
- Regular assessments of supply security and power prices by the federal government.
- A 'reasonable' annual compensation for energy-intensive industries in the case of additional power costs that derive from the coal exit law.

Learnings

- The latest round of auctions involved plants that were opened as recently as 2015 (i.e., efficient plants) bidding to be phased out in 2021. This calls for a mechanism to include all elements, such as technical requirements, efficiency, rather than just the economics, national interests, in particular, technology, when designing the phaseout plan.
- Germany's example showcases that it is possible to retire even newer plants if they are surplus to the requirement. Accordingly, India could explore a mechanism that incentivises an early decommissioning of unrequired plants.

B) SOUTH AFRICA

South Africa is looking to retire its coal assets and revive its largest utility's financial viability to and free up investment flows to set up more RE in the country. The plan incorporates a phase-out target and a blended finance facility to retire coal assets and finance renewable assets.

Just transition transaction: Financing accelerated coal phase-out and funding transition of communities in South Africa

Proposed just transition

Disinvestment pressures in South Africa have reduced financial flows into coal power plants while increasing financing for RE technologies. During this period, 'transition finance' is required to ensure the protection of local communities and realise the country's pressing development needs.

> SA is looking at decommissioning to unlever its monopoly utility off stranded debt worth R 488 billion (USD 31.7 billion or INR 2.3 lakh crore).

South Africa requires financing to fund its energy transition and overcome the complex problems that its monopoly utility, Eskom, faces: operational, financial, and structural issues that constrain investment in the energy transition. Its key legacy issues include inefficiency and corruption, leading to wastage of funds; the treasury not having enough funds to offer a further bailout; and inefficient, old, and emissions-intensive coal power plants.

The biggest problem is that Eskom has a debt of R 488 billion (USD 31.7 billion or INR 2.3 lakh crore) and counting (Winkler, Keen, Marquard 2020)[21]. Many issues have contributed to this rising debt, such as coal plant budget overruns, irregular tender activity in coal supply contracts, and non-cost-reflective tariffs. Further, a portion of this debt (around R 200 billion or INR 1.04 lakh crore) is stranded. Eskom is struggling to raise further debt as well as pay its stranded debt due to a lack of access to capital markets. This is because sovereign guarantees, which form a part of Eskom's stranded debt, strain the fiscal framework and have contributed to the downgrading of the country's credit rating. Therefore, Eskom has proposed an innovative solution for these issues.

Intervention structure

A blended finance vehicle has been proposed to solve these problems; it will provide long-term loans to Eskom at a near-commercial rate, conditional on additional mitigation (for commitments as per the Integrated Resource Plan 2019 and social action).[22] These loans aim to fund the additional costs of decommissioning coal and realising a just transition. They would not offer funding to repay loans associated with 'legacy debt'. By funding an accelerated coal decommissioning, the transaction would enable Eskom to access capital markets again,

21. 1 R= INR 5.22

22. Eskom under the Ministry of Mineral Resource and Energy, South Africa, published the Integrated Resource Plan (IRP) in 2019, which does not propose an accelerated decommissioning of coal but instead considers a 50-year lifespan for power plants. The plan suggests retiring 10.5 GW of coal capacity while retaining 7.2 GW of coal capacity in the pipeline until 2030. The recommended blended finance vehicle is conditional on coal decommissioning or repurposing at a faster rate than the IRP 2019 proposes.

thereby enhancing the company's ability to pay off its legacy debt (Winkler, Keen, Marquard 2020).

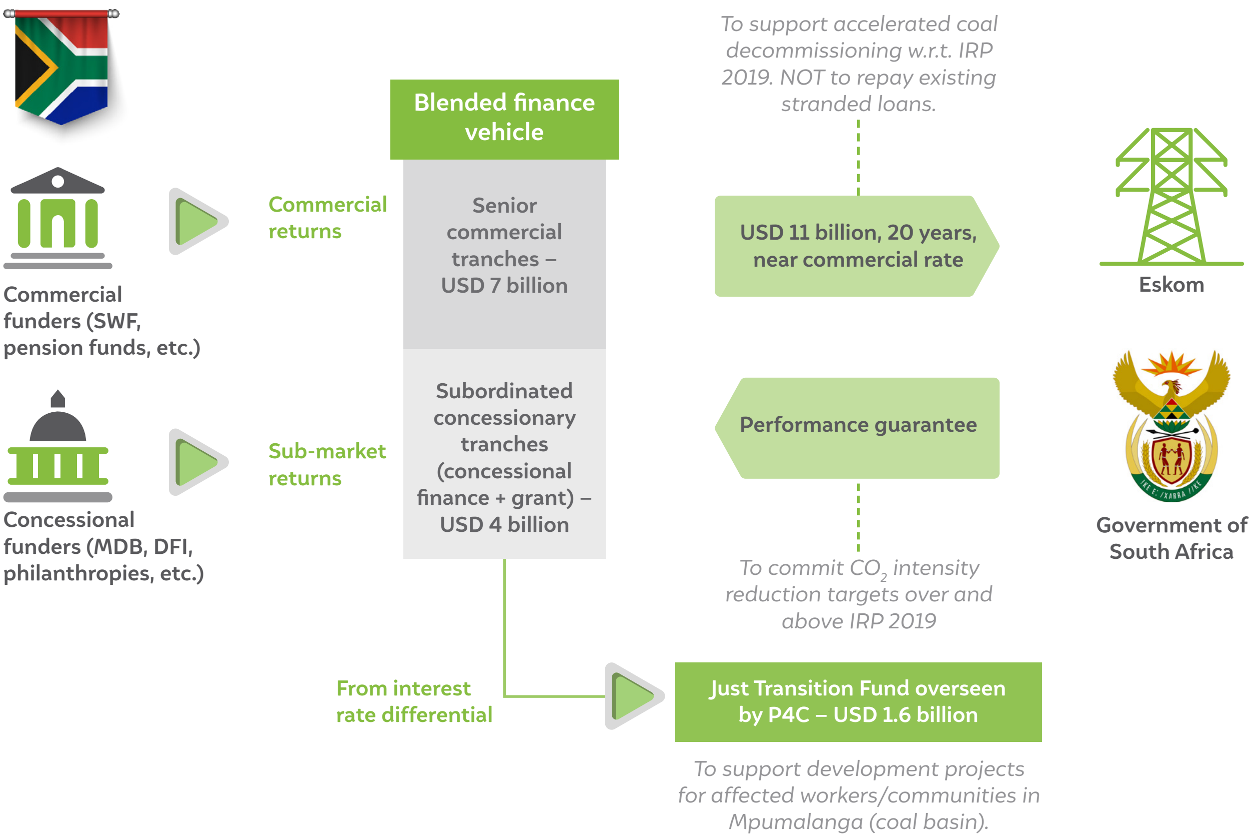
The blended finance vehicle aims to create a just transition fund with the interest rate differential between the loan to Eskom and concessional financing from international climate financiers (~USD 4 billion or INR 29,200 crore). This differential shall accrue annually and, assuming a concessional interest rate of 2 per cent below the commercial rate, we calculate the total loan amount to be yearly flow of USD 80 million (INR 580 crore) for the just transition. Assuming a loan tenure of 20 years we calculate the total loan amount to be USD 1.6 billion (11,680 crore). However, more detailed financial modelling is needed (Winkler, Keen, Marquard 2020). The just transition fund shall be used for the following:

- Packages for coal power plants and mine workers
- Transition management, including processes to execute the eventual decommissioning, strategising, coordination, research, strategy development, and streamlining communications
- Education and upskilling
- RE-based socio-economic acceleration programmes

Key enablers

- An enabling governance framework is critical to the success of a just transition transaction. Key actors include the following:
  - Commercial and concessional funders
  - The national treasury to oversee financial flows
  - The National Energy Regulator of South Africa for creating an enabling policy environment, along with national departments in charge of Eskom, that is, the Department of Mineral Resource and Energy.
- The just transition transaction is currently in the proposal stage. A presidential climate coordinating committee (P4C) has been constituted to oversee and execute the change.

Figure 2 South Africa's just transition transaction structure



Source: CEEW-CEF; Winkler, Keen, and Marquard (2020)

5. Conclusion

Our analysis is the first step to understanding the potential cost implications of the early decommissioning of coal in India. Findings from this study could inform mechanisms adopted to decommission the relevant assets.

The decommissioning process would need further deliberations on the plant's suitability for either decommissioning, mothballing, and repurposing of the plants for RE, storage, and others based on the technical and economically suited options. Further, this would require a pan India mapping of the plants, the future demand of electricity, grid balancing and other aspects to remove the plants away from the system. As the country scales up the programme, another connected sector that needs support and exit plans is coal mining. The transition planning is crucial as the coal sector, which employs close to 5 lakh people directly (and a lot more informally), has substantial dependence on coal-based electricity generation. Another affiliated entity would be the India Railways, dependent to a large extent on the revenue from coal's supply chain to coal-based electricity generators in India

Based on the analysis and mapping of plants, we find that the significant drivers of retirement costs are the payouts to debt and equity holders and the workforce. It is clear that with a properly designed mechanism that considers factors like the age of plants and their efficiency, the country could reduce the costs of the clean energy transition. After analysing these costs at the plant level, it becomes apparent that early decommissioning may not be the most economical solution for all.

To reduce equity-related costs, bidding or reverse auctions could be explored. Such mechanisms could be helpful since equity payouts amount to 29 per cent of the total payout costs, at INR 1.26 crore/MW (USD 0.17 million/MW). As discussed, such a mechanism helped Germany bring the cost of retirement down by almost 60 per cent, to EUR 66,000/MW from the upper cap of EUR 1,65,000/MW; in this case, promoters bid lower rates keeping in mind the uncertainties associated with these projects.

Workforce payouts are likely to add another substantial chunk to the costs—14 per cent on average. An essential step in designing the mechanism would be introducing voluntary retirement schemes or retraining the workforce for other jobs. Such steps would be necessary from an economic standpoint and to allay potential fears associated with early decommissioning among workers.

The country would need to deliberate early decommissioning mechanisms as many plants aged above 20 years, with the majority of their debts paid off, could be financially easier to decommission than newer ones. Also, many such plants might need to make repairs and conduct maintenance, increasing their capacity charges in the future, so a cost-benefit analysis and requirement assessment for the supply could help decide the future steps. Indeed, early decommissioning of these plants may help to reduce capacity charges by over 10 per cent annually. Significantly, for plants above 40 years of age, where the 'O&M' cost head makes up above 60 per cent of the total capacity charges, even higher annual savings on capacity charges, of 14 per cent, are possible.[23]

> **An early decommissioning of the mapped 95 GW capacity could help unlock USD 16 billion and USD 32 billion of equity and debt each.**

As highlighted, we do not recommend a large scale decommissioning, however, when adopted, will help unlock the debt and equity capital to the tune of INR 2.4 core/MW and 1.3 crore/ MW each. If scaled to 45 per cent of the existing capacity mapped in the study, the solution could help unlock INR 2.3 lakh crore (USD 32 billion) and equity worth INR 1.2 lakh crore (USD 16 billion) i.e. total capital worth INR 3.5 lakh crore (USD 48 billion) could be unlocked. This unlocking of capital could potentially help the country achieve the required capital for installing more RE, storage and other projects.

23. The savings on capacity charge payments are possible owing to the payment of only workforce-related expenses and savings on repairs and maintenance, which go up with the age of the plants.

Annexure

Table 4 **Plant-wise breakup of costs associated with early decommissioning and the plants operating parameters**

No.	Plant name	Plant unit	Age (years)	The assumed remaining life of the contract	Capacity under contract (MW)	Variable cost per unit (INR/ unit)	Station heat rate (Kcal/unit)	Debt and equity payouts minus the salvage value of the plant (INR crore)	Debt and equity payouts minus the salvage value of the plant per MW (INR crore/MW)	Equity payouts per MW (INR crore/MW)	Debt payouts per MW (INR crore/MW)	Workforce-related payouts (INR crore)	Workforce-related payouts (INR crore/ MW)	Total cost for an early decommissioning per MW (INR crore/MW)	Average yearly cost for an early decommissioning (INR crore/MW/ year)	Annual savings on capacity charges due to an early decommissioning (%)
1	Barauni Thermal Power Station (BTPS)	Stage 8 & 9	1	24	500	2.32	2500	6,964	13.93	3.46	10.47	398	0.80	14.72	0.61	0.2
2	Neyveli New Thermal Power Station	Units - I , II	1	24	1,000	2.31	2599	5,827	5.83	2.10	3.72	641	0.64	6.47	0.27	1.3
3	Solapur Super Thermal Power Station	NA	2	23	1,320	2.79	2236	7,550	5.72	2.23	3.49	1,222	0.93	6.64	0.29	0.4
4	Barauni Thermal Power Station (BTPS)	Stage 6 & 7	3	22	220	2.79	3000	668	3.04	0.83	2.20	188	0.86	3.89	0.18	1.3
5	Kudgi Super Thermal Power Station	Stage-I	3	22	2,400	3.71	2211	18,957	7.90	3.05	4.85	2,265	0.94	8.84	0.40	0.8
6	Feroze Gandhi Unchahar Thermal Power Plant	Stage- IV	3	22	500	2.51	2348	3,644	7.29	2.76	4.53	472	0.94	8.23	0.37	0.9
7	Bokaro A Thermal Power Station	Unit-I	4	21	500	1.74	2363	4,541	9.08	2.37	6.71	373	0.75	9.83	0.47	0.6
8	Muzaffarpur Thermal Power Station	Stage 2	4	21	390	2.25	2500	4,236	10.86	3.15	7.72	312	0.80	11.66	0.56	0.9
9	Atal Bihari Vajpayee Thermal Power Plant (ABVTPP)	NA	4	21	1,000	1.49	2378	10,529	10.53	0.87	9.66	851	0.85	11.38	0.54	0.4
10	Parli Thermal Power Station	Unit 8	4	21	250	3.09	2353	2,451	9.80	1.07	8.73	240	0.96	10.77	0.51	0.8
11	Seoni Thermal Power Station	Unit-1	4	21	600	2.66	2382	6,488	10.81	3.76	7.05	393	0.65	11.47	0.55	0.5
12	Singareni Thermal Power Plant	NA	4	21	1,200	NA	2304	9,031	7.53	2.69	4.84	931	0.78	8.30	0.40	0.6
13	Bongaigaon Thermal Power Station	Unit I,II and III	5	20	750	2.74	2362	3,607	4.81	1.78	3.03	627	0.84	5.65	0.28	0.4
14	Tamil Nadu Power Limited	NA	5	20	1,000	2.10	2351	6,027	6.03	1.77	4.25	788	0.79	6.82	0.34	0.9
15	Muzaffarpur Thermal Power Station	Stage 1	5	20	110	3.92	3000	404	3.67	1.05	2.63	78	0.70	4.38	0.22	3.1
16	Raghunathpur Thermal Power Station	Units - I , II	5	20	1,200	1.43	2340	7,782	6.49	1.68	4.81	894	0.74	7.23	0.36	0.7
17	Vindhyachal Super Thermal Power Station	Stage- V	5	20	500	1.10	2351	3,788	7.58	2.95	4.63	430	0.86	8.44	0.42	0.7
18	Sikka Thermal Power Station	Units 3 & 4	5	20	500	3.67	2398	4,218	8.44	2.40	6.04	439	0.88	9.31	0.47	0.7
19	Chandrapur Super Thermal Power Station	Unit 8,9	5	20	1,000	2.29	2319	8,029	8.03	0.81	7.22	944	0.94	8.97	0.45	0.6
20	Koradi Thermal Power Station	Unit 8,9,10	5	20	1,980	2.47	2222	16,348	8.26	0.97	7.29	1,869	0.94	9.20	0.46	0.3
21	Anuppur Thermal Power Project	Unit 2	5	20	600	1.92	2362	3,887	6.48	1.55	4.92	410	0.68	7.16	0.36	0.7
22	Inland Tonagatu Power Project	Unit 1	6	19	63	2.13	2765	354	5.62	1.54	4.08	45	0.71	6.33	0.33	1.3
23	NLC Thermal Power Station 2 Expansion	Units - I , II	7	19	500	NA	2483	4,019	8.04	3.04	5.00	393	0.79	8.82	0.48	1.1
24	Kamalanga Thermal Power Plant	NA	7	18	1,050	1.17	2331	5,992	5.71	1.72	3.99	716	0.68	6.39	0.35	1.1
25	Vallur Thermal Power Station	NA	7	18	1,500	1.90	2351	9,822	6.55	2.02	4.52	1,076	0.72	7.26	0.40	0.9
26	Korba West Thermal Power Plant (KWTPP)	NA	7	18	500	1.26	2375	3,896	7.79	1.41	6.38	381	0.76	8.55	0.48	0.5
27	Ukai Thermal Power Station	Unit 6	7	18	500	3.06	2385	3,287	6.57	2.03	4.54	422	0.84	7.42	0.41	0.4
28	Mahadev Prasad Super Thermal Power Plant	Unit 2	7	18	270	1.76	2387	1,685	6.24	1.69	4.55	181	0.67	6.91	0.38	1.2

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29	Niwari TPP	Unit-1	7	18	45	NA	2835	365	8.12	2.87	5.25	28	0.63	8.75	0.49	1.1
30	North Chennai Thermal Power Station	Stage 2	7	18	1,200	2.18	2450	8,428	7.02	–	7.02	1,533	1.28	8.30	0.46	0.4
31	Parichha Exp	Stage 2	7	18	500	NA	2475	2,826	5.65	1.80	3.85	372	0.74	6.39	0.36	1.5
32	Dishergarh Thermal Power Station	NA	7	18	12	3.97	3300	68	5.63	2.13	3.50	8	0.68	6.31	0.35	0.1
33	Koderma Thermal Power Station	Units-I & II	8	17	1,000	1.75	2363	6,052	6.05	1.12	4.94	760	0.76	6.81	0.40	1.3
34	Mauda Super Thermal Power Station	Stage-I	8	17	1,000	2.15	2401	7,743	7.74	3.05	4.69	794	0.79	8.54	0.50	0.9
35	Mejia Thermal Power Station	Unit - VII, VIII	8	17	1,000	1.56	2375	5,438	5.44	1.82	3.62	739	0.74	6.18	0.36	1.1
36	Rihand Super Thermal Power Project	Stage -III	8	17	1,000	1.40	2402	6,122	6.12	2.42	3.71	800	0.80	6.92	0.41	0.8
37	Udupi TPP	NA	8	17	1,200	NA	2333	5,396	4.50	1.41	3.08	777	0.65	5.14	0.30	1.1
38	Vindhyachal Super Thermal Power Station	Stage- IV	8	17	1,000	1.05	2375	6,798	6.80	2.73	4.07	805	0.81	7.60	0.45	2.4
39	Mahadev Prasad Super Thermal Power Plant	Unit 1	8	17	270	1.76	2387	1,626	6.02	1.68	4.34	178	0.66	6.68	0.39	1.3
40	Butibori Power Project	Units 1 & 2	8	17	600	2.19	2400	4,681	7.80	2.36	5.44	424	0.71	8.51	0.50	1.0
41	Bhusawal Thermal Power Station	unit 4,5	8	17	1,000	2.79	2375	8,590	8.59	1.62	6.96	883	0.88	9.47	0.56	1.1
42	Bina TPP	Unit 1 & 2	8	17	500	NA	2450	3,371	6.74	2.13	4.61	337	0.67	7.42	0.44	1.3
43	Mettur Thermal Power Station Expansion	Stage 3	8	17	600	3.06	2450	6,168	10.28	3.42	6.86	737	1.23	11.51	0.68	0.7
44	Harduaganj Thermlal Power station Exp	NA	8	17	500	2.67	2475	3,153	6.31	2.06	4.24	365	0.73	7.04	0.41	1.5
45	Chandrapura Thermal Power Station	Unit 7 & 8	9	16	500	1.37	2357	2,192	4.38	1.47	2.92	362	0.72	5.11	0.32	2.0
46	Durgapur Steel Thermal Power Station	Units I and II	9	16	1,000	1.76	2441	5,156	5.16	1.29	3.87	701	0.70	5.86	0.37	1.4
47	Indira Gandhi Super Thermal Power Project	Stage I	9	16	1,500	2.32	2363	8,518	5.68	2.24	3.44	1,052	0.70	6.38	0.40	1.1
48	Maithon Right Bank Thermal Power Plant	Units-I and II	9	16	1,050	2.41	2375	4,904	4.67	1.62	3.05	685	0.65	5.32	0.33	1.2
49	Simhadri Super Thermal Power Station	Stage-II	9	16	1,000	2.69	2389	5,811	5.81	2.45	3.36	754	0.75	6.56	0.41	1.3
50	Sipat Super Thermal Power Station	Stage-I	9	16	1,980	1.38	2306	10,260	5.18	2.22	2.97	1,585	0.80	5.98	0.37	1.3
51	Khaparkheda Thermal Plant Station	Unit 5	9	16	500	2.37	2375	3,063	6.13	0.86	5.26	429	0.86	6.98	0.44	0.7
	Total/average for plants aged <10 years of age		**6**	**19**	**40,860**	**1.98**	**2,366**	**2,80,759**	**6.87**	**1.98**	**4.89**	**17,168**	**0.81**	**7.68**	**0.41**	**0.9**
52	Rayalaseema Thermal Power Plant	Stage 3	10	15	210	3.36	2500	550	2.62	2.62	0.00	148	0.71	3.33	0.22	4.0
53	Barsingsar Thermal Power Station (CBFC technology)	NA	10	15	250	1.21	2548	1,672	6.69	2.75	3.94	176	0.70	7.39	0.49	1.6
54	National Capital Thermal Power Station (NCTPS) – Dadri	Stage I	10	15	980	NA	2378	4,877	4.98	2.18	2.80	707	0.72	5.70	0.38	0.9
55	Korba Super Thermal Power Station	Stages I, II	10	15	500	0.67	2393	2,537	5.07	2.08	3.00	366	0.73	5.80	0.39	1.1
56	Dr Narla Tatarao Thermal Power Station	Stage IV	11	14	500	2.74	2450	828	1.66	1.66	0.00	343	0.69	2.34	0.17	3.3
57	Parli Thermal Power Station	Units 3, 4, 5	11	14	500	3.08	2450	2,205	4.41	1.04	3.37	402	0.80	5.21	0.37	1.7
58	Paras Thermal Power Station	Unit 8	12	14	500	2.54	2450	2,454	4.91	1.05	3.86	394	0.79	5.70	0.42	1.6

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59	Bhilai Expansion Power Project	NA	12	13	500	1.62	2404	2,459	4.92	2.12	2.80	342	0.68	5.60	0.43	2.2
60	Kahalgaon Super Thermal Power Station	Stage I	12	13	1,500	1.88	2425	4,962	3.31	1.48	1.83	1,033	0.69	4.00	0.31	1.7
61	Mejia Thermal Power Station	Unit IV	12	13	500	2.58	2450	802	1.60	1.60	0.00	326	0.65	2.26	0.17	5.0
62	Sipat Super Thermal Power Station	Stage I	12	13	1,000	1.44	2375	3,835	3.84	1.77	2.07	668	0.67	4.50	0.35	1.9
63	Kutch Lignite Thermal Power Station (KLTPS)	Units 1, 2, 3	12	13	75	2.03	3000	574	7.66	2.73	4.92	55	0.73	8.39	0.65	0.8
64	Rayalaseema Thermal Power Plant	Stage 2	13	12	420	3.36	2500	463	1.10	1.10	0.00	269	0.64	1.74	0.15	4.4
65	Dr. Shyama Prasad Mukherjee Thermal Power Station (DSPMTPS)	NA	13	12	500	1.42	2500	1,860	3.72	1.35	2.37	320	0.64	4.36	0.36	2.2
66	Parichha Exp	NA	13	12	420	3.21	2475	1,159	2.76	0.77	1.99	250	0.60	3.35	0.28	3.0
67	Feroze Gandhi Unchahar Thermal Power Plant	Stage II	14	11	210	2.93	2450	651	3.10	1.51	1.58	132	0.63	3.72	0.34	2.6
68	Vindhyachal Super Thermal Power Station	Stage II	14	11	1,000	1.05	2375	2,881	2.88	1.38	1.50	650	0.65	3.53	0.32	2.2
69	Mejia Thermal Power Station	Units I, II, III	15	10	210	2.60	2450	233	1.11	1.11	0.00	118	0.56	1.67	0.17	5.0
70	Rihand Super Thermal Power Project	Stage I	15	10	1,000	1.40	2375	2,602	2.60	1.26	1.35	621	0.62	3.22	0.32	1.9
71	Ramagundam Super Thermal Power Station	Stages 1, 2	16	9	500	2.37	2375	1,254	2.51	1.25	1.26	289	0.58	3.09	0.34	2.1
72	Talcher Super Thermal Power Station	Stage I	17	8	2,000	1.21	2375	2,295	1.15	0.87	0.27	1,073	0.54	1.68	0.21	4.5
73	Simhadri Super Thermal Power Station	Stage III	17	8	1,000	2.72	2375	2,193	2.19	1.35	0.84	616	0.62	2.81	0.35	4.0
74	Leh.Mo TPS	NA	17	8	920	NA	2440	1,130	1.23	0.49	0.73	456	0.50	1.72	0.22	0.0
75	NLC Thermal Power Station Expansion	Units 1, 2, 3, 4	18	7	420	NA	2750	501	1.19	0.80	0.40	177	0.42	1.61	0.23	6.0
76	Jojobera Power Plant	Unit 2	18	7	120	2.77	2552	163	1.36	1.00	0.36	54	0.45	1.81	0.26	6.4
77	Budge Budge Thermal Power Station	NA	18	7	750	NA	2470	1,597	2.13	1.21	0.92	432	0.58	2.71	0.41	0.8
78	Jojobera Power Plant	F Station	19	6	120	2.82	2543	145	3.15	1.52	1.63	596	0.64	3.78	0.63	5.1
	Total/average for plants aged 10 -20 years		**14**	**11**	**16,605**	**1.57**	**2,428**	**46,884**	**2.84**	**1.37**	**1.47**	**11,013**	**0.69**	**3.47**	**0.31**	**2.4**
79	Feroze Gandhi Unchahar Thermal Power Plant	Stage I	21	4	420	NA	2450	238	0.57	0.57	0.00	131	0.31	0.88	0.22	13.2
80	Vindhyachal Super Thermal Power Station	Stage I	21	4	1,000	1.05	2375	540	0.54	0.54	0.00	367	0.37	0.91	0.23	12.0
81	Mejia Thermal Power Station	NA	22	3	630	2.60	2450	234	0.37	0.36	0.01	153	0.24	0.62	0.21	18.1
82	Gandhinagar Thermal Power Station	Units 3, 4	22	3	210	3.49	2460	72	0.34	0.34	0.00	54	0.26	0.60	0.20	16.8
83	Wanakbori Thermal Power Station	Units 1–6	22	3	210	3.14	2460	65	0.31	0.31	0.00	54	0.26	0.57	0.19	4.0
84	Talcher Super Thermal Power Station	Stage I	25	5	1,000	1.25	2375	991	0.99	0.99	0.00	379	0.38	1.37	0.27	9.0
85	Dahanu Thermal Power Station (DTPS)	Units 1, 2	25	5	500	3.29	2312	509	1.02	0.66	0.36	182	0.36	1.38	0.28	8.1
86	Khaparkheda Thermal Power Station	Units 8, 9	25	5	840	2.81	2614	393	0.47	0.33	0.13	336	0.40	0.87	0.17	9.7
87	Kahalgaon Super Thermal Power Station	Stage I	26	5	840	1.99	2450	849	1.01	1.01	0.00	348	0.41	1.42	0.28	10.2

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	Rayalaseema Thermal Power Plant	Stage 1	26	5	420	3.36	2500	269	0.64	0.64	0.00	156	0.37	1.01	0.20	10.8
	Odisha Power Generation Corporation	Unit 1	26	5	420	1.41	2450	331	0.79	0.62	0.17	144	0.34	1.13	0.23	8.3
	North Chennai Thermal Power Station	NA	26	5	630	2.30	2393	2,632	4.18	0.99	3.18	286	0.45	4.63	0.93	6.2
	Kutch Lignite Thermal Power Station (KLTPS)	Unit 7	27	5	215	2.16	3231	314	1.46	0.88	0.58	84	0.39	1.85	0.37	9.8
	Anpara Thermal Power Station	Stage 1	27	5	1,000	1.62	2410	698	0.70	0.70	0.00	352	0.35	1.05	0.21	7.2
	National Capital Thermal Power Station (NCTPS) – Dadri	Units 7, 8	28	5	840	3.28	2450	594	0.71	0.71	0.00	306	0.36	1.07	0.21	9.8
	NLC Thermal Power Station 2	Units 1, 2, 3	28	5	840	2.33	2900	86	0.10	0.10	0.00	285	0.34	0.44	0.09	13.6
	Chandrapur Super Thermal Power Station	Units 4, 5	28	5	1,920	2.33	2670	405	0.21	0.11	0.10	768	0.40	0.61	0.12	10.8
	Tanda Thermal Power Station	NA	29	5	440	2.36	2750	420	0.96	0.61	0.35	163	0.37	1.33	0.27	11.2
	Total/average for plants aged 20 -30 years		**25**	**5**	**12,375**	**2.16**	**2,528**	**9,641**	**0.78**	**0.55**	**0.23**	**4,549**	**0.55**	**1.15**	**0.24**	**10.6**
	Farakka Super Thermal Power Plant	Stages I, II	30	5	1,600	2.00	2403	1,110	0.69	0.69	0.00	590	0.37	1.06	0.21	9.8
	Bokaro B Thermal Power Station	Unit I	30	5	630	1.72	2700	163	0.26	0.26	0.00	225	0.36	0.62	0.12	12.1
	Gandhinagar Thermal Power Station	Units 3, 4, 5	30	5	420	3.69	2625	79	0.19	0.19	0.00	164	0.39	0.58	0.12	13.4
	Ropar TPS (GGS-STPS)	NA	30	5	840	NA	2450	384	0.46	0.32	0.14	309	0.37	0.82	0.16	1.4
	Southern Generating Station	Stage 1	30	5	136	NA	2900	90	0.66	0.43	0.23	61	0.45	1.11	0.22	3.4
	Vindhyachal Super Thermal Power Station	Stage IV	31	5	1,260	1.12	2450	537	0.43	0.43	0.00	478	0.38	0.81	0.16	12.5
	Rihand Super Thermal Power Station	Stage 3	32	5	1,000	1.40	2335	1,025	1.03	1.03	0.00	373	0.37	1.40	0.28	6.3
	Feroze Gandhi Unchahar Thermal Power Plant	NA	32	5	420	NA	2450	334	0.80	0.80	0.00	152	0.36	1.16	0.23	10.2
	Torrent Power Limited, (Ahmedabad Power Plant)	E Station	32	5	121	3.27	2455	142	1.18	0.63	0.55	46	0.39	1.57	0.31	3.5
	Dr Narla Tatarao Thermal Power Station	Stages I, II, III	32	5	1,260	2.90	2550	533	0.42	0.42	0.00	468	0.37	0.79	0.16	11.7
	Ramagundam Super Thermal Power Station	Units I, II	33	5	2,100	2.19	2396	893	0.43	0.41	0.01	780	0.37	0.80	0.16	9.9
	NLC Thermal Power Station 2	Units 1–10	33	5	630	2.33	2900	24	0.04	0.04	0.00	214	0.34	0.38	0.08	14.2
	Mettur Thermal Power Station	NA	33	5	840	2.97	2500	1,248	1.49	0.37	1.12	381	0.45	1.94	0.39	9.4
	Anpara Thermal Power Station	Stage 3	33	5	630	1.87	2475	134	0.21	0.21	0.00	231	0.37	0.58	0.12	12.7
	Korba Super Thermal Power Station	Units I, II	33	5	2,100	0.72	2396	642	0.31	0.31	0.00	806	0.38	0.69	0.14	10.5
	Wanakbori Thermal Power Station	Unit 5	35	5	1,260	3.26	2625	600	0.48	0.22	0.25	491	0.39	0.87	0.17	6.9
	Tuticorin Thermal Power Station	Units 1, 2, 3, 4	35	5	1,050	NA	NA	2,086	1.99	0.51	1.48	477	0.45	2.44	0.49	8.4
	Parichha	NA	35	5	220	3.90	2980	43	0.19	0.00	0.19	79	0.36	0.55	0.11	15.0
	Singrauli Super Thermal Power Station	Stage II	35	5	2,000	1.23	2413	540	0.27	0.26	0.01	742	0.37	0.64	0.13	10.5
	Hasdeo Thermal Power Station (HTPS)	NA	36	5	840	1.50	2650	316	0.38	0.24	0.13	306	0.36	0.74	0.15	11.5

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117	Torrent Power Limited, (Ahmedabad Power Plant)	D Station	36	5	121	3.26	2455	142	1.18	0.63	0.55	46	0.39	1.57	0.31	3.5
118	Bhusawal Thermal Power Station	Units 1, 2	38	5	210	3.12	2770	91	0.43	0.13	0.31	84	0.40	0.83	0.17	11.8
119	Koradi Thermal Power Station	Unit 5	38	5	420	3.32	2874	85	0.20	0.08	0.12	168	0.40	0.60	0.12	12.9
120	Ukai Thermal Power Station	NA	39	5	610	3.31	2625	244	0.40	0.15	0.24	238	0.39	0.79	0.16	11.5
	Total/average for plants aged 30- 40 Years		**33**	**5**	**20,718**	**1.79**	**2,380**	**11,486**	**0.55**	**0.38**	**0.17**	**7,908**	**0.40**	**0.94**	**0.19**	**10.0**
121	Nashik Thermal Power Station	Units 8, 9, 10	40	5	630	3.39	2736	194	0.31	0.10	0.20	252	0.40	0.71	0.14	13.1
122	Obra B TPS	A	40	5	1,000	1.52	2755	296	0.30	0.13	0.17	364	0.36	0.66	0.13	11.8
123	Torrent Power Limited, (Ahmedabad Power Plant)	Plants D, E, F	42	5	120	3.20	2450	142	1.18	0.63	0.55	46	0.39	1.57	0.31	3.5
124	Harduaganj TPS	B	42	5	165	3.47	3150	24	0.15	0.15	0.00	59	0.36	0.51	0.10	16.3
125	Panki	NA	43	5	210	3.45	2980	20	0.10	0.08	0.01	76	0.36	0.46	0.09	16.8
126	Talcher Thermal Power Station	Stage II	45	5	460	1.11	2850	336	0.73	0.73	0.00	172	0.37	1.10	0.22	13.7
127	Korba East Thermal Power Station (KTPS)	NA	47	5	440	1.90	3110	285	0.65	0.23	0.42	161	0.37	1.01	0.20	12.1
128	Obra A TPS	Stage 2	49	5	194	1.60	2890	73	0.38	0.23	0.15	71	0.37	0.74	0.15	15.9
129	Chandrapura Thermal Power Station	Units I, II, III	54	5	390	2.75	3100	82	0.21	0.21	0.00	140	0.36	0.57	0.11	14.8
130	NLC Thermal Power Station 1	Stage 2	54	3	600	2.75	4000	45	0.08	0.04	0.04	139	0.23	0.31	0.10	26.5
	Total/average for plants aged >40Years		**46**	**5**	**4,209**	**2.31**	**3,033**	**1,496**	**0.36**	**0.21**	**0.14**	**1,480**	**0.38**	**0.71**	**0.15**	**14.0**
	Total/average for plants <25 years of age		**10**	**15**	**59,935**	**1.85**	**2386**	**3,28,792**	**5.49**	**1.75**	**3.74**	**44,858**	**0.74**	**6.23**	**0.40**	**1**
	Total or average for plants >25 years of age		**34**	**5**	**34,832**	**2.01**	**2509**	**21,474**	**0.62**	**0.42**	**0.20**	**11,698**	**0.38**	**0.99**	**0.19**	**10**
	Total/average for all the plants		**18**	**12**	**94,767**	**2.00**	**2431**	**3,50,266**	**3.70**	**1.26**	**2.44**	**56,556**	**0.61**	**4.31**	**0.37**	**2**
	Total/average (USD million)						-	**47,982**	**0.51**	**0.17**	**0.33**	**7,747**	**0.08**	**0.59**	**0.05**	

Source: CEEW-CEF analysis using tariff orders for the 130 plants

Note:

1. *The green boxes for costs related parameters indicate a value favourable to a decommissioning vs. the average value for plants with longer than 25-year lifespans.*
2. *The red boxes highlight values above INR 2.01/unit for the plants/units.*
3. *The red boxes in the station heat column signify values above 2,450 Kcal.*
4. *For a few of the plants aged <10 years, the debt and equity–related payouts have a value higher than INR 8 crore/MW. Such high costs are related to overruns due to delays or initially quoting lower prices at the time of bidding for projects, which due to cost overruns were revised later.*
5. *The associated values are average numbers for the three torrent power units, based on cumulative capacity charges and the associated cost heads–related breakup.*

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From the just transition perspective, under the event of an early decommissioning, on average, the workforce related compensation comprises 14 per cent of the total cost share at INR 0.6 crore/MW (USD 0.08 million/MW).

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