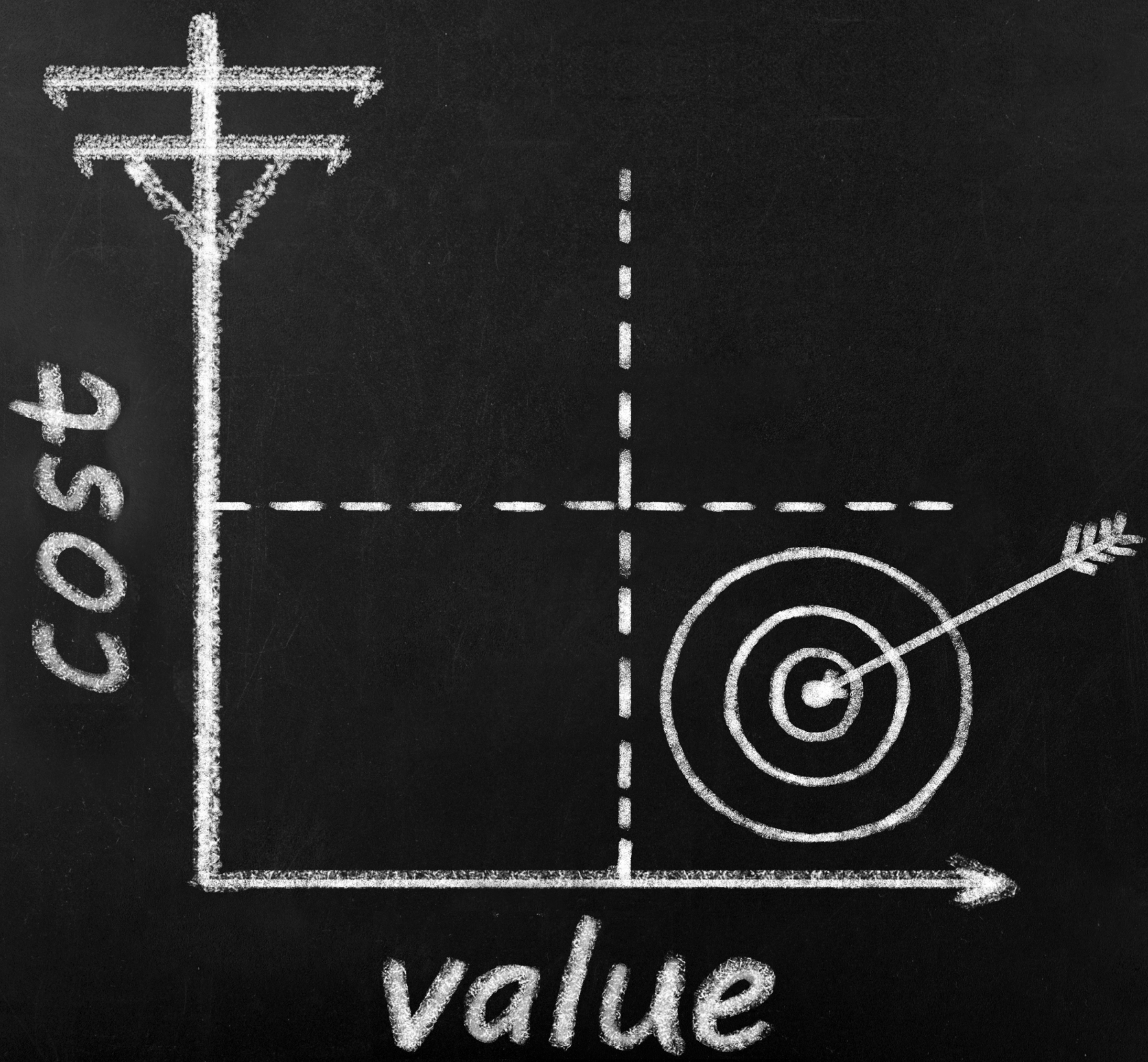
Cost-effectiveness of Discom Operations in Uttar Pradesh

Impact of UDAY, Power Purchase Planning and Dispatch

Prateek Aggarwal, Karthik Ganesan, and
Danwant Narayanaswamy

Report | July 2020



India's power sector is undergoing a rapid transformation with changing energy mix.

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"The UP power sector has long been facing structural and financial issues in spite of meeting its power requirements satisfactorily. For the persisting finance and profitability challenges in the distribution segment there is a need to introspect on the cost-effectiveness of discom operations."

Karthik Ganesan
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An engineer by training, Karthik leads The Council's work on the power sector. His research has focused on the operational reform of discoms in India and the competitiveness of power generation sources. He holds a master's degree in Public Policy from the Lee Kuan Yew School of Public Policy at the National University of Singapore. He also holds an BTech in Civil Engineering and an MTech in Infrastructure Engineering from the Indian Institute of Technology, Madras.

"An efficient market for electricity has to involve UP, which is the second largest consumer. Establishing the benefits for efficient dispatch and procurement is important to find acceptance for broader paradigms of market-based economic dispatch.

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"Utilising the available resources to their fullest potential and ensuring adequate coal supply to cheaper plants throughout the year would significantly reduce the overall power procurement cost. For this to happen, it is important that the discom duly address the operational and administrative hurdles which hinder optimal power procurement."

Coal-based generation forms a significant share in Uttar Pradesh

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Abbreviations

ABR	average billing rate
ACoS	average cost of supply
APPC	average power procurement cost
APR	annual performance review
ARR	annual revenue requirement
AT&C	aggregate technical and commercial
CAGR	compound annual growth rate
Cal	calories
CEA	Central Electricity Authority
CEEW	Council on Energy, Environment and Water
CEF	Centre for Energy Finance
CERC	Central Electricity Regulatory Commission
D&A	domestic and agriculture
DDUGJY	Deen Dayal Upadhyaya Gram Jyoti Yojana
Discom	distribution company
DT	distribution transformer
DVVNL	Dakshinanchal Vidyut Vitran Nigam Limited
FY	financial year
GPS	gas power station
GoUP	Government of Uttar Pradesh
HEP	hydro-electric power plant
I&C	industrial and commercial
IPP	independent power producer
ISGS	inter-state generating station
KESA	Kanpur Electricity Supply Authority
KESCO	Kanpur Electricity Supply Company Limited
INR	Indian rupees
LED	light-emitting diode
LNG	liquefied natural gas
Kcal	kilocalories
kWh	kilowatt-hour
MOD	merit order dispatch
MoU	memorandum of understanding
MT	million tonnes
MUs	million units
MVVNL	Madhyanchal Vidyut Vitaran Nigam Limited
MW	megawatt
MYT	multi-year tariff
NAPM	non administrative price mechanism
NHPC	National Hydroelectric Power Corporation
NLDC	National Load Dispatch Centre
NTPC	National Thermal Power Corporation
PIB	Press Information Bureau
PLF	plant load factor
PPA	power purchase agreement
PRAAPTI	payment ratification and analysis in Power procurement for bringing transparency in invoicing of generators
PSU	public sector undertakings
PVVNL	Paschimanchal Vidyut Vitaran Nigam Limited
PuVVNL	Purvanchal Vidyut Vitaran Nigam Limited
RE	renewable energy
RLDC	regional load dispatch centre
SAUBHAGYA	*Pradhan Mantri Sahaj Bijli Har Ghar Yojana*
SLDC	State Load Dispatch Centre
STPS	super thermal power station
T&D	transmission and distribution
Transco	transmission company
UDAY	*Ujwal Discom Assurance Yojana*
UP	Uttar Pradesh
UPERC	Uttar Pradesh Electricity Regulatory Commission
UPJVNL	Uttar Pradesh Jal Vidyut Nigam Limited
UPPCL	Uttar Pradesh Power Corporation Limited
UPPTCL	Uttar Pradesh Power Transmission Corporation Limited
UPRVUNL	Uttar Pradesh Rajya Vidyut Utpadan Nigam Limited
UPSEB	Uttar Pradesh State Electricity Board
UPSLDC	Uttar Pradesh State Load Dispatch Centre
UT	union territory

Uttar Pradesh has a total transfer capacity of 14,500 MW.

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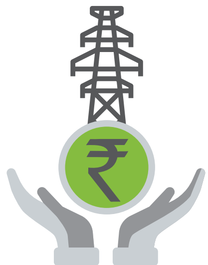
Executive summary

It has often been suggested that a true test of reform efforts, especially in the power sector, will be in their implementation in India's most populous state - Uttar Pradesh. The primary challenge (and in some sense the opportunity) is that the starting base for performance is quite low in the state, and to top this, nearly 8 million consumers have been added in the last two years under an ambitious *Saubhagya* scheme. As the *Ujwal Discom Assurance Yojana* (UDAY) scheme, which was expected to provide some cheer to the power sector, has come to a close, we evaluate how the state of Uttar Pradesh (UP) has performed and study the challenges the state faces by way of high-cost electricity that it is saddled with.

First, we undertake a qualitative and quantitative evaluation of the impact of the UDAY scheme, in improving the financial and operational performance of UP's state-owned discoms and suggest follow-up measures based on our observations. For quantitative assessment, we rely on data reported to the regulators and those found in statutory filings with regard to the financial and physical performance of the utilities in UP. We then look at the current utilisation of the existing contracted capacity[1], analyse the financial implications of the current procurement practices, and explain the reasons for suboptimal practices, if any. We devote a significant portion of our analysis to operational performance—extent of utilisation of the generation assets commensurate with their variable costs. We assess the merit order dispatch (MOD) based procurement to evaluate if the lowest cost power is consistently being dispatched and arrive at cost savings that can be possibly achieved if MOD were followed. To accomplish this task, we perform a greedy optimisation that procures as much from lower cost resources, subject to pre-determined conditions on availability, for our evaluation.



By ensuring strict adherence to merit order dispatch (MOD), UP discoms can potentially save INR 900 crore on annual basis

When assessing the financial impact of the UDAY scheme, we find there are large variations between what is reported to the regulator (in true up filings) and that reported through audited books, which is what the state financing agencies make use of. Both these figures contradict each other. For example, the audited books for FY 2016-17 still indicate that on each unit being sold, the state has lost more than 56 paise while the regulator, in the trued-up order, reported that the discoms have achieved a net positive margin on each unit sold. Undisbursed additional subsidies requested by discoms from the UP government play an important role in determining the discom's financial health.

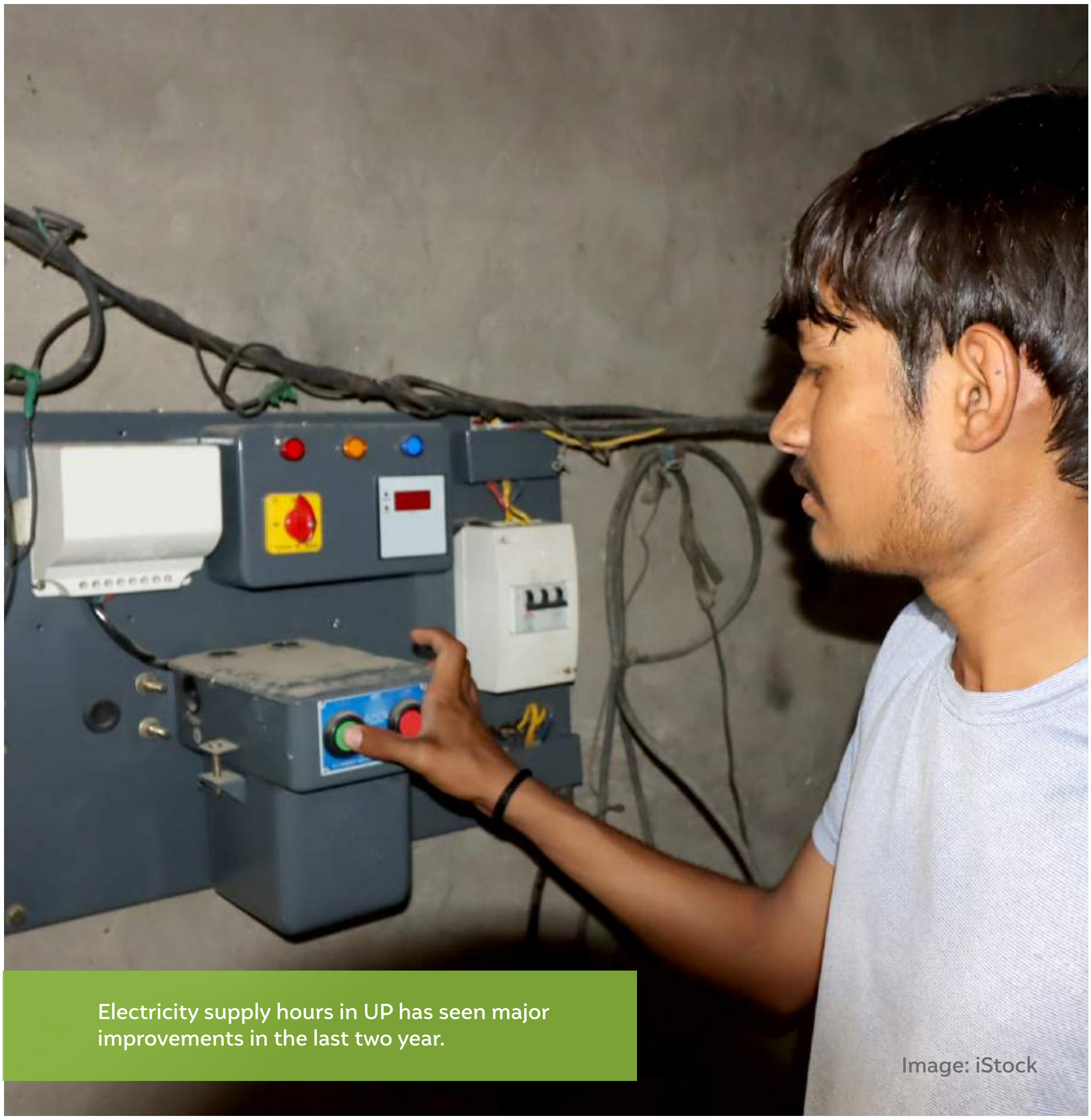
The discoms of Uttar Pradesh are paying nearly six per cent (INR 3,000 crore) of their total cost of procurement just as stranded fixed charges to three recently contracted generation

1. We limit this to generating stations that are entirely allocated to Uttar Pradesh as the operations of shared stations (central government and some private independent power producers [IPPs]) cannot solely be dictated by the needs of the state alone.

sources. Despite the hefty spend, these sources are utilised very poorly. This payout is likely to climb up to INR 10,000 crore in the early 2020s. The need for paring power purchase expenditures is even more necessary now, as the impact of the ongoing COVID-19 pandemic is likely to last, continuing to affect demand recovery and the consumer's ability to pay. Given the overall surfeit of power and imbalances in demand across the country, it would be prudent to take advantage of other resources before the focus moves to contracting or commissioning new capacity. A full cost–benefit analysis of alternatives becomes absolutely essential before any long-term decisions are made.

Finally, and most crucially, we note that there was an opportunity to save INR 900 crore in each of the last three years by simply following the MOD approach. We found several reasons for deviating from the MOD: (i) poor coal availability at some low-cost generating stations, (ii) poor operational scheduling, and (iii) perhaps an inherent preference to have state-owned generators dispatch on account of flexible payment terms. As the country, including UP, prepares for market-based economic dispatch, it is important to get first principles right in the limited set of plants that are entirely under the control of the State Load Dispatch Centre (SLDC). This approach necessitates better coal allocation practice among stations, but more importantly, our analysis also finds that variable cost does not capture the thermal efficiency of power plants. We find that the variable cost is almost entirely a function of the delivered cost of coal, and this suggests that reporting on station heat rates is either spurious or unreliable. A true market-based mechanism must ensure that the distortions around the delivered price of energy are removed, and the most efficient plants are allowed to generate power.

1. Introduction



Electricity supply hours in UP has seen major improvements in the last two year.

Image: iStock

Despite being the fourth largest producer and the second largest consumer of electricity, Uttar Pradesh (UP), India's most populous state, housed nearly one third of the unelectrified population in the country till recently. The implementation of *Pradhan Mantri Sahaj Bijli Har Ghar Yojana (SAUBHAGYA)* completely changed the scenario by bringing an additional 8 million consumers to the grid. Yet, the per capita electricity consumption in the state stands at half of the national average (CEA 2019). Since the state reorganisation (with the bifurcation of UP and creation of Uttarakhand as a separate state) in 2000, UP has increased its total installed generation capacity five-fold to 25,799 MW[2] (as of September 2019) and all villages in the state have been connected to the distribution grid.

2. It denotes the installed capacity of power utilities in UP, including an allocated share in joint and central sector utilities.

The recent (seventh) annual integrated rating of state distribution utilities ranked the five state-owned electricity distribution companies (discoms) in UP as poorest in terms of performance on a composite metric. Kanpur Electricity Supply Company Limited (KESCO) alone showed moderate operational and financial performance capability, while the other four discoms were categorised as having a poor performance capability (MoP 2019).

Public distribution companies across the country in general have been reeling under heavy financial losses and the resulting debt burden due to a host of reasons, ranging from political to cultural to operational to economic. In September 2015, the total outstanding debt of the discoms across the country stood at INR 4,30,000 crore. Out of this, the share of UP discoms was INR 53,200 crore, it was 147 per cent of the trued up revenue for FY 2015-16 (PIB 2016). To alleviate the power utilities from the burden of debt, and to improve their overall performance, the government of India (GoI) launched the *Ujwal Discom Assurance Yojana* scheme on 20 November 2015. UDAY was conceived as the permanent solution to the endless cycle of bailouts of discoms and their continuing poor performance. UDAY's main aim was to improve their financial stability and operational efficiency for ensuring a sustained growth of discoms (PIB 2016).

Data on discom performance in recent years reveals that the ambitious UDAY scheme hasn't been able to take them out of the red. Discoms continue to incur large commercial losses, which stood at INR 28,369 crore at the national level at the end of FY 2018–19, registering a steep 88.60 per cent increase year-on-year (Chatterjee 2019, UDAY n.d.). For a brief period though since the launch of the UDAY scheme in November 2015, discoms reported declining losses. As per data available from 28 states/union territories (UTs), discoms lost INR 0.27 for every unit (kWh) of electricity supplied (the gap between cost of supply and revenue realisation on every unit) in FY 2018–19, and their aggregate technical and commercial (AT&C) losses stood at 18.20 per cent at the end of FY 2018–19 (Chatterjee 2019, UDAY n.d.).

Discoms in UP have to shoulder the needs of an additional 8 million consumers added under the *Saubhagya* scheme

By the last year of the UDAY scheme (2019–20), overall improvements in infrastructure have been made—increased metering of urban and rural feeders, metering of distribution transformers (DT), and a roll-out of smart metering to retail consumers on a pilot basis in select distribution pockets. Even as infrastructure was undergoing improvement, discoms in UP were burdened with the challenge of adding 8 million new consumers over two years under the *Saubhagya* scheme. They also suffered a financial setback, as their fiscal space was constricted by the Uttar Pradesh Electricity Regulatory Commission (UPERC), which sought to adjust the debt taken over by the government of UP under the UDAY scheme against the extant regulatory assets[3]. Given this background, it would prove useful to take stock of the general health of discoms by analysing their key performance metrics using publicly available data and other records and also gain a snapshot of the financial and operational performance of discoms in the state in the context of UDAY. A range of metrics—some of those listed below—can be used to study the current state of the power sector in UP:

I. **The financial position of discoms**

- Debt taken over by government of UP, the remaining debt, and their overall implications
- Revenue recovery (in light of increasing rural load) and revenue gap
- Tariff revisions vis-à-vis the UDAY proposal
- Power purchase costs

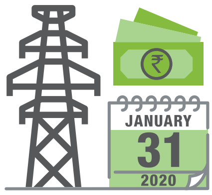
3. Regulatory assets include previously incurred losses that are in the nature of deferred expenditure and that can be recovered from consumers in future provided they are allowed by the Electricity Regulatory Commission.

II. **Operational improvements and technical upgradations (progress and correlation between fiscal space and operational improvements)**

- AT&C loss reduction
- Feeder level metering and others

In terms of spend, power purchase costs constitute between 75 and 80 per cent (on average) of the total costs of supply incurred by a discom (Bharadwaj, Ganesan, and Kuldeep 2017). These, in turn, depend on the quality of the generation assets contracted and their costs. Generation assets are continuously added (under the aegis of state agencies), assuming that the demand for power would continue to increase at an annual rate of 7–9 per cent. In UP, despite the addition of 8 million households since October 2017 under the *Saubhagya* scheme in an intense electrification drive (Saubhagya n.d.), no noticeable uptick in electricity demand/supply was observed (details in Section 3.2). However, as per the discoms projection, the demand is projected expected to pick up in the next three-year period.

At the national level, the plant load factor (PLF) of coal-based plants dwindled to 61.07 per cent during 2018–19 from 78.6 per cent during 2007–08 (CEA, Growth of Electricity sector in India from 1947- 2019, 2019). Some of the coal-based generation assets are now stranded or continue to be utilised despite their unsustainable PLFs for a range of reasons. An imprudent capacity expansion occurred in the period 2010–15. Following a slowdown in demand after 2012, power purchase agreements (PPAs) on offer for new plants suffered a decline. Coal supply from domestic mines slumped. All these factors led the power sector into a downward spiral (Spencer 2019). Moreover, newer power plants were commissioned without a due diligence on the economic returns of such assets. Authorities tasked with planning let go of prudence in the last decade.



UP discoms accounted for 15% of all outstanding dues to generators

Discoms have been facing a steady deterioration of finances on account of a persistent revenue shortfall, which is a result of poorly designed tariff structures and their inability to bill and account for the power sold. The effects of such poor practices have spiralled into taking a toll on the financial standing of discoms, as they are unable to make timely payments for their energy purchases from the generators (Nirula 2019). For instance, the dues the UP discoms owed to generators stood at INR 13,326.61[4] crore at the end of January 2020 (PRAAPTI 2019).

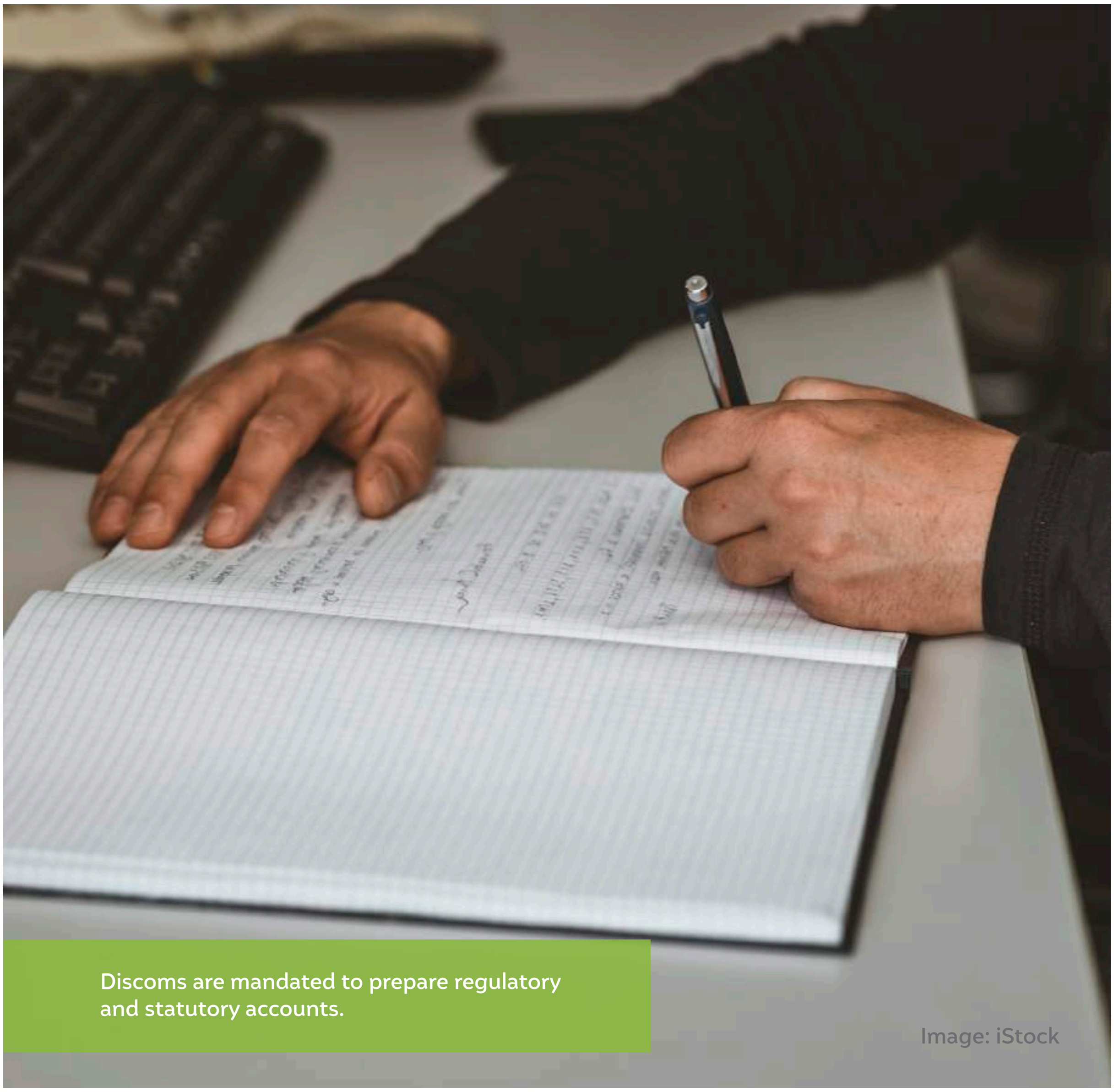
To improve the financial health of discoms, minimising costs associated with the operation of the existing and committed (under construction and planned) generating stations becomes absolutely essential. Keeping this in mind, we pursue a few key questions in this study.

We first set out to evaluate the impact of the UDAY scheme in terms of improvement in the financial and operational performance of state-owned discoms in UP and suggest follow-up measures based on our observations. Then we seek to gain insight into the current utilisation of existing contracted capacity,[5] the financial implications of current procurement practices, and explain the reasons for suboptimal electricity dispatch, if any. Our overall objective through this analysis is to identify avenues for optimisation of power procurement costs in the short to medium term.

4. Excluding the disputed amount of INR 1,956 crore.
5. We limit this to those generating stations which are entirely allocated to Uttar Pradesh as the operations of shared stations (central government and some private IPPs) cannot solely be dictated by the needs of the state alone.

In the section that follows, we discuss the methodology and approach that we adopted for our analysis. In Section 3, we provide a comprehensive overview of power demand and supply situation as well as segmentation of supply. In Section 4, we discuss the findings of our assessment of the UDAY scheme and the opportunities that exist for improving procurement efficiency in the state. In Section 5, we conclude by providing some concrete steps for cost savings through our calculations, which the state can implement, and furnish some learnings for the next round of interventions to improve operational and financial performance of discoms in UP.

2. Methodology and data



Discoms are mandated to prepare regulatory and statutory accounts.

Image: iStock

We analysed the performance of discoms in UP after the implementation of UDAY using a combination of a qualitative and quantitative approaches. We performed quantitative assessment based on data from several sources. First, we relied on the interpretation of data on the financial and physical performance of the utilities of Uttar Pradesh, as reported to the regulators and statutory filings. Operating data were obtained from the UDAY portal, tariff filings of Uttar Pradesh Power Corporation Limited (UPPCL), and tariff orders of UPERC. For qualitative assessment, we looked at the social, economic, and political setting in UP. We leaned heavily on other studies that have established the root causes of malaise in power distribution in UP. We extend these findings to explain their impact on the UDAY scheme over the last three trued-up years (FY 2015-16 to FY 2017-18).

We then undertook an evaluation of power procurement—both on a planning horizon (a few years ahead) and operation horizon (dispatch – day ahead or intra-day). This exercise was mainly quantitative, illustrating the costs that the discoms in UP impose on their consumers by way of suboptimal practices, if any. The initial analysis is descriptive in nature, documenting the prevailing contracted capacity, the variable and fixed costs associated with such capacity, and the extent of utilisation over the years. We provide segmentation of the capacity across different metrics and comment on the characteristics of each metric. Our focus here is trained on the operational performance of discoms—extent of utilisation of the assets commensurate with their variable costs. We assess the current merit order dispatch (MOD) based procurement to evaluate if the lowest cost power is consistently being dispatched and calculate the cost savings if MOD were followed. We perform this calculation through a greedy optimisation that procures power as much from lower cost resources, subject to pre-determined conditions on its availability. We also explore reasons for possible deviation from MOD and the steps needed to enable its implementation in full. We conclude with an estimate of the capacity to be contracted over the next decade and its implications.

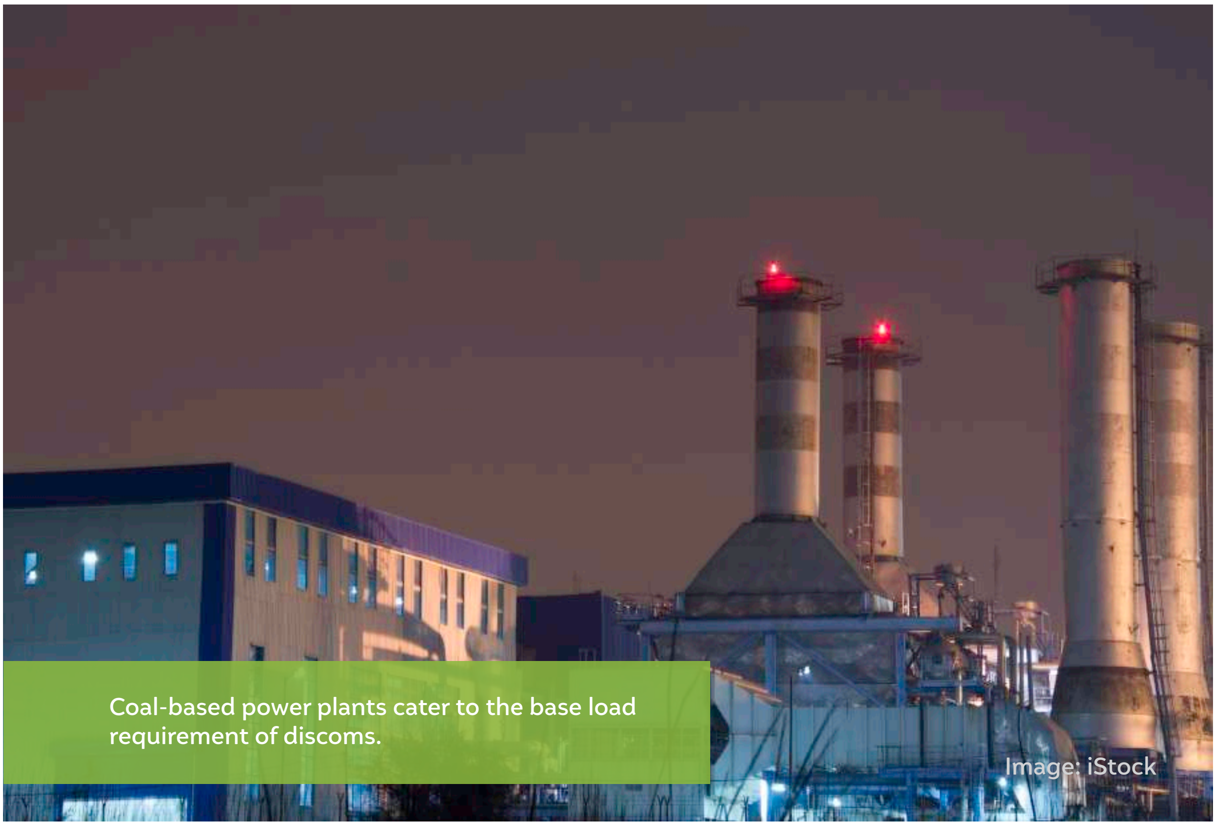
The operating data were gleaned from UPPCL tariff filings, UPERC tariff orders and other orders, and daily and monthly data sets of Central Electricity Authority (CEA). The data on the following parameters were collected for generating stations supplying power to state-owned discoms in UP and UPPCL:

- Daily gross generation from FY 2015–16 to FY 2018–19
- Net procurement from generating stations from FY 2015–16 to FY 2018–19
- Plant load factors and auxiliary consumption
- Daily coal stock availability
- Upcoming generation capacity
- Trued-up data for FY 2015–16 to FY 2017–18 and annual performance review (APR) data for FY 2018–19

In our analysis, only[6] coal-fired state-owned generation stations and state-based independent power producers (IPP)[7] have been considered to evaluate the overall procurement efficiency and how different power plants are positioned to provide outputs that minimise the overall cost of power for the discoms. We carry out the analysis for a three-year period from FY 2016–17 to FY 2018–19.

6. Generating station based on hydro, nuclear, and renewables are considered must run under the merit order dispatch.
7. As these IPPs are entirely allocated to the state, and given the current procurement practices, they are entirely controlled by the State Load Dispatch Centre.

3. Overview of the power sector in Uttar Pradesh: energy demand and procurement



Coal-based power plants cater to the base load requirement of discoms.

Pursuant to the early reforms and restructuring process at the turn of the century, the erstwhile Uttar Pradesh State Electricity Board (UPSEB) was unbundled into the following three separate entities through the first Uttar Pradesh Electricity Reforms Transfer Scheme dated 14 January 2000:

- Uttar Pradesh Power Corporation Limited (UPPCL), vested with the function of transmission and distribution within the state
- Uttar Pradesh Rajya Vidyut Utpadan Nigam Limited (UPRVUNL), vested with the function of thermal generation within the state
- Uttar Pradesh Jal Vidyut Nigam Limited (UPJVNL), vested with the function of hydro generation within the state.

Through another Transfer Scheme dated 15 January 2000, assets, liabilities, and personnel of Kanpur Electricity Supply Authority (KESA) under the erstwhile UPSEB were transferred to Kanpur Electricity Supply Company Limited (KESCO), a company registered under the *Companies Act, 1956*.

After the enactment of the *Electricity Act, 2003*, UPPCL (responsible for both transmission and distribution functions) was further unbundled along functional lines. As a result, four new discoms were created, vide *Uttar Pradesh Transfer of Distribution Undertaking Scheme*, 2003, to undertake distribution and supply[8] of electricity in the areas under their respective zones:

- Dakshinanchal Vidyut Vitran Nigam Limited (Agra Discom or DVVNL)
- Madhyanchal Vidyut Vitran Nigam Limited (Lucknow Discom or MVVNL)
- Paschimanchal Vidyut Vitran Nigam Limited (Meerut Discom or PVVNL)
- Purvanchal Vidyut Vitran Nigam Limited (Varanasi Discom or PuVVNL)

Subsequently, on 18 July 2007, the Uttar Pradesh Power Transmission Corporation Limited (UPPTCL), a transmission company (Transco), was entrusted with the transmission of electricity to various utilities within the state. This function was earlier vested with UPPCL.

3.1 Generation capacity tied up for Uttar Pradesh

The state has witnessed massive capacity addition between 2009 and 2019. Private sector investment, which contributed a mere 378 MW in 2009, accounted for nearly half (12,600 MW) of the generation capacity in the state in 2019 (CEA 2019).

From a procurement perspective, the firm tied-up capacity stood at 22,156 MW (as on March 2019). Out of the total firm tie-up capacity, 31 per cent rests with the central inter-state generating stations (ISGS)[9] (6,869 MW) followed by state IPPs (6,381 MW), state-owned stations (5,947 MW), and other (private) ISGS (2,959 MW). A station-wise listing of the firm-contracted capacity is provided in Annexure I

Generation assets located within the state contribute more than 12,000 MW of firm tied-up capacity and offer greater flexibility to the State Load Dispatch Centre (SLDC) and discoms, as these generators are entirely under the control of SLDC and are available to meet all contingencies. Apart from firm tie-ups, the discoms also have the option to buy any form of power from the exchanges or make bilateral contracts for short-term arrangements. The breakdown of generation capacity based on ownership of assets is shown in Figure 1.

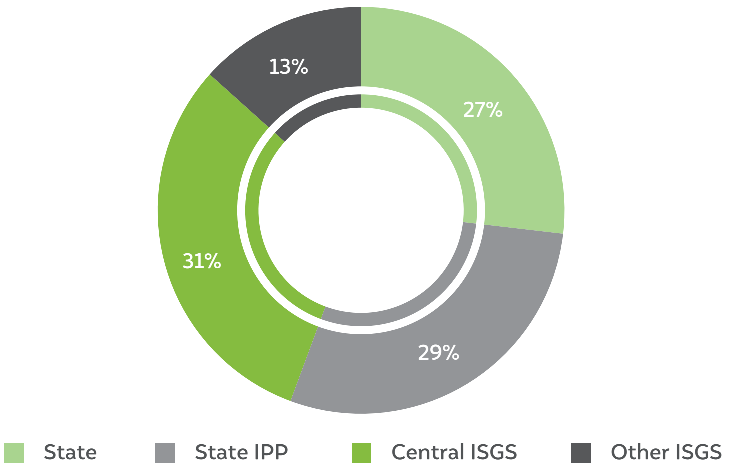


Figure 1
State-based stations contribute to more than 50 per cent firm tie-up capacity

Source: Authors' adaption from UPERC tariff orders; UPPCL tariff filings and UPSLDC

8. Fresh distribution licenses for each of these entities was issued only in 2010.
9. Refer Section 4.2.1 of the brief for more details on state, state IPP, central ISGS, and other ISGS.

Further, coal-based plants remain the major source of power generated in UP. This has contributed to the state's high cost of supply as some coal-fired power stations have high fuel cost. Nearly 83 per cent of the long-term contracted power is from coal-based generation sources, followed by hydro and renewable (15 per cent) and nuclear (1 per cent). The fuel-wise share of generation as on March 2019 is shown in Figure 2

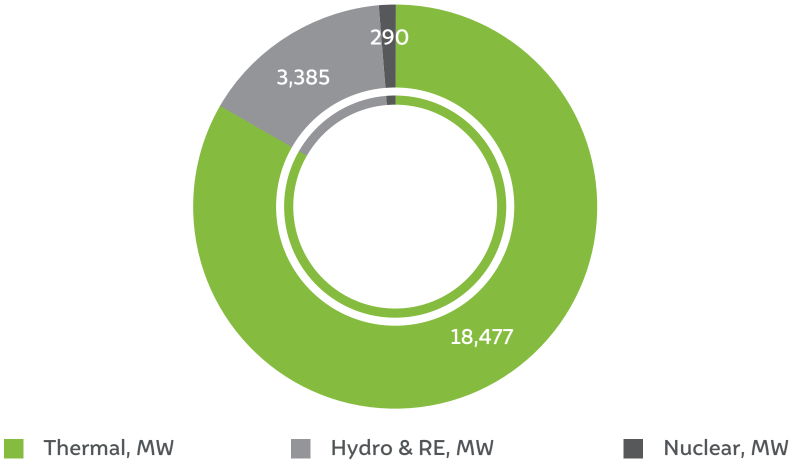


Figure 2
UP is largely dependent on coal-based generation sources

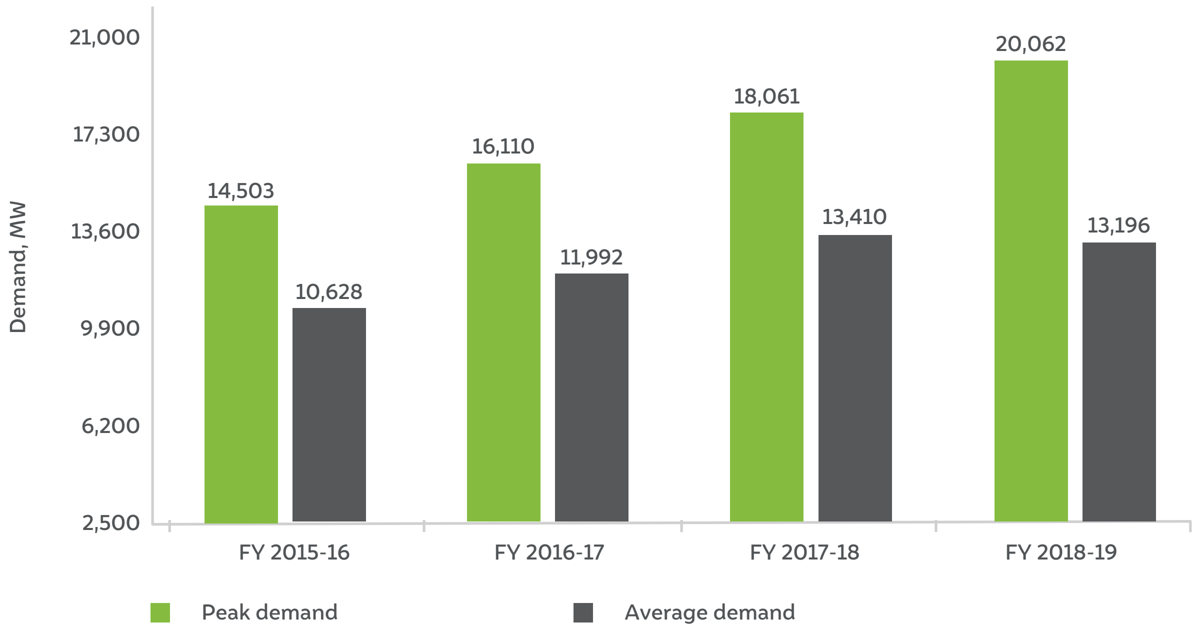
Source: Authors' adaption from UPERC tariff orders; UPPCL tariff filings and UPSLDC

3.2 Power and energy demand in Uttar Pradesh

Between 2009 and 2019, peak demand in UP increased by 57 per cent and the overall energy requirement went up by 55 per cent (CEA 2019). Presently, during summer season, demand spikes to 22,500 MW during the peak hours (7–11 p.m.), cooling to 16,500 MW during daytime. The peak demand during winter matches the summer daytime value of 16,500 MW, going down to 10,500 MW during daytime. The demand gap between peak time and daytime is a maximum of 6,000 MW, and UP has been struggling to find the optimum balance in generation to meet this variation in demand (Kumar 2019).

A focused electrification drive in the state in the last few years has led to the peak and average demand respectively growing at a compound annual growth rate (CAGR) of 8 and 10 per cent (Figure 3). In contrast, the average demand fell by 2 per cent in FY 2018–19. The reasons for this dip are not clear, given that newly electrified households should have resulted in at least a marginal increase in load. Conversations with officials at the utility suggest that some of the reasons could be the regularisation of informal connections (preventing theft) as part of the electrification drive. Metered connections have increased rapidly, but have curiously led to a decrease in demand. One possible explanation is consumers are now wary of having to pay for the electricity they use and possible decrease in incidences of theft. This dip, however, makes future demand predictions uncertain. Discoms do not seem to have taken a serious note of this dip and remain upbeat about growth in demand for the next three years, as could be gathered from tariff petitions recently filed by them.

Figure 3 Peak demand has grown with a CAGR of 8 per cent in the last four years



Source: Author's adaption from UPSLDC

3.3 Power procurement cost

Discoms in UP had to cope with high costs of power purchase (when compared to Madhya Pradesh, Maharashtra, Rajasthan, and Punjab[10]). The strain on their finances has resulted in high retail tariffs for their overall consumer base. There are a number of reasons for the high cost of power procurement, but there is always enough room to optimise the variable costs by streamlining the operation of power stations and rationalising coal allocation and supply. Table 1 provides a comparative view of the average power procurement cost (APPC) across select states. Clearly, UP's APPC is one of the highest.

States	Average power procurement cost (APPC, INR/kWh)	Generation mix (%)		
		State	Central ISGS	Other ISGS
Madhya Pradesh	3.75	28	13	59
Maharastra	4.04	41	19	40
Punjab	4.18	57	24	19
Andhra Pradesh	4.40	60	21	19
Rajasthan	4.69	54	24	22
Uttar Pradesh	4.62	45	25	30
Karnataka	4.81	72	20	8

Table 1
Uttar Pradesh's average power procurement cost: one of the highest in the country

Source: Author's analysis from tariff orders of various state electricity regulatory commissions for FY 2019–20

10. To the extent possible, states have been selected to capture the diversity on the basis of generation mix from state, central ISGS and other ISGS

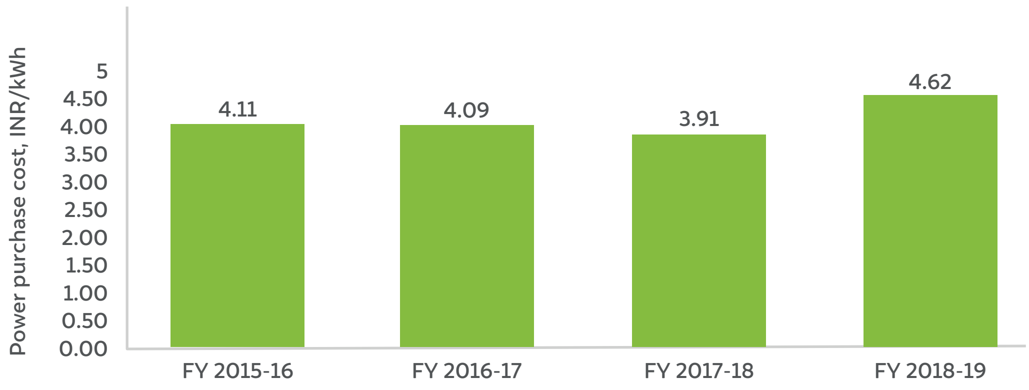


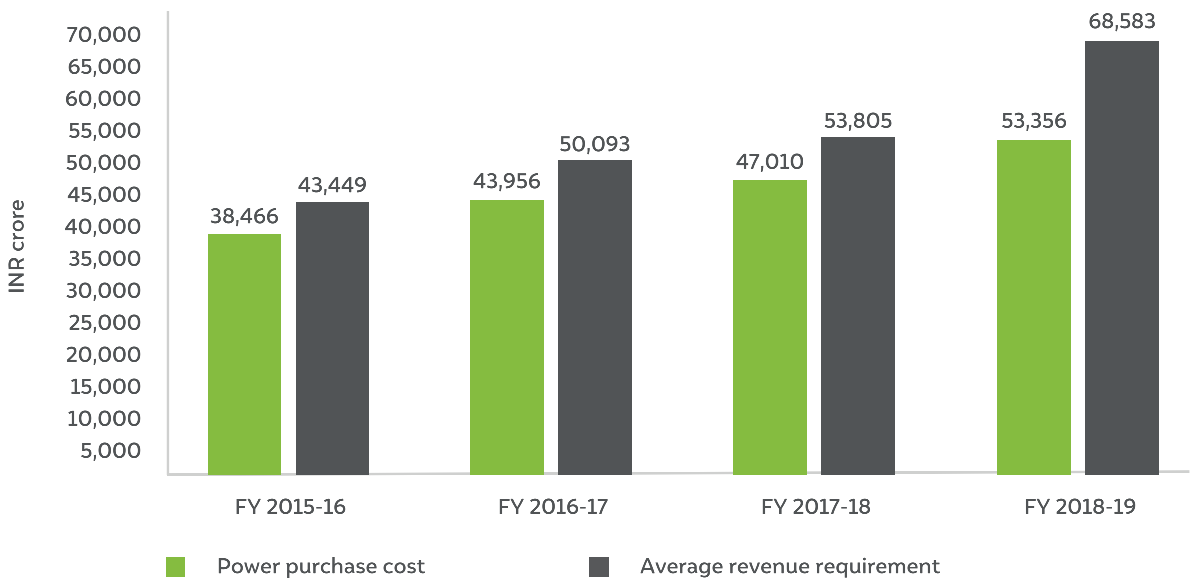
Figure 4
UP has seen a sudden rise in power procurement cost

Source: Author's adaption from UPERC tariff orders

Typically, discoms incur 75–85 per cent of their total annual expenditure on power purchase cost.

Figure 5 explains the expenditure spread of discoms over the last four years. It could be observed that in FY 2018–19, other costs have risen much more sharply, and as a result, the share of power purchase costs has relatively come down.

Figure 5 Power purchase cost eats up 75–85 per cent of the total expenses



Source: Authors' adaption from UPERC tariff orders; UPPCL tariff filings and UPSLDC
Note: FY 2018–19 is an APR figure, while the rest financial years are the trued-up expenses

More importantly, our analysis also points out that power purchase alone eats into 85 to 90 per cent of the total revenue realised by discoms, leaving little room on the table for covering other costs.

3.4 Expected growth in demand

The consumption patterns of various segments and revenue realised by discoms from those segments are not compatible. In 2018–19, domestic consumers accounted for 44 per cent of consumption but contributed 38 per cent to revenue by sales for discoms. Agricultural consumers sliced 14 per cent of consumption, while providing only 6 per cent to revenue. However, industry shared 19 per cent of consumption but returned 24 per cent of revenue from sales to discoms (UPERC, Uttar Pradesh Electricity Regulatory Commission 2019). This skewed revenue that discoms generate will certainly have a bearing on their ability to service growing consumption from households, especially the millions of newly electrified ones as well as the needs of those already connected.

UPPCL expects demand to grow at a CAGR of 6 per cent over the next decade, as gathered from its recent submission to the regulator. While the average load is expected to rise from 13,000 MW to 31,613 MW, peak load is estimated to increase from 22,000 MW to 40,690 MW by 2029–30 (UPERC, Uttar Pradesh Electricity Regulatory Commission 2019). The average to peak ratio is projected to improve from 1.69 (in FY 2018–19) to 1.29 (in FY 2029–30), which is a healthy sign and indicates a levelling of load—either autonomously or otherwise.

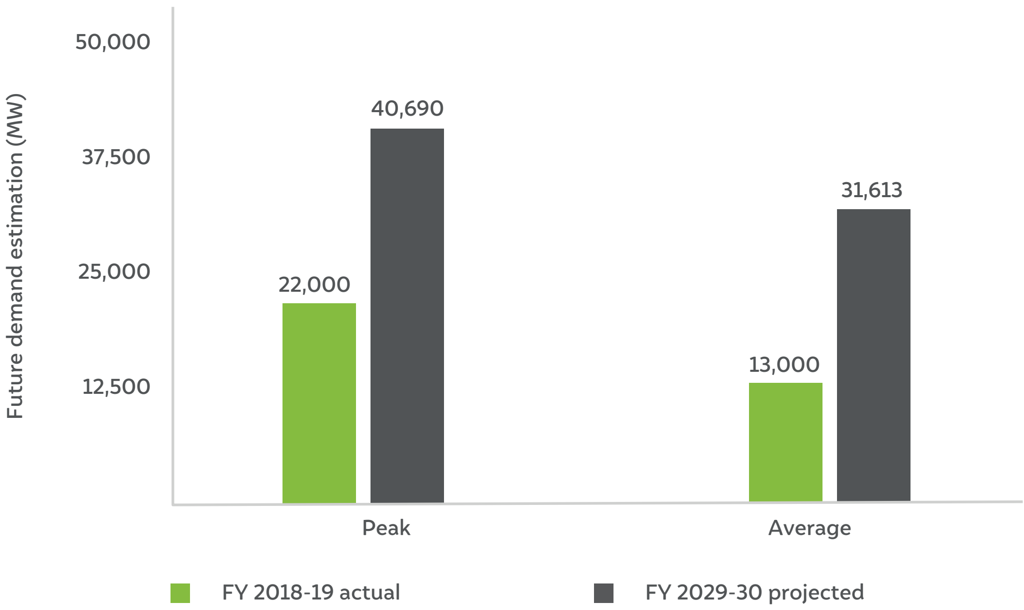


Figure 6
Average demand in FY 2029–30 projected to grow by 143 per cent

Source: Adapted from UPERC order in petition no. 1478/2019 (approval of long-term procurement of UP discoms)

It would be prudent to reflect on how even short-to medium-term demand planning has fared in the state as we assess the state's decision to contract more capacity for future demand.

Reliable and accurate electricity demand projection helps discoms to plan power procurement in advance for the short-term (one month to one-year period), medium-term (one to seven-year period), and long-term (more than a seven-year period) horizons. But overestimation of demand results in the undue burden of fixed charges in power procurement cost, ultimately leading to discoms charging higher consumer tariffs. In contrast, underestimation of demand results in power shortages, forcing discoms to resort to either load shedding or costly power purchase. In the short run, it may also result in system imbalances and applicable penalties.

The projection of energy requirement by UPPCL and its discoms forms the basis for long-term power procurement decisions, or approval of capacity addition plans by the state.

Figure 7 shows how the requirement was overestimated by the UPPCL and discoms. While the forecasted demand (with respect to the multi-year tariff planning and approvals) overshot by 30 per cent for FY 2018–19, it went 50 per cent overboard for FY 2019–20. This overestimation means discoms incur undue financial burden to honour contracts for procuring excessive capacity.

A whole-of-sector approach—combining long-term electricity demand forecast with power procurement options beyond contracting or commissioning new capacity—would not only help utilities economise their overall cost of power procurement but also alleviate supply risks, especially with the growing share of renewable energy sources.

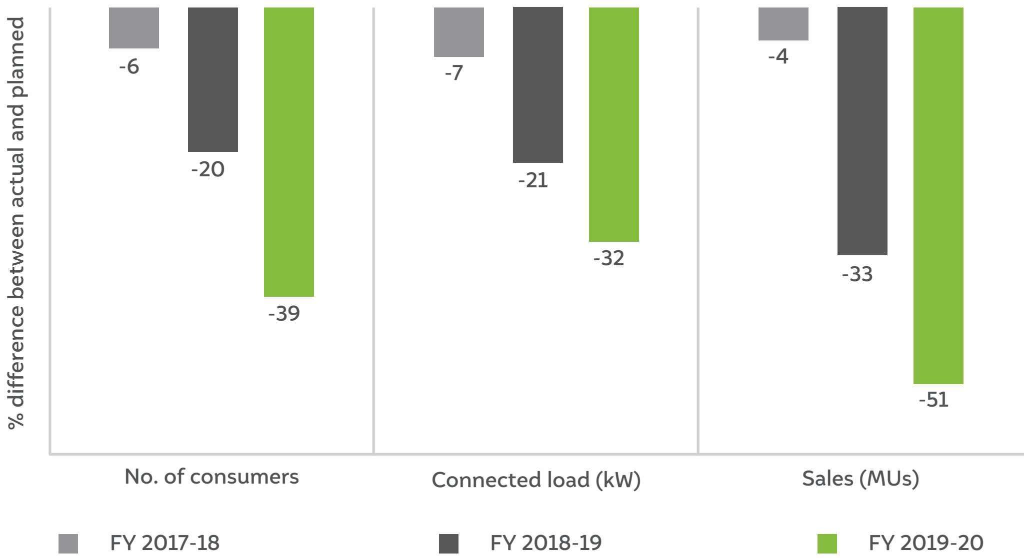


Figure 7
Overestimation of the energy requirement during the multi-year tariff period

Source: Adapted from UPERC tariff orders; UPPCL tariff filings, and UPSLDC

3.5 Capacity expansion plans

Plans for augmenting procurement are already in place in tune with the projected demand by the state. A total of 27,843 MW—comprising 11,999 MW of thermal, 1,594 MW of hydro, 1,250 MW of wind, and 13,000 MW of solar and other renewable sources—is likely to be contracted for long-term supply. Projects in the newly contracted capacity are in the planning or construction stage. At the same time, 1,325 MW of thermal capacity will be retired (UPERC, Uttar Pradesh Electricity Regulatory Commission 2019).

Figure 8 provides the share of thermal and hydro sources in the upcoming addition. Station-wise thermal and hydro capacity addition plan is provided in Annexure IV.

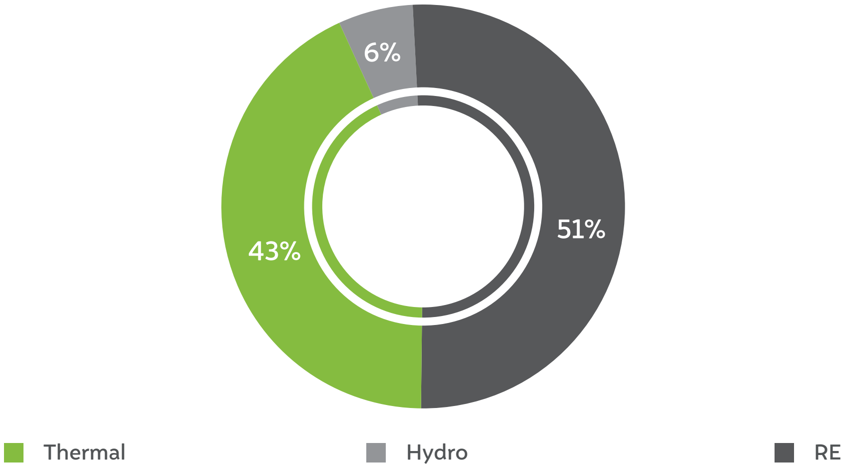


Figure 8
RE will dominate future capacity addition

Source: Adapted from UPERC order in petition no. 1478/2019 (approval of long-term procurement of UP discoms)

Figure 9 shows the expected commissioning of thermal and hydro capacity and

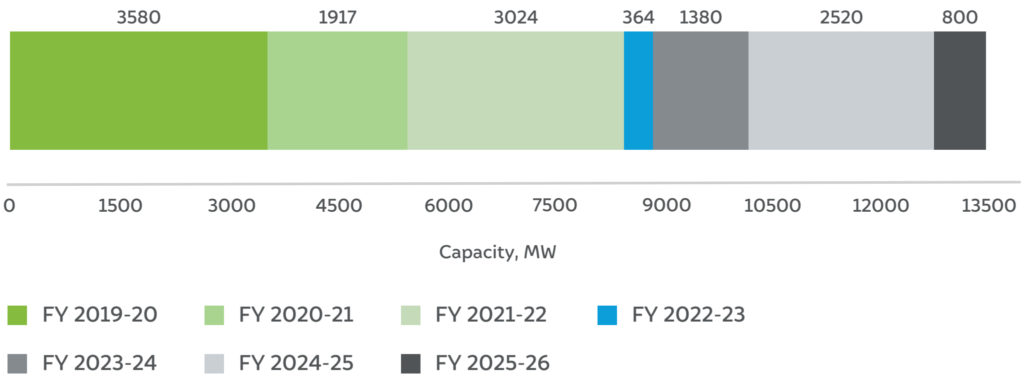


Figure 9
More than 60 per cent of planned capacity is expected to be commissioned by FY 2021–22

Source: Adapted from UPERC order in petition no. 1478/2019 (approval of long-term procurement of UP discoms)

Figure 10 provides the ownership share of the upcoming capacity. Much of the capacity will come on board in the near-term and will be driven by state-owned companies.

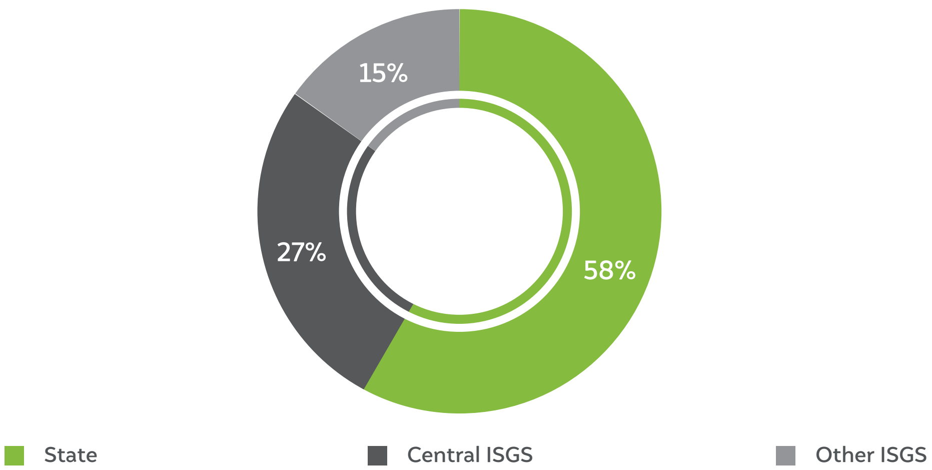
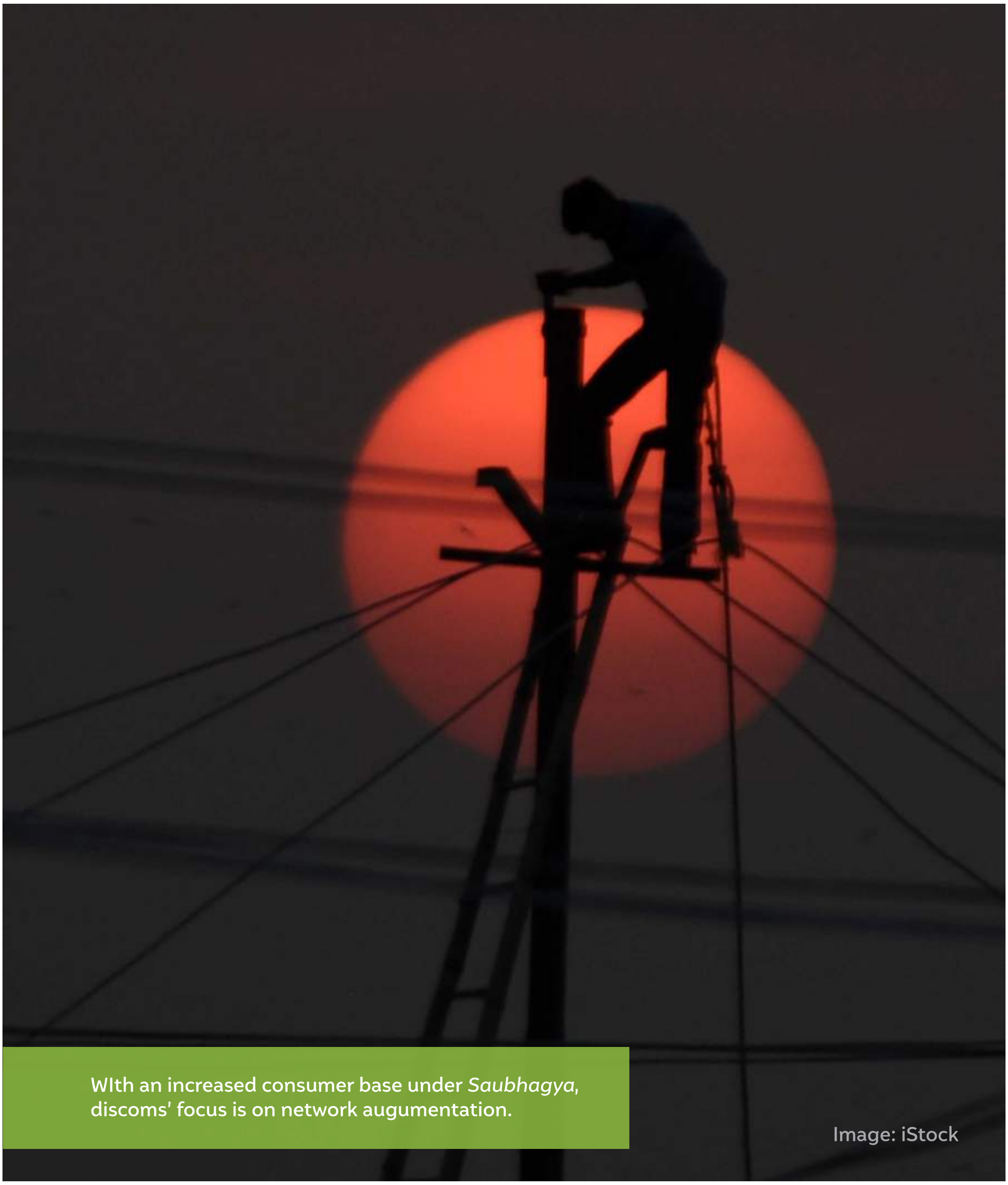


Figure 10
State ownership will drive the upcoming capacity addition

Source: Adapted from UPERC order in petition no. 1478/2019 (approval of long-term procurement of UP discoms)

4. Analysis and key findings



WIth an increased consumer base under *Saubhagya*, discoms' focus is on network augumentation.

Image: iStock

The central and state governments have initiated a number of schemes to improve the operational and financial health of discoms. The interventions range from financial restructuring (or bailout) (Ahluwalia Committee 2001, Central FRP Scheme 2012), to operations, infrastructure, and technology improvements (APDRP 2001, R-APDRP/IPDS 2008, DDUGJY & SAUBHAGYA 2014/2017, Smart Grid Pilot project & NSGM 2012-15), and structural reform (Electricity Act 2003). The overwhelming view among experts in the sector is that these efforts still have not helped sustain discom operations, despite small wins.

In the continuing efforts to streamline discoms, the government of India's UDAY scheme, launched in November 2015, marks the latest attempt to address the severe financial stress that discoms have been subjected to due to accumulation of debt. The focus of UDAY remained on improving the overall efficiency of discoms and their financial turnaround (Nirula 2019). UDAY identified a range of interventions to improve the financial status of discoms. How these interventions were sequenced, and weighing in on their political and economic consequences, is critical to evaluating UP's experience with the scheme. This section briefly looks at the pre- and post-UDAY scenarios.

4.1 Reviewing the progress of UDAY

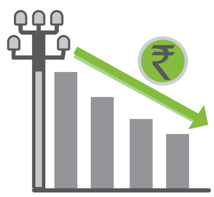
On reviewing the progress under the *UDAY* scheme, the rating agency CRISIL has pointed to limited gains from the scheme and a reversal in fiscal order of the power sector that portend alarming consequences for the state economy (Mishra 2019, Jai 2019, Quartz India 2019). UP also failed to capitalise on UDAY's ambitious plans.

Even after implementation of UDAY, discoms in UP still don't show any signs of achieving financial resurrection. Like many of the states, UP is set to miss the UDAY targets set for the end of the fiscal year (2019–20). Despite interventions made through UDAY, discoms in UP failed to make any headway from a reasonably low base of operational and financial efficiency. We look into the political economy of the state that has shaped and constrained UDAY outcomes in the state. "The sub-par" outcomes can be traced to misplaced priorities and a lack of institutional capacity and coordination.

4.1.1 What was UDAY meant for?

In September 2015, when UDAY was launched, accumulated debts of discoms in UP had touched INR 53,212 crore. To restore its discoms to good health, UP joined the scheme in January 2016. The scheme placed emphasis on financial and operational efficiencies to achieve a financial turnaround of discoms in a time-bound manner. To pursue this goal, the debt burden of discoms was substantially slashed, as state governments took over a larger part of the accumulated debts, as per UDAY's mandate.

However, after implementation of the scheme, states were to benefit from reduced cost of supply, which discoms could pass on to consumers by way of tariff reduction. High-figure net gains were also expected to be achieved. As better efficiencies would reduce the cost of supply, it was claimed, UDAY will make discoms financially and operationally healthy. Well-run discoms enable the governments to brighten and transform the lives of millions. Estimates for UP forecasted an overall net benefit of INR 33,000 crore by way of savings on interest cost, reduction in losses, energy efficiency, and coal reforms over four years of the scheme's run in UP (PIB 2016). Keeping with the standard prescriptions designed at the centre, UP's UDAY targets included the following:



UP discoms were mandated to bring down AT&C losses from 32.36% (2015–16) to 14.86% (2019–20)

- UP government to take over 75 per cent of discoms' accumulated debts over two years (50 per cent in FY 2015–16 and 25 per cent in FY 2016–17) to allow better fiscal space to discoms.
- Discoms to bring down AT&C losses from 32.36 per cent in 2015–16 to below 15 per cent (14.86 per cent) by 2019–20. The state government was made accountable for any gap in meeting the target and required to pay an increasing share of the gap starting from 2017–18.
- Discoms were required to achieve loss reduction through various technological

interventions like DT metering, feeder metering, rural feeder segregation, feeder level energy audit, and smart metres for targeted consumers.

- Discoms were asked to eliminate the gap between the average cost of supply and average revenue realised through timely tariff revisions.
- The scheme also stressed on state governments to push for compliance on renewable purchase obligation and promotion of energy efficiency (especially LED bulbs).

4.1.2 What has been the impact of the UDAY on the financial health of discoms?

In simple terms, in order to improve their financial viability, public discoms must increase their revenue and bring down expenses. Payments realised from consumers against the electricity bill constitute the revenue for discoms while expenses comprise electricity procurement costs and operating costs, including financing and overheads. Discoms operate in a highly regulated market and their ability to increase revenue is limited, as regulators face many challenges in price setting, which is only augmented by consumer segmentation. Since all utilities face this limitation, one way to improve performance is to minimise costs, including those associated with electricity procurement, overheads, and AT&C losses (CEEW-CEF analysis 2019).

Input for our analysis

- The cost of power purchase (for every unit of electricity supplied) is made up of the following:
  - Cost per unit of electricity purchased
  - Cost of energy loss (the difference in units purchased and those supplied)
- Overheads per unit of electricity supplied, including operational and management costs, employee costs, and other costs
- The cost of finance per unit of electricity supplied, comprising interest and other costs towards loans, and the interest towards deposits by consumers and others
- Costs towards depreciation of assets deployed per unit of electricity supplied

We used trued-up and audited data for FY 2015–16 to FY 2017–18. We analysed the revenue generated by discoms and the costs associated with the electricity supplied during the period FY 2015–16 (pre-UDAY) to FY 2017–18 (mid-UDAY). We see that the two accounts—trued-up and audited—provide a different position of the discoms on various parameters, and it is necessary to reconcile the differences. Table 2 provides an insight into the impact of UDAY scheme on various parameters.

Particulars	Trued-up accounts (INR/kWh)			Audited accounts (INR/kWh)		
	FY 2015 -16	FY 2016 -17	FY 2017 -18	FY 2015 -16	FY 2016 -17	FY 2017 -18
Revenue per unit sold	6.91	6.98	5.93	6.31	6.13	5.93
Average cost of power purchase (include transmission charges)	4.11	4.09	3.91	4.16	4.12	4.02
Spread between sales price and cost of power purchase	2.80	2.89	2.02	2.16	2.00	1.91
Cost of energy loss	1.48	1.53	1.43	1.49	1.54	1.47
Gross margin per unit sold	**1.33**	**1.36**	**0.60**	**0.66**	**0.46**	**0.44**
Overhead cost per unit sold	0.49	0.45	0.47	0.57	0.58	0.63
Cost of finance per unit of electricity sold	0.24	0.27	0.24	0.92	0.35	0.48
D&A cost per unit sold	0.27	0.25	0.14	0.10	0.10	0.14
Net margin per unit of sales	**0.32**	**0.39**	**-0.24**	**-0.93**	**-0.56**	**-0.82**

Table 2
Trued-up account paints a different picture in comparison to audited accounts

Source: Adapted from UPERC tariff orders and state discoms fillings

Note: Trued-up accounts refer to trued-up ARR tariff orders issued by UPERC and audited account have the general meaning as balance sheets

Observations:

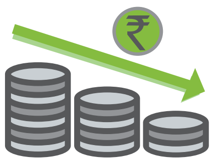
1. The trued-up accounts and the audited accounts provide a different picture of each parameter, pointing towards the need to establish a common source of information for evaluation of parameters.
   - As per the audited accounts, the cost of finance per unit sold has definitely decreased over the study period, which is unfortunately not corroborated by the trued-up accounts.
2. As per the audited accounts, the net margin on per unit sold has remained negative throughout the UDAY period. This clearly means that large financial losses still persist.

In the subsequent section, we delve into the reasons why the UDAY scheme could not bring about the intended change in the overall health of discoms.

4.1.3 Why UP could not achieve desired outcomes?

Political economy of the state has complicated the implementation

Since the early years of unbundling, the competitive multi-party political environment in the state has been intricately shaped by electoral priorities. Successive governments in the state have been keen to cater to demands for access, quality, and subsidies to build their electoral vote bank, often undermining economic rationales. Despite holding advantage of an early mover on electricity reforms and sustained planning, UP could not pursue any serious reforms in electricity distribution. The frequent succession of chief ministers and shifting political coalition often resulted in stalled reforms in the face of electoral fears (Balls 2018). The state's inability to manage demands for access and institutionalised subsidies opened up informal patterns of access and erosion of consumers' accountability to discoms, resulting in the wilful flouting of fundamental principles of electricity supply, viz. metering, billing, and collection. Ganesan, Bharadwaj, and Balani (2019) argue that indifference to proper metering,



Throughout the UDAY period, the net margin on per unit sold has remained negative, implying large financial losses.

billing, and collection in the state has not only dented discoms' finance but has also created a trust gap between the consumers and discoms.

In comparison to other states, UP has a much larger share (and number) of subsidised domestic and agricultural consumption, coupled with a small base of industrial and commercial consumption, which has constrained the fiscal space for discoms to pursue electricity-centred redistributive welfarism, i.e., cross-subsidise domestic and agriculture from business consumers. The limitations of a low-income state to provide subventions have equally contributed to the fiscal disarray of discoms. Organised demands for access and subsidies in the face of a shrunk fiscal space have placed UP's power sector in a vicious cycle. Table 3 provides a comparative view of the mix of domestic/agriculture and industrial/commercial sales across select states. Clearly, UP has a disadvantage on this account.

States	D & A (%)	I & C (%)
Bihar	73	27
Uttar Pradesh	70	30
Punjab	55	45
Madhya Pradesh	55	45
Andhra Pradesh	58	42

Table 3
Domestic/agriculture (D&A) consumer sales is twice than industrial/commercial (I&C) sales in Uttar Pradesh

Source: Authors' analysis from various state's electricity tariff orders

Disproportionate policy response and misplaced outcomes

Though UP signed the UDAY memorandum of understanding (MoU) within a few months of the scheme's launch, there was little progress in the implementation of the scheme for more than a year until a new government took charge in March 2017 following assembly elections. The delay could be partly explained by the past trend of rolling down reform implementation to successive governments (Balls 2018). Simultaneously, a lack of institutional clarity and coordination contributed to the slow start. The regulators, despite their oversight on tariff revision and ability to hold the discoms accountable for their financial and operational efficiencies, were neither consulted in setting the targets nor briefed on their responsibilities. Multi-layered institutional structure for electricity distribution—involving a holding company at the top and five discoms—created coordination challenges. As a result, designation of officers to monitor the progress was also delayed. The assembly elections in 2017 and subsequent change of government brought in political alignment between the state and the centre and created pressure for UDAY implementation.

Little success in addressing purchase cost

The poor fiscal position of discoms is further exacerbated by high power purchase costs, which amount to 75–85 per cent of the discom's total expenditure. The UP government deferred politically unpopular tariff rationalisation and cost recovery measures, instead prioritising supply-side cost reduction. To this end, UPPCL identified high-cost supply sources. Although the discoms could not successfully renegotiate PPAs with some expensive plants, they managed to cancel PPAs for a capacity of 7,040 MW slated to be been commissioned by 2021–22. Simultaneously, there is an emphasis on planning to reduce supply-side costs. UPPCL has commissioned studies to find ways for optimal use of its supply resources (Singh and Swain 2018).

Turning around operational performance

To improve operational efficiency, the discoms have invested in customer call centres, created alternative avenues for bill payment, including self-reading and online payment, and have initiated ways to raise consumer awareness on these avenues. Though UPPCL initiated a discussion on setting up key performance indicators for officers-in-charge and improved employee management, no concrete action has been taken so far. The technical interventions by discoms have yielded mixed results. While feeder level metering is complete for both urban and rural areas, DT metering has also been completed for urban areas. But rural DT metering remains as low as 8 per cent (UDAY Portal). While rural feeder audit has been completed, rural feeder segregation and smart metering are yet to be implemented.

UP government deferred politically unpopular tariff rationalisation and cost recovery measures, instead prioritised supply-side cost reduction

Moreover, the outcomes have not been encouraging. AT&C losses are reported to be higher (37.95 per cent in the quarter ending in June 2019) than the baseline (UDAY Portal). The persisting gap between average cost of supply and average revenue realised (INR 0.63/kWh) could be attributed to poor metering, billing, and collection, and as indicated by the cost (INR 1.47/kWh, for FY 2018) towards energy lost in the system. A bulk of the agricultural consumers are not metered. Most of the domestic consumers covered under the *Saubhagya* or other rural electrification drives are not yet regularised under the billing system, and it is only expected to happen gradually. Those consumers who have meters are not billed on time, leading to delay in receiving payment (Ganesan, Bharadwaj, and Balani 2019). Tariff is being revised regularly, keeping with the UDAY requirements, but those revisions do not reflect the inflation and actual cost to serve (Sharma, Moerenhout and Garg 2018).

The current utilisation of existing contracted capacity,[11] the financial implications of current procurement practices, and reasons for suboptimal practices are detailed in the next section.

4.2 Suboptimal scheduling and its costs

Large, centrally driven schemes such as UDAY, the Financial Restructuring Plan, and many others in the past have not brought about any significant change in the cost of supply for the discoms in UP. As discussed before, power purchase costs entail the single largest expenditure (ranging from 75 to 85 per cent) for the discoms. The high cost of power purchase has a significant impact on retail tariffs. Therefore, it becomes necessary to weed out inefficiencies in the procurement process to address the larger issue of revenue gap (the gap between average cost of supply and average revenue realisation) for the discoms.

4.2.1 Sources of long-term power procurement

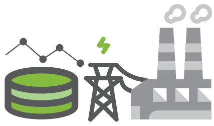
Discoms source their power requirement from a mix of long-term and short-term sources in order to meet consumer demand in the areas they supply power. The generating stations supplying to UP can be broadly categorised as follows:

a. Stations that are (more or less) 100 per cent allocated to UP's discoms are termed as 'state and state IPPs'.

b. Stations that are allocated to two or more states (including UP) are termed as 'central ISGS and other ISGS'.

11. We limit this to those generating stations which are entirely allocated to UP as the operations of shared stations (central government and some private IPPs) cannot solely be dictated by the needs of the state alone.

State and state IPP stations: State generating stations are commissioned and run by a state government agency and state IPPs are owned by private players/owners; in most cases, they supply only to discoms within the state. In UP, generating stations owned by UPRVUNL (wholly state government–owned thermal power utility) and UPJVNL (wholly state government–owned hydro power utility) come under state ownership, whereas generating stations (or the privately owned generation stations) such as Prayagraj Power Generation Company Limited (1,980 MW), Rosa thermal power plant (1,200 MW), Lalitpur Power Generation Company Limited (1,980 MW), Bajaj Energy Limited (450 MW) are state IPPs; depending on their size and PPAs, they could supply to multiple states in some cases.



Discoms need to weed out inefficiencies in the procurement process to address revenue gaps

Central ISGS and other ISGS: Central ISGS are the generating stations that are commissioned and run by a centre government agency and whereas other ISGS are owned and operated by private players. In most cases, these stations supply to multiple states. Central ISGS are owned by the public sector undertakings (PSUs) of the central government—for example, the National Thermal Power Corporation (NTPC) and National Hydroelectric Power Corporation (NHPC). They supply power to two or more states, depending upon how the government allocates their supply of power. Other ISGS such as Sasan ultra mega power project (3,960 MW), KSK Mahanandi power plant (3,600 MW), and MB Power (1,200 MW) supply to two or more states.

4.2.2 Optimisation of procurement among state plants

Share of the State and Centre in Uttar Pradesh's power procurement

Over the last four years, state and state IPP together contributed to more than half of the total contracted capacity, total procurement mix, and the total procurement expenditure incurred by the discoms. Figure 11 details the central and state share in the power procurement mix.

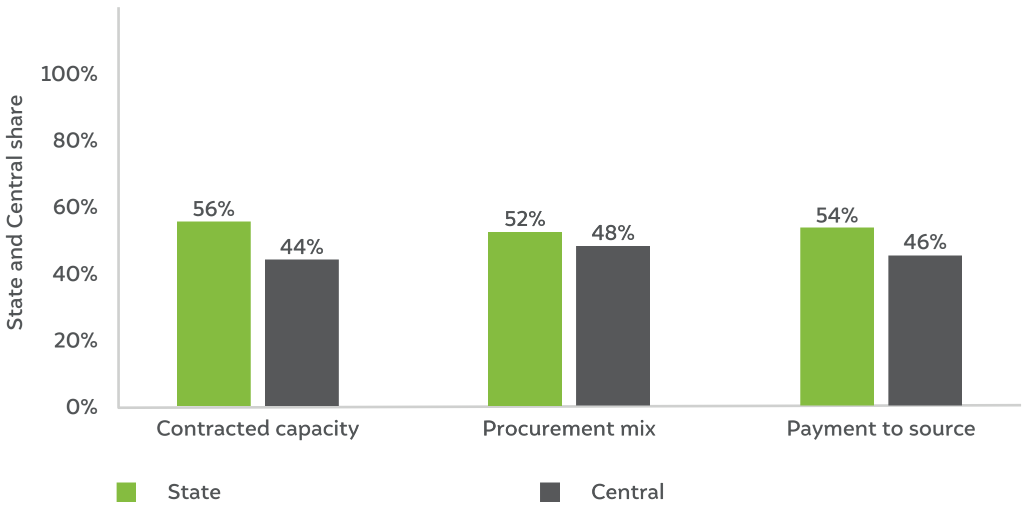


Figure 11
State-based plants contribute 50 per cent of the procurement mix in FY 2018–19

Source: Adapted from UPERC tariff orders; UPPCL tariff filings, merit portal and UPSLDC

Note: State means state and state IPP; central means central ISGS and other ISGS

What determines efficiency?

Power purchase agreements with generating stations entail a two-part cost: (i) fixed cost (based on the availability of stations) and (ii) variable cost (based on usage/procurement from the stations). Contractually, fixed cost payments have to be made by discoms commensurate with their availability and irrespective of the actual utilisation of the generated power. Therefore, any decision on cost optimisation of power purchase has to be based on variable costs.

Figure 12 highlights the variable cost associated with the different types of generating stations. The larger the bubble size, the larger is the share in the overall procurement mix. State and State IPP stations represent the cheapest and the costliest variable cost-based stations, respectively.

Figure 12
State IPPs costliest and central ISGS the largest provider of electricity

Source: Authors' adaption from UPERC tariff orders; UPPCL tariff filings, merit portal and UPSLDC

State plants accounted for one-third of power procurement over the last four financial years. Further, the contribution from other ISGS has increased at the cost of central ISGS, and this represents a move to a lower cost base (Figure 13).

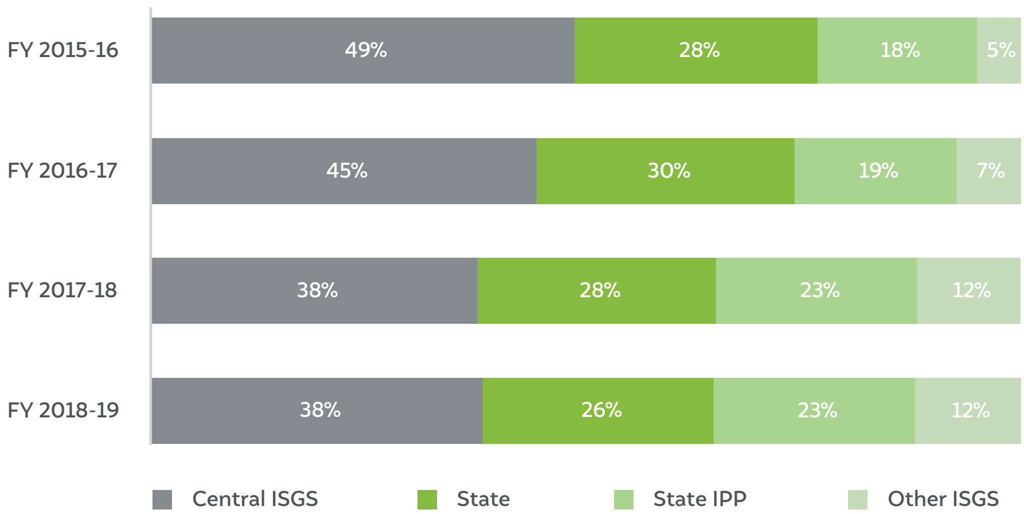


Figure 13
Procurement from central ISGS stations have been decreasing over the years

Source: Authors' adaption from UPERC tariff orders; UPPCL tariff filings, merit portal and UPSLDC

Procurement from central ISGS and other ISGS stations have limited flexibility, in terms of their operation and scheduling as they are directly controlled by National Load Dispatch Centre (NLDC) or other regional load dispatch centres (RLDCs) as appropriate. The demand and allocation of other buyers also determine their level of flexibility. Hydro power stations, even those within the state, have planning and scheduling constraints due to their seasonal variability. Hence, they are dealt with in real time based on their availability. Therefore, for the purpose of the analysis, only state-owned thermal generating stations and state-based thermal IPP (as they are almost entirely allocated to the state and can be controlled by a state agency) have been considered in the analysis. We focus on plant utilisation levels and overall procurement efficiency and how different types of power plants are suited to provide electricity in a more optimal mix. The thermal-based state and state IPP contribute to more 40–50 per cent of the annual energy supply, and this analysis provides a lower bound for potential savings by requisitioning power from the cheapest sources.

Power procurement cost is optimised by utilising low-cost generating stations to their fullest potential

One way to optimise power procurement cost is by utilising low-cost generating stations to their fullest potential, thereby reducing the quantity of power to be purchased from stations that are more expensive and de facto lower in the merit order. We start with the Business as Usual (BAU) procurement operation (as it panned out) for FY 2016–17 to FY 2018–19 from state and state IPPs, and iterate through to lower cost stations by achieving target PLFs. We consider the variable cost parameter, daily generation, daily coal availability and other stated technical/operational constraints that prevent plants from achieving design PLFs.

It is worth reiterating some of our assumptions and the steps involved in this 'greedy optimisation' process:

- The plants have been sorted based on the variable cost of electricity supply. Variable costs are mostly available at the plant level and sometimes at the unit level.
- PLF optimisation targets and auxiliary consumption have been set based on the combination of the daily generation data from CEA, the generators' tariff filings, and the past performance and availability of plants (for more details refer to Annexure II).
- Unit-wise modelling based on monthly procurement data from FY 2016–17 to FY 2018–19.

In this iterative exercise, we maintain the constraints mentioned above and shift generation on a daily time-step to cheaper plants that have un-requisitioned surplus. We estimate that discoms could have achieved potential savings of about INR 843 crore, INR 1,029 crore, and INR 918 crore in FY 2018–19, FY 2017–18, and FY 2016–17 respectively. The high-demand period requires power procurement from the majority of the plants, and a result, the savings achieved then, are lower than in other months – consistently across the three years (refer Annexure III). The system-wide potential savings are shown in Table 4, whereas station-wise payout details are provided in Table 5.

Period	Actual procuremnet (INR crores)	Reallocation scenario (INR crores)	Potential saving (INR crores)
FY 2018-19	11,859	11,016	843
FY 2017-18	13,516	12,487	1,029
FY 2016-17	11,815	10,897	918

Table 4
Potential saving in excess of INR 800 crore each year

Source: Authors' analysis

Note: Annualised PLFs for optimal allocation has been shown at Annexure II

Table 5 Station-wise actual and reallocation cost modelling

Plant name	Ownership	Variable cost (INR/kWh)	Procurement cost in FY 2018-19 (INR crore)		Procurement cost in FY 2017-18 (INR crore)		Procurement cost in FY 2016-17 (INR crore)	
			Actual cost	Reallocation cost	Actual cost	Reallocation cost	Actual cost	Reallocation cost
Anpara-B	State	1.52	1057.12	1119.9	973.25	1119.9	1062.87	1057.12
Anpara-D	State	1.53	1159.96	1121.32	776.35	1121.32	590.79	1119.9
Anpara-A	State	1.63	643.06	730.64	597.4	730.64	501.67	1121.32
Obra-B	State	1.73	569.63	647.87	703.57	647.87	561.94	730.64
Lanco	State IPP	1.85	1306.72	1479.63	1353.21	1479.63	1378.4	647.87
Prayagraj Power	State IPP	2.39	1696.82	3039.64	1215.84	2103.95	976.47	1479.63
Rosa-1	State IPP	2.83	1140.27	1545.83	2025.27	2269.56	2128.5	1051.98
Lalitpur	State IPP	3.15	1628.57	1298.92	2554.77	2819.32	1043.79	2204.28
Parichha Ext.	State	3.2	580.76	32.19	833	128.1	754.8	2187.91
Parichha Ext. Stage- II	State	3.21	817.76	0	973.32	66.8	910.33	280.36
Harduaganj Ext.	State	3.25	865.01	0	1067.12	0	995.29	72.99
Parichha	State	3.35	49.47	0	61.08	0	136.92	0
Harduaganj	State	3.39	70.82	0	76.22	0	155.38	0
BEPL[12] Kundrakhi	State IPP	3.46	64.33	0	60.6	0	146.07	0
BEPL Utraula	State IPP	3.51	62.73	0	6165	0	132.69	0
BEPL Maqsoodapur	State IPP	3.7	47.49	0	56.55	0	141.22	0
BEPL Barkhera	State IPP	3.71	50.57	0	64.55	0	68.47	0
BEPL Khambhakhera	State IPP	3.76	48.32	0	62.4	0	129.25	0
Total			**11859.41**	**11015.94**	**13516.17**	**12487.09**	**11814.84**	**10896.88**
Difference in Actual and Reallocation cost				**843.47**		**1029.08**		**917.97**

Source: Authors' analysis
[$]The authors recognise the stabilisation issue with the Prayagraj power plant in the years 2016 and 2017. However, to simulate the optimum scenario, benchmark PLFs have been considered. A combination of financial and operational factors resulted in the plant not being able to source the amounts of coal it needed

12. BEPL – Bajaj Energy Private Limited

Some corollaries from this reallocation

To begin with, we investigate the relationship between reported fuel cost[13] and variable cost of generation. We find a near perfect correlation between these two parameters. Further, we also find that there is no significant relationship between reported station heat rates and the age of the power plants itself. Therefore, the cost of electricity generation is almost entirely determined by the price of fuel, and the efficiency of operation has no bearing on the costs itself. This is quite confounding, as it suggests that in the limited mix of plants considered, plant efficiency, of which age is a proxy—as newer plants likely to be more efficient—is not a determinant of variable costs. This points to spurious data on heat rates being reported and age itself not being a marker for plant's[14] operation efficiency (refer to Annexure VII).

We find that in FY 2018-19, if power generation would have been reallocated to the lower-cost stations, this would have resulted in a decreased coal requirement of ~ 0.4 MT, as some of these plants have higher efficiencies and are able to deliver more energy with less coal (refer Annexure VI for daily coal requirement of UP plants).

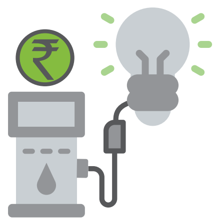
What could be explain the suboptimal dispatch?

The question that merits an answer at this point is: why do the most cost-effective stations not generate as much electricity as possible in the first place? Some plausible factors can explain why:

a. **Poor planning of plant operation:** It is possible that plants that were expensive were requisitioned in the final schedules, in contravention to the MOD, on account of poor operations planning and communication to plants. This in turn, could be a result of the preferential operation of state IPPs, extending to even the more expensive ones, as the payment terms for these stations are more flexible. Our interactions with the SLDC suggest that this was not the case, barring occasions when there are operational constraints at specific plants.

b. **Coal availability at various facilities:** As is clear, this optimal scenario assumes that all plants had adequate coal to generate power at the desired PLFs. Prayagraj, for instance, would be able to achieve the high levels of generation envisaged in the scenario, only if more coal is allocated.

   Despite having adequate coal linkages, plants have been running out of stock more often (Sreenivas and Vembadi 2019). Our analysis determined that in FY 2018–19 alone, the loss of generation attributed to coal short age is 1,647 MU, only accounting for the days when the coal stock was listed as critically low. Table 6 shows that Prayagraj Power, one of the biggest power stations in UP, has been running short of coal for a quarter of the year, specifically during the high-demand summer months. Annexure V shows the status of monthly coal availability in state and state IPPs. It can be seen that during the same summer months while Prayagraj is low on stock, Obra Thermal Power Station (a high-cost source) enjoys a coal stock of more than 50 days. This is where UPPCL needs



The cost of electricity generation is almost entirely determined by the price of fuel

13. We standardise fuel cost to INR/Mcal(refer Annexure VI), given the variability in calorific value (kcal/kg) and the price of coal (INR/kg).
14. It is also possible that the unit-level characteristics are not reflected in plant-level aggregation.

to step in for the reallocation of coal stocks between state and state IPPs in such a way that sufficient coal availability in low-cost generating stations is ensured. There are contractual and legal implications to this transfer, but these options must be explored to ensure the system as a whole benefit from lower cost power. Also, more generally, in order to achieve the targeted maximum PLFs, the coal stock in the plants need to be increased accordingly since the current coal requirement is calculated based on the average PLF of the last seven days or at 55 per cent PLF. The optimal scheduling proposed here will rely on coal availability at the plants to allow for such operation.

c. **Transmission constraints:** We find that this is an unlikely reason for the suboptimal operation. While there is no information available (in the public domain) on specific transmission lines and their utilisation, we look for data to support the premise that concurrent operation of the stations at the desired PLFs is plausible and has occurred. With the exception of Prayagraj, which has consistently been plagued by coal availability and also stabilisation issues, we find that on numerous instances in the peak demand period, the plants have operated simultaneously (when analysed using average daily PLFs) at high loads. This clearly shows that a physical network constraint should not be deterrent to derive the most out of each plant, on other days of the year. It is unlikely then that MOD-based procurement was not possible on account of transmission constraints. Our conversations with technical staff in the UPSLDC and the UPERC reveal that there is some need to operate high-cost generation that is closer to load centres for voltage support. Again, the extent of this need is unlikely to change the overall opportunity that exists in making generation cheaper.

Table 6
Generation shortage due to lack of coal stock

Station	Variable cost (INR/kWh)	Shortage period in FY 2018-19	Actual generation during the shortage period (MU)	Possible generation during the shortage period (MU)	Difference (MU)
Anpara C TPS [15]	1.85	October	8	85	77
Prayagraj TPP	2.39	April to June	7	865	858
Rosa TPP Ph-I	2.83	July to August	6	225	219
Lalitpur TPS	3.15	January	10	281	271
Lalitpur TPS	3.15	May to July	12	168	157
Maqsoodapur TPS	3.70	Oct to Nov	1	31	30
Khambarkhera TPS	3.71	Oct to Nov	3	40	37
Total			**47**	**1695**	**1647**

Source: Authors' analysis

Note: Shortage period doesn't refer to the entire month. It only refers to the days when the coal stock was critically low.

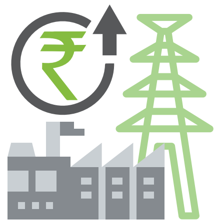
15. TPS and TPP means Thermal Power Station and Thermal Power Plant

4.3 Capacity charges: a significant burden on the discoms

Similar to a few other states, there is a significant difference between the peak and average load in UP. The peak summer load approaches 22,500 MW, whereas the average is around 13,000 MW. In the low-demand period, discoms typically resort to backing down thermal assets. The backdown of capacity in states is in the range of 15–30 per cent of the contracted capacity (Josey, Mandal and Dixit 2017). However, discoms still have to pay fixed charges to contracted generators just for availability. Given that discoms are meeting their 80–90 per cent of power requirement through long-term PPA, they have to still spend on fixed charges for lean months (three to five months in a year) without requisitioning some of the generators. Over the last three years (FY 2016–17 to FY 2018–19), the fixed cost burden on account of low utilisation of just three IPPs (Rosa, Lalitpur and, Bajaj Energy) was to the tune of INR 1,800–3,000 crore (UPERC, Uttar Pradesh Electricity Regulatory Commission 2019). This represents nearly 6 per cent of the total cost of power procurement for the state.

Capacity payments will remain a persistent problem

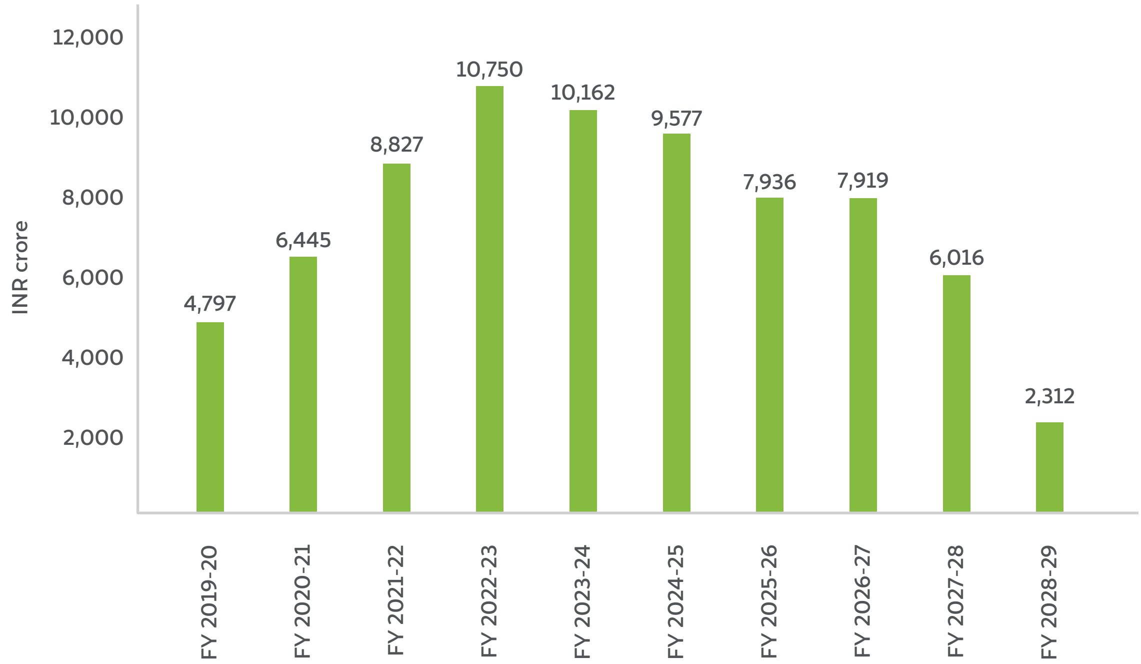
Many of the existing PPAs do not necessarily reflect the best available price (even when they were signed) and certainly do not make economic sense, given the stock of efficient and lower cost thermal generation assets. The power purchase cost (inclusive of inter-state transmission charges and losses) for FY 2018–19 (INR 4.62/kWh) and FY 2019–20 (INR 4.66/kWh) is a reflection of the way current high-cost PPAs are structured and the rigidity they impose on procurement.



The burden of stranded capacity charges due to upcoming addition of plants is expected to peak at INR 10,750 crore in FY 2022–23

The problem of under-utilisation of existing thermal capacity is already huge. The burden of stranded capacity charges due to upcoming addition is projected to be around INR 4,797 crore during FY 2019–20 and is expected to peak at INR 10,750 crore in FY 2022–23 (UPERC, Uttar Pradesh Electricity Regulatory Commission 2019). The upcoming thermal and hydro capacity addition plan is provided as Annexure IV. Stranded capacity charges due to upcoming capacity are depicted in, Figure 14. Despite the regulator acknowledging the level of stranded capacity that is likely to be contracted, approval has been granted for it. This indeed needs to be fixed before these assets are financed and constructed. Going forward, to reduce the capacity charges burden, UPPCL could emphasise on capabilities and not simply capacity (MW) while entering into new procurement contracts and attempt to address peak demand over a shorter window, albeit at a higher price.

Figure 14 Stranded capacity charges will be highest in FY 2022–23



Source: Authors' adaption from UPPCL filings

Our analysis further points out that an additional future demand of 20,000 MU can be met from the existing state and state IPP sources, provided the generation assets are utilised at the optimum levels.

Correspondingly, the burden of stranded capacity charge could be reduced or avoided. However, in order to fully evaluate their ability to satisfy upcoming demand, discoms need to gain a good understanding of daily demand patterns, especially at a consumer category level. Moving demand peaks and aligning them with the availability of assets assumes critical importance.

Evidently, any effort towards the reduction of power purchase cost would have a significant impact on the retail supply tariff charged by discoms. The cost of power procurement is highly dependent on the power procurement portfolio, which means that its optimisation would, in turn, lead to the reduction in power purchase cost, hence retail tariff (Singh et al. 2019).

5. Conclusions and way forward

Stranded capacity charges is the elephant in the room.
It is expected to peak at INR 10,750 crore in FY 2022–23

Image: iStock

The UDAY scheme has infused some urgency in creating much needed infrastructure. However, the political economy of managing subsidies and enforcing the accountability of those managing the distribution system are still mired in existing inefficient settings that have their roots in the past. So there has been little change in the way the consumers engage with the discom and mistrust persists, resulting in poor levels of payments for discom services. The skewed sale share of low-paying consumers hurts the discoms. The AT&C losses in the state are showing no signs of dropping to the levels committed in the first MYT or in the UDAY MoU. It is necessary to develop a robust billing and collection mechanism to recover the cost of supply when cross-subsidising consumers have a low base and, more importantly, to cultivate commercial and industrial segments in the long run. What must we prioritise as we attempt to bring a semblance of solvency to the discom's operations? Who must be the drivers of change in these processes we have identified?

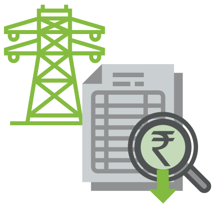
Regulator to ensure transparent detailing of discom performance

In analysing the financial impact of the scheme, we find large variations between what is reported to the regulator (in true-up filings) and that reported through audited books, which is relied upon by financing agencies. The audited books for FY 2016-17 suggest that on each unit being sold, the state has lost more than 56 paise while the trued-up order released by the regulator reveals that the discom has a net positive margin on each unit sold. Undisbursed additional subsidies requested by discoms from the UP government, play an important role in determining the financial health of discoms. This clearly calls for a more transparent exposition of costs involved in the operation of a discom and for regulators to recognise costs and losses appropriately. Capping any of these items in their orders only masks the underlying inefficiency and this then gets reported directly in the national level reporting, as discoms having met the targets under UDAY or any reform scheme.

UPERC, UPPCL, and GoUP working together to jointly reduce power purchase cost

Given the tremendous challenges with augmenting revenue, the default option for the discom is cost reduction. Nearly 80 per cent of the total cost of supply consists of power procurement. UP is saddled with expensive generation—in absolute terms even more so given its overall economic status and lower incomes as compared to some of the more developed states. There are two possibilities to cut back on costs.

The first relates to what can be done with new capacity—what the state is obligated to pay as per contracts with generators and how it can be prudently approached in new contracts.



The audited books suggest that on each unit being sold, the discoms have lost more than 80 paise in recent years

We find that the discoms of Uttar Pradesh are paying nearly six per cent (INR 3,000 crore) of their total cost of procurement just as fixed charges to three recently contracted generation companies, but their utilisation is very poor. This is indeed a significant loss. We also understand that the regulator has approved new capacity procurement over the next decade that will spike up the total 'stranded' fixed cost payments to more than INR 10,000 crore by FY 2022-23. Many of these assets, which are in the planning or pre-construction phase must be rethought as their financial viability upon commissioning will be doubtful. In addition, for the short-term, there is an unutilised generation of more nearly 20,000 MU that the currently contracted plants can provide each year, which discoms can utilise after levelling the load curve in UP, thereby finding a balance between demand seasons. Given the overall surfeit of power and imbalances in demand across the country, it would be prudent to take advantage of other resources before contracting or commissioning new capacity. A full cost–benefit analysis of alternatives becomes absolutely essential before such long-term decisions are made. Thus far these options have not been presented, though in most recent MYT regulations that the state has published, such justifications before procuring power are mandatory by way of a business case.

The second and perhaps the easier target is getting the cheapest generators, from among the plants currently contracted, to provide electricity at the most optimum levels consistently and addressing barriers that prevent them from doing so today. Our study finds that there was an opportunity to save nearly INR 900 crore in each of the last three years by simply following the MOD. The reasons for deviating from MOD are a result of poor coal availability at some low-cost generating stations, poor operational scheduling, and perhaps an inherent preference to have state-owned generators dispatch on account of flexible payment terms.

As the country, including UP, prepares for market-based economic dispatch, it is important to get first principles right in the limited set of plants that are entirely under the control of the SLDC. The state must improve control systems, communication and maintenance practices that allow for as many high-cost and old stations to be backed-down (shutdown, if needed) as often as possible.

GoUP, UPRUVNL, and UPPCL can rationalise coal availability and prices

An important step that could be considered, is the reallocation of coal between the various plants that the state procures from to ensure the most efficient plants are generating as much as technically possible. This will address the issue of non-performing assets and potentially free up high variable O&M expenses that older state-owned stations incur. We observe that the variable cost does not capture the thermal efficiency of power plants. The variable cost is almost entirely a function of the delivered cost of coal and reporting on station heat rates is spurious and unreliable. A true market-based mechanism must ensure that the distortions around the delivered price of energy are removed, and the most efficient plants are allowed to generate at optimum capacity at all times.

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Annexure I:

Table 7: Contracted capacity in UP along with plant characteristics

S. no.	Plant Name	Firm-contracted capacity (MW)	Types of generating station	Owner of station
1	Anta (GPS)	91	Gas	Central ISGS
2	Anta (LF)	113	-	-
3	Anta (RF)	113	-	-
4	Auraiya (GPS)	113	Gas	Central ISGS
5	Auraiya (LF)	234	-	-
6	Auraiya (RF)	234	-	-
7	Alaknanda HEP	287	Hydro	State
8	Anpara A	567	Thermal	State
9	Anpara B	900	Thermal	State
10	Anpara D	900	Thermal	State
11	BEPL, Barkhera	82	Thermal	State IPP
12	BEPL, Khambharkhera	82	Thermal	State IPP
13	BEPL, Kundarkhi	82	Thermal	State IPP
14	BEPL, Maqsoodpur	82	Thermal	State IPP
15	BEPL, Utraula	82	Thermal	State IPP
16	BARA (Prayagraj Power)	1648	Thermal	State IPP
17	Chamera I	109	Hydro	Central ISGS
18	Chamera II	62	Hydro	Central ISGS
19	Chamera III	47	Hydro	Central ISGS
20	Dadri (GPS)	246	Gas	Central ISGS
21	Dadri (LF)	262	-	-
22	Dadri (RF)	262	-	-
23	Dadri I	84	Thermal	Central ISGS
24	Dadri II	98	Thermal	Central ISGS
25	Dhauli Ganga	56	Hydro	Central ISGS
26	Dulhasti	85	Hydro	Central ISGS
27	Farakka	33	Thermal	Central ISGS
28	Harduaganj	94	Thermal	State
29	Harduaganj Ext.	405	Thermal	State
30	Jhanor GPS	0.03	Gas	Central ISGS
31	Jhanor GPS (NAPM)	0.03	Gas	Central ISGS
32	Jhanor GPS (LNG)	0.03	Gas	Central ISGS

S. no.	Plant Name	Firm-contracted capacity (MW)	Types of generating station	Owner of station
33	Jhajjar	28	Thermal	Central ISGS
34	Kahalgoan I	77	Thermal	Central ISGS
35	Kahalgoan II	251	Thermal	Central ISGS
36	KAPP		Thermal	Central ISGS
37	Koldam (NTPC)	204	Hydro	Central ISGS
38	Korba I & II STPS	3.19	Thermal	Central ISGS
39	Korba III STPS	1.56	Thermal	Central ISGS
40	Kawas GPS	0.03	Gas	Central ISGS
41	Kawas GPS (NAPM)	0.03	Gas	Central ISGS
42	Kawas GPS (LNG)	0.03	Gas	Central ISGS
43	Khara HEP	70	Hydro	State
44	Kishanganga	138	Hydro	Central ISGS
45	Karcham W.	200	Hydro	Other ISGS
46	KSK Mahanandi	1000	Thermal	Other ISGS
47	Koteshwar	155	Hydro	Central ISGS
48	Lanco (Anpara C)	1017	Thermal	State IPP
49	Lalitpur Power	1866	Thermal	State IPP
50	Mauda I GPS	3.11	Thermal	Central ISGS
51	Mauda II GPS	4.11	Thermal	Central ISGS
52	Matatila	30	Hydro	State
53	MB Power	343	Thermal	Other ISGS
54	NAPP	138	Nuclear	Central ISGS
55	Nathpa Jhakri	221	Hydro	Central ISGS
56	Obra Hyrdo	90	Hydro	State
57	Obra B	900	Thermal	State
58	Parichha	198	Thermal	State
59	Parichha Ext.	378	Thermal	State
60	Parichha Ext. Stage II	405	Thermal	State
61	Parbati III	105	Hydro	Central ISGS
62	Rihand I	326	Thermal	Central ISGS
63	Rihand II	296	Thermal	Central ISGS
64	Rihand III	340	Thermal	Central ISGS
65	RKM Powergen	350	Thermal	Other ISGS

S. no.	Plant Name	Firm-contracted capacity (MW)	Types of generating station	Owner of station
66	Rapp B	66	Nuclear	Central ISGS
67	Rapp C	86	Nuclear	Central ISGS
68	Rampur	57	Hydro	Central ISGS
69	Rihand Hydro (Pipri)	250	Hydro	State
70	Rosa	1092	Thermal	State IPP
71	Singrauli	754	Thermal	Central ISGS
72	Singrauli SHPS	10	Hydro	State
73	Solapur TPS	2.05	Thermal	Central ISGS
74	Sipat I	6.16	Thermal	Central ISGS
75	Sipat II STPS	2.08	Thermal	Central ISGS
76	Salal I and II	48	Hydro	Central ISGS
77	Sewa II	27	Hydro	Central ISGS
78	Sasan	500	Thermal	Other ISGS
79	Tanda	440	Thermal	Central ISGS
80	Tanakpur	21	Hydro	Central ISGS
81	Tala	45	Hydro	Central ISGS
82	Teesta III	176	Hydro	Other ISGS
83	TRN Energy	390	Thermal	Other ISGS
84	TAPP 3 and 4	4.05	Nuclear	Central ISGS
85	TEHRI	374	Hydro	Central ISGS
86	Unchahar I	63	Thermal	Central ISGS
87	Unchahar II	250	Thermal	Central ISGS
88	Unchahar III	129	Thermal	Central ISGS
89	Unchahar IV	243	Thermal	Central ISGS
90	Uri I	96	Hydro	Central ISGS
91	Uri II	51	Hydro	Central ISGS
92	Vindyachal I STPS	2.91	Thermal	Central ISGS
93	Vindyachal II STPS	2.19	Thermal	Central ISGS
94	Vindyachal III STPS	2.19	Thermal	Central ISGS
95	Vindyachal IV STPS	3.11	Thermal	Central ISGS
96	Vindyachal V STPS	1.56	Thermal	Central ISGS
97	Vishnuprayag HEP	348	Hydro	State IPP
98	UGC	13.7	Hydro	State

S. no.	Plant Name	Firm-contracted capacity (MW)	Types of generating station	Owner of station
99	Sheetla	3.6	Hydro	State
100	Belka	6	Hydro	State
101	Babail	6	Hydro	State
	Total	22,156.45		

Source: Authors' compilation from UPERC, UPPCL & CEA data

Annexure II:

Table 8: Targeted and actual annualised PLFs for an optimal allocation in FY 2016–17, FY 2017–18, and FY 2018–19

Plant name	Ownership	Variable cost (INR/kWh)	Fixed cost (INR/kWh)	FY 2018-19		FY 2017-18		FY 2016-17		Benchmark PLF (%)
				Actual annual PLF %	Targeted annual PLF %	Actual annual PLF %	Targeted annual PLF %	Actual annual PLF %	Targeted annual PLF %	
Anpara B	State	1.52	0.44	87	90	78	90	86	90	90
Anpara D	State	1.53	1.55	90	90	55	90	45	90	90
Anpara A	State	1.63	0.71	81	90	74	90	63	90	90
Obra B	State	1.73	0.67	69	80	48	80	43	80	80
Lanco	State IPP	1.85	0.91	78	85	76	85	79	85	85
Prayagraj Power	State IPP	2.39	1.42	45	80	46	85	75	85	85
Rosa 1	State IPP	2.83	1.56	41	57	72	85	75	81	85
Lalitpur	State IPP	3.15	2.24	31	26	47	56	34	66	85
Parichha Ext.	State	3.20	1.25	55	3	75	12	69	26	85
Parichha Ext. Stage II	State	3.21	1.47	64		72	5	68	6	85
Harduaganj Ext.	State	3.25	1.57	67		78		75		85
Parichha	State	3.35	1	19		16		25		70
Harduaganj	State	3.39	1.48	25		20		34		35
BEPL Kundrakhi	State IPP	3.46	1.84	26		26		58		85
BEPL Utraula	State IPP	3.51	1.89	25		26		52		85
BEPL Maqsoodapur	State IPP	3.70	1.83	18		23		53		85
BEPL Barkhera	State IPP	3.71	1.83	19		25		50		85
BEPL Khambhakhera	State IPP	3.76	1.85	18		24		47		85

Source: Authors' analysis

Annexure III:

Table 9: Month-wise savings achieved out of the re-allocation exercise in FY 2016–17, FY 2017–18, and FY 2018–19

Months	FY 2018–19 (INR crore)			FY 2017–18 (INR crore)			FY 2016–17 (INR crore)		
	Actual	Target	Savings	Actual	Target	Savings	Actual	Target	Savings
April	1,164	1,074	90	1,160	1,089	71	1,126	1,027	98
May	1,208	1,181	27	1,322	1,278	45	977	901	76
June	1,305	1,256	49	1,269	1,189	80	1,004	946	58
July	1,124	1,029	96	1,114	1,015	99	840	732	108
August	941	846	95	1,120	1,043	77	814	636	177
September	993	897	96	1,098	990	108	1,059	928	131
October	1,246	1,157	89	1,150	1,067	83	1,066	987	79
November	832	752	79	1,023	904	119	1,047	966	80
December	767	730	37	1,072	989	82	1,008	964	44
January	835	777	57	1,104	1,017	87	1,068	1,061	6
Febuary	643	572	71	990	906	84	904	854	51
March	803	745	57	1,095	1,000	95	904	895	8
Total	**11,859**	**11,016**	**843**	**13,516**	**12,487**	**1,029**	**11,815**	**10,897**	**918**

Source: Authors' analysis

Annexure IV:

Table 10: Unit-wise thermal and hydro capacity addition plan

FY	Plant name	Type	Ownership	Expected commissioning date	Tied-up capacity (MW)
FY20	Meja	Thermal	State	Apr-19/ Sep-19	1024
	Hydro Medium Term Tender	Hydro	Other ISGS	Aug-19	700
	New Nabinagar Units 1 and 2	Thermal	Central ISGS	May-19/Sep-19	140
	Kemeng HP Unit 1, 2 & 3, 4	Hydro	Central ISGS	Jul 19/ Aug-19	56
	Tanda II Units 1 and 2	Thermal	Central ISGS	Aug-19/Mar-20	1008
FY21	Harduaganj Ext. Stage II	Thermal	State	Jan-20	660
	New Nabinagar Unit 3	Thermal	Central ISGS	Aug-20	70
	Ghatampur Unit 1	Thermal	State	Nov-20	427
	Tapovan Vishnu Garh Units 1,2,3,4	Hydro	Central ISGS	Nov-20/Dec-20/ Jan-21/Feb-21	100
	Obra-C UNIT-1	Thermal	State	Dec-20	660
	Jawaharpur	Thermal	Central ISGS	Dec-20	660
FY22	Obra-C UNIT-2	Thermal	Central ISGS	Apr-21	660
	Jawaharpur	Thermal	State	Apr-21	660
	Ghatampur Units 2 & 3	Thermal	State	May-21/Nov-21	854
	Lata Tapovan HEP	Hydro	State	Oct-22	34
	Parbati II	Hydro	State	Dec-21	156
	Panki	Thermal	State	Jan-22	660
FY23	Vishnugarh Pipal Kothi	Hydro	Central ISGS	Dec-22	166
	Khujra STPP UNIT-1	Thermal	Central ISGS	Mar-23	198
FY24	Subansiri Lower	Hydro	Central ISGS	May-23	182
	Pakaldul	Hydro	Central ISGS	Aug-23	200
	Khujra STPP Unit 2	Thermal	Central ISGS	Sep-23	198
	Singrauli Stage III	Thermal	Central ISGS	Dec-23	800
FY27	Tellaya Thermal	Thermal	Central ISGS	May-26	400
	Obra D Unit 1	Thermal	State	Sep-26	800
	Karchana	Thermal	Other ISGS	Nov-26	1320
FY30	Obra D Unit 2	Thermal	State	Sep-29	800
	Total Thermal				**11,999**
	Total Hydro				**1,594**

Source: Authors' compilation from UPERC, UPPCL filings & CEA data

Annexure V:

Table 11: Average days of coal availability during FY 2018–19 in state and state IPPs in UP

Plant name	Apr	May	June	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Anpara TPS	18	13	11	15	19	17	16	14	13	12	12	14
Parichcha TPS	13	23	18	7	2	3	2	4	14	13	8	9
Harduaganj TPS	13	17	4	2	4	4	3	2	2	2	18	11
Anpara C TPS	1	3	3	4	2	4	2	12	18	12	2	7
Obra TPS	55	55	49	32	20	11	6	7	16	20	22	21
Prayagraj TPP	2	3	2	3	9	8	10	6	6	6	3	3
Rosa TPP Ph-I	3	3	2	2	5	2	2	6	32	43	60	64
Lalitpur TPS	6	3	2	3	10	20	8	5	4	4	16	33
Kundarki TPS	0	0	0	0	0	2	7	9	8	8	8	12
Utraula TPS	0	0	0	0	0	3	7	11	11	11	11	13
Maqsoodpur TPS	0	0	0	0	0	22	8	8	7	7	7	10
Khambarkhera TPS	0	0	0	0	0	23	4	10	10	10	10	12
Barkhera TPS	0	0	0	0	0	30	7	5	5	6	9	12

Source: Authors' compilation from UPERC, UPPCL & CEA data

Annexure VI:

Table 12: Daily coal requirement of state and state IPP plants at 85 per cent PLF

Plant name	Variable cost (INR/kWh)	Daily coal requirement at 85% PLF (tonnes/MW)
Anpara TPS	1.55	12.82
Obra TPS	1.73	14.25
Anpara C TPS	1.85	12.20
Prayagraj TPP	2.39	12.60
Rosa TPP Phase-I	2.83	12.09
Lalitpur TPS	3.15	12.75
Parichha TPS	3.23	14.06
Harduaganj TPS	3.28	12.61
Kundarki TPS	3.46	15.25
Utraula TPS	3.51	15.22
Maqsoodpur TPS	3.70	15.28
Khambarkhera TPS	3.71	15.80
Barkhera TPS	3.76	15.72

Source: Authors' compilation from UPERC, UPPCL & CEA data

Annexure VII:

Table 13: Fuel cost and station heat rate of UP plants

Plant name	Age	Variable cost (INR/kWh)	Fuel cost (INR/Mcal)	Station heat rate (kcal/kWh)
Anpara B	26	1.52	0.6	2410
Anpara D	4	1.53	0.58	2410
Anpara A	32	1.63	0.58	2475
Obra B	39	1.73	0.53	2755
Rosa 1	9	2.83	1.03	2475
Parichha Ext.	13	3.20	1.17	2475
Parichha Ext. Stage II	7	3.21	1.17	2475
Harduaganj Ext.	8	3.25	1.18	2475
Parichha	35	3.35	1.17	2980
Harduaganj	41	3.39	1.18	3150

Source: Authors' compilation from UPERC, UPPCL & CEA data

Image: iStock

To provide electricity at the most optimum levels discoms must dispatch the cheapest generators first.

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