Designing a framework of power procurement for a power distribution utility: a case study

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Abstract

Purpose – The study aims to find out an appropriate volume of power to be procured through long-term power purchase agreements (PPAs), the volume to be sourced from the power exchange through day-ahead and term-ahead options and also a suitable volume to be sold at different points of time within a day, which would finally lead to the optimum cost of power procurement.

Design/methodology/approach – The study has considered a Delhi-based power distribution utility and has collected all relevant data from its archival sources. A stochastic optimization model has been developed to capture the problem of power procurement faced by the distribution utility, which is modelled as a mixed integer linear programming problem. Sensitivity analyses were carried out on the important parameters including hourly demand of power, unit variable cost of power available through PPAs, maximum back-down percentage allowed under PPAs, etc., to investigate their impact on daily cost of power under PPAs, daily cost of power under day-ahead and term-ahead options, daily sales revenue and also the net total daily cost of power procurement.

Findings – The findings include the appropriate volume of power procured from different suppliers through PPAs and from the power exchange under day-ahead and term-ahead options and also the surplus volume of power sold under the day-ahead arrangement. It has also computed the total cost of power purchased under PPAs, the cost of power purchased from the power exchange under day-ahead and term-ahead options and also the revenue generated out of the sale of surplus power under the day-ahead arrangement. In addition, it has also presented the results of sensitivity analyses, which provide rich managerial insights.

Originality/value – The paper makes two significant contributions to the existing body of power procurement literature. First, the stochastic mixed-integer linear programming model helps decision makers in determining the right volume of power to be purchased from different sources. Second, based on the findings of the procurement model, a power procurement framework is developed considering the dimensions of uncertainty in power supply and the cost of power procurement. This power procurement framework would aid managers in making procurement decisions under different scenarios.

Keywords Cost minimization, Modelling, Mixed integer programming, Optimization, Power distribution utility, Power purchase agreement, Day-ahead purchase, Optimum power procurement cost, Power procurement framework

Paper type Research paper

Abbreviation

Sets

S = Set of potential suppliers of power, $s \in S$;

A = Set of Agreements; Long-term and Medium-term, $a \in A$;

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T = Set of time intervals, $t \in$ T; and
Ω = Set of scenarios, $\theta \in \Omega$.

Parameters
d_t = Demand of power in t^{th} hour for day-ahead forecast;
U_{sat} = Maximum allocated capacity available from supplier "s" under agreement "a" in t^{th} hour;
C_{sat} = Unit purchase cost of power from supplier *"s"* under agreement "a" in t^{th} hour;
g_{sat} = Maximum back-down per cent allowed on allocated capacity from supplier "*s*" under agreement "*a*" in t^{th} hour;
I_{sa} = Daily fixed cost of power to be paid to supplier *"s"* under agreement "a";
L_s = Transmission loss of power in per cent from supplier *"s"*;
$PC_{\theta t}$ = Unit purchase cost of power from power exchange under scenario "θ" in t^{th} hour;
$SP_{\theta t}$ = Unit selling price of power (in case of surplus) under scenario "θ" in t^{th} hour;
Q_t = Maximum volume of power available from power exchange in t^{th} hour in day-ahead purchase;
$\pi_{\theta(P)}$ = Probability of scenario "θ" for purchase of power; and
$\pi_{\theta(S)}$ = Probability of scenario "θ" for sale of power.

Decision variables
V_{sa} = 1, if power is purchased from supplier "s" under agreement "a";0, otherwise;
X_{sat} = Volume of power to be procured from supplier *"s"* under agreement "a" in t^{th} hour;
$Y_{\theta t}$ = Volume of power to be procured from power exchange under scenario "θ" in t^{th} hour; and
$Z_{\theta t}$ = Volume of power to be sold under scenario "θ" in t^{th} hour.

1. Introduction

A power distribution utility has to face numerous challenges in respect of both demand side and supply side variabilities. Challenges in the demand side include fluctuation in the demand of power within a day, across days in a week depending on week-days or weekend and also across different months in a year. Estimation of the requirement of power during different periods within a day has significant implications. More accurate estimates can lead to efficient operations on one hand and ensure customer satisfaction on the other. Challenges in the supply side of the distribution utility involve sourcing power from a large number of suppliers including thermal power stations, hydropower stations, gas-turbine plants, nuclear power stations, solar power stations, etc., which are located all over the country. The utility has to negotiate with these generators and, finally, enter into an agreement with them for the supply of power. The type of agreements includes long-term, medium-term and short-term contracts with different time horizons in each case. The unit procurement cost of power charged by different generators under different types of agreements significantly differ from each other depending on the sources of supply and numerous other technical and operational factors. The procurement cost exhibits significant variation across different generators. Under such variability, the utility has to enter into an agreement with many generators simultaneously for procuring a substantial volume of power from them.

Power purchased under long-term and medium-term contracts does not fully meet the demand. Because the most pressing challenge faced by a distribution utility is to ensure uninterrupted supply of power to the end consumers. Sometimes the distribution utility has to purchase additional volume of power from the power exchange at a higher price at a very short notice, frequently referred to as day-ahead or term-ahead purchases to meet the sudden spike in demand (Hu *et al.*, 2018; Najafi *et al.*, 2018). This has a significant bearing on the overall power procurement cost of the distribution utility. Cost of power accounts for

75-80 per cent of the total cost of a utility (www.bsesdelhi.com/. . . . . 2015-16_BYPL.pdf). Even a small percentage decrease in procurement cost leads to substantial savings in the total procurement cost. Managers mostly apply their hunches and past experience in determining the specific volume of power to be purchased from different generators and power exchange on an intra-day basis with a view to minimizing the power procurement cost. However, this approach does not guarantee the minimum cost. This has motivated us to view the problem as a multi-sourcing problem of power procurement and to conceptualize and develop a cost optimization model with a view to minimizing the power procurement cost. The above phenomenon has finally stimulated us to design a power procurement framework.

There are numerous applications of optimization models in the management of the supply chain of power. Categories of application include optimization of power flow (Alqurashi *et al.*, 2016), maximization of revenue by a power generation company (Pereira and Saraiva, 2010; Marí *et al.*, 2017); optimal schedule of electricity generation (Jirutitijaroen *et al.*, 2013; Zhang *et al.*, 2016), optimization of power procurement by a distribution utility or a large retailer (Kwon *et al.*, 2006; Woo *et al.*, 2006; Zare *et al.*, 2010a; Beraldi *et al.*, 2011; Yau *et al.*, 2011), optimal sale price of electricity (Hatami *et al.*, 2009), minimization of power procurement cost/maximization of expected profit and the risk of cost volatility (Hatami *et al.*, 2009; Zare *et al.*, 2010a), etc. While recommending the optimum solution for a power generation or a distribution utility, most of the above studies have not dealt with empirical data. Secondly, there have not been many studies that attempted to develop optimal power procurement plans for a distribution utility encompassing both long-term and day-ahead sources of power (Zare *et al.*, 2010b; Beraldi *et al.*, 2011). The present study endeavours to do so by using empirical data collected from its archival sources with specific reference to the Indian context. Finally, the development of the power procurement framework for a distribution utility is a novel objective. The present study seeks to bridge this gap by designing a framework of power procurement based on revelation from the case analysis.

The remainder of the paper is organized as follows. Section 2 provides a brief overview of related literature. Section 3 presents the snapshot of the distribution utility in which the study was carried out. Section 4 describes the mathematical model in detail along with the assumptions. Section 5 presents the input data considered in the present work. Section 6 deals with the data analyses including sensitivity analyses. Section 7 introduces the framework of power procurement. Section 8 presents a discussion, which highlights theoretical contribution and managerial implications of the findings. The paper concludes with a brief summary, limitations and future research directions in Section 9.

2. Literature review

Power management literature is quite rich in terms of the application of sophisticated optimization models in the domain of optimization of power procurement cost, minimization of risk of cost volatility, maximization of profit, etc. Woo *et al.* (2006) demonstrated how a local distribution company (LDC) based in Pacific North-west should rely on the spot market, forward contracts and long-term tolling agreements for procuring electricity to meet customer demand with a view to minimizing the procurement cost variance. They developed a mathematical programming model to derive the efficient frontier that demonstrates the optimal tradeoffs available to the LDC between procurement risk and expected cost. Kwon *et al.* (2006) developed a stochastic programming model that can be used by the supplier of a custom contract to design a procurement strategy for minimizing its expected cost of supply for meeting contractual obligations. The model includes a mix of forward contracts and its own generation with spot purchase of power. Spot selling of power is also incorporated within the model. Hatami *et al.* (2009) developed a mixed-integer stochastic programming model for determining optimal sale price and procurement strategies of electricity for a retailer based in the Iranian electricity market. They considered a trade-off between maximization of expected profit and minimization of risk of profit volatility.

Zare *et al.* (2010a) developed an energy procurement strategy for a large consumer based in Iberian electricity market that purchases electricity from day-ahead and adjustment markets with the objective of realizing minimum cost while controlling for the risk of cost volatility. They suggested a risk-averse bidding strategy to account for the risk associated with uncertain day-ahead and adjustment market prices. Pereira and Saraiva (2010) developed an optimization model for maximization of expected revenue of a generation company considering uncertainty associated with the price volatility and reliability of generation units and, at the same time, ensuring safe operation of the power system.

Yau *et al.* (2011) developed a two-stage stochastic integer programming model that can be used by the supplier of a custom forward contract to design an optimal procurement strategy, which would enable it to meet contract obligations under spot price uncertainty. Beraldi *et al.* (2011) developed an optimal procurement plan for a large electricity consumer based in the south of Italy with the objective of minimizing procurement cost and procurement risk relating to violation of budget constraints. The plan also specified the volume of power to be procured through bilateral contracts and day-ahead electricity market. Jirutitijaroen *et al.* (2013) developed a stochastic programming model for a power generation company that enabled the company to determine the optimal volume of gas to be procured through contracts, an optimal electricity generation schedule, an optimal trading strategy both in the electricity and the natural gas spot markets and also gas storage management. Zhang *et al.* (2016) developed an integrated stochastic mixed integer linear programming model for a continuous power-intensive plant in which production scheduling and electricity procurement were considered simultaneously. The model considers the uncertainty in spot electricity price and product demand. Conditional value at risk was incorporated into the model as a measure of risk. Beraldi *et al.* (2017) developed a stochastic programming framework to capture uncertainty in the demand of electricity and the corresponding spot price. This approach provides the decision maker with a strategy that meets energy needs with high reliability. In addition, this approach also integrates conditional value at risk to minimize potential losses.

Although there exists a significant body of literature in terms of the application of advanced optimization models for maximization of revenue for a generation utility, minimization of cost for a large electricity consumer or a distributor, etc., very few studies have looked into optimizing the power procurement cost for a power distribution utility appropriate in the Indian context. Indian electrical power generation and distribution are unique in the sense that though it is deregulated, competition is allowed only in limited aspects. Many processes are operated through regulated monopolies. In addition, the economic viability of power purchase agreements (PPAs) entered into between the generators and the distribution utilities while determining the optimal procurement plan has not been deeply investigated in the past. Further, hardly any work was found, which has explicitly incorporated back-down percentage into the PPAs entered into between the generators and a distribution utility. Finally, the authors could not find any studies, which have developed a framework of power procurement for a distribution utility based on analysis of empirical data. Thus, there exist considerable research gaps in the sphere of power procurement by a power distribution utility. The present study seeks to bridge this gap.

3. Distribution utility: an overview

The present work has been carried out in a power distribution utility based in Delhi. Delhi, the national capital of India, has got five separate distribution utilities, each supplying power to different territories of Delhi. The distribution utility under consideration supplies power to both the southern and western part of Delhi. It sources power from different generating stations located all over the country. These generating plants are connected to the transmission utilities including both state transmission utilities (STUs) and central transmission utility (CTU), which enable transmission of electricity from generating stations to the distribution utility. Transmission networks are spread across the country like road networks and act like a transporter in the supply chain while distribution utility acts like a retailer in the supply chain. The distribution utility has to negotiate with the associated transmission utilities for transmission of the required volume of power at different points of time. Capacities of the generators and the transmission network are the main constraints at this stage. For day-ahead and term-ahead power requirements, the distribution utility has to negotiate with the power exchange, regional load dispatch centres, state load dispatch centres, trading utilities and regulators.

One of the most peculiar challenges faced by the distribution utility is the fluctuating nature of the cost of power at which the same is to be purchased. However, the price at which it is to be supplied to the end consumers is fixed. Further, the distribution utilities are required to supply power to almost all types of consumers almost on a 24-h basis. Thus, it becomes very crucial on the part of the distribution utility to monitor and control power procurement cost almost on a daily basis. Power procurement cost of a distribution utility consists of several elements including the cost on account of transmission losses, transmission charges, fee and commission paid to the exchange or trading company and some other incidental charges, etc.

The Delhi-based power distribution utility under consideration has both long-term and medium-term PPAs with numerous suppliers for supply of different volumes of power. The present study considers 41 suppliers who have entered into PPAs with the distribution utility. This arrangement indicates the maximum volume of power that could be procured from a particular supplier under a particular agreement. This arrangement also has a provision, which specifies that the utility can request a generator to reduce the supply of certain volume of power in case of decreased demand. This decrease in power supply ranges from as low as 0 per cent to as high as 40 per cent of the total allocated capacity depending on the sources of supply and also the type of PPAs. Technically, this is known as a maximum back-down percentage allowed by a generator for a particular agreement.

Both long-term and medium-term agreements have variable and fixed components of cost. The nature of the costs in both these agreements is almost identical with the only difference being that the cost under medium-term agreement falls slightly on the higher side. For the variable component, each supplier is paid in terms of per unit (kWh) at a predetermined rate. In addition, each supplier also needs to be paid a fixed annual amount per year, which is independent of the volume of power purchased. Under the short-term agreement, the fixed charges are not paid to the suppliers. However, the rates are somewhat higher in this agreement than either long-term or medium-term agreement. Under day-ahead and term-ahead power requirement, cost of power is decided through a two-way bidding process at power exchange and it includes all elements of the cost. For purchasing power under day-ahead, the utility has to submit bids to the power exchange latest by 12.00 h each day for the purchase of power for the next day while purchasing power under term-ahead involves submission of bids by the utility, 3 h before actual consumption for the same day.

The maximum volume of power available under day-ahead and term-ahead purchase depends on the dynamics between demand and supply in the whole region. Sometimes, the distribution utility has surplus power, which needs to be sold to some other utilities at a rate, which depends on the mismatch between demand and supply prevailing at a particular time slot.

The distribution utility has to pay transmission charges to the transmission utilities including both CTU and STUs for transmission of the desired volume of power as the transmission is carried out through the networks maintained by these utilities spread across the nation. However, in the present study, this cost has not been incorporated as this element has hardly any influence on optimizing the total power procurement cost. The decision maker does not have any option to choose a different transmission network or route suggested by the optimization model other than the one which is attached to the generating station. As the transmission of power takes place through long distance interconnected networks, a certain amount of power is lost during transmission, which is technically known as transmission losses. These losses are different for different suppliers depending upon the location of the generator and the route of transmission. The cost of power losses needs to be borne by the distribution utility. The transmission loss varies between 0.5 and 3.5 per cent of the total volume of power purchased.

4. Model

The mixed-integer linear programming (MILP) model was formulated with a view to minimizing the total daily power procurement cost. It is a stochastic optimization model with recourse. In the first stage, long-term suppliers and the appropriate volume of power to be purchased under valid PPAs are found. Volumes under day-ahead and term-ahead options are recourse options.

4.1 Assumptions

- Fixed cost of power was estimated on a daily basis from the annual fixed cost of power to be paid to the suppliers under PPAs for finding out the total daily power procurement cost.
- Maximum and minimum volumes of power available from each supplier under PPAs remains fixed. These depend on maximum back-down percentage allowed for each supplier under long-term and medium-term PPAs.
- Volatility in respect of the cost of power available under day-ahead and term-ahead purchase and also the sale price of power is captured under three scenarios: optimistic, most likely and pessimistic. An assessment of the unit cost of power available under three different scenarios from day-ahead and term-ahead options is made based on the analysis of a large data set of past periods. Further, the assessment on the unit sale price of power was also made based on observation of past data. In addition, the probability of occurrence of all three scenarios both for day-ahead purchase and sale of power was computed.
- Maximum volume of power available through Power Exchange in hourly basis within a day under day-ahead and term-ahead purchase depends on the gap between demand and supply and as such does not remain static. However, certain approximations were made in terms of hourly availability of power under day-ahead and term-ahead options based on the analysis of past data from the exchange.

Formulation

Minimize $Z=$

$$\sum_{s\in S}\sum_{a\in A}\sum_{t\in T}\left[X_{sat}/(1-L_s)\right]*C_{sat}+\sum_{s\in S}\sum_{a\in A}(I_{sa}*V_{sa})$$
$$+\sum_{\theta\in\Omega}\sum_{t\in T}\left(\pi_{\theta(P)}*Y_{\theta t}*PC_{\theta t}\right)-\sum_{\theta\in\Omega}\sum_{t\in T}\left(\pi_{\theta(S)}*Z_{\theta t}*SP_{\theta t}\right)$$

Subject to Constraints:

- Capacity constraints of each supplier under PPAs for each time period:

$$\left[X_{sat}/(1-L_s)\right]\leq U_{sat}*V_{sa}\quad \forall\text{s}, \forall\text{a}, \forall\text{t} \tag{1}$$

- Availability constraints of power from power exchange under day-ahead and term-ahead purchase for each time period:

$$\sum_{\theta\in\Omega}\pi_{\theta(P)}*[Y_{\theta t}]\leq Q_t\quad \forall\text{t} \tag{2}$$

- Constraints on back-down percentage of agreed upon volume (of allocated capacity) under PPAs for each time period:

$$\left[X_{sat}/(1-L_s)\right]\geq(1-g_{sat})*U_{sat}*V_{sa}\quad \forall\text{s}, \forall\text{a}, \forall\text{t} \tag{3}$$

- Demand Constraints:

$$\sum_{s\in S}\sum_{a\in A}X_{sat}/(1-L_s)+\sum_{s\in S}\sum_{\theta\in\Omega}\pi_{\theta(P)}*Y_{\theta t}-\sum_{c\in C}\sum_{\theta\in\Omega}\pi_{\theta(s)}*Z_{\theta t}=d_t\quad \forall\text{t} \tag{4}$$
$$X_{sat},Y_{\theta t},Z_{\theta t}\geq 0,\qquad V_{sa}\rightarrow\text{Binary Variables}$$

The elements of power procurement cost shown in the objective function are as follows: The first element indicates the total daily purchase cost of power under PPAs, the second element denotes the total daily fixed cost of power under PPAs, the third element shows the total daily purchase cost of power under day-head and term-ahead options and the fourth element indicates the total daily sales revenue of power.

5. Data

For finding out optimum solution to the above problem, real-life data on all 11 parameters were collected from the power distribution company. This is shown in Appendix 1 through Appendix 5. Appendix 1 contains the estimated demand data of every 1 h for 24 h. This estimation is based on collection of actual power consumption data in 15 min interval spread over 96 slots in a single day throughout the entire month of August for five years starting from 2011-2012 to 2015-2016. Time series forecasting models were applied in forecasting the volume of power required for every 15 min interval over a single day for the month of August. Details are available in Kumar *et al.* (2017). Later, these demand data were transformed into an estimated hourly demand spread over 24 h in a single day for the month of August. Appendix 2 includes maximum allocated capacity of power of each supplier under PPAs, per unit variable cost of power of each supplier under PPAs, the maximum back-down percentage allowed on allocated capacity from a particular supplier under PPAs, estimated daily fixed cost of power to be paid to suppliers under PPAs and the percentage of transmission losses of power of each supplier. Appendix 3 indicates unit purchase cost of power from the power exchange under day-ahead and term-ahead options under three different scenarios at different time periods and also the unit sale price of power (in case of surplus) under three different scenarios at different time periods. Appendix 4 contains maximum volume of power that is available from the power exchange under day-ahead and term-ahead options at different time periods and, finally, Appendix 5 presents the scenario probability distribution for purchase cost of power under day-ahead and term-ahead options and also the scenario probability distribution for sale price of power in different time slots. The input data with regard to the PPAs considered in the above problem reveals that only long-term PPA is currently being adopted by the distribution utility and the suppliers. The optimization model consists of 1,169 decision variables, out of which 1,128 are linear variables and the remaining 41 are binary variables. In addition, the model has a total of 2,016 constraints.

6. Data analyses

LINGO 14.0 software was used for finding out optimum solution to the above problem. The optimum cost of power procurement per day turns out to be INR 6,55,47,460. The results were shared with the management of the distribution utility, which is currently following an *ad-hoc* approach in determining the volume of power procured from different sources. The management of the distribution utility mentioned that the model resulted in at least 20 per cent savings in the total daily procurement cost. This revelation demonstrates the utility and efficacy of the model from a practical standpoint. The total volume of power procured from different suppliers under long-term PPAs, volume of power purchased from the power exchange under day-ahead and term-ahead arrangement and also the surplus volume of power sold under day-ahead arrangement, were computed individually. This is shown in Appendix 6. The net volume of power purchased turns out to be 34,837,008 units. In addition, the total cost of power purchased under long-term agreement from different suppliers considering both fixed cost and variable cost, the cost of power purchased from the power exchange under day-ahead and term-ahead arrangement and also the revenue generated out of sale of surplus power to the exchange or other distribution utilities under day-ahead arrangement, were calculated. This is shown in Appendix 7. The net cost of power procurement, thus, comes out to be INR 6,90,97,863.

Appendix 6 reveals that 81.6 per cent of the total volume of power is sourced from long-term PPAs and the remaining from day-ahead and term-ahead purchases. Further, Appendix 7 reveals that in monetary terms, the percentage of total volume of power sourced from long-term PPA turns out to be 75.2 per cent while the remaining portion is accounted for by the volume of power sourced from the day-ahead arrangement.

6.1 Sensitivity analyses

The sensitivity of the MILP model was tested by varying the values of the most important parameters with a view to understanding the behaviour of the model with respect to changes in these parameter values. Parameters that are critical for the above decision problem were chosen. Specifically, those parameters were selected over which the decision maker has limited or no control. These include hourly demand of power, the unit variable cost of power from various suppliers under long-term PPAs, the daily fixed cost of power from various suppliers under long-term PPAs, maximum back-down percentage allowed under long-term PPAs and maximum availability of power under day-ahead and term-ahead options.

6.1.1 Impact of variation in demand. The volume of forecast demand of power considered in the original model is considered the base value of demand. The demand of power was varied by 5, 10, 15 and 20 per cent from the base value in both directions and accordingly the impact of this variation in demand was investigated on the daily cost of power under long-term PPAs, daily cost of power under day-ahead and term-ahead purchase, daily sales revenue and also the net total daily cost of power procurement. This is shown in Appendix 8.

The above exhibit reveals that the increase in the cost of power under long-term agreement is quite significant, when the demand of power increases by 5 per cent. However, for the same percentage increase in the demand of power, the cost of power under day-ahead and term-ahead purchase reduces. This happens due to the unit cost of power under long-term agreement of most of the suppliers being lower than the same under day-ahead and term-ahead purchase. The model suggests that the increased availability of power at a somewhat economical rate from the selected suppliers under long-term agreement should be used to the maximum possible extent. This has led to the decreased drawl of power under day-ahead and term-ahead purchase. Further, there has been an increase in the sales revenue under day-ahead sale for 5 per cent increase in the demand of power. This happens probably due to the fact that the model allows the decision makers to consider purchasing more than the required volume of inexpensive power under long-term agreement. This excess power needs to be sold, which results in an increase in the sales revenue. When demand increases from 5 to 20 per cent, the cost of power under long-term agreement indicates a marginal increase. However, for the same percentage increase in demand, the cost of power under day-ahead and term-ahead purchase exhibits a comparatively higher increase. The daily sales revenue shows a marginal declining trend in this range of increase in demand. The possible reason of the above phenomena may be attributed to the near-complete use of power available under long-term agreement for most of the suppliers. Thus, the additional demand needs to be met from the day-ahead and term-ahead options. After meeting the increased demand of power, less power becomes available for sale, which results in decreased sales revenue.

When the demand of power decreases by 5 per cent, cost of power under long-term agreement gradually diminishes. Further, the cost of power under day-ahead and term-ahead purchase reduces even at a slower pace than the same observed under long-term agreement. However, the daily sales revenue in this range of 5 per cent decrease in demand of power shows a very marginal increase. This is probably attributable to the fact that slightly higher volume of power purchased than the actual demand needs to be sold, which eventually results in marginal increase in the daily sales revenue. Beyond 5 per cent decrease in demand, both the cost of power under long-term agreement and the same under day-ahead and term-ahead agreement shows a declining trend. However, the daily sales revenue remains more or less the same.

6.1.2 Impact of variation in the variable cost of power under power purchase agreements. The unit cost of power under long-term PPAs from 41 suppliers has a wide range. It varies from as low as Rs 0.81 per unit to as high as Rs 5.50 per unit, which remains the same during the period of agreement between suppliers and the distribution utility. This set of unit cost of power offered by the suppliers has been considered as the base value, which has been varied by 5, 10, 15 and 20 per cent across all suppliers. The impact of this variation has been investigated on daily cost of power under long-term agreement, daily cost of power under day-ahead and term-ahead purchase, daily sales revenue and also the net total daily cost of power procurement. This is shown in Appendix 9.

It is observed from the Appendix 9 that when the unit cost of power under long-term agreement across all suppliers increases by 5 per cent, daily total cost of power under long-term agreement remains almost the same. However, there is a slight increase in the daily total cost of power under day-ahead purchase and a marginal decrease in the total daily sales revenue of power. This may be attributed to the marginal decline in the volume of power procured under long-term PPAs and, at the same time, little increment in the volume of power procured under day-ahead purchase. When the unit cost of power available under long-term agreement increases by 10 per cent, a significant fall is observed in the daily total cost of power available under long-term agreement and, simultaneously, a significant increase in the daily cost of power available under day-ahead purchase. Daily sales revenue continues to fall gradually in this range. Beyond 10 per cent increase in the unit cost of power under long-term agreement, there is hardly any change in the daily total cost of power procured under long-term agreement and very little rise in the daily total cost of power available under day-ahead purchase. In addition, no significant change in the daily total sales revenue is observed. As regards the total daily net cost of power, the same reveals a gradual and continuous increase, when the unit cost of power continues to increase by 5, 10, 15 and 20 per cent from its base value.

When the unit cost of power available under long-term PPAs decreases by 5 per cent, a significant increase in the daily total cost of power procured through long-term PPAs and, simultaneously, a significant fall in the daily total cost of power available under day-ahead and term-ahead options are observed. In addition, an appreciable increase in the daily total sales revenue is observed. This is probably attributable to the fact that the utility purchases more than the required volume of inexpensive power available through long-term PPAs and smaller volume of relatively expensive power available under day-ahead purchase. The additional volume of power needs to be sold. Thus, the daily total sales revenue exhibits an increasing trend, when the unit cost of power decreases by 5 per cent. Between 5 and 15 per cent decrease in the above cost, there is neither any significant change in the daily total cost of power under long-term PPAs, nor is there any change in the daily total cost of power under day-ahead purchase. However, the exhibit reveals a gradually increasing trend in the daily total sales revenue. The above occurrence indicates that the cheaper power available under long-term PPAs motivates the utility to purchase higher volume than its own demand. The surplus power again needs to be sold, which leads to an increase in the sales revenue. Beyond 15 per cent decrease in the unit cost of power, a sharp increase in the daily total cost of power procured through long-term PPAs and simultaneously a sharp increase in the daily sales revenue of power are experienced. However, the daily total cost of power under day-ahead purchase more or less remains the same. The total daily net cost of power exhibits a gradual decrease, when the unit cost of power decreases by 5, 10, 15 and 20 per cent from its base value.

6.1.3 Impact of variation in the daily fixed cost of power under long-term agreement. The estimated daily fixed cost of power to be paid to 41 suppliers varies from as low as INR 501 to as high as INR 54,960. This set of estimated daily fixed cost of power has been considered as the base value, which is varied by 5, 10, 15 and 20 per cent across all suppliers. The impact of this variation has been scrutinized on daily cost of power under long-term agreement, daily cost of power under day-ahead and term-ahead purchase, daily sales revenue and also the net total daily cost of power procurement. This is shown in Appendix 10.

The above figure reveals that the daily total cost of power under long-term purchase and the cost of power under day-ahead purchase remains almost the same irrespective of increase or decrease in the fixed cost of power. Further, daily sales revenue and, finally, the total daily cost of power also do not reveal any change. The above phenomenon probably establishes the fact that this element of the cost, being independent of the volume of power procured, does not have any significant impact on the total cost of power procurement.

6.1.4 Impact of variation in the maximum back-down percentage under long-term agreement. The back-down percentage in respect of supply of power from the suppliers under long-term agreement varies from as low as 0 per cent to as high as 45 per cent. This option provides the distribution utility the flexibility to spread the procurement of power to cheaper alternatives when they are available. In the present analysis, the back-down percentage is varied by 5, 10, 15 and 20 per cent from its base value across all suppliers. An attempt has been made to investigate its impact on daily cost of power under long-term agreement, daily cost of power under day-ahead purchase, daily sales revenue and also the net daily total cost of power procurement. This is shown in Appendix 11.

The above figure reveals that when the back-down percentage increases by 5 per cent, daily cost of power under long-term agreement and the same under day-ahead purchase do not change. Further, daily sales revenue and the total daily cost also remain the same. This indicates that the increase in back-down percentage by 5 per cent from the base value or in other words, decrease in the availability of long-term sources of power by 5 per cent does not significantly diminish the availability of power under long-term agreement in comparison to the current level of demand. However, when the back-down percentage is increased by 10 and 15 per cent of its base value, the daily cost of power under long-term PPAs increases and correspondingly the daily cost of power under day-ahead purchase decreases. This phenomenon probably suggests that the cost of power available under long-term PPAs is somewhat lower than the same available under day-ahead and term-ahead options and the optimization model attempts to make maximum possible use of power available under long-term PPAs. This eventually results in a higher volume of power purchased under long-term PPAs, which again needs to be sold. Thus, a moderate increase in daily sales revenue is observed in 10-15 per cent increase in back-down percentage. The resultant daily total cost exhibits a declining trend in the above range. Between 15 and 20 per cent increase in back-down percentage, both the daily cost of power under long-term agreement and the same under day-ahead purchase do not change. Further, no change is found in the daily sales revenue and in the net daily total cost of power procurement.

As regards decrease in the back-down percentage, no variation is observed in daily cost of power under long-term agreement and the same under day-ahead purchase up to 15 per cent decrease in back-down percentage from its base value. Probably the above findings indicate that a decrease in back-down percentage by 15 per cent across all suppliers does not increase the availability of power of those suppliers supplying power at cheaper rates. However, when the back-down percentage decreases by 20 per cent, a very marginal increase in the daily cost of power under long-term agreement and a significant decrease in the cost of power under day-ahead purchase are experienced. Consequently, the net daily total cost of power demonstrates a significant decline and the daily sales revenue remains almost the same. The above revelation indicates that the decrease in back-down percentage by 20 per cent probably increases the availability of power of those suppliers supplying power at cheaper rates.

6.1.5 Impact of variation in the maximum availability of power under day-ahead purchase. Maximum availability of power under day-ahead purchase from the power exchange varies depending on the timing of a day spread over 24 slots as shown in

Appendix 4. The data provided in Appendix 4 in respect of available volume of power from the exchange have been considered as the base value, which are varied by 5, 10, 15 and 20 per cent from the base value in both directions. Subsequently, its impact on the daily cost of power under long-term agreement, daily cost of power under day-ahead and term-ahead purchase, daily sales revenue and also the net total daily cost of power procurement are investigated. This is shown in Appendix 12.

The above exhibit reveals that the daily total cost of power procured through long-term PPAs remains unaffected due to either the increase or decrease in availability of power through day-ahead purchase. As the unit cost of power available under day-ahead is comparatively expensive, the utility attempts to meet its demand by procuring maximum volume of power through long-term PPAs. However, there is a very marginal increase in the daily cost of power purchased through day-ahead purchase and also a very marginal decrease in the daily cost of power, when the day-ahead availability of power from the power exchange increases and decreases, respectively. This probably happens because of the fact that the utility tries to purchase a slightly higher volume of power from the day-ahead source with the expectation that it would be able to sell the surplus volume of power at a somewhat higher rate. This is reflected in the gradual upward moving curve of the daily sales revenue, when the day-ahead availability of power increases. The total daily cost curve does not exhibit much variation with respect to change in the availability of power under day-ahead purchase.

The findings of sensitivity analyses indicate that the distribution utility should vary its proportion of power procured under long-term PPAs and day-ahead and term-ahead options, when the unit cost of power under PPAs shows an increasing or decreasing trend. Further, when the availability of power under both long-term PPAs and day-ahead and term-ahead options varies, power procurement plan suggested by the model also varies. Thus, there is a need to develop a power procurement framework, which would provide the distribution utility broad guidelines in respect of procuring power from different sources under different scenarios.

7. Framework of power procurement

The distribution utility has to grapple with two broad issues while procuring power from multiple suppliers and the power exchange: uncertainty in supply of power and the cost of power procurement. It is desirable from the point of view of the distribution utility to have less uncertainty in supply of power for providing uninterrupted electricity to the end consumers. At the same time, it is also prudent on the part of the distribution utility to meet the major chunk of its demand by procuring a substantial volume of power at a very low cost. However, in reality, certain variability in supply of power both from the PPAs and the power exchange are observed. The variability in the available power supply under PPAs is indicated in terms of maximum and minimum allocated volume of power. The uncertainty in supply of power from day-ahead and term-ahead arrangement is quite high and does not have any pre-defined range. As regards the unit cost of power, the data and the analyses reveal that the same exhibits wide variability under PPAs from as low as INR 0.96 to as high as INR 5.5. The unit cost of power under day-ahead and term-ahead option usually seems to be higher than the same available under PPAs. However, this also shows an extreme variability and depends on the mismatch between demand and supply. Based on this revelation, the distribution utility needs to develop a broad framework of power procurement as elucidated in Appendix 13. All four quadrants are explained below.

7.1 Inexpensive and certain supply

This is the most attractive quadrant from the perspective of the distribution utility. Ideally, the distribution utility would like to have its entire demand fulfilled from this quadrant because the cost of power is cheap and, at the same time, sources of supply do not suffer from variability in this quadrant. In reality, this happens when the utility enters into PPAs with the least cost suppliers of power for supply of certain volume of power. Once the agreement between the utility and the suppliers of power comes into force, the utility should attempt to procure maximum allowable volume of power from these suppliers to derive the cost advantage.

7.2 Expensive and certain supply

This particular quadrant seems to be hassle-free from operational point of view because the sources of power supply emanate from the PPAs and are somewhat stable in nature. However, the PPAs signed between the suppliers and the distribution utility falling in this quadrant are not at all economical. Because the suppliers who enter into PPAs with the distribution utility in this quadrant are quite expensive. This can be corroborated from the analyses of the empirical data discussed in Section 6.1. The utility is primarily responsible for providing uninterrupted supply of power to the end consumers. Keeping this in mind and also increase in the demand of power in future, the utility has to enter into PPAs with a wide range of suppliers some of which are quite expensive.

7.3 Inexpensive and uncertain supply

This particular quadrant appears to be lucrative from economic point of view. However, it poses unique operational challenges to the distribution utility. The main operational challenge is in terms of uncertainty in the supply of power as the sources of supply happen to be the power exchange. Under day-ahead and term-ahead option, when the demand of power at a particular interval within a day is not very high compared to the volume of power available from the power exchange in the same interval, the unit cost of power under this scenario becomes quite cheap. It then becomes quite reasonable on the part of the distribution utility to procure an appropriate volume of power from the power exchange. This would enable the utility to meet the demand of end consumers and, at the same time, would allow it to achieve efficiency in power procurement.

7.4 Expensive and uncertain supply

This is the most repulsive quadrant from the perspective of the distribution utility. In ideal situation, the distribution utility would not like to procure power from expensive and uncertain sources of supply. However, the volume of power procured from the stable source of long-term and medium-term PPAs most of the times fail to meet the demand of end consumers in real-life scenario. Thus, the utility has to depend on the power exchange for meeting the sudden spikes in demand through day-ahead and term-ahead arrangement. If the spike in demand of power at a particular interval far exceeds the volume of power usually purchased from the power exchange under normal circumstances, the per unit cost of power sourced from day-ahead and term-ahead options becomes very high. Thus, the utility needs to be very prudent while sourcing power under the above circumstances.

8. Discussion

The present study has made two significant contributions to the existing body of power procurement literature:

(1) the development of simple stochastic MILP model with recourse; and
(2) the development of power procurement framework.

As regards the stochastic MILP model, there are very few studies available pertaining to the determination of optimal power procurement plan for a power distribution utility. Further, with reference to the Indian context, this kind of studies is very scarce. Few aspects of this model need to be highlighted. *First*, uncertainty in the purchase cost of power available from power exchange has been captured in terms of scenario probability based on past data. *Second*, uncertainty in the sales price of power sold to the power exchange and other utilities is also captured through scenario probability based on past data. *Third*, the model includes a maximum back-down percentage allowed on the allocated capacity of a supplier, which gives us an idea about the actual volume of power available from different suppliers. *Finally*, the optimization model has been developed based on real data of demand, supply, transmission loss of suppliers, etc., available from a real-life case of a distribution utility. This may be considered as a significant contribution to data-driven model-building literature with specific reference to power procurement. Simchi-Levi (2014) argued through numerous examples of how data-driven problems give rise to new insights in research.

The output of the model gives rise to several meaningful insights. This includes the set of suppliers to be considered for supply of power to the distribution utility; volume of power to be purchased from the selected suppliers under long-term PPAs; volume of power to be purchased from the power exchange in a particular time slot under day-ahead purchase in a particular scenario; and the volume of surplus power to be sold to the power exchange or other distribution utilities in a particular time slot under a particular scenario. The optimization model suggests that out of 41 suppliers, the utility should purchase power from 29 suppliers under long-term PPAs. Thus, it provides important insights to the managers as to which set of suppliers are attractive and which ones are expensive. This revelation facilitates the distribution companies to revisit the long-term PPAs with the expensive suppliers and bargain with them for better terms and conditions. This makes a realistic sense to the distribution utility because the gap between demand and supply has diminished to a significant extent in today's scenario. Capacity expansion of existing facilities and additional capacities *emanating* predominantly from renewable sources has given buyers in India more bargaining power. The base model further reveals that 18.4 per cent of the total volume of power sourced from day-ahead and term-ahead options account for 24.8 per cent of the total cost of power procurement. This indicates that unit cost of power under day-ahead and term-ahead options is on higher side, and thus, the utility should attempt to fulfill its maximum demand of power from the cheaper suppliers having long-term PPAs.

The model provides a decision-making mechanism to the managers for determining the appropriate volume of power to be procured under long-term PPAs and under day-ahead and term-ahead options, when demand shows increasing or decreasing trend with random spikes. It also provides a valuable insight to the managers on the procurement policy, when per unit cost of power under long-term PPAs varies. The data on the back-down percentage of power under long-term PPAs vary from as low as 0 per cent to as high as 45 per cent. The input data further reveal that the suppliers supplying power at a very low cost do not necessarily offer a very high back-down percentage. For example, the generators supplying power at INR 0.96, 0.99 and 3.26 per unit have a back-down percentage of 0, 0 and 45 per cent, respectively. When the back-down percentage of the suppliers' increases, the available capacity of some of the expensive suppliers becomes restricted, which allows the model to purchase more volume of power from the cheaper options. Thus, the total procurement cost under long-term PPAs increases and the same under day-ahead and term-ahead options decreases. This gives a rich insight to the managers as to how to use an agreed-upon back-down percentage (with different suppliers) in different contexts with a view to minimizing the total power procurement cost.

Power procurement framework developed in the present work by combining the dimensions of uncertainty in power supply and cost of power procurement seems to add a fresh perspective to power procurement literature. This serves as an aid to managers in decision-making in respect of power procurement under different scenarios as follows:

- inexpensive and certain supply;
- expensive and certain supply;
- inexpensive and uncertain supply; and
- expensive and uncertain supply.

9. Conclusion

The entire work has been carried out in two phases. The first phase involves the development of an optimal power procurement plan while the second phase concerns itself with the development of power procurement framework. In fact, the idea of power procurement framework has originated from the findings of the stochastic MILP model. The power procurement framework gives rise to four major scenarios under which the distribution utility has to devise appropriate strategies for procuring power to meet the demand of end consumers at minimum cost.

Stochastic MILP model developed in the present work has resulted in optimal procurement plan. The plan has clearly specified the volume of power to be procured through long-term PPAs and the day-ahead and term-ahead options, which would eventually optimize the cost of power procurement. Currently, the utility is under obligation to purchase at least a certain volume of power from all 41 suppliers under long-term PPAs, despite the unit cost of power of some suppliers being quite high. However, the optimization model suggests that the utility should attempt to procure power only from the selected set of suppliers. The study has carried out sensitivity analyses on different parameters including demand, cost of power under long-term PPAs, back-down percentage, availability of power under day-ahead purchase, etc., and presented the findings with suitable justifications. Finally, the findings of sensitivity analyses have prompted us to develop a power procurement framework keeping in mind the cost of power procurement and uncertainty in the supply of power. This framework could also be made applicable to other distribution utilities.

The study is not without limitations. Day-ahead purchase cost and sale price of power is fraught with volatility. The study has made a simplifying assumption with regard to capturing the volatility of purchase cost and sale price of power by classifying the same under three scenarios and assigning objective probabilities estimated using past observations of relevant data. Based on this, the study has developed a simple stochastic model. Future work should devote towards developing a sophisticated stochastic model, which would capture the volatility of purchase cost and sale price of power in day-ahead markets. Power procurement framework developed in the present work could further be validated by considering examples of distribution utilities from different contexts. Further, the procurement framework provides certain ideas to the future researchers to formulate appropriate procurement strategies of power under different scenarios with a view to minimizing power procurement cost.

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Appendix 1

Time slot (h)	Demand (MW)
00.00-01.00	1,365.059
01.00-02.00	1,279.219
02.00- 03.00	1,226.599
03.00-04.00	1,183.802
04.00-05.00	1,155.934
05.00-06.00	1,170.208
06.00-07.00	1,213.591
07.00-08.00	1,216.287
08.00-09.00	1,246.527
09.00-10.00	1,354.8
10.00-11.00	1,408.829
11.00-12.00	1,437.485
12.00-13.00	1,454.895
13.00-14.00	1,457.025
14.00-15.00	1,518.491
15.00-16.00	1,547.096
16.00-17.00	1,512.66
17.00-18.00	1,487.793
18.00-19.00	1,498.438
19.00-20.00	1,607.364
20.00-21.00	1,645.318
21.00-22.00	1,649.342
22.00-23.00	1,688.472
23.00-24.00	1,625.443

Table AI. Estimated demand data for one day in 24 slots

Appendix 2

Table AII. Maximum allocated capacity (MW), unit variable cost (INR), maximum back-down percentage of each supplier under long-term PPAs, daily fixed cost of power (INR) to be paid to supplier under long-term PPAs and percentage of transmission losses from 00.00 to 24.00 h

Supplier	Maximum allocated capacity (MW) under long-term PPAs	Unit variable cost under long-term PPAs (INR)	Maximum back-down percentage under long-term PPAs	Daily fixed cost to be paid (INR) under long-term PPAs	% of transmission losses
S 1	559	3.26	0.45	50,496.33333	0.0053
S 2	545	3.06	0.45	36,515	0.0053
S 3	381	2.92	0.45	38,608	0.0053
S 4	189	1.32	0.45	1,197	0.0203
S 5	80	1.88	0.45	1,440	0.019
S 6	43.92	1.33	0.45	1,332.24	0.0203
S 7	55.34	1.332	0.45	1,770.88	0.0203
S 8	78	1.34	0.45	8,008	0.0203
S 9	29.64	1.39	0.45	800.28	0.0203
S 10	10.53	2.86	0.45	582.66	0.0231
S 11	20.64	2.86	0.45	1,121.44	0.0231
S 12	12.74	2.86	0.45	849.3333333	0.0231
S 13	235.6	3.64	0.2	7,303.91	0.0056
S 14	9.76	2.73	0.45	673.44	0.0153
S 15	22.39	2.41	0.45	2,067.343333	0.0128
S 16	69.11	2.31	0.45	3,754.976667	0.0128
S 17	13.73	0.96	0	320.3666667	0.0223
S 18	29.58	1.11	0	433.84	0.0128
S 19	27.72	0.99	0	609.84	0.0128
S 20	20.39	2.12	0	971.9233333	0.0128
S 21	25.64	1.51	0	683.7333333	0.0185
S 22	34.69	2.79	0	2,058.273333	0.0128
S 23	34.69	2.16	0	1,827.006667	0.0212
S 24	8.35	1.57	0	501	0.0232
S 25	45.88	2.74	0	1,315.226667	0.0128
S 26	36.73	0.81	0	893.7633333	0.0078
S 27	22.38	2.42	0	1,842.62	0.0078
S 28	43.67	2.7	0	2,489.19	0.0153
S 29	27.34	1.96	0	1,594.833333	0.0153
S 30	62.39	1.19	0	1,372.58	0.0128

(*continued*)

Supplier	Maximum allocated capacity (MW) under long-term PPAs	Unit variable cost under long-term PPAs (INR)	Maximum back-down percentage under long-term PPAs	Daily fixed cost to be paid (INR) under long-term PPAs	% of transmission losses
S 31	20.64	2.37	0	1,549.34	0.0167
S 32	24.53	3.41	0	2,456.89	0.0153
S 33	131.75	2.06	0.3	6,894.916667	0.0103
S 34	43.92	2.46	0.4	2,020.32	0.0103
S 35	59.29	3.12	0	34,098.12	0.0053
S 36	172.1	2.68	0.1	22,086.16667	0.0053
S 37	93.36	2.94	0.1	3,858.88	0.0053
S 38	426.8	3.45	0.1	41,119.88333	0.0053
S 39	6.69	2.75	0	1,235.34	0.0053
S 40	20	2.16	0	6,543.45	0.0332
S 41	20	5.5	0	54,960.4	0.0053

Table AII.

Appendix 3

Time slot	Scenarios for unit purchase cost Most likely	Pessimistic	Optimistic	Scenarios for unit selling price Most likely	Pessimistic	Optimistic
00.00-01.00	4.208	5.1	4.1	2.52	2.2	2.8
01.00-02.00	3.338	4.85	3.1	2.42	2.1	2.76
02.00-03.00	3.1	4.85	2.916	2.26	2	2.45
03.00-04.00	3.1	4.85	2.361	1.71	1.5	1.98
04.00-05.00	2.365	3.5	2.2	1.50	1.3	1.6
05.00-06.00	2.2	3.5	2.08	0.97	0.8	1.04
06.00-07.00	2.557	3.5	2.2	1.68	1.54	1.87
07.00-08.00	2.499	3.5	2.2	1.54	1.4	1.78
08.00-09.00	2.499	3.5	2.2	0.85	0.75	1.02
09.00-10.00	2.504	3.5	2.2	1.71	1.54	1.9
10.00-11.00	2.709	3.85	2.55	1.39	1.2	1.45
11.00-12.00	2.774	3.85	2.55	1.75	1.45	1.9
12.00-13.00	2.85	3.85	2.55	1.79	1.45	1.9
13.00-14.00	2.699	3.85	2.55	1.68	1.42	1.82
14.00-15.00	2.55	3.85	2.425	2.01	1.86	2.34
15.00-16.00	2.55	3.85	2.477	2.17	2.02	2.45
16.00-17.00	2.55	3.85	2.409	2.10	1.96	2.49
17.00-18.00	2.55	3.85	2.175	1.57	1.4	1.98
18.00-19.00	2.55	3.85	2.312	1.56	1.43	1.65
19.00-20.00	4.347	5.1	4.1	3.05	2.8	3.45
20.00-21.00	5.1	6.0234	4.1	4.41	4.1	4.89
21.00-22.00	5.1	5.994	4.1	4.19	3.94	4.56
22.00-23.00	5.075	5.1	4.1	2.96	2.78	3.1
23.00-24.00	4.1	5.1	3.996	2.28	2.03	2.68

Table AIII.
Unit purchase cost and unit selling price of power under day-ahead and term-ahead option from power exchange

Appendix 4

Time slot (h)	Available volume (MW)
00.00-01.00	650
01.00-02.00	650
02.00-03.00	670
03.00-04.00	670
04.00-05.00	670
05.00-06.00	550
06.00-07.00	550
07.00-08.00	550
08.00-09.00	550
09.00-10.00	550
10.00-11.00	875
11.00-12.00	875
12.00-13.00	875
13.00-14.00	875
14.00-15.00	875
15.00-16.00	770
16.00-17.00	770
17.00-18.00	770
18.00-19.00	950
19.00-20.00	950
20.00-21.00	950
21.00-22.00	950
22.00-23.00	860
23.00-24.00	680

Table AIV. Maximum volume of power (MW) available from the power exchange under day-ahead and term-ahead options

Appendix 5

Table AV. Probability distribution of purchase cost and sale price of power under day-ahead and term-ahead options

Variable	Scenario probability		
	Most likely	Pessimistic	Optimistic
Purchase cost	0.70	0.2	0.1
Sale price	0.75	0.15	0.1

Appendix 6

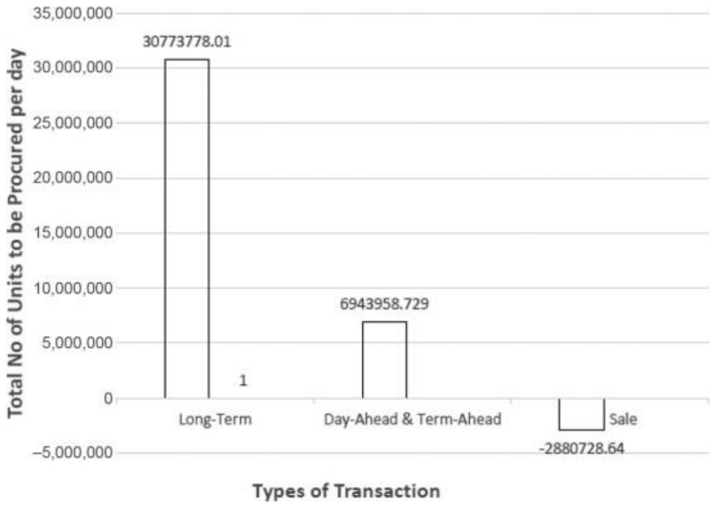

Figure A1.
Optimum volume of power to be procured (in MW)

Appendix 7

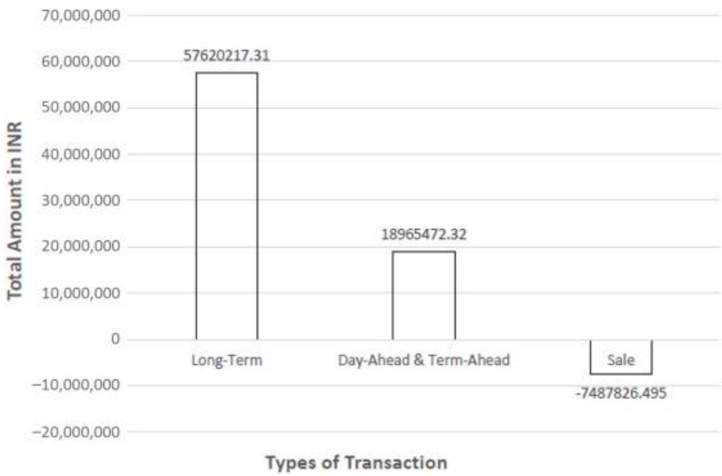

Figure A2.
Optimum cost of procurement of power (in INR)

Appendix 8

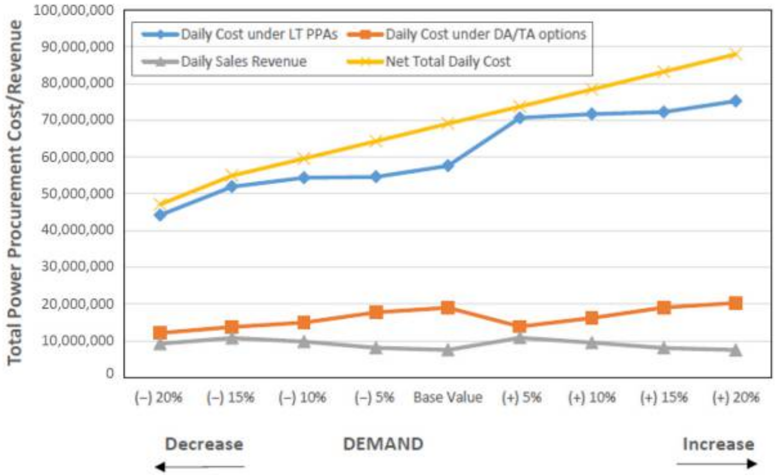

Figure A3.
Impact of demand variation on elemental costs of power procurement

Appendix 9

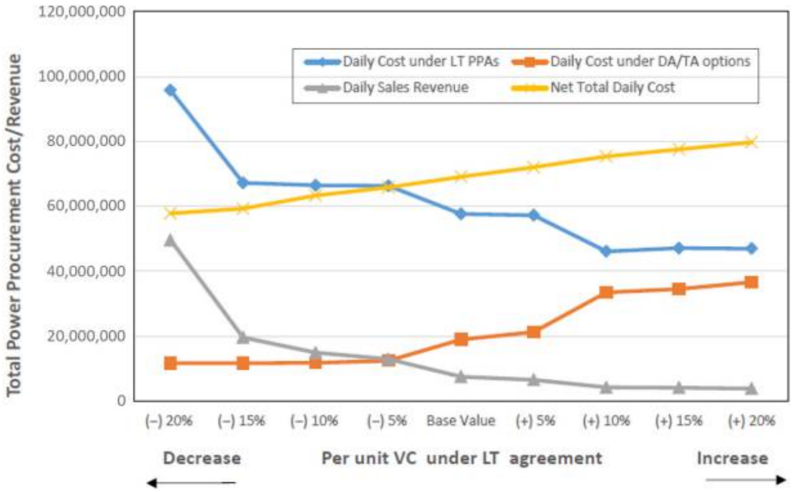

Figure A4.
Impact of variation in the unit cost of procurement under PPAs on elemental costs of power procurement

Appendix 10

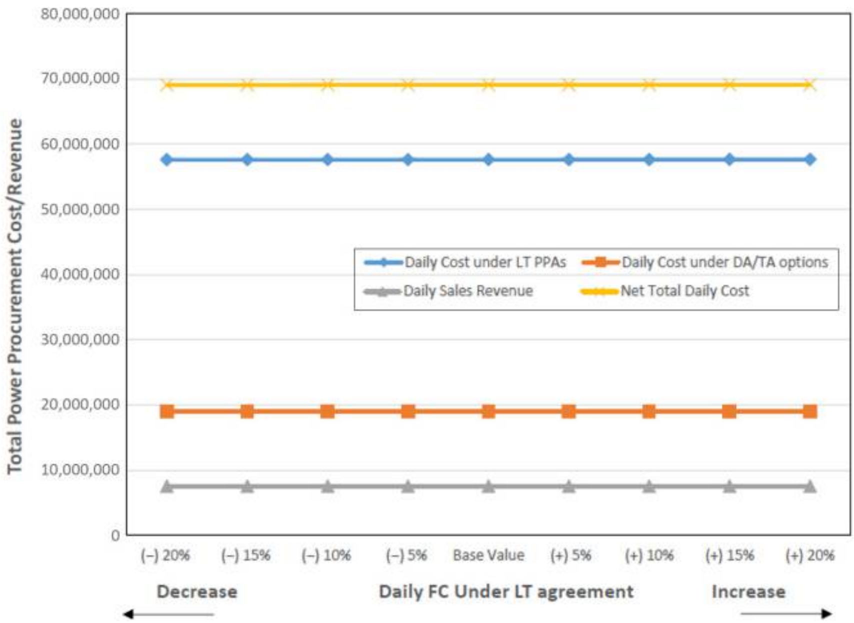

Figure A5.
Impact of variation in the fixed cost on elemental costs of procurement

Appendix 11

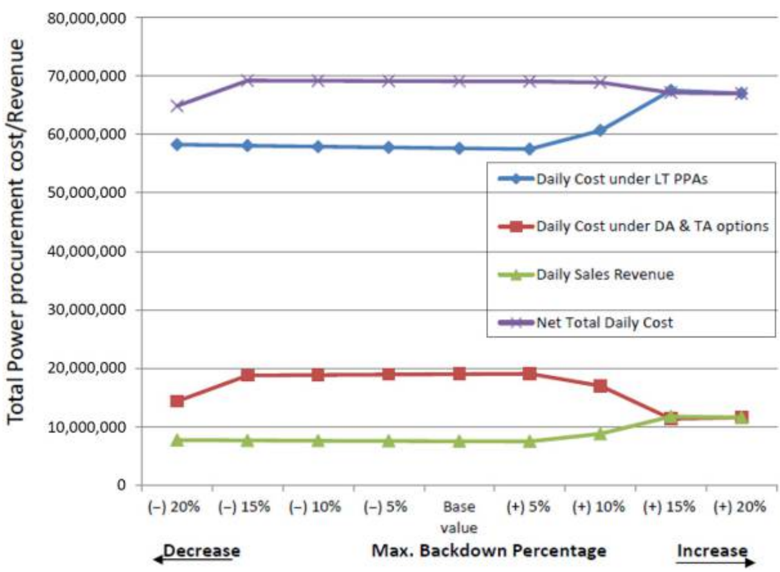

Figure A6.
Impact of variation in the back-down percentage on the elemental costs of power procurement

Appendix 12

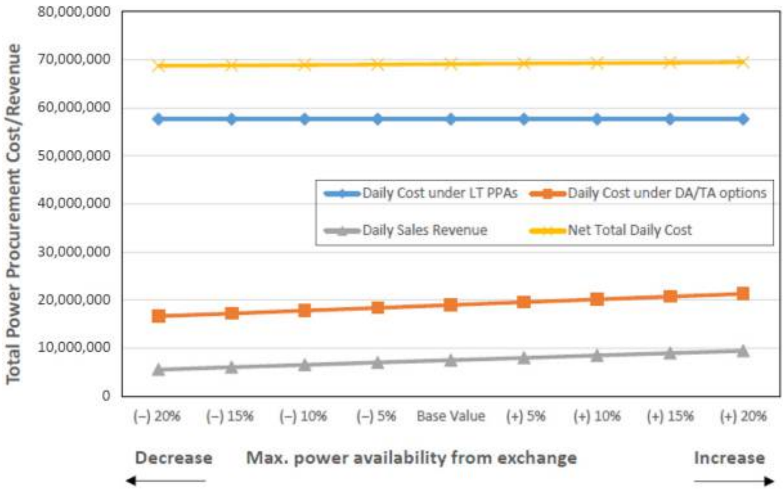

Figure A7. Impact of variation in the availability of power from power exchange on elemental costs of power procurement

Appendix 13

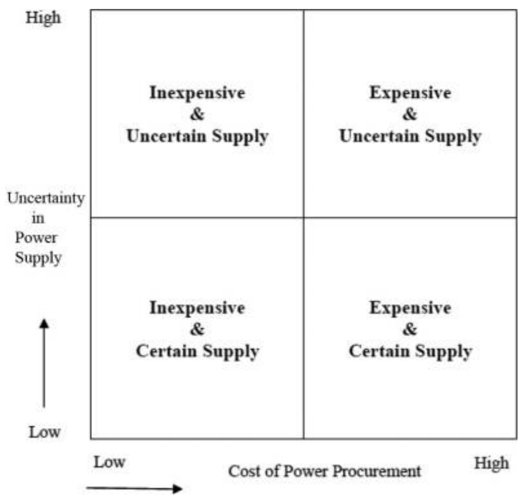

Figure A8. Framework of power procurement

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