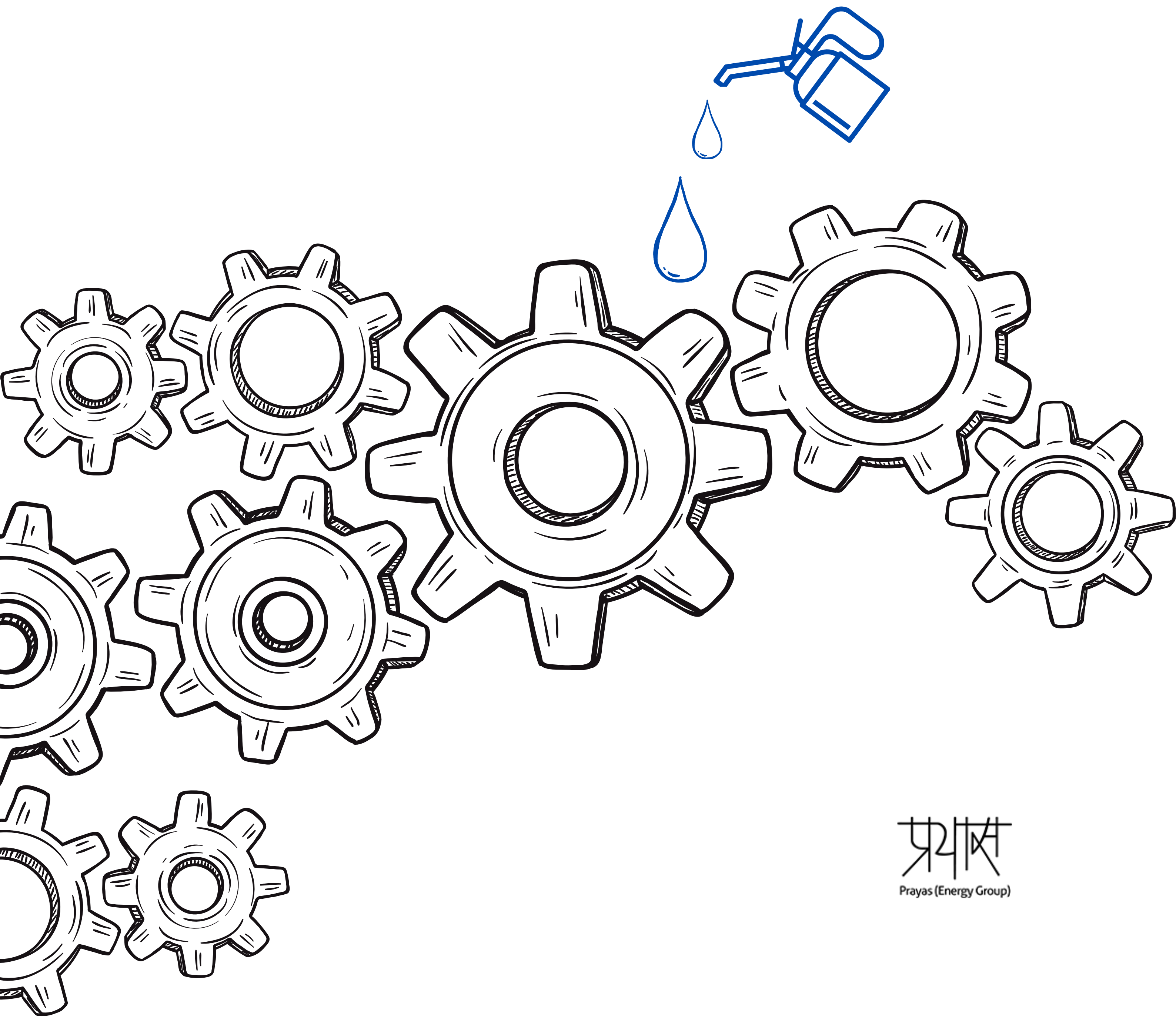
Flexibilisation of the coal-based generation value chain:

A pre-requisite to reduce the friction in energy transition



Prayas (Energy Group)

Flexibilisation of the coal-based generation value chain:
A pre-requisite to reduce the friction in energy transition

Maria Chirayil | Ashok Sreenivas
Prayas (Energy Group)
November, 2023

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Prayas (Energy Group)
Unit III A & III B,
Devgiri, Kothrud Industrial Area,
Joshi Railway Museum Lane, Kothrud Pune 411 038
Maharashtra
☎ +91 20 2542 0720
🖂 energy@prayaspune.org
🌐 https://energy.prayaspune.org/

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Executive Summary

India, like other countries around the world, is undergoing an energy transition. In its unfolding, the transition has and will continue to have a disruptive impact on the power sector, amongst others. A major aspect of such disruption is the changing role of coal-based generation – from a firm, baseload supplier to a supplier that will increasingly need to meet demand when renewables are not sufficient. This necessitates modifications across policy, planning, and operation, in order to ensure that the coal-based generation value chain responds optimally to the changing needs of the sector – and flexibilisation is a key piece of this puzzle.

Why is there a need for flexibilisation? The power sector is moving from depending on dispatchable conventional generation to intermittent and less predictable renewable sources. While coal will remain the majority generator for a while, its role will likely change gradually from a round-the-clock baseload supply source to a swing generator that meets demand when variable renewables are not available. Such disruption on the supply side is also supplemented by increasing uncertainty in electricity demand patterns.

These shifts call for flexible and responsive action to effectively address the challenges and leverage the opportunities that emerge. However, this is at odds with the certainty and predictability that informed the design of several aspects of coal-based generation until now, across both the power and coal sectors. Thus, steps to incorporate flexibilisation must be considered and taken by and for actors in both these sectors.

How can flexibilisation be furthered? While some measures for flexibility have been introduced across the coal and power sectors, these are often insufficiently used. Rigidities still persist, as seen in contracts that dominate the supply of electricity and coal, which have rigid provisions for supply and cost recovery, that is not reflective of the varying demand.

Going forward, flexibilisation should be a priority that is considered and incorporated by sector actors at the planning stage itself, to account for changing realities. This is a complex task for existing coal assets, since flexibilisation must be ensured without disrupting existing contractual conditions. Strengthening of existing flexibility provisions, and ensuring their effective utilisation, should be overseen by regulators. This could include measures like better designed incentives for availability and generation and an optimised approach to providing schedules for operation.

When it comes to new contracts, yet to be signed, improved and new structures that incorporate flexibilisation effectively should be considered. Steps should be taken to revise and enforce better designed fuel supply agreements, and round the clock contracts could also be minimised in the future. Given the move away from round-the-clock contracts, markets will have a larger role to play in the sector, and enabling this increased role is a key aspect towards effective flexibilisation of the coal-based generation value chain. Towards this, encouraging more liquid, transparent, and participative markets while expanding the capacity of sector actors to participate in the same should be taken up.

This report aims to further deliberations on the need for flexibilisation, which could catalyse the requisite changes in policy, regulations and contract structures. Such revisions are much needed to reduce the friction in the highly disruptive energy transition.

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1. Context

The electricity sector in India – and the world – is going through profound changes. Driven by economic, environmental, and policy levers, the sector's energy mix is gradually moving away from conventional sources of generation, particularly coal, to cleaner renewable sources of generation, such as solar and wind. This trend will accelerate going forward, as illustrated by Central Electricity Authority's (CEA) Optimal Generation Mix for FY30, which shows the share of coal in the country's installed capacity going from 51% in FY23, to 32% in FY30 (Central Electricity Authority, 2023). The share of solar and wind installed capacity, in the same time period, increases from 26% to 51%. These renewable sources are inherently intermittent, unlike the conventional options, and are thus, less available and predictable.

This increasingly uncertain nature of the supply side is mirrored by growing uncertainty on the demand side. In the past, electricity demand patterns were fairly predictable – with diurnal and seasonal variations – even as demand increased over time with increasing industrialisation, incomes, and appliance usage. However, existent demand patterns are now likely to be disrupted due to fundamental shifts such as the migration of commercial and industrial consumers away from the distribution companies' (DISCOM) sales mix, increased use of cooling appliances, shift of agricultural loads to day-time, gradual introduction of time-of-day tariffs and greater adoption of electric vehicles. Changing weather patterns also contribute to the uncertainty in demand. For example, the unseasonably dry August led to an unprecedented surge in demand (Nagraj, 2023). These uncertain weather patterns are likely to become more common, as will uncertain demand, in response to these changes. Such demand shifts, coupled with the changing landscape of the supply mix, underscore the need for the electricity sector to be more dynamic and flexible.

But this growing need for flexibility is at odds with the certainty and predictability that traditionally informed the design of various aspects of the sector. In particular, coal-based generation – which provides 70% of electricity today and is likely to play an important role for years to come – was always structured to provide stable base-load generation to meet the predictable demand. This role of coal-based generation will fundamentally change in the coming years to become an increasingly swing generator to meet net load (i.e., load to be served beyond what solar and wind can serve). Therefore, it is unrealistic for its regulatory, operations and contracting structures to remain unchanged.

For instance, coal-based capacity was historically contracted as baseload capacity, since it was dispatchable, and was scheduled for consistent and predictable operations by the utilities. This is evidenced by the contracts that govern transactions between entities in the sector. Distribution utilities that supply electricity to retail consumers mostly procure electricity from generators through long-term (typically 25 year) and round-the-clock (RTC) power purchase agreements (PPAs) for a fixed capacity. Payments under such contracts are typically in two parts – a fixed cost, which is mostly determined based on availability of the plant, and a variable cost, which depends on the amount of generation by the plant. The fixed cost part of the contracts do not account for the varying and uncertain demand across the year and over the years[1].

[1] The long-term and rigid nature of such contracts and these payments, however, helps lower financing risks for generators, which makes it easier for them to raise and repay loans

Similarly, coal-based generators have long-term fuel supply agreements (FSAs) with coal companies for a fixed quantity of coal per year. These contracts also do not provide for supply to vary according to changing demand, and are structured more rigidly with nearly uniform supply and off-take requirements through the year and across the years. In short, the contracts for both power purchase as well as coal purchase are predominantly of the take-or-pay nature for a fixed quantity, even if the demand is not as expected and does not require the planned supply.

This can be illustrated by considering the actual generation from three TPPs, namely Goindwal Sahib TPP (540 MW), Khargone TPP (1320 MW), and Yermarus TPP (1600 MW), commissioned post 2015, which have variable costs of around Rs. 3/unit and long-term PPAs with various DISCOMs. However, over the last few years, as seen in Table 1, these plants generated varying quantities of electricity, often well below the 'expected' generation from the plant[2], and by extension, had lower than expected coal use as well – despite having long-term PPAs and FSAs.

In addition to annual variations and uncertainties in generation, the operation of coal-based capacity is also affected by seasonal variations in demand, as illustrated in Table 2, generation from the three aforementioned TPPs varied significantly across the months in FY23.

As evidenced by Tables 1 and 2, the responsiveness and flexibility of coal capacity will increasingly be necessary. Such requirement will also extend to coal supply, since coal demand ties in with power demand. Ensuring flexibility along the coal-based generation value chain – i.e., the ability of the coal-based generation system to respond reliably and cost effectively to changes in demand and supply in the short and long term – is essential for a smooth energy transition for all stakeholders. Such flexibilisation gains importance in the context of increasing additions of clean, but variable and intermittent, renewable capacity, in order to ensure adequate availability of generation resources to meet demand reliably in the future. The Guidelines for Resource Adequacy Planning for India, finalised in June 2023 by the Central Electricity Authority is partly informed by this (Central Electricity Authority, 2023). Flexibilisation of the coal-based power value chain will be an important element to ensure such Resource Adequacy.

Thus, there is a symbiotic relationship between the coal and power sectors, and a need for resource adequacy in a system with growing renewable energy (RE). Given this, both the coal and power sectors will have to incorporate greater flexibility at a structural level to ensure nimble, responsive, and efficient operations in the new status quo. In this paper we review existing flexibility mechanisms, highlight persisting rigidities and identify opportunities to further introduce flexibility across the coal and power sector value chain[3], in tune with the needs of a smooth transition.

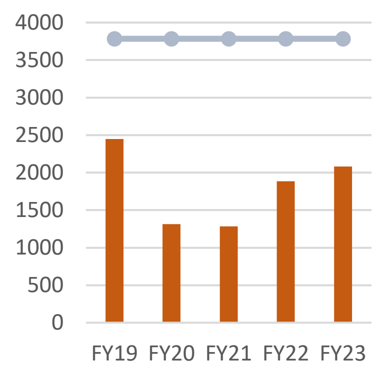
[2] While this period overlaps with the COVID-19 pandemic, the variation can be seen in non-pandemic years also. Moreover, as per generation statistics published by CEA, India's electricity generation hardly reduced during the pandemic – only its growth slowed down significantly.

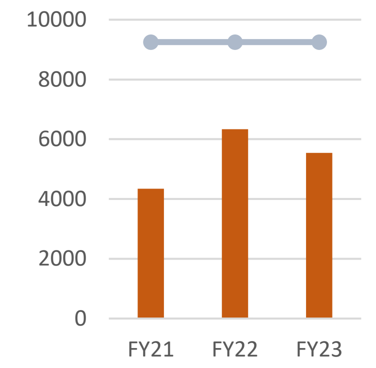
[3] With the emergence of other sources of generation, flexibility needs to be viewed through a more comprehensive lens. The scope of this paper is, however, limited to the coal-based generation value chain.

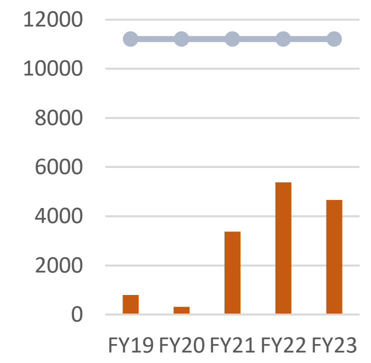
Table 1. Expected annual generation and coal use versus actuals for example TPPs

Goindwal Sahib TPP	Khargone TPP	Yermarus TPP
Capacity: 270x2 MW	Capacity: 660x2 MW	Capacity: 800x2 MW

Generation (MU)

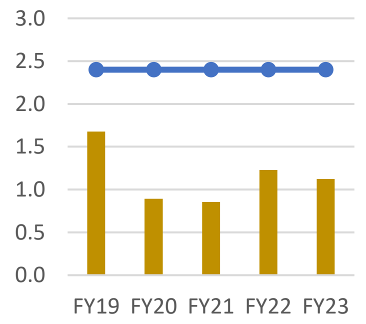


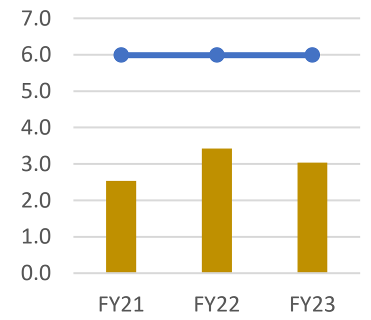


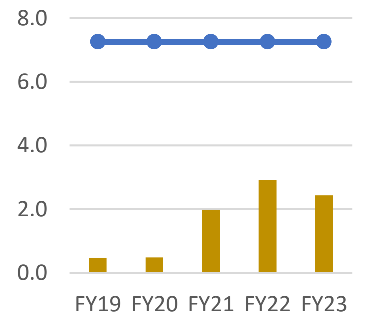


Expected generation at 80% Plant Load Factor (PLF)
Actual generation

Coal use (MT)







Expected coal use at 0.65 kg/kWh Specific Coal Consumption and 80% PLF
Actual coal use

Source: Prayas (Energy Group) compilation from CEA monthly generation report and monthly coal statement

Note: Since Khargone was only fully operational from FY21, only the years from FY21 have been used to assess its generation and coal use. 0.65 kg/kWh specific coal consumption is assumed based on national average specific coal consumption in FY21.

Table 2. Monthly variations in PLFs for the example TPPs in FY23

PLF	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23
KHARGONE STPP	47%	68%	74%	39%	36%	42%	11%	46%	50%	70%	50%	52%
YERMARUS TPP	57%	52%	56%	10%	4%	10%	27%	25%	20%	58%	55%	34%
GOINDWAL SAHIB TPP	28%	44%	48%	47%	48%	28%	32%	34%	47%	56%	73%	59%

Source: Prayas (Energy Group) compilation from CEA monthly generation report

2. Existing flexibility mechanisms

Some flexibility measures already exist along the coal-based generation value chain, where some of these flexibility or responsiveness provisions have been newly introduced in response to the changing sector, whereas others are pre-existing and perhaps motivated by other factors.

2.1. Flexibility provisions in the power sector

The plant load factor, or PLF, has long been used as a metric to assess the economic efficiency of plant operations, since generation is scheduled according to 'merit order' in which plants with lower variable costs are given higher priority. Regulations stipulated by various ERCs, such as Regulation 42(6) of the Central ERC's Tariff Regulations 2019 and Regulation 50.8 of Maharashtra ERC's Tariff Regulations 2019, incentivise generation in excess of the normative PLF on a seasonal basis (Central Electricity Regulatory Commission, 2019; Maharashtra Electricity Regulatory Commission, 2019). This provides an incentive for plants to procure coal at lower cost, so that they can be scheduled more, particularly during periods of high demand.

Availability is another crucial operational parameter, that governs the fixed cost payments of a plant. Some ERCs have introduced weightages to these payments toward encouraging their availability in line with demand. In the tariff regulations of Central ERC and Maharashtra ERC, for example, the annual fixed charges are divided into charges payable for availability during high-demand and low-demand seasons and availability during peak and non-peak hours of the day. As per Regulation 42(2) of the Central ERC's Tariff Regulations 2019 (Central Electricity Regulatory Commission, 2019) and Regulation 50(A)(2) of the Maharashtra ERC's Tariff Regulations 2019 (Maharashtra Electricity Regulatory Commission, 2019), payment of fixed charge is structured such that 20% of the payment is allocated for availability during four peak hours (16.66% of the day) while 80% is allocated for availability during 20 non-peak hours (83.33% of the day)[4]. Thus, the weightage is slightly above-average for peak-hour availability and slightly lower than average for non-peak hour availability. This provides some incentive for plants to be available during peak hours and high-demand periods. However, there is no corresponding higher weightage attached to payment of fixed charges for availability during high-demand months[5].

2.1.1. Flexibility measures for Distribution Companies

As evidenced by the national wind-solar hybrid policy (Ministry of New and Renewable Energy, 2018) and the several tenders floated for wind-solar hybrid projects, distribution companies (DISCOMs) are increasingly not limited to RTC PPAs. Newer, innovative, flexible, hybrid contracts are emerging to address the inherent intermittency of renewables[6]. While these flexibility

[4] Gujarat ERC has also considered similar treatment – of different weightages for availability linked fixed cost recovery across peak and off-peak hours – in their 2023 draft regulations https://gercin.org/wp-content/uploads/2023/10/Draft-GERC-MYT-Regulations2023-for-4th-Control-Period.pdf

[5] Any shortfall in availability during peak hours/high-demand months cannot be made up by excess availability during off-peak hours/low-demand months.

[6] A few examples for tenders of hybrid contracts:
https://www.seci.co.in/view/publish/tender/details?tenderid=53454349303030303930
https://www.seci.co.in/view/publish/tender/details?tenderid=53454349303030303538
https://www.seci.co.in/view/publish/tender/details?tenderid=53454349303030303437

measures are emerging within the RE procurement space, they are still lagging with regard to DISCOMs procuring coal-based power.

There are existing provisions that allow some operational flexibility to DISCOMs. Under Section 14 of the Electricity Act 2003, a DISCOM does not need a license to trade, which means it has the flexibility to sell the excess electricity from the power it has contracted to any other end-user[7]. The Ministry of Power's (MoP) recently introduced Portal for Utilisation of Surplus Power (PUShP) makes this easier by providing a transparent platform for DISCOMs with 'surplus contracted power' at a given time to sell such power at the same tariff to other DISCOMs which may need the power at that time (Central Electricity Authority, 2022). These provisions promote better resource utilisation while introducing some operational flexibility to power supply. They also enable DISCOMs to partially recover the fixed cost they incur on having contracted capacity even at times that they may not need it. However, despite the existence of such options, and the potential benefits of utilising them, little to no uptake has been seen on this front[8].

In addition to this, the DISCOM can swap or bank power with other traders or DISCOMs to manage their periods of power surplus or deficit, as done by the Kerala State Electricity Board with Arunachal Pradesh Power Corporation Pvt Ltd and Kreate Energy Pvt Ltd, to manage their power shortfalls during peak demand months (Kerala State Electricity Regulatory Commission, 2022).

The DISCOM can also employ demand side response measures to incentivise consumers to revise consumption patterns. Time of Day (ToD) tariffs are an example of such demand flexibilisation, where consumers are incentivised to use power during off-peak hours or during hours when electricity is cheap, which can reduce the DISCOM's cost of procuring power. ToD tariffs are used by most states, though only for certain categories of consumers, with varying stipulations and to varying degrees of success (Central Electricity Authority, 2021).

2.1.2. Flexibility provisions for Generators

Similar to DISCOMs, generators also have the provision to sell their unscheduled (but contracted) capacity to a third party, after refusal of the same by its beneficiaries, as stated in their PPAs. Rule 9 of the Electricity (Late Payment Surcharge and Related Matters) Rules 2022 leverages this by allowing the generating company to sell unrequisitioned power on the power exchanges, after the DISCOM intimates its daily schedule for requisitioning power from the generator one day prior (Ministry of Power, 2022). Platforms such as the Discovery of Efficient Energy Price (DEEP) portal, or options such as the Term-ahead, Day-ahead, or Real Time markets – make short term sale of the generator's available excess power possible at competitive market prices to meet the demand of some other consumer. However, even in instances of such market sale of power, the burden of fixed cost still remains with the original procurer(s) though generators are expected to share profits from such sale of power with the original procurer(s). These markets also act as avenues for DISCOMs to meet their demand if their available contracted capacity is not sufficient.

[7] DISCOMs do need to ensure universal supply and resource adequacy, but they are not constrained in how to sell the excess electricity generated from the capacity procured.

[8] An example of such failure to sell surplus power despite the provision to do so has been recorded by the Andhra Pradesh ERC with regard to the state distribution utility in the following order https://aperc.gov.in/admin/upload/RSTFY2021.pdf

Market provisions are also extended to the deployment of ancillary services at the national and regional level, toward decongesting the transmission network, ensuring smooth power system operation, and grid safety and security.

Some other provisions for flexibility and cost optimality have been discussed but implemented only in limited capacity. Market Based Economic Despatch (MBED) of power is one such example, which aims to consider all generators in the country within an integrated approach, and despatch them according to a centralised schedule with lower cost generators getting deployed first (Ministry of Power, 2021). The first phase of MBED was to be implemented in April 2022, but has been deferred to an as yet unknown date. Similarly, Security Constrained Economic Despatch (SCED) aimed to optimise scheduling and despatch of power based on costs but was only applicable to inter-state generating stations which fell under the jurisdiction of the CERC. The pilot for this mechanism was rolled out in 2019 (Central Electricity Regulatory Commisson, 2019). The National Load Despatch Centre has recently proposed a mechanism for Security Constrained Unit Commitment, which aims to extend this further to unit commitment (National Load Despatch Centre, 2023).

The need for operational flexibility for generators with regard to scheduling has also been addressed to some extent through schemes such as "Flexibility in Generation and Scheduling of Thermal Power Stations to reduce emissions" and "Flexibility in Generation and Scheduling of Thermal Power Stations to reduce cost of power to the consumer", both issued in 2018 (Ministry of Power, 2018 b; Ministry of Power, 2018 a). The schemes provide flexibility to generators to supply renewable power against the schedule received for thermal power and to supply power from any of its stations against the schedule received, respectively – as long as the cost of doing so is lower than generation from the scheduled station. Both the schemes envisage sharing of any cost benefits from such implementation with the generator's beneficiaries. The revised scheme for "Flexibility in Generation and Scheduling of Thermal/Hydro power stations through bundling with Renewable Energy and Storage Power" was issued in 2022 (Ministry of Power, 2022). This scheme takes into account India's ambitious COP-26 targets and discusses provisions to comprehensively cover replacement of thermal and hydro power with RE or RE and battery storage, such that DISCOMs meet their RPO without additional financial burden. Such provisions allow generators to optimise scheduling, operate more efficiently, accrue savings while limiting emissions, and enable DISCOMs to meet their RPO targets. However, they do not fundamentally alter the nature of contract between the generator and the DISCOM.

In addition to operational flexibility for generators, there are also technical aspects, such as ramp rates and technical minimum load of a TPP, which need to be made responsive, reflecting the need to integrate the growing renewable additions. The CEA has issued regulations requiring TPPs to be able to operate at a lower minimum load and to be able to ramp their generation up or down at a faster rate (Central Electricity Authority, 2023). This will enable them to be better prepared technically to meet the needs of balancing in a RE-heavy grid. Some existing regulations (such as Regulation 29.6 (a) 0f Maharashtra ERC's Tariff Regulations 2019) already incentivise TPPs for being able to ramp at faster rates, while the CEA recently published an approach paper for how generators could be compensated for higher SHR and O&M costs resulting from operating at lower technical minimum loads (Central Electricity Authority, 2023). For a country like India, not endowed with sufficient gas resources, such measures become critical to integrate more renewables until storage becomes a viable option. Flexibility is further introduced to generator operations through measures such as the deviation settlement mechanism (DSM), which provides penalties/incentives for levels of drawal/injection from/to the grid for ensuring grid stability, which is further strengthened by the aforementioned ancillary services regulations.

2.2. Flexibility provisions in the coal sector

The coal sector also has some flexibility measures introduced especially on an operational level. Most of the supply of coal to thermal power plants[9] is currently overseen by the Scheme for Harnessing and Allocating Koyala (Coal) Transparently in India (SHAKTI) policy (Ministry of Coal, 2019). While the SHAKTI policy predominantly deals with the allocation of long-term coal linkages, SHAKTI B (viii) (a) and (b) deal with the provision of short-term coal linkages to power plants that have no/terminated power supply agreements, provided power so generated is sold through the DEEP portal or in day-ahead markets. This provision was introduced to help revive stressed TPPs without PPAs or linkages, rather than explicitly to enable flexibility. But, in the process it introduces some flexibility in terms of a shorter contract duration and allowing for sale in markets, but it does not extend to optimisation of supply or payments in accordance to varying demand for coal across months and years.

Schemes such as the "Flexibility in utilisation of domestic coal by States" introduced in 2016, allow a generating company to use the coal allotted to any of its plants in a manner that is most optimal to its costs and operations, such that unnecessary long distance coal transport and the related costs could be avoided (Ministry of Power , 2016). Coal tolling is designed to aid state generators to provide their coal linkages to other thermal power plants, as long as it results in a lower variable cost (Central Electricity Authority, 2016). Market options are also available to current coal producers and consumers with the provision of e-auction of coal. With the recent opening up of the coal sector, there are no constraints on end use of coal produced from coal mines that have been auctioned. These mines are expected to begin production in the coming years[10] and it is to be seen under what terms would this coal be offered to consumers. But it is likely that they would also offer some flexibility in how generators can procure coal.

Table 3 summarises the above and provides a snapshot of some key flexibilisation measures currently in place across the coal and power sectors. As illustrated in the table, there is a disjunction in incorporation of flexibility measures across the power and coal sectors. While some measures have been introduced across both, it is clear that many more measures have been introduced in the power sector – particularly recently – while the coal sector largely relies on older, more rigid mechanisms.

Further, most flexibility measures introduced are operational, some of which are deliberately designed with flexibility in mind while some are designed for other purposes but offer flexibility as a by-product. However, there is greater scope for deliberately planning and designing flexibility

[9] Some TPPs run on imported coal, and such supply is predominantly overseen by short term contracts and are affected by the price volatility of international coal.

[10] It is understood that a few mines have recently begun production. See https://energy.economictimes.indiatimes.com/news/coal/five-blocks-of-91-mines-auctioned-under-commercial-mining-policy-start-production/104598038

mechanisms in a rapidly changing sector. Considerations to include dynamic operation and flexibility from the planning level is important given the changing nature of, and expectations from both the sectors.

Table 3. Some key flexibilisation measures in place in the power and coal sectors

Sector	Type	Provision
Power	Operational	PLF incentive to generate at more than normative levels
Power	Operational	Higher weightage to fixed cost recovery for peak hour availability
Power	Operational	DISCOM can sell surplus power on the market
Power	Operational	Portal for Utilisation of Surplus Power
Power	Operational	DISCOM swapping/banking power with other traders
Power	Operational	Demand-side Response Measures such as ToD tariffs
Power	Operational	Markets (DEEP, DAM, TAM, RTM)
Power	Operational	Sale of unscheduled power by generators
Power	Operational	MBED and SCED
Power	Operational	Flexibility to bundle RE or generate from any unit of the same generator
Power	Technical	Operation at 40% technical minimum
Power	Technical	Incentivisation for ramp rate improvement and DSM
Coal	Operational	Short term coal contracts through SHAKTI B (viii) (a)&(b)
Coal	Operational	Linkage rationalisation and coal tolling
Coal	Operational	Sale of coal through E-Auctions

Source: Prayas (Energy Group) compilation

Note: Operational measures are incentives and mechanisms that enable a sector actor to effectively respond to a dynamic situation at low cost. Technical measures include mandates and incentives to enable the infrastructure in the power system to react to changing needs on a real-time basis to maintain the safety of the grid.

3. Persisting rigidities

Even with the recognition of the need for flexibility and the measures being introduced towards its incorporation, anachronistic rigidities continue to persist in the coal-based generation supply chain. A key illustration of this is that most coal-based generation continues to operate within the contours of long-term PPAs and FSAs — which are founded on predictable demand, steady supply and mostly uniform compensation across years/seasons, with little utilisation of available flexibility mechanisms such as sale of excess power. Ideally, contracts governing such supply should provide for sufficient flexibility and incentive to enable meeting demand that is uncertain and varies across time without tying either party down to rigid commitments. However, these contract structures have varying, often limited, degrees of responsiveness to system demand owing to the fact that they emerged in an age where coal made up for almost all of the capacity being added, and the sector was characterised by a significant amount of certainty. Since this is increasingly not the case, these contract structures are rendered less than ideal.

PPAs, for instance, govern the terms under which electricity generators sell electricity to DISCOMs[11]. Most coal-based PPAs are 25-year long contracts which are of the RTC nature, in which the buyer is guaranteed a fixed capacity (MW) for electricity generation.

PPAs also govern the fixed and variable cost payments to generators. From the point of view of understanding rigidity in the payment structure of contracts, it is the fixed charge component that is of interest as it is a lumpsum annual payment that does not vary with demand-supply changes. Typically, the entire fixed cost is payable upon meeting normative availability requirements (usually 85%), with the payment reduced proportionally for lower availability. Most PPAs treat all 8760 hours in a (non-leap) year identically and fixed charges are apportioned equally across them – thus they provide no incentive at all for greater availability during peak demand periods for coal-based generation. Hence, fixed charges would have to be paid uniformly over the year, for the hours of availability and the entire contracted capacity, irrespective of the variation of demand for coal-based electricity. This largely holds true for PPAs governed by both Sections 62 and 63 of the Electricity Act.

Some plants, whose tariffs are regulated by Section 62 of the Electricity Act, operate slightly differently. The tariff regulations of some ERCs, such as the Central and Maharashtra ERCs, distinguish between peak and off-peak hours and between high-demand and low-demand months. They assign a little more weightage to fixed cost recovery for availability during peak hours, as described in Section 2.1, and do not allow a shortfall in availability in peak hours or high-demand months to be made up in off-peak hours or low-demand months. This is unlike PPAs governed by Section 63 of the Electricity Act or Section 62 PPAs governed by regulations in most states, which permit even a shortfall of availability in a peak-demand month to be compensated by greater availability in a non-peak demand month.

In other words, despite some cases of flexibility provisions, the fixed charge payments in both types of PPAs are quite rigid and not sufficiently responsive to peak demand hours or months.

Like PPAs, FSAs are another example of contracts in the upstream segment of the coal-based electricity generation value chain that remain fairly rigid. With the introduction of the New Coal Distribution Policy in 2007 (Ministry of Coal, 2007) and subsequently the SHAKTI coal allocation policy in 2017 (Ministry of Coal, 2017), FSAs were to have become formal contracts governing coal supply from coal companies to electricity generators.

The quantity of coal to be supplied in a year is determined by the Annual Contracted Quantity (ACQ) mentioned in the FSA. This ACQ is divided more or less equally across the four quarters of the year (with a slight dip in the July-September quarter to account for lower production during the monsoon months rather than to account for varying demand, and corresponding increase in the January-March quarter). The quarterly quantity is further divided equally across the three months of the quarter into the monthly Scheduled Quantity. The contracts provide for a small

[11] While there are other forms of contractual arrangements for sale of electricity – such as open access and market-based transactions – long-term PPAs signed by distribution utilities govern the bulk of electricity purchase.

change (5%) in the monthly Scheduled Quantity, as long as the ACQ is respected at the annual level.

According to the FSA structure, penal provisions are only applicable at the annual level with penalties kicking in for under-delivery of coal (by the coal company) or under-lifting of coal (by the consumer) when the annual quantity falls below 80% of the ACQ[12]. In other words, these contracts do not provide for supply to vary according to changing demand within a year, but are structured more rigidly with nearly uniform supply and off-take requirements through the year and across the years. Moreover, as with PPAs, the ACQ is committed to one purchaser whether or not the purchaser needs it. However, unlike PPAs, it seems that many clauses of FSAs are not adhered to in practice – perhaps because the structure of the contracts are out of tune with requirements. There is little evidence of either the seller or the buyer invoking penal clauses against the other party, though actual sale of coal is well below ACQ for many TPPs[13]. This only makes the whole system more ad-hoc and non-transparent, rather than rules-driven, and defeats the purpose of making FSAs contractually binding on both parties – pointing to a need to refine FSAs to be reflective of prevailing realities.

It is clear to see that current contract structures do not provide sufficient flexibility in supply across the hours of a day or days of a year, and by extension, the related payments are also largely unresponsive to sector realities. However, given that they provide reasonable clarity on revenue streams for a long window of time, such long term contracts enable generators and coal companies to raise finance at lower costs. Any changes in the extant structure would affect the risks involved, which should be factored in while proposing alternative structures.

The reason for the prevalence of rigidities in operations and contracts is because of not sufficiently factoring in the changing dynamics of the sector in general, and the role of coal-based generation in particular, during the planning stage. Most states and DISCOMs, for instance, still project their load largely based on historic growth rates and from projections such as the Electric Power Survey (Central Electricity Authority, 2022). These modes of projection do not factor in state level realities, changing demand trajectories and load shapes due to aspects such as increased use of air-conditioners and space cooling appliances, shifting of agricultural load to day-time, increasing use of electric vehicles, increasing electrification of industry and migration of consumers away from the DISCOM to open-access or captive generation. Moreover, multiple scenarios are rarely considered to deal with uncertainties regarding the future. Given that load forecast and resource planning is an important step in informing power procurement and investments, rigorous Integrated Resource Planning (IRP) which accounts for variations in demand and supply is necessary (Central Electricity Authority, 2023). Moreover, given the dynamic demand and supply scenario, such planning exercises need to be revisited and refined regularly. Such planning will enable utilities to get a better understanding of the range of uncertainties involved (Sreenivas & Chirayil, 2022). In turn, it would enable them to procure supply

[12] For short-fall in delivery or lifting below 80% of the ACQ, penalties are telescopic in nature, with the rate of penalty increasing with the quantity of short-fall.
[13] See, for example, coal consumed by the three example plants illustrated in Table 1.

options with the requisite amount of flexibility to meet the likely demand while accounting for uncertainties on both supply and demand sides.

An example which highlights the growing uncertainties and the need for IRP is the growing sales migration away from the DISCOM. In FY20, open access and captive consumption contributed to 15% of the electricity consumption on average in some states (CPR PEG WRI, 2023). Measures such as Open Access (OA) were introduced to foster greater consumer choice and competition. However, they also add to the uncertainty of demand to be met by suppliers such as DISCOMs. In light of the available alternatives, large consumers can choose to migrate away from the DISCOM by setting up a bilateral agreement with generators of their choosing, while compensating the DISCOM (and the transmission company) for the use of their network for such electricity supply and other charges. With the notification of the Green OA Rules last year (Ministry of Power, 2022), even smaller consumers (100 kW and above) can purchase renewable power through open access. In addition, consumers have the choice of setting up their own captive or behind-the-meter systems to meet some or all of their demand. Such captive consumption has been increasing and accounts for 10% of total electricity consumption in the country as of FY22 (Central Electricity Authority, 2023). This provides flexibility to consumers regarding their supplier, and adds to the uncertainty of DISCOMs about their demand base for power purchase (less so for the distribution network). However, this uncertainty is rarely factored into demand projections and planning processes by DISCOMs.

Despite the lack of consideration of such uncertainties and rigidities still extant in the power sector, table 3 brings to light several endeavours that have been made to introduce some flexibility, most of them in the power sector. However, these are not likely to be sufficient as the role of coal-based generation undergoes a rapid transition, and may result in benefits being left on the table if further flexibility mechanisms are not introduced.

4. Furthering flexibility

As discussed in section 2, flexibility is increasingly being recognised as a key requisite for a smooth energy transition. Its introduction and implementation occur differently across the power and coal sectors, and across the planning, operational, and technical fronts. The persisting rigidities discussed in section 3 brings to light the need for a more comprehensive consideration of flexibilisation along the coal-based generation value chain. In this section, we suggest some measures by which such flexibility measures may be introduced.

4.1. Factoring flexibility into planning

Given that flexibility can help address several challenges from improving system efficiency to fine-tuning capacity additions, considering them explicitly at the level of planning becomes crucial.

The power purchase planning process itself should be reviewed to better reflect the changing needs of the sector, and account for the uncertainties and flexibility requirements. Long-term RTC contracting of power by DISCOMs should be carried out for their firm baseload demand alone (with suitable margins). Toward addressing daily or seasonal peaks and other variations, DISCOMs could consider alternative types of contracts and arrangements, or procure competitively priced power through markets and optimise their power purchase with low cost renewables. Such a reconsideration of the power purchase planning process would require

DISCOMs to significantly improve their ability to project demand, identify cost-optimal sources and deal with dynamic markets. DISCOMs will need to be able to maximise the potential of markets by profitably selling their excess power and/or identifying economic opportunities to purchase power from markets, and by procuring power under innovative contract structures. For this, DISCOMs need to acquire and devote specialised resources with suitable support and training.

Depending on the targeted flexibility and the plants and procurers that need to respond to it, measures would have to be introduced at different levels. For instance, amendments in Tariff Regulations can introduce flexibility measures applicable to Section 62 plants, unless mentioned otherwise. Amendments to model PPA structures would be required to introduce flexibility measures for future PPAs of Section 63 plants. Similarly, a mandate from CERC, would only be applicable to inter-state generating plants under its jurisdiction, while state ERCs would have to issue mandates applicable to state owned plants and privately owned plants that are not inter-state. Amendments to the Indian Electricity Grid Code will be applicable to all entities connected to the Inter-state Transmission System, while amendments to a state Grid Code will be applicable to entities connected to the state transmission system. Therefore, given the system level need for flexibility, these measures need to be introduced at multiple levels and by multiple agencies to ensure responsive operation across all plants and DISCOMs. The Forum of Regulators could deliberate upon the required measures to ensure their broader applicability, and facilitate exchange of ideas and good practices across states and their nation-wide implementation.

4.2. Optimisation of existing schemes and contracts

The introduction of much needed flexibility measures, and the revision of existing ones, will be disruptive and their adoption may have to be considered differently for different plants. For units that already have signed PPAs (either those that have been commissioned or yet to be commissioned), a different approach would have to be considered to respect existing contracts and prevent litigious contention. Strengthening and leveraging existing flexibility provisions for thermal capacity and mines that have already been contracted needs to respect existing legal commitments, while balancing the risks and rewards between producers and suppliers. Despite this, it is important that additional flexibilisation measures are introduced to already contracted capacity as well, since they will contribute to a majority of coal-based generation well into the future. For example, around 1/3rd of the currently commissioned coal-based fleet (about 70 GW) has come online post 2015 and can remain operational till 2050.

Most regulations that incentivise generation currently still do so on a 'more is better' basis, especially for baseload capacity. However, this is incongruous with the changing role of coal-based generation, which will increasingly be a swing supplier and grid balancer, given the varying demand and the existence of alternate cost competitive sources of generation. Incentivisation of coal-based generation must thus be devised in accordance to this changing role and the need to ensure optimal utilisation of resources at lowest costs.

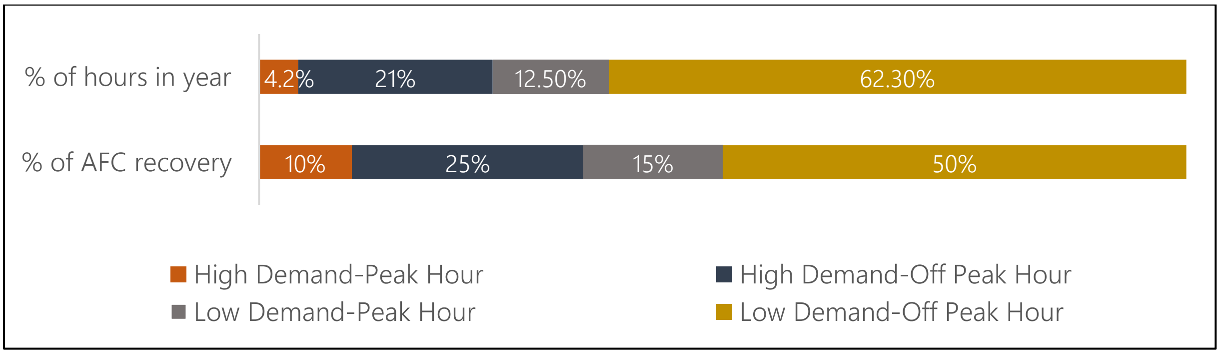
An example of optimised incentivisation is weighting fixed cost recovery of coal-based capacity such that availability during peak periods is encouraged. Such a provision is absent from tariff regulations in most states – where all 8760 hours in a (non-leap) year are treated identically and fixed charges are apportioned equally across them – i.e., they provide no incentive at all for greater availability during peak demand periods for coal-based generation. Even in tariff regulations where such provision exists, such as that of the Central and Maharashtra ERC, they assign insufficient incremental weightage to peak hour availability and no incremental weightage at all for availability during high-demand seasons.

Some incentivisation is provided in some tariff regulations, such as that of the Central ERC, for generation above the normative PLF during peak and off-peak hours, considered on a seasonal basis, as discussed in Section 2.1. In the changing scenario, the need to unconditionally incentivise coal-based generation beyond normative PLF is questionable. There is some merit in encouraging plants to procure low cost coal during high-demand periods, so that they can be despatched on the merit-order stack. Currently, CERC's tariff regulations offer a PLF incentive separately for peak and off-peak generation in excess of the norm achieved on a seasonal basis. However, such incentivisation is most needed during peak hours in the high-demand season and not needed at all during off-peak hours in the low-demand season.

Towards optimising these incentivisation measures and encouraging availability and operation in line with the evolving needs of the sector, Table 4 proposes a structure which separately considers the four combinations of high and low-demand seasons, and peak and off-peak hours.

Table 4. Suggested improvement for PLF/Availability incentivisation

	Peak hours	Off-peak hours
High-Demand Season	Rs. 0.5/kWh PLF incentive 10% of the Annual Fixed Cost Recovery for availability	Rs. 0.25/kWh PLF incentive **25%** of the Annual Fixed Cost Recovery for availability
Low-Demand Season	Rs. 0.25/kWh PLF incentive 15% of the Annual Fixed Cost Recovery for availability	**No** PLF incentive 50% of the Annual Fixed Cost Recovery for availability



Source: Prayas (Energy Group) compilation

Note: High-Demand Season is considered to be a period of three months (92 days) and Low-Demand Season is a period of nine months (273 days). Four hours a day are considered as Peak hours, and the remaining twenty hours are considered as Off-peak hours.

Effectively, the proposal in Table 4 achieves the following with regard to availability-based fixed cost recovery:

- 10% of AFC recovery is linked to just 4.2% of peak-high-demand hours, thus giving a nearly 2.5-fold weightage to those hours compared to average. Similarly, 50% of AFC recovery is linked to 62.3% of off-peak-low-demand hours, thus giving a weightage of only 0.7 to each such hour, compared to the average.

- It increases the weightage associated with peak hour availability relative to existent provisions. Per Regulation 42(2) of CERC's tariff regulations, 20% of fixed cost recovery is allocated to 16.66% (4 peak hours) of the day and 80% is allocated for availability during 83.33% (20 non-peak hours) of the day. As per the proposal in Table 4, 25% of fixed cost recovery can be allocated to 16.66% of the year (1460 peak hours across high and low-demand seasons), and the remaining 83.33% of the year (7300 off-peak hours) can be linked with recovery of 75% of fixed cost based on availability.
- In addition, higher weights for fixed cost recovery can be extended to high-demand seasons. Given the changing role of coal-based generation across seasons, such incentivisation would also be beneficial. As per the proposal in Table 4, 35% of fixed cost recovery is linked to availability in high-demand seasons, which represent 25.2% of the hours in the year.
- While redefining availability-based cost recovery as described above, it would be useful to also redefine what peak hours and high-demand seasons mean for the purposes of incentivising flexible operations of coal-based generation. Instead of basing the definitions of these terms on overall load, net load (i.e., after accounting for the must-run capacity such as solar and wind), should be the basis of their definition. This would be optimal, since the objective of providing greater weightage for TPP availability during peak periods is to encourage availability at times that coal-based generation would be most required, and peak periods based on net load represent these best.

Further, incentives for generation above the normative PLF must be designed such that the highest incentivisation (say Rs. 0.50/kWh) could be provided to plants that have generated in excess of the normative PLF during peak hours in the high-demand season, and no incentive need be provided for such generation during off-peak hours in the low-demand season. A lesser incentive (say Rs. 0.25/kWh) could be provided for operation in excess of the normative PLF during both peak hours in low-demand season and off-peak hours during high-demand season. These incentives should be modest as they are earned over and above the cost of procuring coal and are passed through to consumers.

Such measures could also be considered for coal supply. Currently, FSAs are structured rigidly with nearly uniform supply and off-take requirements through the year and across the years, not taking into account the seasonal variation of demand. However, the practices followed in the sector suggest that these contracts are anyway not adhered to strictly as stipulated, with penalties for under-supply or under-lifting rarely imposed. This essentially means that FSAs – which are meant to be legally binding contracts unlike earlier linkages – continue to be non-binding on either party. It is desirable that FSAs are repurposed as valid, binding contracts that impose obligations and provide rights to both parties. Such repurposing can also be used to introduce the necessary flexibility into coal purchase contracts, while balancing the risks and needs of both the generator and coal company. From the point of view of flexibility to meet the needs of the changing role of coal-based generation, the contracts could include provisions for varying coal demand requirement across the year. They should also include incentives for supply during peak coal-demand seasons, with corresponding penal provisions for under-supply or under-lifting which are implemented in practice.

Within the current power sector framework, there are further avenues for better implementation of extant flexibility measures. For instance, as per the Grid Code and Rule 9 of the Late Payment Surcharge Rules, DISCOMs currently have to provide the generation schedule to their contracted generators on a day ahead basis, after which the generators are free to sell their unscheduled power elsewhere. However, the fixed cost burden remains with the DISCOM that has contracted the power and the profits from sale of power are shared between the generator and DISCOM as per benefit-sharing regulations.

This could be extended by mandating the DISCOMs to provide a coarser schedule (say, an hourly schedule, rather than at a 15-minute block level) on a week/fortnight ahead basis. This should be possible for DISCOMs to do based on past demand patterns and an understanding of their consumer base. This would effectively amount to the DISCOM relinquishing the unscheduled power (as per this coarse schedule) for the forthcoming week/fortnight, and would serve as a constraint for the declaration of their daily schedule. This would provide generators sufficient time and opportunity to identify other consumers to sell their power to and also give the DISCOMs flexibility to optimise their power purchase with more cost competitive alternatives.

As per current provisions in the National Tariff Policy (Ministry of Power, 2016), "*The developer and the procurers signing the PPA would share the gains realised from sale, if any, of such un-requisitioned power in market in the ratio of 50:50, if not already provided in the PPA*". Such provision could be extended to ensure any profit earned by the generator through selling excess power based on the coarser schedule is similarly shared with its beneficiaries. The proposed detailed procedures for Security Constrained Unit Commitment, formulated by the National Load Despatch Centre, is a step in this direction to optimally schedule capacity across the country without burdening consumers (National Load Despatch Centre, 2023). The scheduling mechanism suggested in this paper attempts to further optimise scheduling and utilisation of capacity.

Further, DISCOMs already have the provision to operate as traders and sell their excess contracted power on the market to partly offset the fixed cost of unutilised capacity. But this is seldom utilised, and such power is usually backed down, possibly because DISCOMs anyway recover the full cost from consumers. In a system with growing demand, such practices also lead to the danger that other needy consumers may enter into expensive long-term contracts, which may lead to addition of fresh capacity, even as other parts of the system have excess capacity. Similarly, DISCOMs can swap/bank power with other DISCOMs/traders. Optimal utilisation of this measure could help redistribute excess resources with DISCOMs to utilities that require them. However, there is little evidence of these measures being employed widely.

In the interest of ensuring that these provisions for either relinquishing capacity or selling excess power are utilised, regulators should strongly encourage their uptake through regulations or directives, as it could lead to lower consumer tariffs and optimal utilisation of resources within the country. To start with, regulators could mandate that DISCOMs should publish scheduled, available and contracted capacity at a block-wise granularity. Such data can then be used by the regulators and consumers to hold DISCOMs accountable for inefficient utilisation of their contracted capacity.

4.3. Design of new contracts

Going forward, coal-based capacity, especially new coal-based capacity is less likely to be utilised as baseload. Under RTC contracts, through which coal-based capacity is typically procured, the DISCOM takes on the entire risk of operation of the plant, and is obligated to pay fixed costs to the plant even if it does not generate over a lifetime of at least 25 years. Given this, any new coal-based capacity procurement through such RTC arrangements should be strictly scrutinised, and not allowed unless a sustained need for such capacity and the justification of such investment can be sufficiently validated.

Contract and bid structures governing yet to be contracted coal-based capacity, that is not envisioned to operate as baseload, should be reconsidered. Innovative contracting for non RTC or peak contracts should be deliberated, so that they are more reflective of the dynamic changes in the sector and so that the purchaser is not burdened with excess capacity (and the related capacity charge payments) even when it does not need it round-the-clock. For example, bundled coal and renewable contracts could be considered to meet specific load profiles. In any case, in order to ensure cost competitiveness, all new coal-based capacity, should ideally be procured only through the competitively bid approach as opposed to the regulated method.

In the future, as alternative options (such as renewables with storage) start becoming cost-competitive even for steady, baseload operations, different approaches to contracting – such as technology-agnostic bids – may be considered. If such changes to the extant typical contract structure affect the risks involved in such investments, this would only be a reflection of the changing realities of the sector. Such changes would also lead to necessary caution in fresh investments in coal-based generation, which in turn could aid in reducing non-performing/stressed assets, and thus potentially benefit the system at large.

The contract structure of fuel supply agreements for new mines should also be similarly reviewed. As discussed in section 4.2, extant FSAs are, in practice, non-binding on the parties involved. For new mines, like for existent mines, repurposing FSAs as valid, binding, contracts that clearly stipulate and impose duties and rights on both parties is required and desirable. Flexibility measures that reflect the uncertainties in coal demand and the risk of opening new coal mines should be incorporated in the revised FSA. Similarly innovative and dynamic supply and payment features should inform the coal-supply contracts from mines auctioned for commercial coal mining.

These broad suggestions to amend contract structures to reflect the changing reality of coal-based electricity generation need to be further deliberated, reviewed and refined, based on consultation with all stakeholders involved.

4.4. Role of markets

Given the increasing uncertainties in demand and supply patterns, markets and other short-term supply options will gradually have to play a much more prominent role. Correspondingly, long-term baseload contracts should have a reduced role going forward.

Several market avenues have already been introduced to facilitate the sale and purchase of power, such as term-ahead market, day-ahead market, real-time market, etc. Additionally, measures such as SCED and MBED have also been piloted or proposed. These need to be strengthened with newer, more innovative products and the liquidity on the markets increased to develop robust markets.

In addition to platforms and avenues for market sale and purchase of power, there is increasing scope for market operations for the coal sector as well. Commercial coal mines have recently been awarded to entities and spot e-auction of coal is an extant practise. These provide an opportunity to rethink and redesign coal markets and coal pricing, to make it more responsive to changing demand patterns. For example, transparent and competitive coal markets on a common coal trading platform with shorter-term coal contracts, spot and term markets for coal with multiple sellers and buyers, contracts with time-varying quantities and prices, can all be thought of, as they would be appropriate for the changing scenario. It would be opportune to design such market structures and platforms at this juncture as newer coal producers are likely to enter the market place soon, in a time of increasing uncertainty about coal demand.

5. Conclusions

With the ongoing energy transition, the power sector is rapidly changing and the role of coal-based generation is changing along with it. From being the stable baseload source of electricity, its role will increasingly become that of the swing generator to meet demand unmet by variable sources. Existing structures, dependent on more rigid trends of supply and demand, will increasingly become less fit-for-purpose going forward.

This has been recognised to some extent, and some measures to improve the responsiveness of coal-based generation already exist in the sector. But introducing greater operational and technical flexibility is crucial toward enabling a smoother transition at optimal cost. This is best done by considering the uncertainties around coal-based generation at the planning and design stage, and revisiting the relevant policies, regulations and contract structures to factor in such uncertainties. Given their close interlinkage, flexibility provisions need to be thought about for both the power and coal sectors. Further, the provisions should extend to all coal-based generation, including plants with existing contracts, while respecting existing legal commitments and balancing duties and rights between stakeholders. Existing provisions in such contracts, and/or relevant regulations and policies, should be leveraged and strengthened and flexibility mechanisms should be built into the contracts of capacity yet to be contracted.

Action towards this could include:

- Ensuring broader applicability of flexibility measures at multiple levels aided by the Forum of Regulators
- Supplementing DISCOMs ability and resources to engage with markets toward more dynamic and responsive power procurement planning
- Encouraging availability and generation during periods of peak demand
- Ensuring better resource utilisation by enabling generators to sell unscheduled power and encouraging DISCOMs to trade/sell excess power
- Subjecting new coal-based RTC contracts to stringent scrutiny

- Encouraging more responsive, risk-reflective contract structures for generators and mines yet to be contracted
- Strengthening existing market measures in the power sector and developing transparent, competitive market structures and platforms for the coal sector

The objective of the measures suggested – and this paper – is to propose some ideas and initiate a discourse within the sector to discuss and debate these suggestions further in order to facilitate the requisite changes to policy, regulations and contract structures. The role of coal-based generation is changing fast. The regime governing the coal-based generation value chain needs to change accordingly so as to reduce the friction in the electricity system's transition to a renewables-dominated system.

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Find Prayas (Energy Group) on

https://energy.prayaspune.org

energy@prayaspune.org

https://www.linkedin.com/showcase/prayas-energy-group/

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The power sector in India is going through a disruptive transition, driven by changing economics and concerns regarding climate change. As a result, coal-based generation is likely to gradually morph from a firm, baseload, round-the-clock supplier to a swing supplier, to meet demand when renewables are not sufficient. Toward ensuring that this disruption is minimized and well-managed, the introduction of flexibilisation measures across policy, planning, and operation of the coal-based generation value chain is necessary.

Flexibilisation is required because renewable sources, which will dominate the sector in the years to come, are intermittent. In addition, there is increasing uncertainty even in electricity demand patterns. However, existing mechanisms and contracts in the coal-based generation value chain are premised on predictable generation and demand.

Some measures for flexibility – such as provision to trade surplus power – already exist, but are insufficiently used. Going forward, regulators should ensure that these are used more effectively. In accounting for changing sector realities, it is also essential that flexibilisation measures are incorporated by sector actors at the planning stage itself. However, introducing and strengthening flexibility measures is a complex issue that requires differed consideration for existing coal-based assets and assets yet to be contracted.

In this context, this paper proposes a few ideas such as: better designed incentives for availability and generation; a different approach for providing schedules; explicit consideration of uncertainties in planning; better designed and enforced fuel supply agreements; minimizing round-the-clock contracts in future; and encouraging more liquid, transparent, participative markets for coal and power.

Deliberating upon these ideas and introducing such flexibilisation measures into policy and practise across the coal-based generation value chain can go a long way in reducing the friction in the energy transition towards renewable generation.

Prayas (Energy Group)