Financing the Decommissioning of Thermal Power Plants in India

Modes and mechanisms

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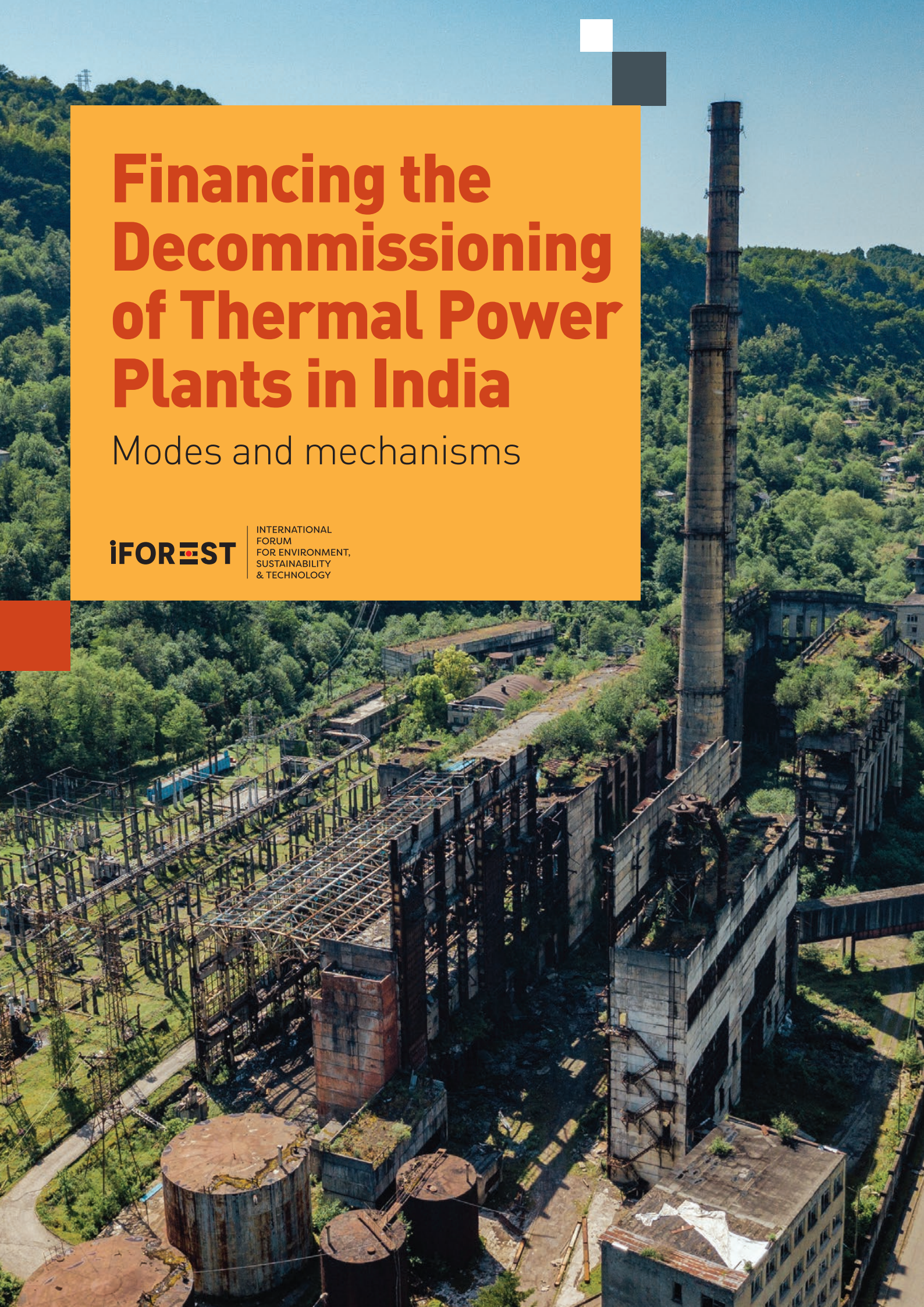

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September 2023

Printed at: Print Edge Inc.

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SECTION 1

Introduction

Coal-based power generation units have been routinely retired in India at the end of their useful life. These units have typically been replaced by larger units of supercritical or ultra-supercritical technology, while the instances of decommissioning of the entire plant have so far been infrequent. This is likely to change as the country's clean energy generation base widens and the need for climate action intensifies. In the coming decades, there will be increased instances of thermal power plants (TPPs) being retired, and old units not replaced by new units. This is already being witnessed, as only 22.5 per cent of the 12 MW capacity retired since 2016 is currently being replaced. Thus, for a country like India, that so far has little experience with decommissioning TPP, it has become important to address its requirements and preconditions including ensuring the availability of adequate financing.

Decommissioning refers to the suite of processes involved in withdrawing a facility from service at the end of its operational life and making the site available for the next planned use. It entails shutdown, deconstruction, and dismantling of the facility; followed by removal of components for reuse, remanufacturing, recycling or storage, disposal of the waste, and environmental remediation.[1]

Global experience indicates that decommissioning of a coal-based TPP can be divided into three stages.[2] The first stage is the **pre-demolition stage** which mainly focuses on events leading to the demolition of plant infrastructure. Key activities at this stage include the shutdown of the plant, securing closed facilities, valuation of assets, transfer of materials, and manpower planning. The second stage is the **demolition stage** which involves the safe deconstruction of chimneys, boilers, buildings, and other structures, and the removal of scrap from the site. The third and final stage is the **post-demolition stage** which involves environmental remediation of the plant site, specifically focused on the ash disposal and coal storage areas.

Decommissioning is thus a full-fledged project, with various cost components pertaining to plant closure, demolition, and remediation. A clear understanding of the expected costs in India's context is currently missing. However, global, and national experience indicates that this cost could be around $50,000 to $150,000 per MW (See Section 2.1).

The challenge in estimating decommissioning costs is that barring a few cost components which may be relevant for all projects, most of the costs depend on the decided end-use of the power plant building and the site. The costs may vary considerably from repurposing the plant site for an alternate use to a complete demolition of the plant for site redevelopment. While the costs in case of repurposing may be lower than if the site is to be readied for redevelopment, decommissioning overall is likely to remain an expensive exercise.

Often, decommissioning costs have been reported to be a massive economic barrier in executing end-of-life management. This is particularly true for countries or geographies where decommissioning of TPPs is not mandated by law, and/or where generation tariffs fail to account for these costs. Power plant owners do not typically set aside funds for end-of-life action, and the salvage value from the sale of scraps is often inadequate to support it. In the absence of clearly earmarked funds and established facilities, public and private companies likely resort to inaction.[3]

This is a massive concern for India as the country is staring at large-scale decommissioning of coal-based units in the coming decades, aligned with the national commitment of net zero by 2070.[4]

In India, power generation is a delicensed economic activity. So there are no specific regulatory requirements governing the commencement and closure of a TPP. The focus of energy sector legislations, policies, and regulations has largely been on planning, designing, construction, operations, and renovation of generation capacity. While some guidance on environmental aspects of the plant closure is available, issues pertaining to financing, labour, land, and reuse remain largely unaddressed.[5]

It is only recently that the issue of financing decommission costs has received regulatory attention, with the Central Electricity Regulatory Commission (CERC) including these costs as a 'key issue' to be addressed in the generation and transmission assets' tariff going forward, as indicated in the approach paper published for the new tariff regulations to be drafted for the 2024-2029 tariff period.

To support the regulatory discourse, this report maps the key cost components arising during TPP decommissioning, financing mechanisms introduced in other regulated energy markets to cover such costs, existing provisions in India and the recommendations going forward.

SECTION

2

Cost components

Decommissioning a coal-based TPP in a 'just transition' context entails several technical, environmental, social, and economic interventions to ensure that the closed power plant site is fully remediated, the economic loss of dependent workforce and communities are compensated, and new economic opportunities and environmental outcomes are created for communities to benefit from.[6] Global experience indicates that the involved costs can be broadly categorized[7] across the following heads:

1. **Closure, demolition, and remediation:** This refers to interventions pertaining to the demolition of structures, removal of equipment/scraps for salvage, and remediation of the site, particularly remediation of contaminated areas where coal and ash are handled.
2. **Compensation to owners:** The closure of power plants before the end of life often entails financial payouts to the owner companies to cover the present value of the return on equity, interest on the capital loan, and depreciation costs over the remaining period of useful life.
3. **Labour and community transition:** A significant amount of effort is involved in providing economic and employment support to the workforce affected by plant closure in the form of compensations, skill redevelopment, and re-employment support. Investments in economic diversification are further needed to build community resilience.
4. **Land repurposing:** This pertains to preparing the land for alternate economic purposes through repowering of existing infrastructure or repurposing of facilities or redevelopment of plant site.[8]

Each component of the just decommissioning cost can be covered by varying sources of funds. For instance, compensation to owners for early plant closure is typically covered by public funds set aside by federal, state, or local governments to encourage decarbonization. Similarly, building community resilience requires interventions at a scale that may not be feasible for plant owners and would require public funding.

However, the technical interventions required for the closure, demolition, and remediation of power plants as well as for preparing the site for repurposing are expected to be covered by the plant owners. Thus, these costs need to be accounted for in the overall cost of plant ownership and operations, including the generation tariff of the power plant.

These technical costs[9] can be divided across three stages of the decommissioning project – pre-demolition, demolition, and post-demolition phase. Each of these stages entails several activities and cost heads.

I. Pre-demolition phase

- Operations and maintenance costs, including employee costs and station overheads that continue post-retirement of the power plant.
- Cost of compensation to be paid to the workforce as per the existing law of the land.[10]
- Cost of planning for closure, including engaging expert agencies for conducting environmental and social assessments, technical evaluations, and planning the closure project. This stage includes the identification of facilities to be demolished and to be retained, the extent of present hazardous and non-hazardous waste, reusable components and materials, environmental effects, and health and safety requirements.
- Cost of securing statutory clearances/licenses/permissions as per the environmental regulation, such as for removal and disposal of asbestos, abatement of hazardous material, etc. (See box 1 for the existing environmental guidelines on TPP closure)
- Cost of tendering and contracting demolition works to expert agencies.

II. Demolition and clean-up phase

- Cost of identification, removal, and transportation of scrap, salvageable equipment and machinery, and valuable assets for resale or reuse before demolition is initiated.
- Cost of plant demolition, including chimneys, boilers, buildings, and all identified structures, while complying with safety norms.
- Costs of separation, recycling, and disposal of the demolition materials according to valid guidelines and standards.
- Cost of site clean-up, especially the ash dump area and the coal handling plant.

III. Post-demolition phase

- Environmental remediation due to contamination of groundwater or soil, as identified in the pre-demolition phase.
- Any contingency costs due to unforeseen environmental damages discovered in the demolition phase, such as incurred towards identification and mitigation of contamination of soil, water, or habitat.
- Any manpower cost for monitoring and manning the site, till its repurposed or redeveloped.

2.1 Cost of decommissioning

Global experience indicates wide variations in the cost of TPP decommissioning.[11] In the US, which has witnessed large-scale retirement of coal assets in the past decades, the cost of decommissioning is seen to vary significantly due to location-specific factors. A study of 28 TPP decommissioning projects in the US estimated the mean cost of decommissioning to be US$ 117,000 per MW.[12] While the costs are seen to be driven by several location-specific factors, typically the per MW decommissioning costs are lower for larger capacity plants, due to lower incremental costs of planning and execution.

Decommissioning costs are typically seen to be higher for European countries due to a significant share of worker support programmes. For instance, in Germany, coal company LEAG was paid a compensation of EUR 1.75 billion by the German government for decommissioning its lignite power plant and for closing its associated mines in the Lusatia region. In this case, the per MW decommissioning cost for 2,790 MW of capacity by 2030 is estimated to be about €149,328 or $164,261 per MW.

In developing countries, the cost of decommissioning is likely to be relatively lower. In the case of South Africa, the country's Just Energy Transition Investment Plan (JET IP) has allocated an investment of ZAR 19.3 billion for decommissioning 22 GW of coal-based power generation capacity during 2023-35. This reflects the estimated costs as planned by the electricity utility Eskom for the indicated time and is additional to the costs of repowering and repurposing projects and other

Box 1: Environmental requirements of TPP closure in India

Environmental considerations are vital throughout the various stages of power plant decommissioning and add significantly to the cost of closure. In India, the Central Pollution Control Board (CPCB), under the Ministry of Environment, Forest and Climate Change (MoEFCC), notified the draft 'Environmental Guidelines for Decommissioning a Coal/Lignite-Fired Power Plant' in July 2021 which identifies the key measures to be undertaken by plant owners after the retirement of a TPP for complying with already existing state and central environmental laws, regulations and rules.

Key provisions in this context are:

A. To account for changes in wastewater discharges, the plant's Consent-to-Operate (CTO) under the **Water (Prevention & Control of Pollution) Act, 1974** has to be revised and/or a new CTO and new stormwater permit obtained.

B. On account of visible emissions and disturbance of the soil during the demolition of infrastructure, the plant's CTO under the **Air (Prevention and Control of Pollution) Act in 1981** is to be revised and/or a new CTO sourced.

C. All hazardous waste and storage areas need to be treated and disposed of as per the **Hazardous and Other Wastes (Management and Transboundary Movement) Rules**, 2016 (HWM Rules 2016) issued under the **Environment (Protection) Act, 1986**. Key measures required are to dispose of asbestos-containing material, polychlorinated biphenyls (PCBs) and toxic metals, mercury-containing lights, and other chemicals.

D. E-Wastes needs to be disposed of/recycled as per the **E-Waste (Management) Rules, 2016**. Proper authorization for the management of e-waste needs to be taken as per the rules.

E. The waste generated in the power plant dismantling process is to be managed and disposed of in line with the **Construction and Demolition Waste Management Rules, 2016**.

F. Managing accumulated fly ash and closure of ash ponds as per the MoEFCC's **Fly Ash Utilization Notification, 1999**, as amended from time to time.

infrastructure investments. In this case, the per MW decommissioning cost is about $55,268 per MW.

In the case of India, there is limited clarity on the actual costs as there are only a limited number of instances where TPPs have been decommissioned. A recent study estimated the direct and indirect cost of decommissioning a 1,000 MW thermal power plant to be $58.11 million and $45.80 million, respectively.[13] The direct costs include all plant-specific decommissioning costs, other than contingency costs such as for environmental remediation. Another study focusing on four TPPs in Tamil Nadu estimated the direct decommissioning costs to range from $37,000 per MW to over $45,000 per MW.[14]

As for the experience, a recent example of plant decommissioning in India is that of the 460 MW Guru Nanak Dev Thermal Plant (GNDTP) in Punjab which was permanently shut down on January 1, 2018.[15] Regulatory filings by its owner Punjab State Power Corporation Limited (PSPCL) provide some indication of its cost of closure.

In its petitions filed with the Punjab State Electricity Regulatory Commission (PSERC) in 2022, PSPCL prayed for an impairment loss of ₹4,826.2 million along with a carrying cost of ₹1,380 million up to March 31, 2021, which aggregates to a cost of ₹6,206.2 million.[16] (See Section 3.2 for a detailed discussion on impairment cost).

In addition to impairment loss, GNDTP was indicated to have incurred other costs such as capital expenditure of ₹4.4 million[17] and miscellaneous losses and write-offs of ₹61.2 million (in compliance with the statutory auditor's observation).[18] The aggregate cost of closure considering these cost heads amounts to ₹6,271.8 million or ₹13.63 million per MW. In terms of current dollars, this amounts to an aggregate cost of $78.39 million or $170,429 per MW. The costs are on the higher side due to the plant's substantial undepreciated capital, as it had undergone renovation and modernization (R&M) in 2014 for an investment of ₹6.9 billion.

Overall, from the existing examples and studies, the decommissioning costs are expected to range from $50,000 to $150,000, depending on factors such as the plant size, the environmental damage, the decided end use of the site and the salvage value of scraps and equipment.

SECTION

3

Provisions for recovery of decommissioning costs in India

Power generation in India is a delicensed economic activity, hence, there are no regulatory requirements governing the commencement and decommissioning of a TPP. Following a generating company's (GENCO's) decision to retire its plant or unit, the Central Electricity Authority (CEA) needs to be informed about the decision. Unless grid security is a concern as raised by the Regional Power Committee (RPC), the closure proceeds and the CEA deletes the plant from its database.[19]

Since a majority of the energy market in India is regulated, tariffs of power generation plants are defined based on the terms and conditions identified by the regulator. For the ongoing tariff period i.e. 2019-2023, the Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2019 identifies the cost heads to be recovered through generation tariffs, along with the mechanism for recovery.

The tariff regulations provide for a two-part tariff for power plants. The first part allows for recovery of fixed charges, which comprises interest on loan capital, depreciation loss, operation, and maintenance expenses (excluding fuel costs), taxes on income, return on equity, and interest on working capital at a normative generation level. The second part of the tariff allows for energy charges or variable charges which specifically cover the fuel cost per unit of generation, based on several performance indicators including plant load factor, station heat rate, secondary fuel oil consumption, auxiliary consumption, etc.

In the existing mechanism, there is no explicit provision mentioned for accounting for and recovery of costs pertaining to power plant decommissioning. The expectation is that the salvage value of the plant recovered from the sale of assets and equipment should be adequate to cover the cost of closures.

3.1 Salvage value of closed plant

The current CERC tariff regulations for TPPs state that 'the salvage value of the asset shall be considered as 10 per cent and depreciation shall be allowed up to a maximum of 90 per cent of the capital cost of the asset'. The end-of-the-life value of a power plant – the salvage value – is expected to be adequate for covering decommissioning costs.

However, global and Indian experiences indicate that the salvage value might not be adequate, and there are many uncertainties involved. The salvage value recovered depends on the ongoing commodity prices (especially iron and steel), as well as the demand for second-hand equipment at the time. Meanwhile, decommissioning costs are also very site-specific. These depend on the extent of environmental damage caused during plant operations and the intended end-use of the site. At some sites, salvage value may suffice, while in others it may not be adequate.

In the existing tariff mechanism, there are no provisions to cover scenarios where:

- The cost of closure is higher than the salvage value of the power plant, either due to a low value recovered from the sale of scraps or due to substantial investments required for a legally compliant closure and decommissioning.
- The plants or units are decommissioned prior to the completion of their useful life, due to any statutory orders or due to technological obsolescence, or any other factor beyond the plant owner's control.

3.2 Impairment loss of assets

From an accounting perspective, decommissioning costs and losses of a company are accounted as impairment of assets. According to the Indian Accounting Standard (Ind AS) 36, impairment is a scenario where the carrying amount of an asset exceeds its recoverable amount.[20]

The carrying amount of an asset represents its book value, which is typically its original cost adjusted for accumulated depreciation and any impairment losses previously recognized. The recoverable amount is the higher of an asset's 'fair value less costs to sell' or its 'value in use'. The 'fair value less costs to sell' is the amount obtainable from selling the asset less any costs directly associated with the sale. Meanwhile, 'value in use' is calculated as the present value of the future cash flows expected to be derived from the asset.

Box 2: Impairment loss of GNDTP

The 460 MW GNDTP of PSPCL was retired from operations on January 1, 2018, after becoming operative since October 1, 2017.[21]

In PSPCL's tariff petition for 2023-2024 submitted to the PSERC,[22] the GENCO submitted that the disposal of assets of the four units of GNDTP has been completed as on August 4, 2022. It further prayed to be allowed an updated impairment loss of ₹4,826.2 million along with a carrying cost of ₹1,380 million up to March 31, 2021. This aggregates to a total of ₹6,206.2 million.

This impairment cost accounts for the sale of scraps and equipment. In 2020-21, PSPCL entered into an agreement with Mumbai-based HR Commercial Private Limited for ₹1,641 million for the dismantling and disposal of the old GNDTP power plant.

The PSERC is yet to take a final decision on the plant's impairment loss as a part of the true-up of the 2017-18 tariff order when PSPCL submits the final report on the disposal and utilization of assets and the land of GNDTP.

The impairment loss is calculated as the difference between the carrying amount of the asset and its recoverable amount. When an impairment is identified, the company needs to recognize the impairment loss and adjust the carrying amount of the asset as per the principles of the Ind AS 36 standards. This entails:

- Measurement: The impairment loss is measured as the difference between the carrying amount of the asset and its recoverable amount, as described earlier.
- Recognition: The impairment loss is recognized as an expense in the statement of profit and loss unless the asset is carried at revalued amount.
- Reversal: If the recoverable amount of an impaired asset increases in a subsequent period due to a change in circumstances, the impairment loss can be reversed. This is recognized as a gain in the statement of profit and loss.
- Disclosure: The company is required to disclose information about the nature and amount of impairment losses recognized during an accounting period, including the affected asset classes and the reasons for impairment.

From the perspective of the power generation sector, the mechanism for recovery of an impairment loss is presently missing in the tariff mechanism. This is complicated because the asset is no longer generating power for sale, and its power purchase agreement (PPA) with the relevant beneficiaries may have expired leaving no legal obligation for payment. Further, while some GENCOs especially state-owned ones, can include the impairment loss in their annual revenue requirement, this may not be feasible for an independent power producer.

3.3 Change in law provision

The existing tariff regulations allow for the recovery of any capital cost arising in ensuring compliance to 'change in law' within the period of an ongoing PPA. The regulations define 'change in law' as an enactment of a new law, or amendment of existing law, or change in interpretation or conditions by a competent body, or a change in bilateral or multilateral agreement with countries impacting the generating station. It allows for the truing-up of tariffs after considering the impact of uncontrollable factors in the nature of 'change in law', as well as force majeure. It provides for the financial gains and losses by a GENCO on account of uncontrollable parameters to be passed on to the relevant beneficiaries.

Change in law provision can be applicable in scenarios where a power plant is forced to shut down in case of legal requirement due to environmental or climate concerns. For instance, change in law led to the closure of the 705 MW Badarpur Thermal Power Station (BTPS) which was permanently retired by October 15, 2018, due to a closure order passed by the Supreme Court-appointed Environment Pollution (Prevention and Control) Authority (EPCA).[23] However, under the existing regulations, change in law consideration has been provided only in the context of additional capitalization of expenditures and not for payment of decommissioning costs or recovery of impairment loss.

Overall, the legal provision regarding the financial aspect of decommissioning requires significant reforms to ensure that adequate resources are available with GENCOs for a just decommissioning.[24]

SECTION

4

Mechanisms adopted to pay for decommissioning

In India, there are laws for the closure of energy assets, that provide a clear mechanism for financing end-of-life activities. For instance, existing regulations require a coal mine closure to be planned prior to the initiation of mine operations and a fixed amount (per hectare of the mine land area) to be submitted in an escrow amount annually to pay for progressive and final closure activities. Meanwhile, in the case of nuclear power plants, a decommissioning levy is imposed on every unit of power sold and deposited in a decommissioning fund. This fund is to be utilized for executing a range of activities involved in decommissioning a nuclear power plant.

For financing decommissioning of TPPs, similar mechanisms of accruals overtime are witnessed globally. In several American states with regulated power markets, decommissioning costs are being transferred to ratepayers depending on the decision of their public service commissions.[25] The typical mechanism calls for the utilities to estimate the decommissioning project cost for power plants (much prior to the planned retirement) and that cost is added to the rate base to generate the funds over time. In this mechanism, to minimise the ratepayer's risk and responsibility, states have passed laws to clearly identify the types of decommissioning costs that utilities may recover through rates.

In the case of states with deregulated/competitive power markets in the US, the publicly listed GENCOs are expected to incorporate decommissioning costs as part of their cost of doing business and report them as an asset retirement obligation (ARO). This is the obligation associated with the retirement of a tangible long-lived asset as part of the annual financial report submitted to the US Securities and Exchange Commission.

In addition to these mechanisms, examples are emerging where innovative financial tools are being utilized to reduce the cost burden of TPP decommissioning. In this case, public and private funds are being pooled and utilized for the refinancing of loans and equity, compensating contractual parties, and supporting decommissioning costs.

These are discussed below in detail:

4.1 Funding for coal mine closure in India

Decommissioning of a coal mine involves several issues including physical closure of mines, disposal of infrastructure and physical assets, environmental management and remediation, labour compensation, etc. The procedure for coal mine closure in India is guided by 'Guidelines for Preparation of Mining Plan for the Coal and Lignite Blocks' issued by the Ministry of Coal in December 2019, as amended from time to time.[26] The guidelines provide for the development of closure plans for progressive mine closure and final mine closure, as well as the mechanism to pay for the closure.

As per the guidelines, the mine owners are required to open a fixed deposit escrow account in any scheduled bank, with the Coal Controller Organization (CCO) as the exclusive beneficiary, prior to the commencement of any activities on the mining site. This fund is utilized both for funding progressive closure as well as final closure.

As per the 2019 notifications, the fund to be submitted in the escrow account amount to ₹900,000 per hectare for an opencast mine, and ₹150,000 per hectare for an underground mine. These rates are to be considered base rates for 2019 and adjusted through notification from time to time based on the wholesale price index.

The mine owner is required to deposit an amount equal to the annual closure cost each year, throughout the mine's life, compounded at the rate of 5 per cent annually. The annual closure cost is computed considering the total project area of the mine multiplied by escalated rate, divided by the balance life of the mine.

In case, during the final review of closure plans five years prior to the date of closure, the funds are assessed to be insufficient to cover the cost of final mine closure, the mine owner is to provide additional funds to cover the gap, failing which the competent authority may decide on a fund recovery mechanism.

The mine owner can withdraw up to 50 per cent of the total deposited amount including the accrued interest after every five years in line with the periodic examination of the progressive mine closure plan.

The amount released is equal to expenditure incurred in the past five years, or 50 per cent of the deposited amount, whichever is less.

At the end of the mine closure project, the mine owner is required to procure a final mine closure certificate from the Office of the Coal Controller, stating that all works have been completed as per the approved mine plan. Failure to do so can lead to the forfeit of the assured sum.

While this mechanism is in practice, there are issues concerning the adequacy of funds raised through the pre-decided standard unit rates for all mines, since mine closure costs typically vary considerably depending on geological conditions and required environmental remediation.[27]

4.2 Funding for nuclear power plant closure in India

Decommissioning of a nuclear power plant entails decontamination, dismantling, salvaging equipment and materials, and handling, treatment, conditioning, and storage/disposal of radioactive and inactive wastes generated. India's Atomic Energy Regulatory Board (AERB) issued the safety manual AERB/SM/DECOM-1 in March 1998 on decommissioning of nuclear facilities covering the details with respect to its requirements, criteria, and procedure.[28] As per the regulation, Nuclear Power Corporation of India Limited (NPCIL) is required to submit the preliminary decommissioning plan prior to being granted authorisation for the operation of a nuclear facility. This plan needs to be revised and submitted to the AERB every five years considering new developments.

To cover the costs, a decommissioning levy is collected from the consumers of electricity from nuclear power stations.[29] The levy is collected in a separate fund called the Decommissioning Fund, which is held and managed by NPCIL on behalf of the Department of Atomic Energy (DAE), Government of India. It is prudently invested, to generate optimum returns while maintaining adequate safety and liquidity. In December 1988, the DAE issued a notification to levy a decommissioning charge of 1.25 paise per unit on the electricity sold by nuclear power plants. In October 1991, it was revised to 2 paise per unit. As of March 2023, NPCIL has accumulated ₹27,547.2 million in the Decommissioning Fund.

There have been concerns raised with respect to the adequacy of these funds as well. A detailed report by the Comptroller and Auditor General (CAG) noted that the decommissioning reserves seemed inadequate when compared to the global experience of nuclear plant shutdown.[30] It also noted that the AERB had not worked out the decommissioning cost formula in any of its documents. The CAG recommended that clear timelines should be set for preparation and approval of decommissioning plans and that financial arrangements for decommissioning should be laid down more clearly and the decommissioning charges reviewed on a periodic basis.

4.3 Funding for TPP closure in the US

The US has witnessed a significant number of TPPs being decommissioned in recent decades. According to the Global Energy Monitor database, nearly 148.5 GW of coal-based power generation capacity has been retired in the US since 2000. Even in 2022, the retired coal capacity in the country stood at 13.5 GW. By 2031, nearly 37 per cent of the existing 212 GW capacity is likely to be further retired.[31]

The country initially struggled with managing these retirements, as a majority of the closed plants were left abandoned rather than decommissioned. According to a September 2016 article published in the Power Magazine, of the 200 power plant sites comprising 600 units retired between 2000 and 2016, only 35 had been demolished, and 15 were sold for redevelopment.[32] This was partly attributed to a lack of decommissioning mandates and partly due to a lack of financial resources by the GENCOs.

Even now, coal decommissioning in the US is not regulated by a uniform national guideline or procedure; however, several legislations and regulations have been drafted across several states to support decommissioning-related activities.

For instance, the state of **Montana** adopted **Coal-Fired Generating Unit Remediation Act** in 2017.[33] The act calls for the development and submission of a 'remediation plan' to the Montana Department of Environment Quality no later than three months after a coal-fired generating unit is retired and no earlier than five years prior to the unit's planned retirement. The plan can include a general overview of the site, anticipated future uses of the affected property, remediation information, reports, studies, or other evaluations related to remediation, and must attain a degree of clean-up of the affected property consistent with the legal obligations.

In Florida, the Public Service Commission (PSC), the state utility regulator, under the **Electric Utilities Dismantlement Studies Rule**[34] issued in 2016 requires power GENCOs to update cost estimates based on new developments, technological improvements, and forecasts, to evaluate alternative technologies, and to revise the annual accrual needed to recover the decommissioning costs. Each utility is required to file a dismantle study for each site every four years which must include in-service and estimated retirement date, percentages of ownership, assumptions, methodology, escalation rates used in converting the current estimated dismantlement costs to future estimated costs, estimated expenditures, projected date to cease operations, and supporting schedules for inflation analysis, data, including the contingency allowance, used in developing the dismantlement cost estimates and annual accruals proposed by the utility.

Under the **Code of Washington**[35], for a facility to be closed, it must provide the Washington State Department of Ecology with a plan for the closure and post-closure of the facility at least 24 months prior to closure or 24 months prior to start of decommissioning report work, whichever is earlier. The plan must include:

- A detailed estimate of the cost to implement the plan,
- Financial assurance and its methods to fund the closure and post-closure of the facility,
- A decommissioning and site restoration plan to restore physical typography, clean-up of hazardous substances on site, future uses of the site, and coordination with local and community plans for economic development in the vicinity of the site.

The **Illinois Administrative Code**[36] has a special section on the closure of ash ponds which requires a closure plan that contains a site map, a description of the ash pond such as contents, estimated volume of material contained, and an analysis of structural integrity, closure activities, hydrogeologic site investigation, ground trend analysis, and construction quality assurance. The plan must also include specifications, and drawings for the groundwater collection trench and discharge system, an estimate of complete closure, and a proposal for the groundwater management zone. Under the cost estimates section, the owner or operator must submit a detailed written cost estimate for closing the Coal Combustion Residuals (CCR) surface impoundment, preliminary corrective action costs, and total costs of a corrective action plan for remediation (if any) which is adjusted for inflation annually.

Some states also require the identification of risk levels for various surface impoundments under closure plans. For instance, in 2014 the **Coal Ash Management Act** (CAMA)[37] of **North Carolina** requires the owner to submit a Coal Combustion Residuals Surface Impoundment Closure Plan which categorises impoundments into high risk, intermediate risk, and low risk. The plan must include a facility description, site maps, results of a hydrogeologic, geologic, and geotechnical investigation of and groundwater modelling of the site, description of beneficial use of the CCR, the responsibilities and authorities for monitoring and testing activities, sampling strategies, and reporting requirements, provisions for disposal of wastewater and management of stormwater, provisions for the final disposition of the CCR, list of all permits required and a description of post-closure monitoring and care for an impoundment for a minimum of 30 years.

Meanwhile, there are a few states that do not specifically require a laid-out plan but do have provisions for the closure of certain CCR units. For instance, the **Virginia Waste Management Act**[38] requires the closure by removing all CCR in accordance with the standards established by Virginia Solid Waste Management Regulations by either beneficially reusing the CCR or discarding it in a permitted landfill. The timeline given to complete the closure is no later than 15 years after initiating the closure process. A 'transportation plan' (as part of the process) must be developed to minimize the impact of transporting CCR on adjacent property and communities. Hence, the owner or operator of the CCR unit is required to submit two reports describing the closure plans and proposals to beneficially reuse CCR. Moreover, the owner or operator is also required to identify options for utilizing local workers, consult with the Commonwealth's Chief Workforce Development Officer on opportunities to advance the workforce goals (such as furtherance of apprenticeship and other workforce training programs) and hire local workers on a priority.

For funding TPP closure action, these laws and regulations identify various financing options and mechanisms focusing on the allocation of funds, rate adjustment, regulatory liabilities, tax incentives, etc. These are discussed as follows:

(a). Financing mechanisms aligned with federal guidance

Several states including Illinois,[39] Ohio,[40] Washington[41] and North Carolina[42] have closely adopted guidelines laid by the US Environmental Protection Agency (EPA)

regarding financial assurance for closure under 'Title 40 – Protection of Environment' the Electronic Code of Federal Regulations (eCFR).[43] Key provisions in this context include:

- Facility owners/operators dealing with hazardous waste are required to make payments to the **closure trust fund** annually over a "pay-in period" where:
  - » The first payment must be equal to the current closure cost estimate, divided by the number of years in the pay-in period.
  - » Each subsequent payment can be determined by the formula '(CE-CV)/Y' wherein CE is the current closure cost estimate, CV is the current value of the trust fund, and Y is the number of years remaining in the pay-in period.
  - » After the pay-in period is completed and the current closure cost estimate changes, the owner or operator must equal the estimate to the recent evaluation of the trust fund.
- The facility owners/operators are also required to provide a **surety bond** guaranteeing payment into a closure trust fund and performance of closure. They are also required to establish a standby trust fund where all payments made thereunder will be deposited by the surety directly into the standby trust fund.
- To guarantee end-of-life action, facility owners/operators are required to provide an irrevocable **letter of credit**, issued for at least one year, as well as provide **closure insurance or a corporate guarantee**.

These regulations typically provide for the use of **multiple financial mechanisms**, where an owner or operator can establish more than one financial mechanism per facility which are limited to trust funds, surety bonds guaranteeing payment into a trust fund, letters of credit, and insurance. Also, allowed is the use of a **financial mechanism for multiple facilities** wherein an owner or operator may use a financial assurance mechanism for more than one facility.

(b). Allocation of specific funds

There are multiple instances of states allocating specific funds to finance closures. For instance, in Montana's Coal-Fired Generating Unit Remediation Act,[44] there is a provision for the Montana Department of Environment Quality to administer a **revolving fund** called the 'Environmental Quality Protection Fund' and prepare a list of priority sites for remedial action. The fund can be used for remedial actions in response to a release of hazardous or deleterious substances, conducting an appropriate investigation, negotiation, legal action to identify liable persons, obtaining the participation and financial contribution of liable persons, and recovering costs and damages incurred by the state.

The fund pools resources from various sources including money collected from administrative and civil penalties, forfeited financial assurance, environmental taxes, funds allocated by the legislature etc. In case of insufficient funds, the department may apply for a grant from the environmental contingency account. However, if there is an insufficient balance to remediate a specific facility within one year, all donated and granted funds must be returned to the grantor.

Another example of an allocated fund can be found in the Coal Ash Pollution Prevention Act[45] of Illinois where a special fund has been created in the state treasury is called the **'Coal Combustion Residual Surface Impoundment Financial Assurance Fund'**. Funds forfeited to the state from any performance bond or other security are placed in the fund and utilized for the purpose for which the performance bond or other security was issued.

(c). Clause for rate adjustment

Some states also provide for adjustment of the tariff rate to cover the costs associated with the closure of a CCR Unit. For instance, the Virginia Waste Management Act[46] requires the State Corporation Commission, the state regulator, to authorize an adjustment in tariff rates to recover closure costs, and to not consider closure as an 'option'.

As per the act, the annual revenue requirement recoverable through a rate adjustment clause should not exceed $225 million over a 12-month period. In case of under-recovery, i.e. if the required revenue is more than $225 million, the balance amount is to be recovered through the rate adjustment clause up to three succeeding 12-month periods. The act provides for any such costs to be allocated to all the customers as a non-bypassable charge, irrespective of the generation supplier.

In Nevada, Senate Bill 416[47] which was enacted as Chapter 395 of the laws of 2015 also allowed all reasonable costs of decommissioning and disposal of surplus assets to be charged to the utility's customers. The law requires utilities to create and execute a plan for timely clean-up and disposal of surplus assets. It also requires assets that are not disposed of in a timely manner are to be 'removed from the responsibility of the utility's customers.' This is to create an incentive mechanism for timely action.

(d). Transfer of regulatory liabilities

Another mechanism identified in the Revised Code of Washington in Title 80 on Public Utilities[48] (2017) allows the Washington Utilities and Transportation Commission to authorize an electrical company to place amounts from regulatory liabilities into a retirement account to only cover decommissioning and remediation costs of eligible coal units. These liabilities are not to be altered, reduced, impaired, or limited from the date of commission approval until all costs are recovered or paid in full. The mechanisms also provide for any remaining funds in the account to be returned to customers post-recovery.

4.4 Funding mechanisms for supporting early closures

Innovative financial tools are being explored for supporting decommissioning of TPPs that have substantial remaining economic life as well as long-term contractual obligations for the sale of power. In this scenario, public and private finance is being utilized through various financing mechanisms to help power plant owners with decommissioning, through repayment or refinancing of loans; compensating parties during PPA renegotiations; supporting buy-out of fuel purchase agreements or any other contractual obligation, as well as supporting with the economic cost of a just decommissioning.[49] There are several examples from the Global North as well as the Global South where these instruments have been or are being utilized.

For managing the cost of outstanding debt, the typical instruments being used are:

- Lending/refinancing of loans through asset- or corporate-level loans;
- Arranging financing through underwriting, structuring, and placing loans and bonds (including securitizations and transition bonds);
- Arranging concessional or blended finance;
- Providing insurance and hedging products; and
- Providing trust banking services on coal securitizations.

Asian Development Bank's (ABD) Energy Transition Mechanism (ETM) is a leading example in this context. The ETM was launched by the Bank at the COP26 to accelerate the retirement and repurposing of coal-based TPPs through public and private finance through refinancing, acquisition, or suitability-linked corporate loans, as well as to scale up clean energy and energy storage investments and to achieve a just energy transition.

Under this, ADB has set up ETM Partnership Trust Fund to pool funding from various sources (government sources, philanthropies, climate finance, and other investors and lenders) to then provide concessional debt to retire coal-based power generation assets, in addition to other transition support activities. Through the ETM, ADB is providing $250 million in refinancing to Indonesia's Cirebon-1 plant owned by Cirebon Electric Power (CEP).[50] The financing support is designed to prepone the plant retirement by 15 years.

Similarly, several mechanisms are being utilized for cost-of-equity financing including arranging funds through managed transition vehicles (MTVs); providing, or underwriting private equity, tax equity, and/or public equities; mezzanine financing such as preferred equity; philanthropic grants, etc. These measures are also being piloted across the world. For instance, in the Philippines, ACEN Corporation created a $316 million MTV in July 2022 to accelerate the retirement of the six-year-old, 246 MW South Luzon coal plant.

Meanwhile, additional cash flow sources can also be utilized by plant owners to raise additional funds, such as through carbon credits or monetization of other environmental or health benefits, sale or lease of any asset, available grants from the government, etc.

These financial tools are crucial to be mobilized to reduce the impact of the decommissioning costs and the impairment losses on the ratepayers.

SECTION

5

Considerations for India

At present, there is little guidance available in India on dealing with the decommissioning costs. These costs are not explicitly covered in financial calculations and disclosures. Decommissioning costs are not factored in during tariff determination. No funds are kept aside by plant owners for end-of-life activities, while salvage value is assumed to be sufficient for enabling decommissioning. If decommissioning is not made financially viable, generation companies are likely to abandon the plants in an 'as-it-is' state (as has been widely witnessed in the US over the past decades), creating multiple environmental problems. Thus, there is a need to create mechanisms that provide financial security to plant owners to enable decommissioning.

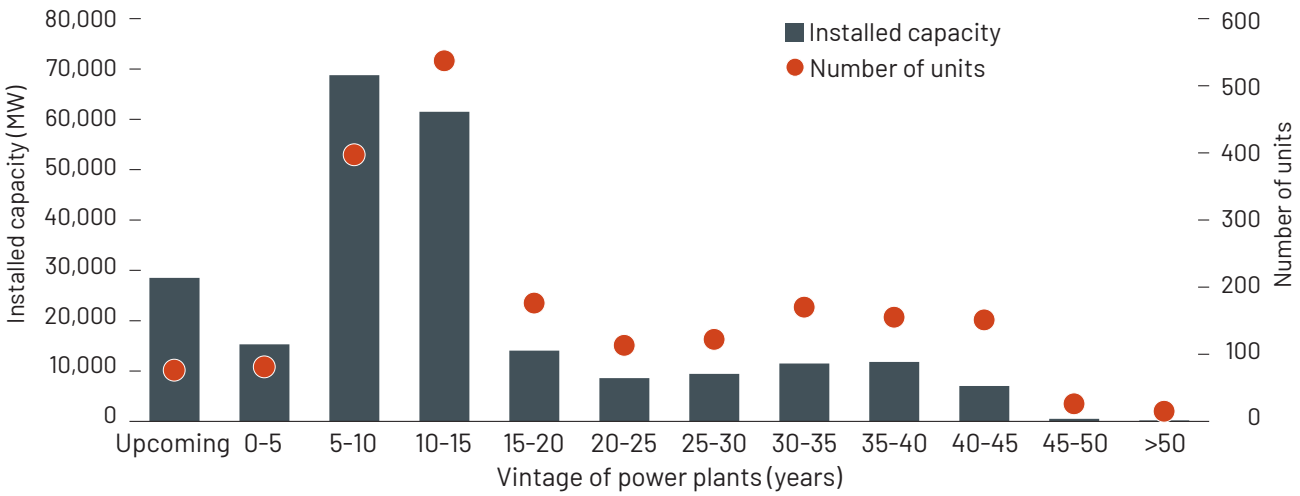
The CERC has recognized this requirement under the approach paper published for the new tariff regulations to be drafted for the 2024-2029 tariff period, calling for including "appropriate provisions in the tariff regulations to deal with all eventualities". The guiding principle mentioned in the approach paper is to devise a mechanism such that decommissioning is 'cost neutral to the GENCOs and also does not impact the beneficiaries.' The objective is 'to reduce risk perception among investors and provide the necessary clarity on such matters thus reducing litigations.'

An advantage of India's regulated power market and the tariff structure for TPPs is that the majority of the utility power plants in India are designed to depreciate to 90 per cent of the plant value in 25 years. So, for plants that have been in operation for a long period of time, the debt and the equity have been paid off to a large extent. Also, very little utility capacity in India operates as merchant capacity. Further, given the principles specified in the Electricity Act of "safeguarding of consumers' interest and at the same time, recovery of the cost of electricity in a "reasonable manner" under Section 61 on tariff regulations, payments for anticipated profits to power plant owners are not envisaged.

The CERC's approach paper suggests that the net profit/loss post decommissioning and disposal of assets may be adjusted in one go from the beneficiaries, duly factoring in the unrecovered depreciation. However, it would be more appropriate to adopt a mechanism that allows for the accrual of funds over a long period of time, prior to the planned decommissioning to protect the plant owners from a liability default. In the absence of upfront funds being available, plant owners may be required to raise working capital for decommissioning through short-term loans, which may not be easy to come through at low costs, as the plant would be closed or on the verge of closure.

In the case of India, a scenario-based mechanism of financing decommissioning costs may be needed, given that operational power plants have a very wide-ranging age profile. At present, India has a coal-based installed capacity of 208.6 GW and an upcoming capacity of 28.5 GW. Nearly 76 per cent of the operational capacity is less than 20 years of age; and has at least 5 years of remaining operating life to collect decommissioning costs. Of the remaining 24 per cent, only 9 per cent is very old capacity that has completed 35 years in operation.

Graph 1. Vintage of India's coal-based installed capacity



Source: Based on the CEA database

Given the vintage profile of the installed capacity, the following scenarios can be considered for the recovery of decommissioning costs:

Scenario 1: For existing power plants that have at least five years of operational life remaining and for upcoming power plants that will be decommissioned at least after 25 years of operational life (these plants would be depreciated by at least 90 per cent at the time of decommissioning)

In this category, the installed capacity aggregates to 188 GW. This includes 159.6 GW of existing capacity (considering the life of the plant as 25 years) as well as 28.5 GW of upcoming capacity. For this category of plants, around $18.8 billion is estimated to be required for decommissioning activities (assuming an average cost of $100,000 per MW). For these power plants, a tariff-based mechanism for overtime accruals of decommissioning costs should be considered, along the following lines:

- Prepare state-wise plant decommission plan along with detailed cost estimates:
  - » All existing power plants that have at least five years of operational life remaining should be mandated to prepare and submit decommissioning plans, within a year of notification of new regulations.
  - » All upcoming plants should be mandated to prepare and submit decommissioning plans before beginning commercial operations.
  - » The closure plans should include a detailed cost assessment of the activities and tasks to be undertaken during plant decommissioning. The net cost should reflect the total decommissioning cost minus the proceeds from the sale of equipment, scraps and other material.
- Allow recovery of the estimated decommissioning costs from the TPP tariffs after detailed verification and assessment of the decommissioning plan by a competent authority. This authority could be a committee of relevant organizations including CPCB, CEA, and CERC/SERC.
- Based on the review of the decommissioning plans and cost estimates submitted by power plants under this category, the committee should ascertain an average per unit cost of decommissioning for each state. The decommissioning cost should then be approved by the SERC and charged at a uniform rate (Rs per kWh of electricity sold) on all power plants in this category in the respective states.
- The 'decommissioning tariff component' should be revised every three years to account for the changes in the decommissioning cost.
- These funds collected through the 'decommissioning tariff component' of power plants should be deposited annually by the power plants in a state-specific fixed deposit escrow account in a scheduled bank, with a competent authority (the SERC) as its exclusive beneficiary.
- The escrow account fund should be utilized exclusively for funding power plant decommissioning in the given state.
- Given the nature of the power plant closure, where units are typically retried at different points in time, power plants should be allowed to use the decommissioning fund both for progressing closure as well as for final closure.
- A power plant must approach the identified competent authority (SERC) for withdrawal of funds for partial closure or final closure, at least two years prior to the date of retirement after the final decommissioning plans have been drafted, indicating the exact amount of money required for undertaking the decommissioning activities.
- During the decommissioning phase, the plant owner should be able to withdraw 25 per cent of the requirement at the time of retirement. The next round of withdrawals should be allowed up to a maximum of 25 per cent in three rounds, after an audit of the expenses already incurred and the remaining expenses. The last 25 per cent should be released after the verification of the final closure.
- At the end of the decommissioning project, at least within three years from the date of retirement, the power plant owner must submit a detailed report on the closure activities along with the project completion certificate from the competent authority (the SPCB) stating that all works have been completed as per approved plan, along with the detailed financial report.

Box 3: Tariff impact of decommissioning costs

Even under a stringent assumptions of power plants operating for a maximum of 25 years, the impact of the decommissioning tariff levied for the 188 GW of coal-based power plant capacity categorized at Scenario 1 plants is likely to be minimal at about 8.8 paisa per unit. The impact is likely to be highest in case of Haryana at 12 paisa per unit where the average remaining life of power generation units is about 11 years, while the impact is likely to be lowest in Assam at 6.9 paisa per unit where the average life of the power plants is 19 years.

State-wise estimated decommissioning tariff

State	Scenario 1 capacity (MW)	Decommissioning tariff (₹ per unit)	State	Scenario 1 capacity (MW)	Decommissioning tariff (₹ per unit)
Andhra Pradesh	10,510	0.087	Maharashtra	20,606	0.088
Assam	750	0.069	Odisha	8,240	0.093
Bihar	8,420	0.076	Punjab	4,420	0.089
Chhattisgarh	20,578	0.092	Rajasthan	7,525	0.096
Gujarat	12,695	0.101	Tamil Nadu	13,540	0.072
Haryana	5,120	0.126	Telangana	10,510	0.074
Jharkhand	7,970	0.078	Uttar Pradesh	22,160	0.072
Karnataka	7,750	0.093	West Bengal	9,302	0.105
Madhya Pradesh	18,020	0.086	Total	1,88,116	0.088

Note:
1. Scenario 1 plants include all existing coal-based TPPs that have at least five years of operational life remaining and all upcoming power plants;
2. All plants are assumed to operate for a maximum duration of 25 years; and
3. The average decommissioning cost is assumed to be $100,000 per MW.

Scenario 2: For power plants that have less than five years of operational life remaining (these plants would be depreciated by at least 90 per cent at the time of decommissioning)

This category of plants aggregates to 49 GW of capacity, which would require around $4.9 billion for decommissioning activities (assuming an average cost of $100,000 per MW). In this scenario, lumpsum recovery of expenses from distribution companies would become necessary. The following mechanisms may be followed in this case:

- Prepare and submit a plant decommission plan along with detailed cost estimates at least two years before the planned retirement or within six months of notification of new regulations, whichever is earlier.
- Allow recovery of the estimated decommissioning costs from the beneficiaries (discoms) after detailed verification and assessment of the decommissioning plan by the competent authority. This authority could be a committee of relevant organizations including CPCB, CEA, and CERC/SERC.
- The recovery of costs should be through payments made in at least three installments by the plant beneficiaries, with the first payment for 50 per cent of the decommissioning cost, two years prior to the retirement date. The second installment should be collected after one year from the retirement date for 25 per cent of the amount and for the remaining 25 per cent after two years from the retirement date. The contribution of the last installment can be adjusted based on the actual expenses remaining, as per audited expense reports.
- The funds collected through the lumpsum payments should be deposited by the discoms in a state-specific fixed deposit escrow account in a scheduled bank, with a competent authority (SERC) as its exclusive beneficiary.
- The escrow account fund should be utilized exclusively for funding power plant decommissioning. The plant owner must approach the identified competent authority (SERC) for withdrawal of funds, based on a mutually agreed schedule, indicating the exact amount of money required for undertaking the decommissioning activities.

- During the decommissioning phase, the plant owner should be able to withdraw 25 per cent of the available fund at the time of retirement. The next round of withdrawals should be allowed up to a maximum of 25 per cent in three rounds, after an audit of the expenses already incurred and the remaining expenses.
- At the end of the decommissioning project, within three years from the date of retirement, the power plant owner must submit a detailed report on the closure activities along with the project completion certificate from the competent authority (SPCB) stating that all works have been completed as per approved plan, along with the detailed financial report.

Scenario 3: For existing power plants that will be decommissioned before completing 25 years of operational life (wherein the plant has not fully depreciated)

TPP capacities may shut down prior to the planned retirement due to multiple possibilities, ranging from climate mitigation to economic unviability. In this case, debt and equity will not have been fully paid, while there aren't adequate funds accumulated in the escrow account for paying off the decommissioning costs.

In case of premature closure, the burden of recovery of the remaining depreciation value and the decommissioning cost cannot be imposed on the ratepayers through tariffs. In this case, power plant owners should be encouraged and expected to identify innovative financial mechanisms and arrive at a private deal with climate funds, multilateral banks, or other sources for relief and recovery of decommissioning costs.

However, there may be cases when private deal may not be possible. To deal with such cases, the government can think about creating a corpus fund. This fund can source finance from international climate funds, domestic and international sources including philanthropy, etc.

Across all these three scenarios, the regulations allowing recovery of decommissioning costs through the ratepayers should clearly provide for the following:

I. Clear identification of costs that can be recovered through tariffs to minimize the risk of overburdening the consumers with undue costs.

The regulations allowing for recovery of decommissioning costs must clearly identify all costs that will be allowed to be recovered from the ratepayers through tariff. The following considerations are crucial in this context:

- If a power plant has failed to comply with environmental regulations during its operations, which has led to environmental degradation and contamination, the plant owner should be made liable to pay for the expenses for that component of decontamination activities from his profits.
- Recovery of unpaid debt and equity should not be allowed from the decommissioning cost component as this is part of the risk of business operation. Only the cost of the technical set of activities needed to prepare the plant site for repurposing or redevelopment should be considered for recovery from tariffs.
- Some of the cost of just transition activities, such as compensation to workers, labour reskilling and reemployment should be covered in the decommissioning cost to be recovered from tariffs.

II. Plant owners should be encouraged to tap into all available financial support mechanisms to reduce the cost burden of plant closure on ratepayers.

The power plant owners should be encouraged and expected to explore all avenues of raising funds to support decommissioning costs, to reduce the burden on ratepayers. This should apply to all power plants that have fully or partially depreciated. As discussed earlier, there are several innovative financial tools and mechanisms that are being created using public, private, and philanthropic funds that can be identified and utilized by power plant owners to reduce the economic burden of closure. These funds can be accounted for in the final decommission plan and the funds to be raised through tariffs can be accordingly adjusted.

SECTION

6

Conclusion

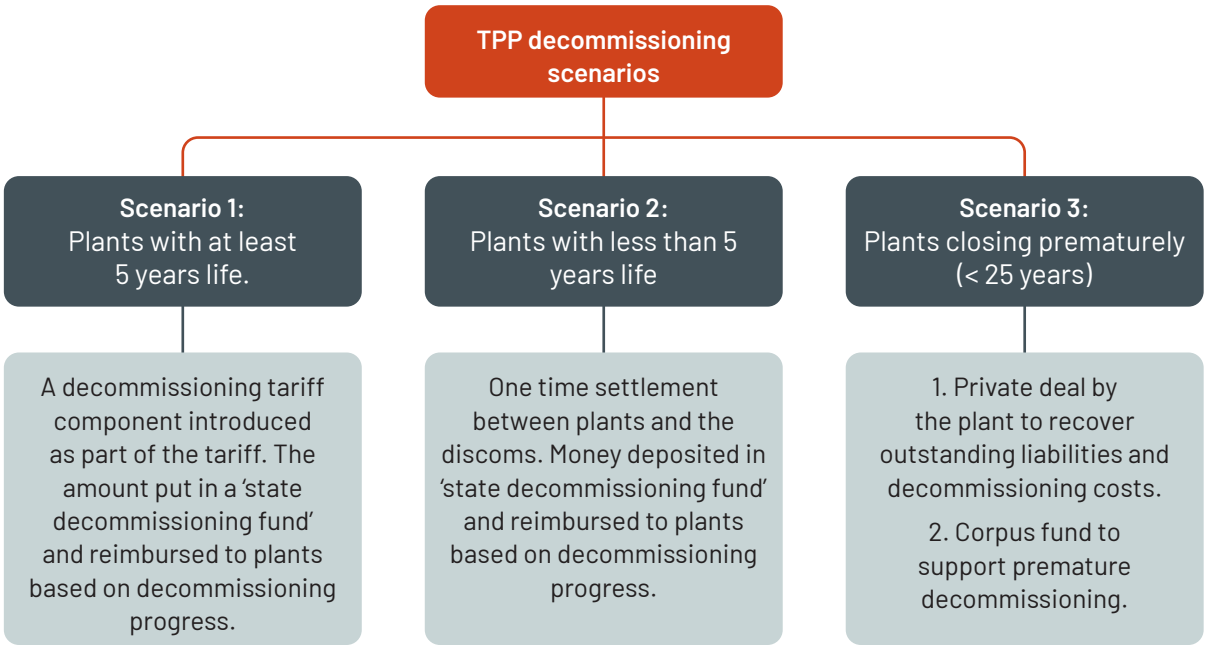
Decommissioning a coal-based TPP entails a complex set of technical interventions required for the closure of a power plant, demolition of structures, and remediation of the plant site, to ensure repurposing or redevelopment. This cost can vary considerably depending on several site-specific factors, and it is typically seen to vary between $50,000 per MW to $150,000 per MW. In the existing tariff mechanism, there is no explicit provision mentioned for accounting for and recovery of these costs, and the salvage value from the sale of scraps is often inadequate to support it. Providing for this cost is therefore crucial for ensuring that there is no economic barrier in executing end-of-life management.

The typical mechanisms for the closure of energy assets, in the case of coal mines and nuclear power plants in India as well as for closure of TPPs in the US, indicate that accruing the estimated requirement over the plant's lifetime is the most appropriate mechanism. Such a mechanism is necessary to protect power plant owners from a liability default. In the case of India, a scenario-based mechanism of financing decommissioning costs may be needed, given that operational power plants have a very wide-ranging age profile.

Three scenarios can be considered in this context. The first scenario includes all existing plants that have at least five years of operational life remaining as well as the upcoming plants. In this case, a decommissioning tariff component can be added to generation tariffs to allow recovery of decommissioning costs. This can be used to set up state-level funds, from which costs can be reimbursed. For the second scenario, which includes plants with less than five years of operational life, a mechanism of one-time settlement can be thought of between plants and discoms, through a state-level fund. In case of the third scenario, where power plants are prematurely shutdown, additional funds would need to be raised through private or public sources to recover outstanding liabilities and decommissioning costs.

As India stares at large-scale decommissioning of coal-based power plants in the coming five decades, aligned with the national net zero commitment, providing for such mechanisms is crucial for ensuring that the plants are adequately decommissioned and the plant sites are made available for repurposing or redevelopment.

Figure 1. Recovery mechanisms across decommissioning scenarios



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