Chapter 7

Capacity expansion Model

7.1 Background

Investment right from the days of the publicly owned vertically integrated structure has remained most contentious issue in the power sector of many countries. India's quest to recover investment cost has been quite challenging. Commercial viability loomed large in the tone of many amendments of Electricity Supply Act 1948 and committee reports that were set up after the independence. The problem of the recovery of the costs became so serious that the World Bank stopped financing of the power plants through State Electricity Boards and helped India to create the National Thermal Power Corporation (NTPC) and the National Hydro Power Corporation (NHPC) during the second half of seventies under the ownership of the Government of India. SEBs (State Electricity Boards) were expected to buy power from these companies. In order to make sure that these organisations does not face defaults, asset confiscation from the SEBs were mandated. Indeed, defaults took place and NTPC grew many folds over the time due to assets transfer from SEBs.

This could solve the problem of defaults for World Bank but getting the additional capacity was still a problem. In order to motivate private/foreign investment American style Independent Power Producer (IPP) programme[1] was initiated. IPPs sold power to respective State Electricity Boards under a power purchase agreement (PPA) decided by the state/central regulatory commissions. Because of various in-

[1]Public Utilities Regulatory Policies Act (PURPA) 1978 of the US enabled the entry of purely non-utility generating companies. This Act required unities to buy power from cogenerators, renewable energy based plants and IPPs at the rates decided by Federal Electricity Regulatory commissions.

centive problems it, failed to bring in the intended amount of investment. This kind of programmes were initiated in many developing countries for adding capacities in the generation sub-sector. In order to ensure the participation of the private/foreign investors, many risk covering and high return provisions were introduced in power purchase agreements. In case of India, the respective state governments acted as guarantor of the SEBs in case of defaults by them. This guarantees were further beefed up by the counter guarantee of the central government. Investors were provided with a fixed rate of return on their equity and insurance against exchange rate fluctuations and fuel cost. Incumbent incentive ambience in which such investment projects got the green signal was not very friendly to long term interest of the power sector.

In this model, a potential IPP has to approach the state government instead of the SEBs who are supposed to buy power from them for finalising the deal[2]. This created incentive for the political representatives to appropriate some pecuniary benefits. It was made sure that IPPs do not become the victim of hold-up problems since there was only one buyer of output produced by it. Such bilateral monopoly situations typically lead to hold-up problems when huge sunk costs are involved as is the case of generation sub-sector. As potential investor has no way to recover his cost if the buyer declines to buy *ex-post.* On the other hand, the buyer has all the incentive to overstate the importance of investment *ex-ante.* Therefore, the contract between IPP and the State Electricity Board/distribution company is to be worded in such a way that the IPP recovers all its costs through the tariff paid by SEBs, thus controlling for opportunistic behaviour of the SEBs/DISTCOs and also simultaneously making sure that IPPs are not able to misuse the provisions of the contract for opportunistic behaviour. In case of most of the PPAs, the design of the contract was such that it was successful in controlling the opportunistic behaviour by the the SEBs but

[2]There are two routes of engaging an IPP – 1) Memorandum of Understanding (MoU) and 2) competitive bidding. Politicians, till now, have preferred MoU route as they can appropriate some pecunary benefits. we have commented on this in chapter 4

did not effectively control for the opportunistic behaviour by the IPPs. This problem itself was a manifestation of perverse incentive structure at higher levels – the relation between the political representatives and the SEBs. The contract was usually decided by the government representatives instead of the SEB managers who have many more things in their objective function than just minimising the cost of the electricity for meeting the demand. Politicians in power used their position to benefit themselves unduly through kickbacks from the potential investors. These kickbacks were included in the contract through various provisions which would be recoverable over the time through tariff. This resulted into very high cost of procurement of power by the SEBs. in fact, in many cases, SEB's own generation cost was much lower than tariffs that were charged by IPPs. Because of this, opposition for IPPs grew up very strongly and contracts were renegotiated in many cases. Series of renegotiations and judicial conflicts in PPAs must have had its effect on the future potential investors. As a result IPP programme has failed to bring in expected investment in the power sector (Bell 2003).

In 2006, the Central Electricity Regulatory Commission came up with a staff paper documenting failure of the IPP programme and suggested spot market mechanism for motivating efficient investment in generation sub-sector in terms of fuel choice and location of the plant (CERC 2006). Some scholars have already argued that large developing countries like India with weak regulatory system have high likelihood for successful operation of the spot market (Phadke 2006). This is because life in such countries are less dependent on electricity so people can respond to high prices by reducing their demand i.e., price elastic demand, thus reduced scope for market power exercise. Inelastic demand in western electricity markets are considered to be one the major contributors of market power exercise. We have already shown in our previous chapter that it is not end the users who will respond to high prices but the SEBs/distribution companies who serves the end users. Political representatives usually through informal means force the regulator to keep the prices at less than optimal level for political considerations. This reveals politicians' willingness to accept load shedding in times of high prices in the spot market. Therefore, the demand response in developing country like India would not be an individual choice as imagined in the context of developed countries. Instead, it is an outcome of political equilibrium in the society. Sub-optimal retail tariff fixed by the regulator (under political pressure) limits the ability of the SEBs/distribution companies to satisfy the earmarked level of demand in hours of high prices. We have already seen that even small reduction in demand by SEBs/distribution companies have considerable effect on the spot market prices (chapter 7).

We intend to model investment behavior in a competitive set up. Expectation about future prices that are going to be realized in spot market are the sole motivator of the investment. Each generating stations bid as per their short run marginal cost. Most important signal for future investment is the scarcity rents earned by each fuel type of the plant which have discuused in chapter 6. Scarcity rents earned by respective fuel-type generators will drive proportionate levels of investment in different fuel types. We underline the intuitive idea of such mechanism in the following paragraphs.

7.2 Generation Planning in a Market Based model

The theory is that if the market is organized such that all generating units bid their marginal cost of production to a system operator who dispatches plants and sets a market price based on the marginal (last) bid accepted, then a least cost dispatch will be achieved and efficient price signals will be provided for all production, consumption, and investment decisions. Generators will not have to guess about the clearing price in order to maximize profits and efficiency will not be distorted by incorrect guesses (Fraser 2001).

In such a system it is easy to see how the proper price signal encourages short-run efficiency in production and consumption. For instance, what bidding strategy would maximize short-run profits for a firm that was a pure price taker, i.e., had no ability to influence market prices? Under this model such a firm maximizes profits by bidding at marginal cost.

- If the firm bids above marginal cost, there is a chance that the firm would not be dispatched and yet could have made profits at the market-clearing price.
- Conversely, if the firm bids below marginal cost, there is a possibility that the firm would be dispatched at a price that was less than its costs and would therefore make losses.

Marginal cost bids, with a single clearing price as described above, produce the proper price signals to encourage efficiency in production and consumption and maximize the short-run profits of a firm in a perfectly competitive market. Yet, it is less easy to see how the above market model will provide the right incentives in a competitive market for development of an optimal amount of capacity, and that too of the right type, as the old industry model did. The theory is, however, rather simple. Market participants theoretically have incentives to build the same amount and type of capacity as central planners. The same basic economic principles apply to decentralized investment decisions as did to centralized ones-the difference is that the centralized model relies on internalizing quantity decisions and the decentralized one relies on external price signals, profit incentives, and the existence of well-structured markets.

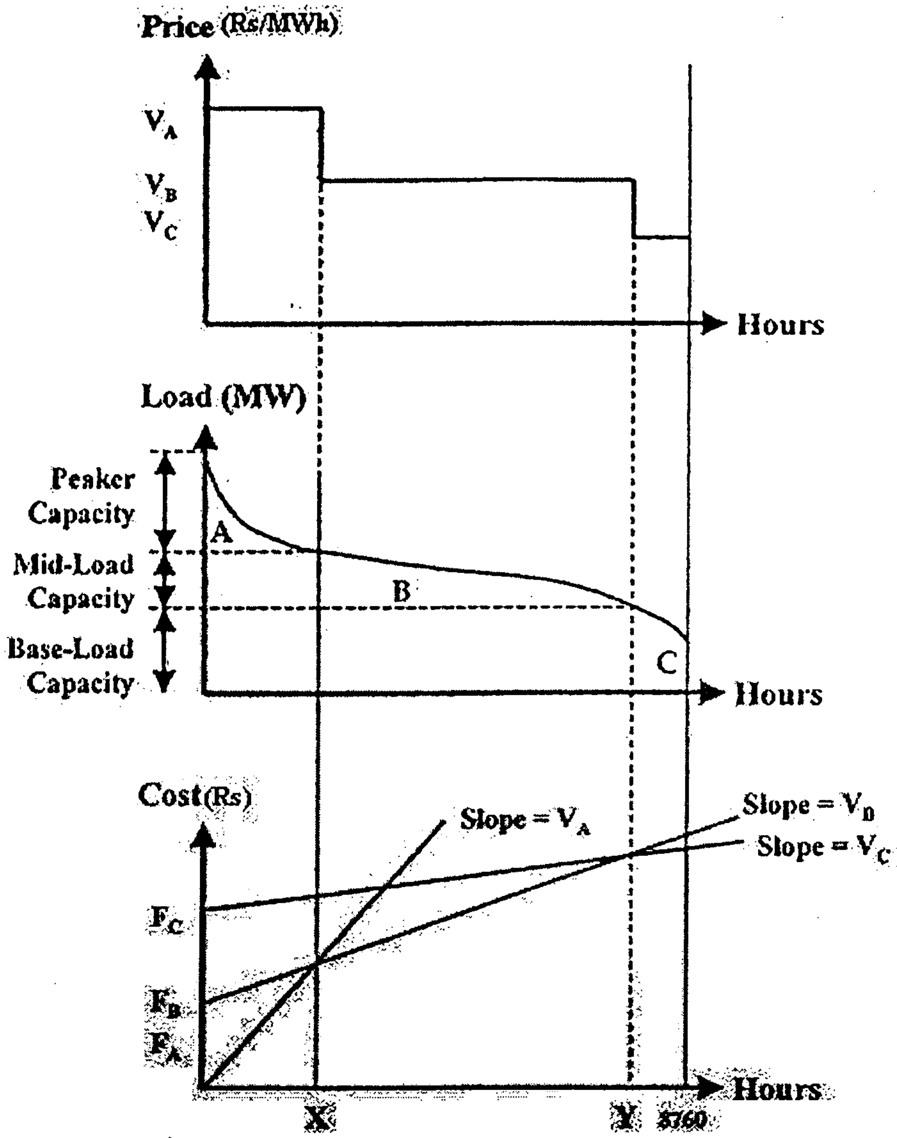
In the following we illustrate how marginal cost bids and a clearing price based on these bids will provide the right incentives in a competitive market for development of an optimal amount of capacity, and capacity of the right type. In below we ouline the mechanism of development optimal capacity of gneration in terms technology types. It is an abridged version of mechanism oulined by (Fraser 2001).

7.2.1 Step 1: Determination of Peaking Capacity

Let us assume (for keeping things simple) that peaker has zero fixed cost and each plant is of one MW capacity. In peak hours, the market price would be equal to the marginal cost of the peaking plant V_A. So he will make zero economic profit. The term "economic profit" refers to profits in addition to those necessary to remain in business –an economic profit of zero doesn't mean that the generator will go bankrupt. The answer to the question, "How many peakers will be built?" is determined by a profitability analysis of mid-load plants. We represent it in a three panel figure (Figure 7.1) .The mid panel of the figure represents annual load duration curve with three load categories A, B and C representing peak, mid and base loads respectively. The lowest panel in the figure represents usual cross over diagram where total cost of the different types of the plant are compared to know competitiveness of different types plants. The top panel gives annual price duration curve. Mid-load plants will undercut peakers at the level of output, X, where they can first recover all their costs, fixed and variable. This occurs when $PX = F_B + XV_B$, where P is the price in the spot market F_B and V_B are fixed cost and the marginal (variable) cost of the mid load plant.

Alternatively, the crossover point between peakers and mid-load plants is defined by the function $XV_A = F_B + XV_B$, as shown in (Figure 7.1) i.e., if the price of the spot market remains at V_A for X hours, mid-load plants which obviously run during peak load can recover their total fixed cost and variable cost. Therefore in each additional hour that these units run beyond X, they are price-setters and thus receive a price equal to their marginal cost.Thus, peakers are not dispatched in any additional hour beyond X. Economic profits for mid-load plants therefore remain at zero. Since no peaker runs beyond X hours, the economic profit of peakers stays at zero. But it is to be kept in mind that base load plants that are also running during X hours and later are in the process of recovering their total fixed cost because their variable cost(V_C) is less then V_A and V_B. The level of peak capacity that will be built is shown in the vertical axis of the mid panel of the figure.

Figure 7.1: Determination Capacity for different types of Plant



Source: Adopted from (Fraser 2001)

7.2.2 Step 2: Determination of the Mid-Load Capacity

The answer to the question, "How many mid-load plants will be built?" is determined by a profitability analysis of base-load plants. Base-load plants will undercut mid-load plants at the level of output, Y, where they can recover all their costs, fixed and variable cost i.e., when the revenue from running in Y hours first equals or exceeds $F_C + YV_C$ where F_C is total fixed cost of the base load plants. Since the revenue from running in Y hours equals $F_B + YV_B$ (because mid-load plants make zero economic profits), the crossover point between mid-load plants and base-load plants is defined by the point where $F_B + YV_B > F_C + YV_C$, as in Figure 7.1. Alternatively, if the Price of the spot market remains at V_A for X hours and at V_B for $Y - X$ hours base load plants will be able to cover all of their fixed cost.Therefore, they will become the price setters in the spot market for each additional hour beyond Y hours. The capacity of mid-load plants that would be built is shown in the vertical axis of the mid panel of the figure 7.1. Economic profits of the base load plants therefore remain at zero, and hence the economic profit of all generators built is zero

7.2.3 Step 3: Determination of the Base-Load Capacity

Simple answer to this is that base-load plants will meet all the remaining capacity requirements not met by peakers and mid-load plants. Thus we see that results are same as is usually achieved in centralised planning models. But in this model we achieve the results through centralised price discovery system and profitability analysis.

Suppose, for any reason the market does not produce the right allocation of capacity, market participants will have profit incentives to self-correct the allocation. For example, if the proportion of peakers is too high, then existing mid-load plants will have economic profits greater than zero and the new mid-load plants will have incentives to enter. This would push down the prices until their economic profits are zero, and therefore no more entery. The opposite would be true if there are too many mid-load plants and too few peakers.

7.3 The Model

Let us consider the problem from the system operator's point of view. The system operator (regulator) of the bulk market tries to minimise the total cost of the meeting demand in the long-run. In order to meet the demand some new plants have to be introduced in the system. In order to incetivise the new plants regulator includes the the recovery of the fixed cost of the new plants in his objective function i.e., total cost of meeting loads. We take such an objective funtion for system operator because many libralised markets are facing decline in the reserve margin. Experts claim that energy only markets (which we solved in chapter 6) does not provide ennough incentive for optimal capacity addition (see chapter 8 for review on this issue). Existing plants do not need such incentive as they would consider their investment as sunk cost. Existing plants would be producing as long as they are able to recover their total variable cost.

In the spot market, producers are profit maximizer. They dispatch their power plants in order to minimize the total cost. As generators are assumed to be perfectly dispatchable, j represents the different technologies. In the following we represent the problem of the system operator (regulator) of the bulk market. Now that he is acting in log run horizon he optimises not only on the production from the existing capacity of different technologies as was done in the short run model of the chapter

6 and 7 but also by changing the capacity of the different technologies itself.

$$
\begin{aligned}
&\min_{x_{i,\ell},y_j} \sum_{\ell} \tau(\ell)\left(\sum_{i\in I} v_i x_i z_{i,\ell} + \sum_{j\in S_p,S_m,S_b} c_j y_j\right) + \sum_{\forall \ell} \sum_{j\in S_p,S_m,S_b} F_j y_j \\
&s.t. \begin{cases}
\sum_{\ell=p,m,b}\left(\sum_{i} x_i z_{i,\ell} + \sum_{j\in S_p,S_m,S_b} y_j\right) = D_p & \pi_p \\
\sum_{\ell=m,b}\left(\sum_{i} x_i z_{i,\ell} + \sum_{\forall j\in S_m,S_b} y_j\right) = D_m & \pi_m \\
\sum_{\ell=b}\left(\sum_{i} x_i z_{i,\ell} + \sum_{j\in S_b} y_j\right) = D_b & \pi_b \\
x_i \leq \bar{x}_i & \mu_{i,\ell} \\
z_{i,\ell} = 0,1 & \\
\sum_{\ell=p,m,b} z_{i,\ell} \leq 1 &
\end{cases}
\end{aligned}
\tag{7.1}
$$

In expression (6.2) ℓ represents peak load (p), mid-load (m) and base load (b) respectively. τ represents the duration of load ℓ. Therefore, $\tau(\ell)$ represents the duration of a particular load segment. For our simulation purpose we have annual load duration curve of three steps. τ i.e. duration for $\ell = p$ is 438 hours (representing peak load), $\ell = m$ is 2190 hours when (representing mid-load) and $\ell = b$ is 6132 hours when (representing base load). This division of 8760 hours among diffrent load segment is based on the study of Sengupta (1992). S_p, S_m, S_b are sets of new plants (candidate plants) for peak load, mid-load and base load respectively with each having j technology. v_i is the marginal (variable) cost of the existing plant i. x_i is production from plant i in load segment ℓ. c_j and y_j are the variable cost and capacity of the new plant of technology j respectively. $z_{i,\ell}$ is the integer variable with 0 (when the plant is not dispatchable) and 1 (when plant is dispatchable) values for old plants. F_j is the annualised unit cost [Rs/MW] of the capacity of technology j. The objective function in (7.1) is the sum of the operating costs and investment cost (only for new candidate plants) over different plants' technology and time segments. First three constraints are basically stating that total production from existing and new plants in each load segment has to be equal to the total load of that period. Fourth constraint states that production of the old plants cannot exceed their designed capacity. There are three types technology that has been considered for investment in new plants – coal fired, combined cycle gas turbine (CCGT) and diesel generation sets. CCGT plants can be fired from two alternative fuels gas and naphtha. The dual of the first three constraints appearing in right side of the respective constraint in expression 7.1 i.e., π_p, π_m and π_m divided by the respective numbers of hours of load duration gives us the long run marginal cost (LRMC) of meeting given loads. The dual associated with the fourth constraint (capacity constraint of the old plants) will provide us with scarcity rents earned by the old plants in different load segments.

This model decides the optimal capacities of the new plants of above three technologies to minimise the total cost of meeting the loads around the year.

7.4 Data & Results

Our results are based on the following assumptions about load and costs of the technology given in tables 7.1 and 7.2. Duration of different loads are based on a study by Sengupta (1992). Information regarding levels of load are based on the data provided by the Central Electricity Authority of India. We have taken representative of each load segment i.e., peak load, mid-load and base load on the basis of data that we obtained on monthly load pattern of India in table 6.2

We assume perfectly inelastic demand i.e., vertical demand curve. Given loads in table 7.1 for given number of hours will be met by the production from existing plants and new candidate plants that are going to be in place. Fixed cost [Rs/MW] (overnight annualised unit costs plus Operation and maintenance cost) and variable cost [Rs/MWh] (fuel cost) are given in table 7.2. Information regarding fixed costs

Table 7.1: Assumptions about load and their duration

	load	duration	Share in Duration
Units	MW	Hours	%
Base	46350	6132	70
Mid	61800	2190	25
Paek	82400	438	5
Total	..	8760	100

are taken from the data of overnight costs of the plants that have recently achieved techno-economic approval from the CEA[3]. Assumption regarding fuel cost of new plants are based on the heat rate of the best performing NTPC plants and prices of fuel as given in the Report of the Expert Committee on Fuels for Power Generation (CEA 2004).

Information regarding capacity of old thermal plants are available from the website of the CEA and data regarding their fuel cost is calculated by obtaining the heat rate of each plant. Heat rates of some of the plants were obtained from CEA website. For the rest of the plants tariff orders by the respective regulators were used. After obtaining the heat rates we got the fuel cost [Rs/MWh] of the plants from following formula.

$$\text{Fuel cost per unit}(c_i) = \frac{\text{Heat Rate}}{\text{Calorific value}} \times \text{Price per unit of fuel}$$

calorific value of the specific fuel and their price were obtained from Report of the Expert Committee on Fuels for Power Generation (CEA 2004).

Two scenarios are considered here for India's power sector for capacity additions – 1) India has suffient gas supplies to meet fuel upcoming CCGT plants and 2) India does not have access to gas supplies for new plants but has sufficient naphtha supplies. In scenario (1) LRMC of mmeting loads throughout the year remain less when compared to second scenario as variable cost gas fired CGGT plants are definitely

[3]http://www.cea.nic.in/Thermal/Project%20Appraisal/private-thermal.pdf

Table 7.2: Assumptions regarding costs of new technology

	Overnight Cost	Fuel Cost
Unit	Million Rs/MW	Rs/MWh
Steam	7.95	890
Diesel	6.46	6160
CCGT(Gas)	6.24	679.31
CCGT(Naphtha)	6.24	3474.4

cheaper than the naphtha fired plants while their fixed cost are same. The differences between the two scenarios are more stark in when one compares LRMC of required amount of capacity additions to meet the peak loads.

Table 7.3: LRMC of meeting different load scenarios

Segment	load	Price [Rs/MWh]	
Unit	MW	only Gas	Only Naphtha
Base	46350	912.07	925.6
Mid	61800	983.63	1013.02
Peak	82400	10145.63	17720.98

In both scenarios the model suggests capacity additions from only CCGT technology. Even with very high cost of naphtha steam plants are not able to compete because of very high capital cost of coal plants. In both scenarios 1570 MW of the capacity is added by the CCGT technologies and nothing by rest of the technologies. Old diesel generating sets are operative only during the peak. Our results are based on restrictive assumption that there is no cost/hurdle in transporting electricity within the country. For example some of the northeast regions use diesel generating sets as stand alone system due to prohibitive cost of laying down transmission network in those areas. The competence of CCGT as suggested by the model can be corroborated from the fact that most of the independent power producers (IPP) establishment in India has opted for this technology.

The spot price as indicated by LRMC that provide sufficient incentive to investors for meeting the loads are quite high for both the scenarios (see Table 7.3). The question that whether such a price can be supported by the system. In the earlier chapter it was demonstrated that regulators usually fix less than optimal retail tariff for distribution companies which does not allow them to buy power from the spot market during peak hours when prices are very high. This is on account of the political influence of the government over the regulators of retail sector, often exercised through informal means. Reduction of demand during peak hours due to revenue constraint faced by the distribution companies will not allow such high prices to prevail in the spot market. Alternatively, This means that we have a system where is demand is responsive to budget constraint instead of price. Therefore, as long as the regulated retail tariff are fixed at less then optimal level it would not be possible to incentivise the investment in new plants. ..

7.5 Conclusion

As we have documented in earlier chapter that setting regulated retail tariff of electricity at less than optimal level brings about deviation in purchase plans of the SEBs/distributions companies, which has considerable effect on the prices that are realised in the spot market. Prices determined in such manner will have implications for investment as in a market based regime, prices are sole motivator for investment. The above model demonstrated the need of very high peak prices in order icentives the investment in new plants so that peak shortages of power can be removed in India. Our earlier model on demand response has clearly shown that there are remote chances that the spot market will achieve such high spot prices during peak hours owing to political influences exercised by state governments over the regulators. Under market based spot market model it would be hard to bring in new investment until regulators are sufficiently independent in fixing an optimal retail tariff.