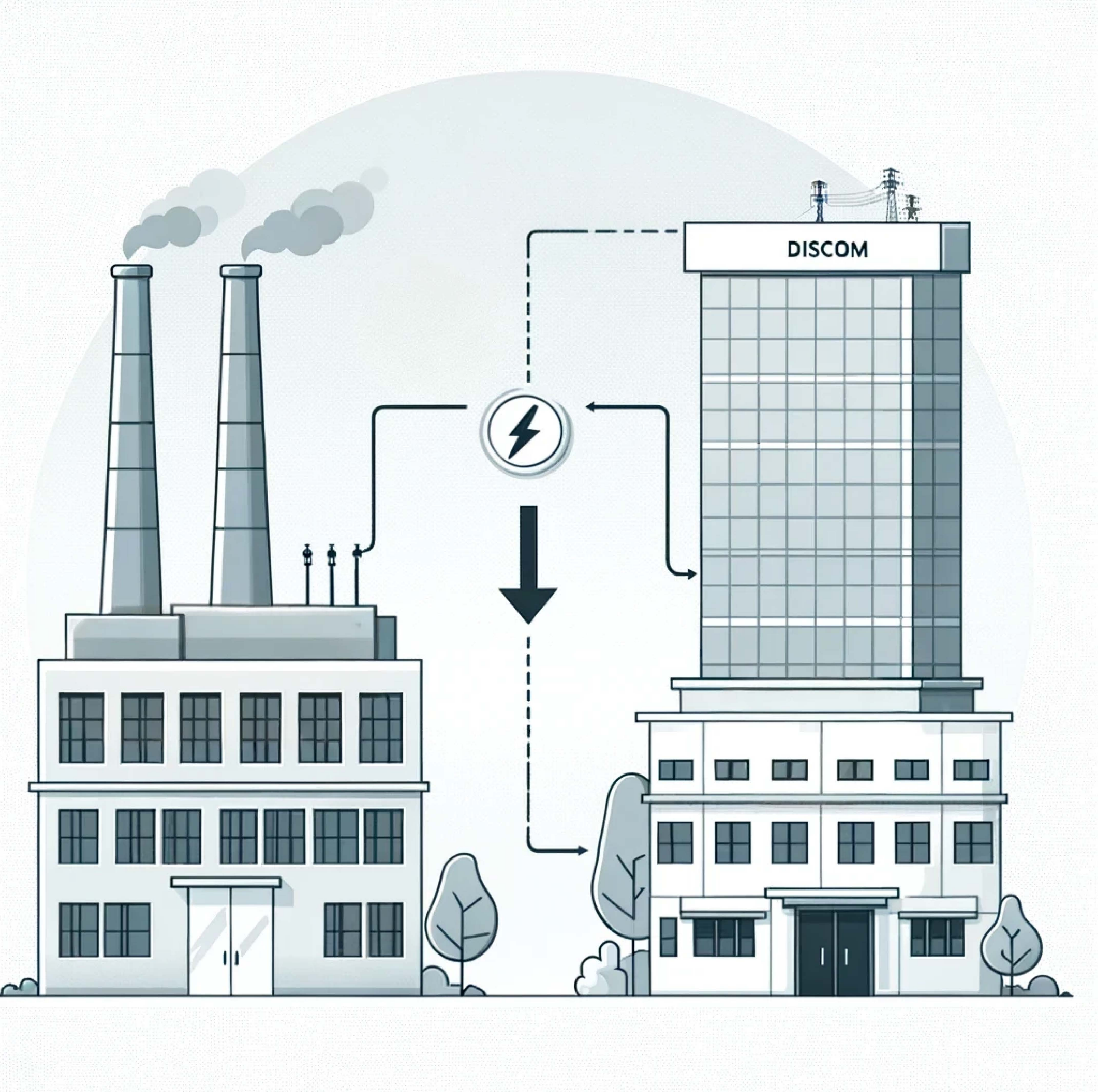
WEC India
Study on PPA Related Issues



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1. INTRODUCTION

World Energy Council India (WEC India) appointed Deloitte Touche Tohmatsu India LLP ("Deloitte" or "DTTILLP") to study the issues relating to Power Purchase Agreements in India.

The Scope of Work for the study covered primarily the following topics/areas.

This report is based on data and updates provided by the Central Electricity Authority and utilities across several states in India. International examples have been studied by Deloitte through its own network and publicly available sources, which are referenced at various points in the report.

The Draft Report is organised in the following two sections.

1. Analysis on PPA related issues and study of various market models covering the following:

    a. Analysis of current demand supply situation of the country and issues being faced by the distribution companies in operating in a regime of over 95% of their procurement locked into long-term power purchase agreements.

    b. Assessment of the future demand-supply situation and how resource adequacy [1]would pan out in the future years.

    c. Study of international wholesale power markets and how did they transit from bilateral contracting to liberalised market operations.

    d. Study of international examples of Distribution Operations and Retail Competition.

    e. Lessons for India and options for restructuring contracting for power in the future.

2. Renewable Integration Cost: The objective is to cover elements of integration costs, or the effective cost of renewable electricity, which will need to be considered in the Indian environment and report on any attempts made by other studies to quantify these additional costs of integration

[1]Resource adequacy for an electric power system means that there are sufficient generation and demand-side resources available to meet customers' current and projected electricity needs, including a reserve margin, at all times in a particular period of time.

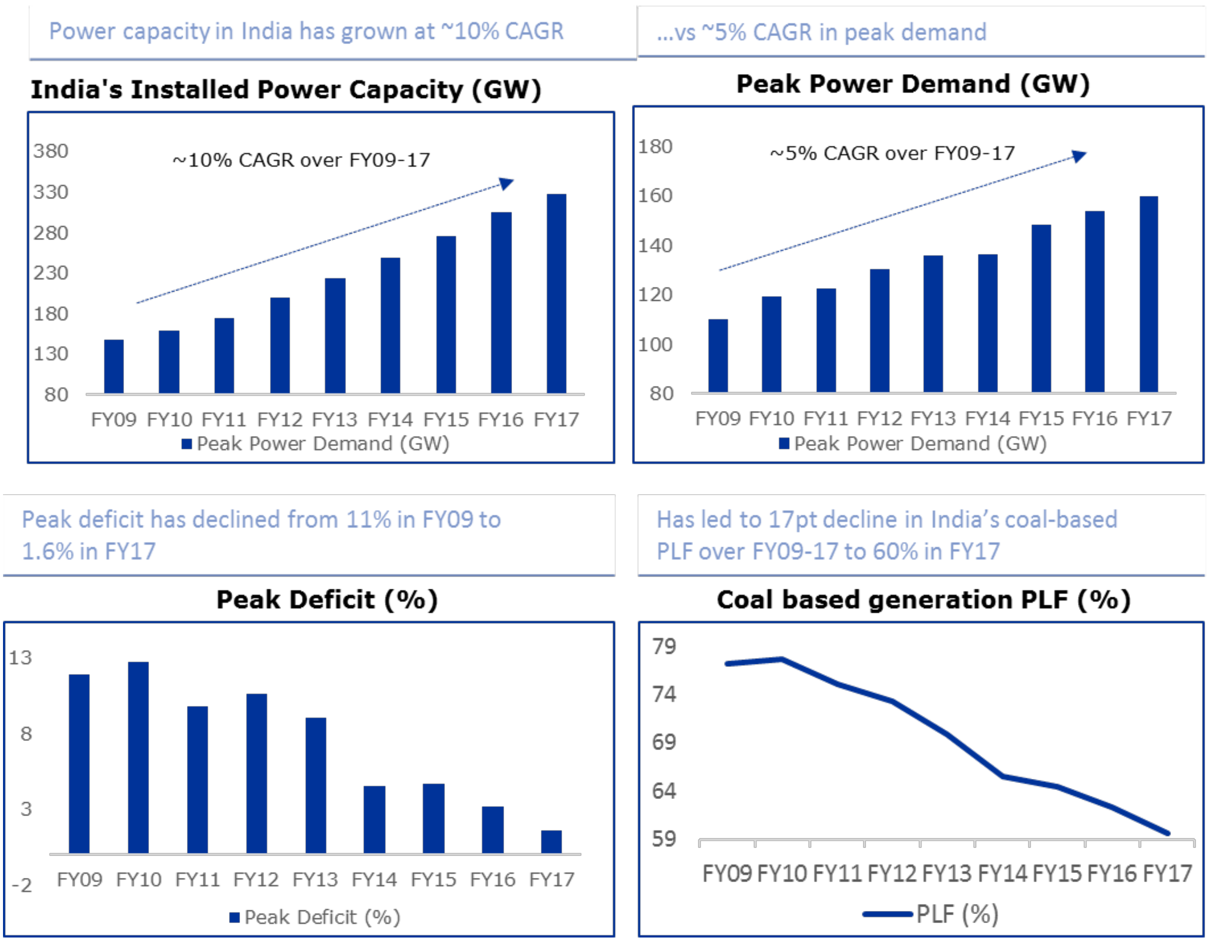
Chapter two

Analysis of PPA Related Issues in India

2.1. BACKGROUND

The Indian power sector has witnessed a sharp decrease in peak and energy deficits over the last four years. Considerable addition of conventional generation capacities led by unprecedented private sector investments coupled with projected growth in industrialization and economic activity has encouraged state power distribution utilities to tie up with several generators through long-term power purchase agreements.

FIGURE 1: POWER SCENARIO IN INDIA



In the recent past, there have been some instances of signed Power Purchase Agreements (PPAs) being cancelled by state distribution utilities or single buyer entities, as the case may be. In addition to such cases of cancelled PPAs, there is around 15.5 GW of un-tied coal based generation plants, which are complete but unable to supply power on a firm basis.

The country has also gone through a sustained period of decreasing tariffs for solar and wind power projects auctioned under the national and state policies, with wind and solar tariffs both beginning to settle substantially below INR 3.00 / kWh[2].

With lower than expected growth in peak demand over 12th five year plan period combined with an overhang of untied installed capacities and lower discoveries of renewable energy prices, state distribution / procuring utilities have ceased holding competitive bid processes for tying up long-term PPAs and are reluctant to sign on to long-term contracts in the future. This is in addition to the propensity to re-negotiate PPAs for already commissioned projects.

[2] At a wind power auction held by Solar Energy Corporation of India (SECI) in February 2018, the lowest tariff recorded was INR 2.44/kwh. Lowest solar tariffs recorded by SECI in its auctions under National Solar Mission has also been INR 2.44/kWh recorded in May 2017.

This creates issues not only in the short-run but also over the planning horizon, as conventional power plants take substantial planning and lead times to be commissioned and shortfalls in capacity cannot be rectified quickly in the future, should deficits emerge once again with demand inevitably picking up in India's developing economy.

Lower than expected demand growth, temporary surplus conditions and lower RE prices have made state utilities reluctant to sign long term PPAs

2.1.1. EXAMINING THE EXIT CLAUSES IN THE EXISTING PPAS

A few representative category of existing PPAs were analysed to examine options available to both contracting parties on early termination of agreement. The outcomes have been summarized below, while specific clauses have been outlined in Annexure II.

a. Review of Power Purchase Agreements of NTPC

It appears from a preliminary study that in the current structure of NTPC PPAs, there is neither an option to exit the contract nor provisions for review or renegotiation of terms and conditions.

b. Review of PPAs of IPP projects

There is significant variability in existing PPAs with IPPs. However, PPAs which were signed in compliance with the competitive bidding guidelines of the Ministry of Power, GOI, have followed the standard bidding documents and they have similarity in termination provisions. There are no exit clauses in these PPAs. However, there are specific termination provisions in the case of specified events of defaults, which provides rights to the non-defaulting party to seek termination. As far as termination payment is concerned, the party initiating termination due to default by the other party, is liable to get liquidated damages / risk purchase for a fixed term depending on the status of the power project, i.e., whether it is under construction or operation. For example, operation projects have capacity charges for 3 years as penal payment for the defaulter party.

c. Review of PPAs of RE projects in Andhra Pradesh, Telangana and Tamil Nadu

In case of the above Renewable Energy PPAs, there are specific termination clauses exercisable by one party in case of specified events of default by the other party.

2.2. POWER SUPPLY SITUATION IN INDIA

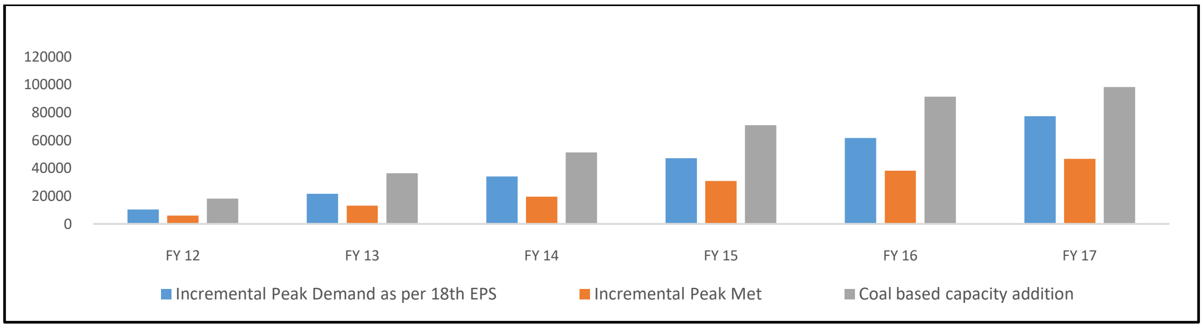
2.2.1. POWER SUPPLY POSITION

India has transcended from an era of chronic power shortages into an energy surplus scenario over the past 2-3 years. The major reason for this transformative shift is an unprecedented amount of conventional generation capacity addition over the 12th Five Year Plan period. As per Central Electricity Authority, against a target of 88,537 MW for conventional generation, actual addition was close to 100 GW. Over 55% of this capacity was added by the private sector.

In the absence of strictly monitored planning guidelines such as Resource Adequacy or Reserve Margins[3], as strictly monitored and enforced in liberalized international wholesale electricity markets, states in India planned such investments based on the demand projections in the 18th Electric Power Survey carried out by the Central Electricity Authority (CEA). The analysis below indicates the comparison of peak demand projections as per 18th Electric Power Survey (EPS), actual peak demand met during those years and corresponding coal based capacity additions.

[3] A measure of available capacity over and above the capacity needed to meet normal peak demand levels.. For instance, a reserve margin of 15% means that an electric system has excess capacity to the amount of 15% of expected peak demand. For a producer of energy, it refers to the capacity of a producer to generate more energy than the system normally requires. For a transmission company, it refers to the capacity of the transmission infrastructure to handle additional energy transport if demand levels rise beyond expected peak levels.

FIGURE 2: ALL INDIA- INCREMENTAL PEAK MET / EPS TARGET VS CUM. CAPACITY ADDITION (MW) OVER FY11 BASE



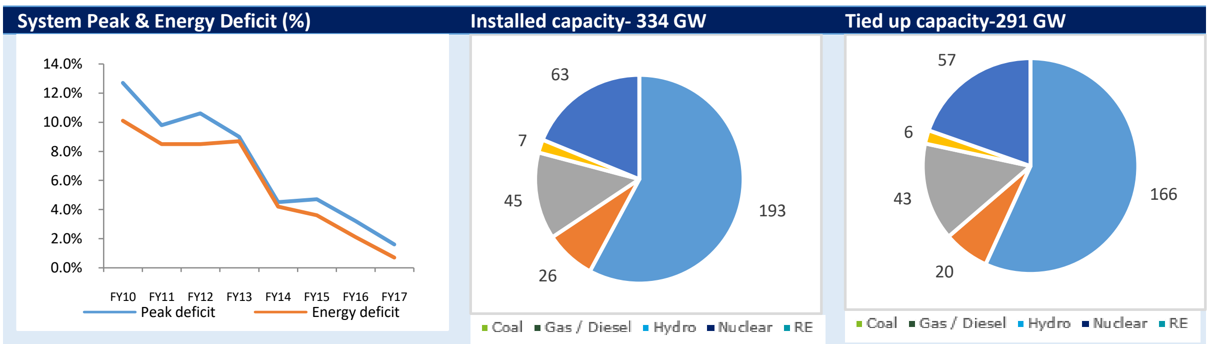
In contrast to unprecedented levels of capacity addition in coal based generating capacity over the 12th Five Year Plan period, demand growth fell well below levels projected in the 18th EPS. It was cumulatively 50% lower than the growth projected over FY12-FY17. While the past few EPS' have over-projected levels of peak demand, the expected demand growth was much lower in 18th EPS, presenting a double-edged problem of over-achievement in capacity addition and lower levels of demand growth particularly in the industrial segment over the past few years.

Peak deficit for the country as a whole has thus reduced from 12.7% in FY 2009-10 to 1.6% in FY 2016-17. Similarly, energy deficit has reduced from 10.1% in FY 2009-10 to 0.7% in FY 2016-17. The system peak demand met by India during 2016-17 was ~159 GW. Calculations suggest that the non-coincident peak demand (if peak demand of all states are added up, even though they occur at different times and would not contribute fully to the all India peak demand met) would be around 189 GW for the same year.

Presently, the country has around 334 GW of installed capacity of which ~291 GW is contracted under long-term PPAs. As most states are witnessing energy surplus, there has been a dearth of new procurement bids by any of the states resulting into almost 15.5 GW of new coal based generation still as un-tied.

Increased coal based capacity addition coupled with lesser than projected demand growth has led to overcapacity in the system leading to reduced peak / energy deficits and increase in stranded capacities and dearth of new procurement bids by the States

FIGURE 3: INSTALLED AND TIED UP CAPACITY



International Energy Agency (IEA) planning standards suggest a target of 15% reserve generation capacity, over and above the peak demand witnessed to be required in the system to meet demand reliably without unreasonable loss of load. It is observed from the table below, that the current capacity available in the country, to meet the peak demand, is not substantially above the limits if such a standard was to be considered. Regional and state-wise break-up is enclosed at Annexure III.

TABLE 1: PEAK DEMAND AND CAPACITY AVAILABLE

Non-coincident peak demand (GW)	Capacity required (including reserves at 15%) (GW)	Capacity available		
		Fuel type	Installed (GW)	Available to meet Peak (GW)
189	**218**	Coal	193	193
		Gas / Diesel	26	5[4]
		Hydel	45	18[5]
		Nuclear	7	6
		RE	63	15[6]
		Total	**334**	**237**

The above analysis suggests that although it may appear that there is a substantial power surplus situation in the country and excess of capacity has been added over the past few years, the extent of generation capacity available, is not too far from acceptable levels if states were to contract such capacities keeping their individual peak demands in mind. ***It is however worth asking why states contract capacities in isolation without regards to the regional or national level reserves, despite substantial efforts in creating one synchronous national grid and institution of measures such as Un-Requisitioned Surplus (URS[7]) for central sector generating stations, DEEP[8] and access to power exchanges for short-term electricity.*** This issue is further analyzed with reference to international practices in contracting of power in more liberalized wholesale power markets.

2.2.2. REGION WISE DEMAND- SUPPLY SCENARIO

Electricity is a concurrent subject in the country. It is important to ascertain if the levels of generation resource planning carried out by different states in the country are adequate. State distribution utilities in different states have signed long term PPAs since 2010 to cater to their year-on-year demand growth. In most cases, it is observed that the states have signed up for long term PPAs from conventional sources to the extent of their peak demand and planning margins and in few states these capacities are in 30% excess of peak demand experienced. The RE rich states in the western and southern region, viz. Maharashtra, Andhra Pradesh, Karnataka, etc. have excess contracted capacities, more than the resource adequacy planning limits resulting into surplus situations. The analysis has been presented in Annexure III.

2.2.3. FUTURE PROJECTIONS OF DEMAND SUPPLY

The 19th EPS is believed to have moderated demand expectations significantly and it matches current levels experienced in FY18. A comparison between 18th EPS and 19th EPS projections is presented below along with demand expectations if Power for All is achieved by 2022.

[4] *Gas Capacity has been considered at 20% of installed capacity to reflect non-availability of gas for power sector*

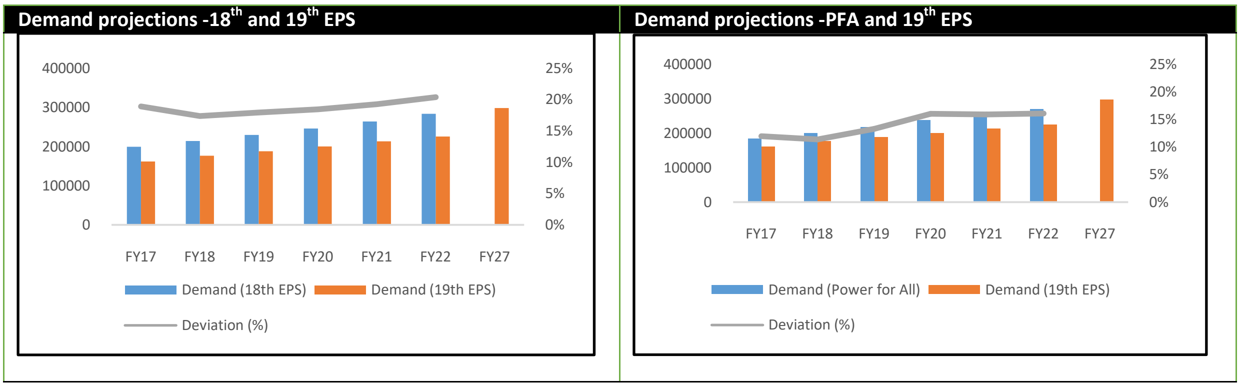
[5] Hydro availability has been considered at 18 GW as per lower bound of peak winter availability for India – June 2017 Report on Operational Analysis for Optimization of Hydro Resources & Facilitating RE Integration in India by POSOCO

[6] RE contribution taken at 25% as per thumb rules adopted in most US Markets for Resource Adequacy

[7] The Central Generating Stations are scheduled on a day-ahead basis. Usually, generating stations offering cheaper power are fully scheduled by States. In case the State does not wish to utilize the power, the power remains un-requisitioned and unsold. URS is the difference between power scheduled and power utilized for a generation plant.

[8] DEEP (Discovery of Efficient Electricity Price) is an e-Bidding and reverse auction portal for procurement of short-term power by state distribution utilities through competitive bidding. Launched by the Ministry of Power in April 2016, the web portal seeks to ensure seamless flow of power from sellers to buyer with the objective to introduce uniformity and transparency in power procurement and at the same time promote competition in electricity sector

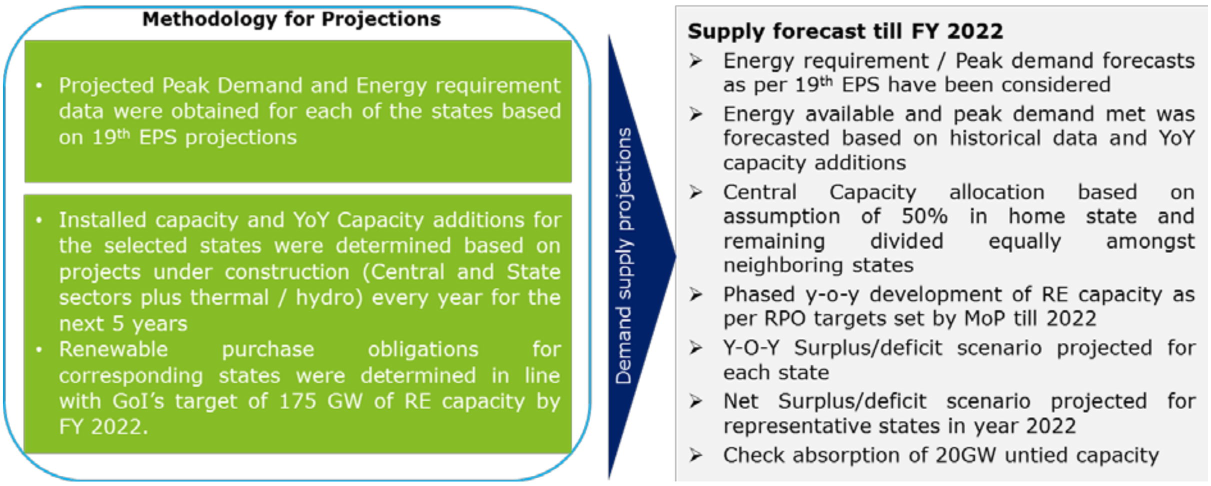
FIGURE 4: DEMAND PROJECTIONS



The 19th EPS projects peak demand to reach 226 GW in FY 2022 whereas 18th EPS projected the demand in 2022 to be 283 GW. A state-wise analysis of projected demand and supply was carried out to examine if the current situation of surplus generation changes over the future. For this analysis, few states (9 in number - Uttar Pradesh, Gujarat, Tamil Nadu, Madhya Pradesh, Punjab, Karnataka, Haryana, Rajasthan and West Bengal) which contribute to almost 65% of the overall demand, were analysed based on date provided by these states. Demand supply projections for each of these states were carried out till 2022 and analysed whether they would continue to be in surplus or in an energy deficit state.

The detailed methodology adopted for the same is elucidated below-

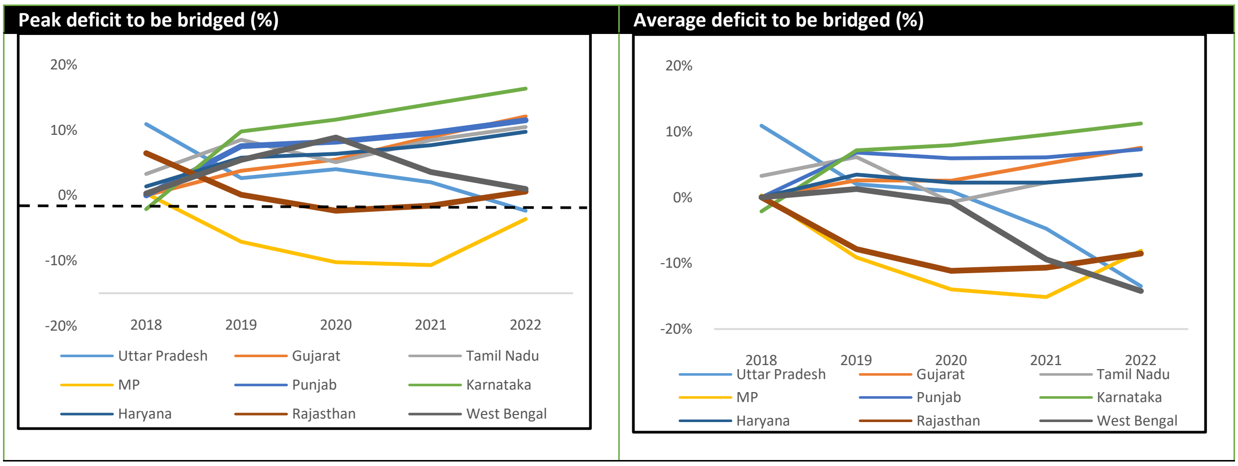
FIGURE 5: FORECAST METHODOLOGY



The detailed state-wise results are provided in Annexure IV whereas the details on year-on-year addition of generation capacities, in each of the states, have been provided in the Annexure V. These are based on data provided by CEA and the states with the Ministry of Power. Data on procurement planned from various upcoming generating units shared by the state distribution utilities, are shown in Annexure VI. Only those plants, which are expected to commission by FY2022, have been considered for the analysis of demand-supply position of states.

Based on the above methodology, demand-supply situation for FY 18 to FY 22 for the selected states is reproduced as follows.

FIGURE 6: DEMAND-SUPPLY SITUATION FOR FY 18 - FY 22



The above analysis indicates that:-

1) Even if these states would be power surplus in near term (1-2 years), most of them would experience peak demand deficits from FY 2020 to 2022. Few states will also experience average demand deficits by FY 2022.

2) Few states like UP and West Bengal, would continue to be in surplus scenario.

3) The situation could change significantly if the new MOEF norms for coal based power plants are enforced, which would result in more than 20 GW of capacity requiring to be retired on account of their inability to meet emission standards.

4) The net deficit, aggregated over all these nine states at the end of 2022, shows that it is enough to absorb the currently stranded untied coal based generation capacity of around 15.5 GW in addition to planned capacities contracted by these states until 2022.

The following can be inferred based on the above analysis of the current and future demand-supply situation:

a) Current Long-term Capacities in excess of Peak Demand of States

A combination of robust and unprecedented coal-based generation capacity additions (led significantly by the private sector) and lower than expected demand growth over the 12th Five Year Plan period has led to interim surpluses across all regions.

b) Reserve margins will change significantly over FY22-FY27

Existing contracting situation is not way over required reserve margins if non-coincidental peaks of states were to be considered[9]. With demand growth projected over FY23-FY27 period, the current levels of contracting would be inadequate in meeting non-coincident peaks even after considering untied capacities and future under construction capacities. The situation will change dramatically if over 33 GW of capacity (operating for over 25 years by 2020) are to be retired on account of inability to meet emission standards. Further, addition of 175 GW of RE capacity would add variability in the system and balancing requirements of power from reliable and flexible conventional power sources would increase.

[9] More integrated market operations and reserve sharing across states in a region, could bring down reserve requirements to much lower levels. This however requires changes to day ahead and real time market operations.

c) Lack of scientific and accurate Resource Adequacy Planning

States continue to contract capacities based on EPS demand projections and resort mostly to long-term contracting to meet their peak demand. There is no prescribed guidance on Resource Adequacy and sharing of reserves across states is ignored by the States, resulting in a considerable surplus at the national level, based on coincident peak demand met.

d) Lack of adequate regulatory scrutiny of Resource Adequacy / Contracting

Lack of prescribed criteria of determining Resource Adequacy / Planning Margins means SERCs depend upon EPS to scrutinize contracting requests by Distribution Utilities. This is quite different from the way regulators in liberalized markets scrutinize power procurement and contracting in the liberalized international markets. As a result of being guided by traditionally bullish projections in the EPS, a few states have contracted capacities much above their resource adequacy limits through over-estimation of demand and under-estimation of supply contribution to meeting peak demand requirements.

e) Absence of alternate market models

There is a need for flexible contracting / market products in addition to long term PPAs to ensure efficiency in procurement by distribution utilities. Locking in to very long-term PPAs in an era where India transits from deficits to surplus is untenable and comes at significant cost of inefficiencies being borne by the consumer

There is a need for generation capacity planning based on Resource Adequacy as well as reserves sharing across states to minimize any possible overcapacity in the system. Resource Adequacy criteria should be enforced through adequate regulatory scrutiny. Flexible contracting market models in addition to long term PPAs to ensure efficiency in procurement by distribution utilities

Chapter three

Review of International Wholesale Electricity Markets

3.1. OBJECTIVES OF WHOLESALE ELECTRICITY MARKET

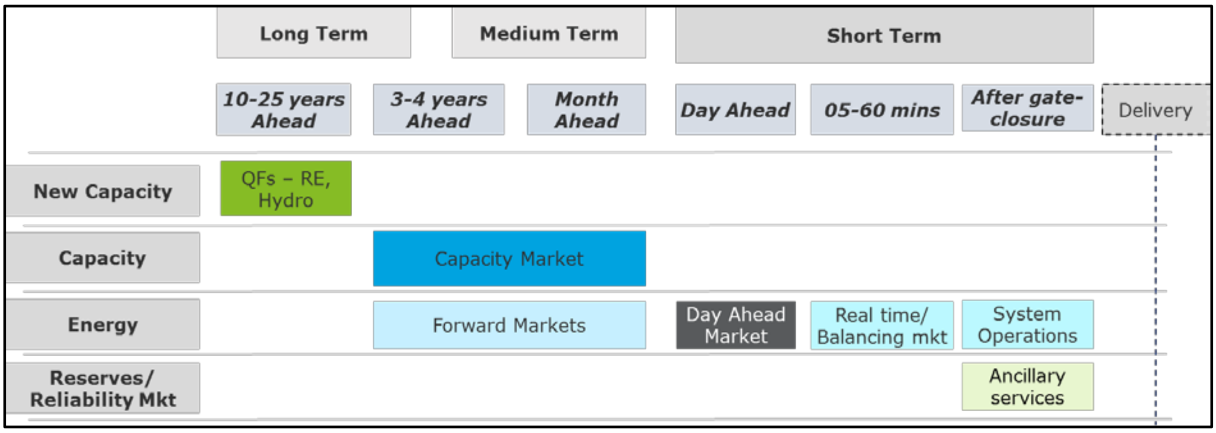
Wholesale Electricity Markets (WEM) are designed to provide generators and retailers / suppliers / distribution companies to trade in electricity, usually over shorter terms. The objectives of WEMs can be broadly stated as the following.

1) Ensure non-discriminatory open access for suppliers and Load Serving Entities / Distribution Companies
2) Achieve lower production / supply costs through competition
3) Optimization in dispatch and lowering overall reserve requirements
4) Achieve market signals to drive future investments
5) Ensuring the market provides appropriate incentives for efficient long-run investments
6) Transit wholesale energy segment from regulation to oversight and monitoring

3.2. DIFFERENT BUILDING BLOCKS OF WHOLESALE ELECTRICITY MARKET

Electricity has been traded bilaterally or on exchanges, and contracts for electricity is struck over periods ranging from several years ahead to intraday trading markets. The different building blocks of Wholesale Electricity Markets are displayed in the figure below.

FIGURE 7: BUILDING BLOCKS OF WHOLESALE ELECTRICITY MARKET



Qualifying Facilities: In the United States, certain class of generating facilities receive special rate and regulatory treatment and are known as qualifying facilities (QFs). They generally fall into two categories: qualifying small power production facilities (geothermal, renewable, installations less than a specific size as notified by appropriate Commissions) and qualifying cogeneration facilities. QFs can sell energy and capacity to a utility, provided the purchasing utility has not been relieved from its QF purchase obligation. With limited exceptions, QFs generally have the option of selling to a utility either at the utility's avoided cost or at a negotiated rate. QFs also generally have the option to sell energy either "as-available" (i.e., as the QF determines such energy to be available for such purchases) or as part of a legally enforceable obligation for delivery of energy or capacity over a specified term.

Capacity Market: The Capacity Market is a mechanism introduced to ensure that electricity supply continues to meet demand in the longer term. The Capacity Market operates alongside the energy market. As more intermittent renewable generation technologies comes on stream, the Capacity Market is increasingly seen as means to provide back-up generators and demand-side responders to help balance the network at times of stress. Participants are paid a per kW/ MW rate for the capacity they offer to the market. This capacity needs to be available when System Operators / Utilities call upon providers, at any time during the contracted period. The electricity producers are paid according to how much electricity they can produce rather than how much electricity they actually sell. While the consumers of the load serving entities pay the electricity charges as per their use (variable charges), generators are paid the fixed price for making their capacities available during the required periods. The capacity bids ideally would include the price of energy charges. There is no separate contracting of energy (variable) costs with the generators.

Potential Capacity Market participants can bid for contracts in auctions held three-four years ahead of the delivery date. Supplementary auctions are held a year ahead of delivery, with the intention of capturing capacity from demand-side responders, and to allow any secondary trading of capacity obligations secured in the first round.

Forward and Future Market: The Forward & Future Markets operate from a year or more (could be 4-6 years) ahead till the market closes at a time defined as Gate Closure when the System Operator takes on the role of residual balancer. Forwards and Futures are contracts for firm delivery of electricity at a certain time in the future for a price agreed upon today, which is known as forward price. Forward markets have provisions to contract energy as well as capacities that will be needed to meet future peak demand on the system, and then provide market-based revenues to resources that can fulfil that commitment.

Futures are standardized contracts that could further be traded on power exchanges. Forwards are mainly bilaterally traded over-the-counter and are not standardized. Also, forwards are usually not further traded. A forward contract is similar to a future contract in the sense that it is an agreement that locks in the price of a product to be delivered at a future date. However, future contracts, are more standardized products in terms of contract specifications, trading locations, transaction requirements, and settlement procedures than the forward contracts. The structure under forward contract is entirely determined by two parties involved in the transaction. Also forward contract are not traded on an exchange and are traded OTC or bilaterally, thus removing chance of anonymity. The delivery quantity specified in electricity futures contracts is often significantly smaller than in forward contracts.

Day Ahead Market:The Day-Ahead Energy Market (DAM) is a financial market where market participants purchase and sell energy at financially binding day-ahead prices for the following day. The DAM market is usually based on the bid and offer data submitted to the Market Operator by the market participants. Day-Ahead markets provide a forward market to hedge against the spot price volatility. The buyers and sellers can be large energy users, distribution retailers/utilities, power plant owners, or financial traders. Day-Ahead markets are generally used in conjunction with real-time/spot markets to balance how market participants deviate from their day ahead energy positions.

Balancing/ Real time Market: The balancing/ real time market enables market participants to optimize their position and correct their day-ahead nominations due to better information on weather forecasts, unexpected power plant outages, etc. It is also referred as an intra-day market or adjustment market and operates through the day until the market closes at a time defined as Gate Closure when the System Operator takes on the role of residual balancer.

After Gate Closure: The contracts between generators and suppliers, even after adjustment in the balancing/real time market, do not always balance out in practice. Following Gate Closure, the System Operator (SO) is able to evaluate the net imbalance on the grid. The SO's role is to then balance the system in real-time, ensuring that supply meets demand at all times, and alleviates any transmission or delivery issues on the transmission system. The SO looks at all the balancing reserves that can meet these requirements, and selects the economic option through ancillary market operations.

Ancillary Market: Ancillary services maintain electric reliability at times of variability in generation output and demand side fluctuations. These services are produced and consumed in real-time, or in the very near term and can be broadly classified into the two kinds of reserves.

Regulation reserves: Regulation reserves instantaneously provide the power difference between supply and demand required during the lag period while generation is catching up to supply or while generation is decreasing in response to lower demand

Operating reserves: Operating reserves are used to maintain the balance of supply and demand when an unexpected system event occurs. These reserves provide capacity, the System Controller can call on with short notice to correct any imbalance. These reserves can come from the supply side or from the demand side. There could be minimum of three types of operating reserves:

1) **Spinning reserves:** To provide spinning reserve a generator must be on line (synchronized to the system frequency) with some unloaded (spare) capacity and be capable of increasing its electricity output when a signal is received from the system operator. During normal operation, these reserves are provided by increasing output on synchronized equipment or by reducing load on pumped storage hydroelectric facilities.
2) **Non-spinning reserves:** These come from generating units that can be brought online in 10 - 30 minutes. Non-spinning reserve can also be provided by demand-side resources.
3) **Supplemental reserves:** These come from generating units that can be made available in 30 minutes and are not necessarily synchronized with the system frequency. Supplemental reserves are usually scheduled in the day-ahead market, allowing generators to offer their reserve energy at a price, thus compensating cleared supply at a single market clearing price. This only applies to ISO/RTOs, and not all reliability regions have a supplemental reserve requirement.
4) **Black start generating units:** These units have the ability to go from a shutdown condition to an operating condition and start delivering power without any outside assistance from the electric grid. Hydroelectric facilities and diesel generators have this capability. These are the first facilities to be started up in the event of a system collapse or blackout to restore the rest of the grid.
5) **Reactive power:** Power plants can produce both real and reactive power, and can be adjusted to change the output of both. Special equipment installed on the transmission grid is also capable of injecting reactive power to maintain voltage limits.

3.3. MARKET DESIGN FOR SENDING OUT EFFECTIVE PRICE SIGNALS

It is essential to send out effective price signals to the investors and consumers through market design. The most appropriate market design for resource adequacy would depend on an optimal mix of portfolio of these products and approaches. For example, an energy only approach would rely purely on the market, through scarcity pricing, to incentivize needed capacity investments. A capacity market or payment mechanism, on the other hand, aims at providing market participants with a more certain stream of revenues than what is delivered by energy-only markets. Capacity markets provide an additional incentive, which price signals alone in electricity market do not provide for capacity developers.

Capacity market prices may exhibit volatility, even when based on supply and demand fundamentals. This is due to the relative steepness (inelasticity) of the capacity supply curves and the lumpiness of investments. Most of the existing generation facilities would have relatively low going-forward avoidable costs and will offer at a low price in the capacity market. New generation facilities would have higher going-forward avoidable costs and would offer at a higher price. The large difference in offer prices can therefore lead to a near vertical supply curve between the offers of existing and new generation.

The steepness or inelasticity of the capacity supply curve can depend on the length of the forward period. In markets such as NYSO and MISO, where the forward period is quite short, suppliers must commit to either exit or enter the market long before the auction clears. In contrast, in markets such as PJM, ISO-NE, and GB, the suppliers can offer capacity in advance of making a commitment to exit or enter and hence can offer at their expected avoided cost which provides more competition and more elasticity to the supply curve.

The shape of the demand curve can also affect the level of price volatility. The choice of an extremely flat demand curve can lead to very little price volatility, but could inefficiently dampen the effects of the supply-side fundamentals, causing strong price signal during times of capacity surplus and a dampened signal during times of shortage. In contrast, experience has shown that a perfectly inelastic demand curve can lead to excessive volatility when combined with a steep supply curve.

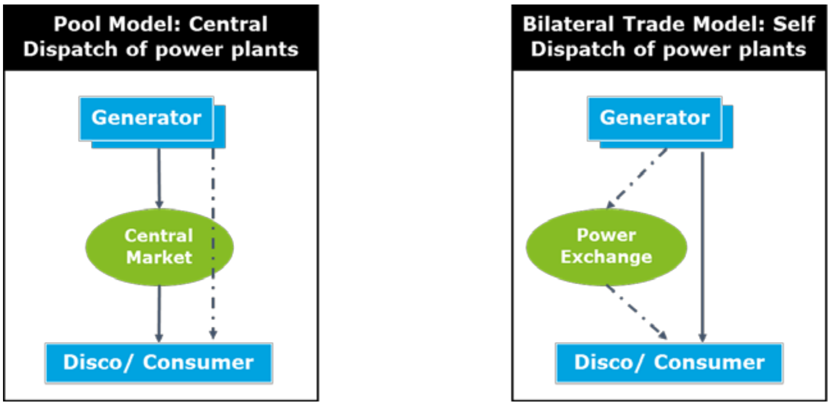
3.4. BROAD CLASSIFICATION OF WHOLESALE ELECTRICITY MARKETS

3.4.1. CENTRALISED MARKET OPERATIONS (MANDATORY POOL) VS DECENTRALIZED (VOLUNTARY EXCHANGES)

Centralized markets or power pools are characterized by tight control set by the System Operator (SO) attempting to optimize unit commitment, dispatch, transmission access (LMP) and ancillaries. It is a system where participation is mandatory and all suppliers and LSEs (Load Serving Entities) / Retailers / Distribution Utilities sign Participating Agreements with the Pool / Regional Transmission Operator. Pools are distinguished from exchanges thorough integration of the energy, transmission, ancillary services markets, and most significantly, by a centralized optimization of unit schedules that takes account of operational considerations.

The advantage of a pool is the tight integration of all aspects of system operations, which might enable productive efficiency, and it is less vulnerable to imperfect links among the prices in a sequence of energy and transmission markets. Its disadvantages lie in the consequences of complete centralization, since it requires mandated participation and compliance with specified operating schedules.

FIGURE 8: TYPES OF WHOLESALE ELECTRICITY MARKET MODELS



The alternative to a power pool model is a decentralized market. Decentralized markets on the other hand provide for degrees of self-dispatch / bilateral operations and voluntary power exchanges for residual trade. This means that sellers and buyers freely enter into bilateral contracts for power supply. Traders can act as an intermediate between buyers and sellers dealing in standard contracts .In parallel to the bilateral contracts, a voluntary power exchange is also operated for residual trade. The real time differences between the contracted volumes and the actual metered volumes are subsequently settled by the system operator through running a balancing market in order to establish a market-based price for the settlement of these imbalances. India opted for a decentralized market structure through the provision of multiple voluntary power exchanges.

In reality, both these market forms have merged to some extent. Most Centralized Markets currently allow for bilateral contracting (integrated forward market) and self-scheduling (e.g., for must-run units) to some degree.

3.4.2. ENERGY MARKET VS CAPACITY MARKET

Electricity markets could be broadly classified into two dominant types: energy only markets (EOMs) such as those operating in Australia, New Zealand, ERCOT (Electric Reliability Council of Texas), USA etc. and capacity-energy markets (CEMs) which make a separate payment for capacity availability in addition to actual electricity generation, such as those operating in most U.S. RTOs. Both forms of electricity markets have become more sophisticated over time with co-optimized markets for ancillary services, close-to-real-time operation and management of transmission constraints.

In an EOM market, the energy spot market plays a central role and has a direct influence on the contract prices. In an EoM market, generators are paid for the electricity they produce based solely on the wholesale price of electricity, which fluctuates. The volatility in spot prices in an EOM market arises from continuous fluctuations in supply-demand balance. The key features of this market include:

- LSEs / Retailers / Distribution Utilities pay only for the energy they consume
- Spot price of electricity fluctuates based on supply and demand.
- The prices of electricity send signals in the market for new investments or capacity mothballing. In a way, an EOM is a self-correcting system and considered to be an efficient market mechanism.

As variable renewables have a low or zero marginal cost, their increasing share in the electricity mix is leading to lower wholesale electricity prices in competitive electricity markets. The profitability of conventional power plants often gets threatened due to both shorter runtimes and increasing need for flexibility. However more importantly, the energy only market under very high renewable penetration lacks the incentive to promote new investments in conventional generation capacity, a situation often referred to as the 'missing money problem'. Existing power plants, which would be backed down during periods of high renewable generation, would be the first to get mothballed, as prices realized during short periods of peak demand may not be adequate to recover costs.

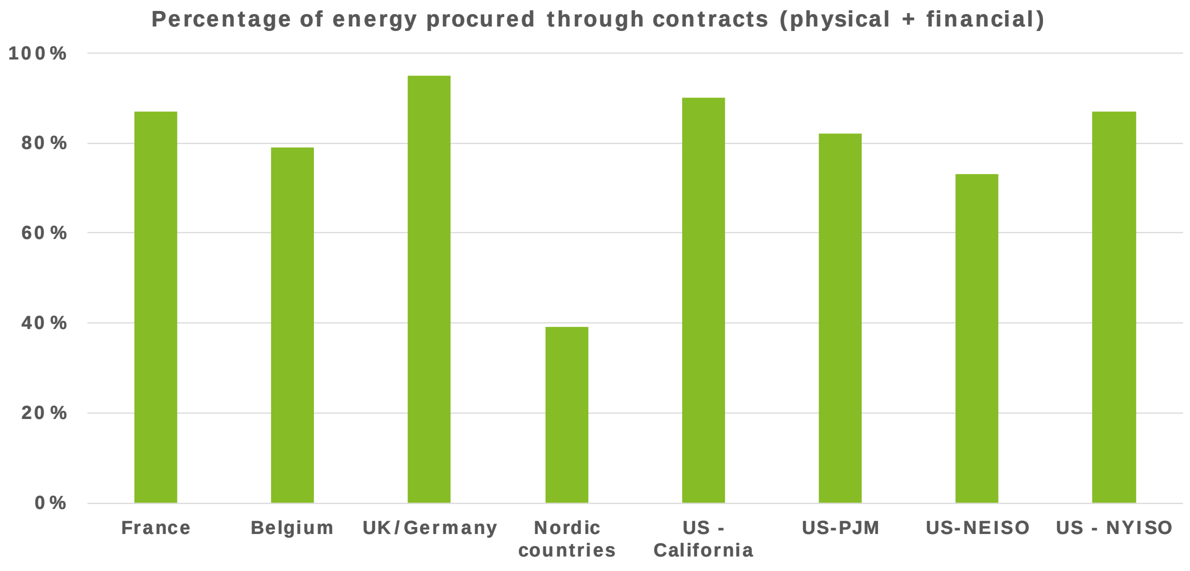
In the light of the above concerns about resource adequacy and lack of investor interest in setting up new capacities, most advanced countries have introduced capacity mechanisms. It is a mechanism to reward the availability of electrical generation capacity in order to ensure that electricity supply can match demand in the medium and long term.

3.4.3. CONTRACTING IN WHOLESALE ELECTRICITY MARKETS

It is often misconstrued that institution of WEMs would translate to bulk of the electricity being procured from the spot markets (day-ahead and real-time markets). In effect however, different terms of contracts ranging from a few days ahead up to 6-7 years are entered into either for delivery of power (physical contracts) or as financial hedges of different kinds.

The proportion of bilateral contracting which exists in liberalized WEMs is summarized in the graph below. For decentralized markets such as in the US examples, these are broad estimates as it will depend on the strategy employed by each individual LSE/ Distribution Utility / Retailer.

FIGURE 9: ENERGY PROCURED THROUGH CONTRACTS



Source: Data collated from Market Monitoring reports in the US, UK and Nordpool and are for years between 2003 – 2006; latest reports don't report such information; contracting would vary from LSE to LSE

Regulators in several jurisdictions in the US require load serving entities / retailers / distribution utilities to demonstrate resource adequacy through rolling annual submissions. These would involve examination and approval of utilities procurement plans, including the need to demonstrate that they have flexible contracts covering 90% of their requirements for ensuing 12 months and 100% (by a factor of the target reserve margin) of their monthly requirements on a month-ahead basis.

In reality, only a portion of the capacity is locked into long-term power purchase agreements/ contracts procured by utilities through competitive Request for Offers (RFO) processes. New build conventional power is usually signed up 3-7 years in advance of delivery, through long-term contracts, with most contracts having a duration of 7-10 years. Across jurisdictions in the US, LSEs/retailers procure anywhere between 10%-40% of their annual resource requirement from long-term sources ranging from 7-10 years. The rest of the procurement is from shorter term contracts ranging from 3-4 years ahead up to a few days forward. These shorter-term contracts include bilateral PPAs as well as capacity market auctions.

There are a wide variety of physical and financial contracts, which are signed between a generator and a supplier. These could be the following.

- **Forwards** — Bilateral contracts for physical delivery (e.g., PPAs)
- **Swaps**— Fixed-price forward bilateral contracts (e.g., contracts for differences)
- **Tolling Agreements** — Bilateral agreements where off-taker acts as market scheduler for power plant, subject to contractual constraints (typically an option, functionally similar to contract for differences)
- **Futures** — Standardized, exchange-traded contracts for future delivery, typically never delivered (e.g., on-peak summer futures contract)
- **Options** — Bilateral contracts that give the off-taker the option to use, purchase power, or earn revenues from a generator (e.g., heat rate call options, revenue put options)

These contracts are further explained in Annexure VII.

3.4.4. RESOURCE ADEQUACY IS A KEY CONSIDERATION FOR WEMS

Resource adequacy is the ability to supply load with adequate generation resources. It is traditionally defined as ability to provide adequate supply during peak load and generation outage conditions Measured as "Loss of Load Probability" or LOLP (likelihood of involuntary "Loss of Load Events" or LOLE).

Resource adequacy is often expressed in terms of "target" or "planning" reserve margins and is based on normalized load and generation outages.

This is a fundamental reliability consideration of WEMs worldwide and is increasingly monitored and enforced. This is because, it is now widely recognized that an energy market by itself, due to caps on prices, present a "missing money" problem with regards to new capacities, which require regulatory/administrative interventions.

Capacity auctions are routinely conducted by LSEs/Retailers (equivalent of distribution utilities) to meet demand obligations. These are determined through detailed resource adequacy exercises on a rolling basis and procured starting from up to a few years in advance up to gate closure. LSEs/Retailers (equivalent of distribution utilities) hold periodic auctions to procure such capacities.

In addition to these auctions, centralized auctions of capacities could be conducted by the system operator to procure shortfalls in reliability margins. A central agency (usually the transmission system operator) decides upon the amount of likely capacity deficits a few years in advance and contracts capacity, which is a strategic reserve, usually through a competitive tender/ auction. The contracted power plants are activated in case of capacity shortfalls, according to pre-determined criteria. These could be options contract whereby the counterparty is given an option to procure electricity at a predetermined strike price. The counterparty will exercise the option in situations of scarcity, when the price on the spot market exceeds the strike price of the option.

A summary of the various kinds of capacity procurements across U.S. RTO/ISOs is presented in the table below. The price-demand curve is designed based on the reserve margin requirements in such a way that the price at that margin is usually sufficient to cover costs of a new peaking plant. Further the contracting details for few of these U.S. states are provided in the Annexure VIII.

TABLE 2: KINDS OF CAPACITY PROCUREMENT IN US

Forward period		Procurement	Demand Curve
California		Bilateral	NA
MISO (Previous)		Bilateral + Voluntary Auction	NA
MISO (2013/14+)		Bilateral + Mandatory Auction	
NYISO		Bilateral + Voluntary & Mandatory Auction	Price MW
PJM		Bilateral + Mandatory Auction	
ISO-NE		Bilateral + Mandatory Auction	

4 3 2 1
Forward Commitment Period
Delivery Period

Voluntary Forward Auction
Mandatory Deficiency Auction
Reconfiguration Auction

Source: Resource Adequacy Requirements, Scarcity Pricing, and Electricity Market Design Implications by Johannes P. Pfeifenberger, the Brattle Group

Likewise, capacity markets in the UK conduct auctions pre-dominantly for one-year contract durations. On an average, around 95% of the three/ four year ahead auctions are for a delivery period of one year.

A brief of capacity auctions being carried out in the U.S. is summarized in Annexure VIII

3.5. ELECTRICITY MARKET TRANSITIONS

Electricity operations were organized around vertically integrated utilities in most parts of the world until unbundling, wholesale and retail competitions were introduced across liberalized regimes. This section discusses examples of market transitions in UK and US.

3.5.1. UK Electricity Market Transition

United Kingdom began its deregulation further to the Electricity Act of 1989, paving way for splitting the vertically integrated CEGB into two generators (National Power and PowerGen), a transmission company (National Grid) and 12 Regional Electricity Companies (RECs).

The legislation also paved way for the creation of the England and Wales (E&W) Pool -- a short-term wholesale electricity market with mandatory participation from all generators above 100 MW size. The E&W pool operated on the basis of arriving at system marginal price (SMP) every half hour based on day-ahead bids submitted by generators.

The Pool yielded significant volatility in prices through early 1990s and was eventually replaced with net pool arrangements resulting in permitted bilateral contracting between generators and load serving entities / suppliers and only residual electricity being procured from the power exchange.

An important element of the industry restructuring was the divestiture / privatization of the Generators (PowerGen and National Power) along with the emergence of several IPPs. To protect generator margins ahead of privatization, vesting contracts (price hedges) were entered into for a fixed period (7-10 years), which ensured a minimum price and capacity/ volume certainty over this period for the generators. It meant that the generators received top up payments if pool prices were lower than vesting contract thresholds. Over time, generators were forced to separate assets and divest further to reduce market power.

Distribution (RECs) in UK was completely privatized by 1993 and full supply competition introduced in phases with large industries free to choose their own generation by 1990, small industries / commercial consumers by 1994 and residential consumers by 1999. Currently multiple suppliers are permitted in the licensed area of a primary electricity supplier, which is the erstwhile REC owning the distribution wires / network.

3.5.2. Market Transition in the United States

The federal Public Utility Regulatory Policies Act of 1978 (PURPA) was a legislation which created new market entrants in the form of independent power producers (IPPs) with long-term contracts (PPAs) covering the life of the plants.

Through the 1980s, several parts of USA faced increase in costs of electricity with utilities demanding rate increases (retail tariff increases) and several on the verge of bankruptcy. This period was also marked by an increase in contracted long-term capacity by the utilities, which exerted substantial system costs for electricity consumers. A response from state regulators (Public Utility Commissions) was to force utilities to undertake Integrated Resource Planning (IRP), factoring in resource adequacy and energy conservation. This helped keep retail rates under check for a while but were still perceived to be high.

In 1996, the federal regulator, FERC, introduced a landmark open access legislation through Order No. 888. This marked a shift to organized electricity markets, as even vertically integrated utilities could choose to buy capacity and energy rather than building their own plants.

A subsequent FERC Order No.2000 in 1998 provided for the reorganisation of transmission into Regional Transmission Operators (RTOs), which nudged the industry to voluntarily organise into centralised market operations under the RTOs. As a result, several RTOs/ISOs emerged in the U.S. with regional operations often cutting across state boundaries. The prominent ISOs/RTOs in operation in the U.S. are

- PJM - Pennsylvania-Jersey-Maryland Independent System Operator (USA),
- MISO - Midcontinent Independent System Operator (USA)
- CAISO - California Independent System Operator
- SPP - South West Power Pool
- NYISO – New York Independent System Operator
- NEISO - New England Independent System Operatorand
- ERCOT - Electric Reliability Council of Texas

Transition to wholesale electricity markets were inconsistent with the predominantly long-term contracting structures that existed prior to 1998. States devised several mechanisms to ensure such contracts were transited into liberalised market structures. For example, state of California brought in a specific legislation to transit IPP contracts to markets through the provision of a competitive transition charge, levied as a non by-passable surcharge on all LSEs and paid for by consumers.

In several other states, divestiture proceedings were used to pay off some of the stranded costs of long-term generation contracts.

The Californian market failure in 2000-2001 is often referred to in discussions on power market reforms and is worth examining to understand how faulty market design and piece-meal political and regulatory interventions can quickly upend competitive market operations. A summary of the market design and its failure is outlined in the following box. It has several important lessons on the pitfalls of incomplete market designs and contributed significantly to a transformed and much robust market re-design in California.

CALIFORNIA MARKET CRISIS OF 2000-2001

The Power Market Reform of 1996

- Electricity generation, transmission and supply was dominated by three geographically delineated investor-owned utilities – Pacific Gas & Electric, (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E). These were vertically integrated until 1996 but were "encouraged" to sell off their generation as a part of the reform process. 25% of California is supplied by vertically integrated municipal utilities, which was unaffected by the crisis.
- The reform process was aimed at lowering electricity prices in the state, which were substantially higher (about 50% higher than national average) than neighbouring states and believed to be affecting the economy in the state.
- In return, the utilities were allowed to impose a "competitive transition charge" on consumers' electricity bills to recover "stranded costs" (above-market costs) associated with purchase from IPPs and nuclear plants under state-mandated procurement contracts. Such PPAs formed about 40%-50% of the procurement capacity of the utilities.
- Retail tariffs were frozen for 4 years or until the time stranded costs were fully recovered. This was accompanied by a mandatory 10% reduction in tariffs for residential and small consumers to last for four years from 1 January 1998.
- A mandatory spot market for day-ahead and day-of trading, called the Cal PX was established and the three large utilities required to buy and sell all of their requirements through the Cal PX.

The crisis and its aftermath

- The electricity market operated quite well for the first 2 years (1996-1998), although with rising demand, generation surplus in the state eroded quickly and the volatility of the spot markets did not send out adequate signals for addition of new generation capacity.
- Combination of exogenous factors led to a unique spiral of increasing prices in the wholesale electricity market in California. Electricity demand spiked significantly in the summer of 2000 due to rising IT industry demand and HVAC demand in the face of the highest recorded temperatures in the state in 106 years. Energy requirement spiked up by 12.5% over 1999 levels (against an average of 1.3% per annum over the past 9 years) and peak demand was higher by 6.2%. Prevailing drought situation caused hydropower imports, which formed one-fifth of California's capacity to reduce drastically. The average price of natural gas also shot up significantly in 2000 across the country but accentuated further in California by the surging demand and pipeline bottlenecks in the southern part of the state.
- While the above factors (surging demand and gas prices, no new capacity addition, decline in hydropower output), caused wholesale electricity prices to spike, retail demand and tariffs were insensitive to wholesale costs since tariff rates for most consumers were frozen until utilities collected all their "stranded costs".
- With most electricity purchased from the spot market and largely unhedged, the utilities were driven to near bankruptcy with increase in wholesale electricity payments by $11 Billion in the summer of 2000 compared with 1999. Inability of utilities to meet purchases at such high costs resulted in rolling blackouts commencing in December 2000.
- State Government and the regulator intervened to restructure the markets, with a series of measures, including direction from FERC to enter into mandatory long-term contracts and a move towards a voluntary spot market structure with e reorganisation of the ISO/RTO.

Lessons from the failure

- Faulty market design with deregulated wholesale market but inadequately regulated retail tariffs with price caps.
- Mandatory spot market without any capacity obligation or capacity payment mechanism resulted in a lack of incentives for future capacity addition. Existing reserve margins were rapidly eroded with rising demand in 2000.
- Mandatory spot markets have had very few takers in the last two decades since the crisis and where they exist; utilities are encouraged to protect themselves through hedging mechanisms (e.g., CFDs, financial contracts, etc.)
- Improper market governance to control exercise of significant market power by generators in 1999-2000.

3.6. KEY TAKEAWAYS FROM REVIEW OF INTERNATIONAL MARKETS

Following are the key takeaways from international electricity market transitions and the operation of Wholesale Electricity Markets (WEMs).

- WEMs are effective in bringing in competition and reducing the cost of power, provided resource adequacy is carefully monitored and implemented and access to transmission is fair and non-discriminatory.
- Contracting in a regime where reserve margins are adequate, should transit away from being predominantly long-term PPAs to a judicious mix of contracts based on the requirements of the load serving entity / retailer / distribution utility.
- Long-term contracts are required for construction of new generation assets but the term of such contracts have come down to 7-10 years in most parts of US. Across jurisdictions in the US, LSEs/retailers/distribution utilities procure anywhere between 10%-40% of their annual resource requirement from long-term sources ranging from 7-10 years. The rest of the procurement is from shorter-term contracts ranging from 3-4 years ahead up to a few days forward.
- The short-term market (day-ahead and intra-day) accounts for residual energy needs and constitutes anywhere between 5%-20% of overall annual requirements across most international markets. A notable exception is the Nordpool, where significant hydro availability with associated low marginal costs, translates into very high proportion of procurement in the spot market by LSEs/retailers/ distribution utilities.
- Most international markets offer multiple options to LSEs/retailers/distribution utilities to flexibly adjust their procurement portfolios through offering / procuring capacity contracts on a regular basis. In addition to this, access to financial contracts allows additional flexibility to fulfil resource / procurement requirements in the market place.
- Critical to the WEM is the monitoring and implementation of Resource Adequacy / Reserve Margins on a scientific manner. Absence of this would result in either an over-contracting of generation with consequent impact on consumer / system costs or the emergence of reliability concerns around scarcity and loss of load in extreme cases.

Chapter four

Contracting Options for India

The current issues faced by Distribution Utilities in the country with respect to perceived issues with long-term PPAs are guided by the following considerations.

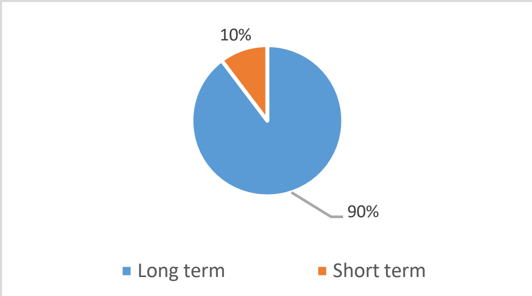
1) Existing surplus / un-tied capacities will force the market to re-think long-term PPAs as the default contracting option.
2) Untied capacities provide a good option for testing medium / shorter term capacity auctions
3) Transitioning to shorter / medium term contracts, backed by effective and accurate demand projections as well as well-enforced Resource Adequacy, requires confidence of investors and financiers in Wholesale Electricity Markets.
4) ***Reneging on / vitiating signed contracts will not be in the long-term interest of the sector and has longstanding adverse implications for the electricity industry particularly when generation capacity additions have been strongly private sector led.***
5) Resource Adequacy needs to be enforced with well-defined guidelines for the adoption of distribution utilities in the future.

4.1. INCOMPATIBILITY OF THE CURRENT PROCUREMENT OPTIONS

The current regime for procurement is overwhelmingly weighted towards long-term PPAs with over 90-95% of the procurement by distribution utilities through this mode. This includes those procured under regulated tariffs as per section 62 of the Electricity Act, from government-owned generators and those procured under Case-1 or Case-2 competitive processes, primarily from the private sector under section 63 of the Electricity Act.

Medium term contracting has been resorted to only by a handful of distribution utilities for very small quantities of power.

FIGURE 10: ELECTRICITY TRANSACTIONS IN INDIA (FY 2017)



There is no possibility on the part of distribution utilities to re-trade contracted capacities. They have the option of selling energy bilaterally or through the power exchange(s) but participation in these market mechanisms remains minimal.

The intra-day power market continues to suffer from drawbacks including the lack of collective transactions, long turnaround time for trades and limits on schedule revisions by distribution companies, etc.

As a result, the country is in effect in a 100% capacity market while resource adequacy remains quite high at the levels contracted by distribution utilities.

4.2. DESIRED GOAL OF RE-STRUCTURING OF CONTRACTING

While it is evident that the existing generation surplus / un-tied capacities will be absorbed over the next few years, the current adequacy in resources presents an opportunity to restructure contracting structures in line with international practices.

India, with its federal structure, consciously adopted a decentralized market arrangement with voluntary participation in power exchanges. This model for short-term market operations needs to be persisted although significant changes in operations are required in the short-term market to make it more participatory and meaningful.

The deliberations in this section however focuses on the bilateral contracting options for the future.

The goal of restructuring is to achieve the following.

- Discoms are able to operate a flexible portfolio of contracts with peak and base capacity procurements and active participation in the energy markets for balancing loads on a daily and real-time basis
- Tenure of new term contracts stand limited to a maximum of reasonable debt servicing period (~10-12 years) years in future auctions as confidence in capacity market auctions and energy markets improve over the period.
- Defined and periodic capacity market auctions (preferably collective and multi-party) are held with options for re-trading of excess capacity by Discoms
- Flexible generation resources should be more actively utilized in the day-ahead market
- Real time / Intra-day market should be restructured to improve liquidity and balance out residual imbalances

New long-term contracts should be allowed for ~10-12 years whereas capacity market auctions should be held with options for re-trading of excess capacity by Discoms.
Day ahead / real time / intra-day market should be revamped to improve liquidity and balancing

4.3. PROPOSED OPTIONS IN THE INDIAN CONTEXT

Following two options can be considered for restructuring contracting options in the Indian context.

Option 1:	**Phase in contracting changes over time** (Begin with untied and new capacity auctions and transit others after a review of capacity market auctions in 4-5 years)

This could be achieved through the following steps:

- Begin with medium term contracting (not exceeding 4-5 years) for all commissioned new thermal generating assets where PPAs have not been signed. This will include the untied capacity of ~15 GW. The scope for medium term contracting can be extended to all new capacities, once the entire gamut of stranded capacities are tied up. Defined and periodic capacity market auctions (preferably collective and multi-party) held by a central nodal agency with options for re-trading of excess capacity by Discoms should be introduced. Terms of contracting in such auctions should not exceed 4-5 years.
- Contracting for new build capacities would be required by 2022 and these could be brought in through contracting over 10-12 years contracts instead of the current practice of 25 years for coal-based capacities.
- Undertake a review of existing long-term contracts in 2022 and based on success of periodic capacity auctions, develop a roadmap for transiting all such contracts where long-term debt servicing has been completed to shorter-term contracts through the periodic capacity market options route.
- Institute financial contracts over time to allow *inter alia* for re-trading of contracted capacities amongst distribution utilities.
- Day-ahead market to be revamped to provide products and means of procuring flexible resources.
- Real time / Intra-day market restructured to improve liquidity and balance out residual imbalances
- Resource adequacy / reserve margin guidelines scientifically framed by Central Electricity Agency with inputs from POSOCO and the states. These are then to be strictly stipulated in regulations at the state level and monitored by the SERCs. The guidelines should include a roadmap for reducing long-term contracts (in excess of 4-5 years) in the portfolio of procurement resources to levels below 50% in a phased manner.

Option 2:	**Transit to desired end state with a one-time restructuring** (Provide partial / full transitioning risk-protection to existing contracts)

This could be achieved through the following steps:

- Existing IPPs and Central / State owned generating station contracts are transited into a form where they can be re-traded amongst distribution utilities.
  - Competitively bid out contracts under section 63 of the Electricity Act, 2003 have fixed tenures and any reduction in tenure will need to be mutually agreed on a case-to-case basis.
  - For projects with regulated tariffs determined under section 62 of the Electricity Act, 2003, a transition mechanism could be agreed to move into a regime of auctioning of capacities after the end of long-term debt service. In other words, for contracts where long term debt has been fully serviced, Discoms facing over-contracted capacities could be allowed to re-trade these contracts through a centrally organized auction process. This may require risk-protection mechanisms to cover for likely stranded costs to be faced by some generators.
- New coal based capacity contracts for the future to be built through 10-12 year contracts and allowed to participate in a centrally organized auction process beyond this tenure. All future Case-1 and Case-2 bid processes to be held for 10-12 year contracting instead of the current practice of 25 years for coal-based capacities.
- Defined and periodic capacity market auctions (preferably collective and multi-party) held by a central nodal agency with options for re-trading of excess capacity by Discoms. Terms of contracting in such auctions should not exceed 4-5 years.
- Institute financial contracts over time to allow *inter alia* for re-trading of contracted capacities amongst distribution utilities.
- Day-ahead market to be revamped to provide products and means of procuring flexible resources.
- Real time / Intra-day market restructured to improve liquidity and balance out residual imbalances
- Resource adequacy / reserve margin guidelines scientifically framed by Central Electricity Agency with inputs from POSOCO and the states. These are then to be strictly stipulated in regulations at the state level and monitored by the SERCs. The guidelines should include a roadmap for reducing long-term contracts (in excess of 4-5 years) in the portfolio of procurement resources to levels below 50% in a phased manner.

Following are the pros and cons of the proposed options of changes to contracting for power in India.

TABLE 3: EVALUATING OPTIONS OF CHANGES TO CONTRACTING POWER IN INDIA

Options	Pros	Cons
Option 1: Phase in contracting changes over time	• Protects existing contracts and starts only with un-tied/ merchant power plants which is less disruptive • Builds confidence amongst investors and lenders in shorter-term contracts and in proper design of a centralized capacity market auctions • Allows time for associated changes in the short-term	• Starting only with un-tied and new capacity auctions may set unrealistically low benchmarks in an environment of perceived surplus by the Distribution Utilities. • CGS/SGS stations which form bulk of the higher priced contracts need to be reset competitively to make procurement portfolios move

Options	Pros	Cons
	(day-ahead and real-time market run by power exchanges) market to be brought in.	away from long-term contracts.
Option 2: One-time restructuring of existing contracts	• Ensures envisaged design of the market is achieved with enforced restructuring of contracts • Has the potential to bring in real competition and significant gains in wholesale electricity price reductions.	• CGS/SGS can legally resist these changes, requiring policy/legal interventions, which can derail the process • Will require the Central / State Governments to institute risk protection mechanisms and provide financial cover for likely stranded costs of generators • Does not provide time for buy-in of financiers / investors, who will tend to load risks into shorter term bids, raising prices in the market • Can be disruptive as variations across states and viability of Discoms is ignored in this approach

There is no accurate answer to optimal portfolio to be held by a Distribution entity in terms of long-term vs medium term and short-term power purchase contracts. Utilities, in the west, have evolved their strategies based on the pre-market situation they were, the rate at which market attained maturity and the resource adequacy requirements put by the Regulators .Few guiding principles that could help Discoms take an informed decision in this regard are the following:

- Long terms PPAs could be signed to meet the base demand (say approximately 50%-70% of the peak demand requirements) whereas the seasonal variations and peak power requirements could be met through medium/ short-term contracts and spot market.
- In addition to long-term capacities, Discoms could be specified to meet annual capacity requirements through shorter-term contracts (both physical and financial) ahead of the year to cover 100% of its estimated peak. Variations from these contractual positions can then be subsequently met from the day-ahead and intra-day market operations.
- Regulatory oversight on short-term market participation and optimisation could push Discoms to start looking for arbitrage and optimisation gains in the week-ahead, day-ahead and intra-day markets to realise overall benefits to the consumers.

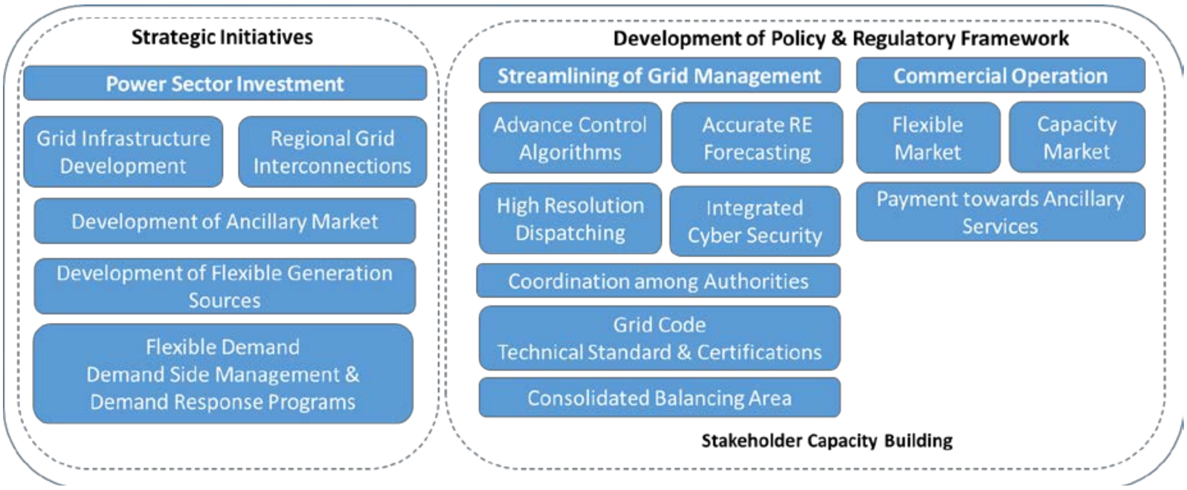
Chapter five

Renewable Integration and its Associated Costs

The use of renewable energy, primarily wind and solar electricity generation sources, is poised to grow significantly in the Indian power system. The Government of India has created a visionary installed capacity target of 175 GW RE by 2022 including 60 GW of wind and 100 GW of solar. India's Nationally Determined Contributions extend this ambition to 40% non-fossil fuel based electricity generation capacity by 2030. Global experience demonstrates that power systems can integrate this high amount of Variable Renewable Energy (VRE), but evidence-based planning helps facilitate this integration at least cost.

The various costs associated with RE power includes the cost of augmenting the grid capacity for bulk transfer of RE power, balancing costs to smoothen the variable generation and minimize the effect of difference between forecast power and actual generation by RE sources in various time scales, and thirdly, the cost implications to conventional plants for inducing flexibility in operations. It is an interplay of several initiatives as depicted below.

FIGURE 11: INTERPLAY OF RE INITIATIVES



Government of India has taken a number of steps in integrating large scale renewables that is planned to come by 2022. The section below presents an analysis of these various initiatives by Government of India and its agencies.

TABLE 4: GOI INITIATIVES FOR LARGE-SCALE RENEWABLES INTEGRATION

Area	Measures	Remarks
Policy	India's Renewable Electricity Roadmap-2030	Legal, institutional and policy changes that will be needed to successfully adopt RE on large scale
	National Electric Mobility Mission Plan (NEMMP)	Promotion of electric and hybrid vehicles
	Guidelines on cross border trade of electricity- 2006	Larger footprint to facilitate large scale RE integration
	Expert committee at GOI level on large scale integration of RE-2015	Key recommendations such as need for thermal flexibility, tighter frequency control, reserves, ancillary services, forecasting scheduling and imbalance handling mechanism and robust data telemetry and communication systems.
Regulatory	Scheduling, Accounting, Metering and Settlement of Transactions in Electricity (SAMAST)-2016	Forum of Regulators report, highlighting need for better discipline by various stakeholders to manage variability by large scale RE integration
	Forecasting, Scheduling and	Model Regulations by FOR

Area	Measures	Remarks
	Deviation settlement of Wind and Solar -2015	
	Deviation Settlement Mechanism at intra-state level- 2017	Model Regulations by FOR
	Draft connectivity standards for Renewables	Provisions related to frequency response, HVRT, LVRT, ramping requirements, voltage regulation requirements, compliance monitoring etc.
	Amendments to Indian Electricity Grid Code (IEGC)	4th amendment- 55% technical minimum for conventional thermal units 3rd amendment- Forecasting and scheduling framework for RE, decentralized forecasting, 16 revisions for RE in a day
	Imbalance handling	Definition of RE rich state with more deviation limits and RE deviation charges delinked from frequency
	Ancillary services	Implemented w.e.f. April 2016, Tertiary reserves (RRAS Up/Down) Markup price of 50 paisa/unit for RRAS Up and 25% saving of variable charges retained by generators for RRAS Down
	Reserves and Automatic Generation Control (AGC) by CERC – 2015	Primary reserve- Size of the largest generator in the country, Secondary reserve- Largest generating station in the region and , Tertiary reserve- 50% of the largest generating unit in the state control area
	Changes in market design	Sub-hourly bidding in power exchange since April 2012 and 24x7 electricity market since July 2015
	Other interventions	Draft regulations for transmission planning, staff paper for electricity storage and CERC regulation for communication system for inter-state transmission of electricity
Transmission Planning	Green Energy Corridors	Coordinated planning for RE evacuation, HVDCs and STATCOMs
	National Electricity Plan- 2006	RE contribution around 20% in 2021-22 and 24% in 2026-27
	One nation one grid	Synchronous operation of all regions and trans-national interconnections
Power System Operation	Upgradation of control centers and dedicated control center for renewables Large scale deployment of phasor measurement units Optimization of hydro resources	Upgradation of RLDCs/SLDCs in 2016 and NLDC by 2019 Establishment of Renewable Energy Management Centers in select RE rich states More than 1600 PMUs under Unified Real Time Dynamic State Measurement (URTDS) scheme FOLD report on optimization of Hydro resources
RE Grid Integration Studies	RE Grid Integration Studies	Joint project of MOP, GoI and USAID on assessment of high RE integration impact on power system- Final report released in June 2017 Key recommendations include- Transmission planning, incentive for flexible thermal generation, RE flexibility and larger balancing area

Further, there are number of technical challenges that need to be addressed in order to integrate large scale VRE in the system and for that several pilot based solutions are launched to test the success of each such solutions. Once these are successful, a nationwide rollout and regulations supporting the implementations will be planned. Costs of such solutions could then be ascertained appropriately through a simulation.

TABLE 5: SOLUTIONS & APPROACH TO TECHNICAL CHALLENGES

Technical Solutions	Approach
Increasing flexibility of the Conventional Plants	Most of the thermal fleet in our country is comprised of old stations and are technologically incapable of responding to quick ramp up and ramp down requirements, emerging from fluctuations in RE generation. Therefore, it is important to build flexibility in the existing fleet of conventional generating plants as well as develop gas, hydro and pumped hydro storage plants which could be utilized

<table>
<tr><th>Technical Solutions</th><th>Approach</th></tr>
<tr><td></td><td>for meeting the fluctuations in load profile as well maintaining system stability. Adequate incentives are required to be built into the regulations for plants which could demonstrate flexibility. The cost of introducing flexibility in existing thermal generation is yet to be ascertained and NTPC is participating in several pilots on the same.</td></tr>
<tr><td>Estimation of Balancing Reserve Requirement</td><td>A recent report released by PGCIL in December 2016 (Renewable Energy Integration-Transmission and enabler), highlights that due to high penetration of solar energy, grid will witness high ramp down and ramp up requirements. The study has come out with a requirement of ramping up and down for two scenarios: 15% RE penetration (74 GW) & 30% RE penetration (116 GW) by year 2019.

<table>
<tr><th>Ramp</th><th>15% RE Scenario (MW/min)</th><th>30% RE Scenario (MW/min)</th></tr>
<tr><td>Solar Morning Ramp(Down) 7-11 am</td><td>33</td><td>150</td></tr>
<tr><td>Solar Evening Ramp (Up)4-6 pm</td><td>17</td><td>125</td></tr>
<tr><td>Demand Evening Ramp(Up) 6-8 pm</td><td>250</td><td>275</td></tr>
<tr><td>Total Balancing Reserve Required during evening ramp (4-8pm)</td><td>32 GW in 4 hours</td><td>48 GW in 4 Hours</td></tr>
</table>
Though, above analysis indicate that there is sufficient availability based on pan India requirement of the balancing reserves for the 74 GW RE penetration, but operability of these reserves is an issue due to long term PPA commitments of these sources</td></tr>
<tr><td>Forecasting and Scheduling</td><td>Equipping all states with the latest state of art load forecasting tools and facilities are required along with capacity building of the system operators. A roadmap for establishment of Renewable Energy Management Centres (REMC) in RE rich states with the provision of external forecasting service providers has already been envisaged and is under implementation. Greater focus needs to be accorded to weather forecasting in India to make it useful for RE forecasting. The cost of REMC deployment and its operations need to be integrated in the total RE integration cost.</td></tr>
<tr><td>Improved Market Operations (including ancillary services)</td><td>While the ancillary services have been implemented at the inter-state level, a similar framework is required to be implemented at the State level for efficient operations. A time sliced market services on ancillary operation with incentive for generators is yet to be evolved, which would provide better insights on associated costs.</td></tr>
<tr><td>Resource Planning and Storage</td><td>While the National Electricity Policy talks about 5% spinning reserve, currently the reserves are insufficient to respond to grid fluctuations with target of 175 GW of Renewable Energy. To fulfil this requirement, flexible generators such as reservoir based hydropower plants, gas based generating plants, storage systems, etc., which could respond and adjust to the demand-supply fluctuations in a short time frame, would be required. Also, storage as well as automated demand side management are flexible energy services which may help in shifting the generation or load as necessary to meet the gap between the renewable generation and demand. Resource planning is therefore an iterative process that need to continuously take place and evolve as the system absorbs more and more RE power.</td></tr>
<tr><td>Improving Transmission capacity and System Operations</td><td>Renewable capacities are concentrated in a few states and therefore it is important to have expanded transmission capacity for accommodating higher RE generation at few locations and its evacuation to load centers. While India has integrated its regional networks, the limitation in inter-regional capacity still results in restriction in demand in some regions/ states.</td></tr>
</table>

RE Integration costs therefore depends upon multiple factors and is guided by complex non-linear functions between capacity additions of RE and increase in costs. An approach adopted internationally is production cost modelling to assess increase in operating costs for RE integration. The tool simulates optimal scheduling and dispatch of available generation by minimizing total production cost subject to physical, operational, transmission and market constraints. The fixed cost is considered to be a sunk cost and the objective function tries to minimize the variable cost of generation to meet the system load. The total system costs can be calculated accurately under a range of varying conditions, with the cost differences typically dominated by the fuel cost savings provided by renewables.

A similar study titled *"Pathways to Integrate 175 Gigawatts of Renewable Energy into India's Electric Grid"* has been undertaken by NREL under a USAID funded GTG program. Using advanced weather and power system modelling designed specifically for the study, the multi-institutional study team explored operational impacts of meeting India's RE targets (175 GW by 2022) and identified actions that are favourable for integration. The results demonstrate that power system balancing with 100 GW of solar and 60 GW of wind is achievable with minimal integration challenges, bringing benefits of reduced fuel consumption and emissions. Meeting existing regulatory targets for coal flexibility, enlarging geographic and electrical balancing areas, expanding transmission in strategic locations, and planning for future flexibility can enable efficient and reliable operation of the power system now and in the future. Amongst the central strategy pointed out by the report to balance increased variability introduced by 175 GW of wind and solar in the system is increased flexibility in coal based power plants. The operational costs of cycling are estimated in the report to be in the range of $0.92-$2.36/MWh (6 paisa/kWh to 15 paisa/kWh). This ignores the additional capital investments required to make plants flexible. This has been estimated to be in the range of INR 3.9 cr to INR 7.8 crores for 200 MW units of NTPC10. At an estimated PLF of 49% for sub-critical units, this results in higher capacity charges ranging from 0.90 paisa/kWh to 1.8 paisa / kWh.

Ultimately, such additional costs need to be modelled in the form of adders to RE generation to estimate cost of integration. The added cost of flexibility in coal based stations due to renewable penetration of 175 GW thus translates to approximately 17 paisa/kWh to 44 paisa/kWh of RE generation. Factoring in other integration costs requires modelling with and without RE, which is outside the ambit of this study.

On similar lines, market operators and regulators internationally provide varying estimates of cost of integration in their systems. For example, Electric Reliability Council of Texas estimated the cost of integrating its first 10,000 MW of wind, to be about $0.50 per MWh (~ 3.25 paisa/kWh) of wind generation. An IEA study, for wind penetrations of up to 20% of gross energy demand, states that the incremental operating cost, due to uncertainty, ranged between 1 €/MWh to 4 €/MWh ($1.30/MWh to $5.20/MWh or 8 paisa/kWh to 34 paisa/kWh).

Although this appears to be a simple question, in practice, calculating the integration cost has proven to be overly complex and no universal approach has been adopted internationally.

[10]Task Force Committee Report on Flexibilisation of Thermal Power Plants – Progress under IGEF sub-group 1

Chapter six

Increasing Effectiveness of Regulatory Commissions

Independent regulation was first introduced in the Indian electricity sector in the State of Odisha in 1995 and was followed by other states consequently. Following the example of Odisha and few other states which followed with similar structural reforms, Government of India enacted the Electricity Regulatory Commissions Act, 1998 which enabled the formation of CERC at the center for regulation of inter-state entities and SERCs for regulation of intra-state entities. The roles and responsibilities of the regulatory commissions were further endorsed, emphasized and strengthened through the enactment of the Electricity Act, 2003.

6.1. ISSUES AND CONCERNS

One of the key intentions of setting up a Regulatory Commission was to introduce transparency in all decisions and provide independence from interference of Government into day-to-day operations and decision-making. Significant achievements have been made by the CERC and SERCs in terms of drafting progressive regulations, tariff determination, increasing private sector participation, etc. However, few of the issues, regarding functioning of the ERCs, still remain and persist. These are summarized in the table below:

TABLE 6: ISSUES WITH FUNCTIONING OF ERCS

Particulars	Details
Selections and appointments	• The selection committee is comprised of administrators of the State Government. Usually retired administrators are appointed as Members of the Commission as a recognition of their efforts and service to the State Government during their career. • Often, in regulatory commissions, the staff is appointed on deputation from other departments of the state government for a pre-determined tenure. This often leads to lack of motivation for the appointee to internalize his work and achieve desired objectives. In addition, once the depute leaves office and goes back to his original department, it again leads to a major disconnect
Independence	• There is a lack of independence in decision making of the ERCs, particularly in tariff matters, in most States. This is largely due to the fact that appointments of Members are mostly made by the serving administrators of the State Government who often had to pay their regards and show their loyalty by obliging to what State Governments demand. In addition, there is a lack of financial independence of the Regulators from the State Government and the expenses are mostly being funded by State Budgetary allocation.
Compliance	• The Electricity Act mandates open access in order to optimise the use of available electricity in the country. However, very few State Regulators have progressively given out open access approvals to applicants and complied with the Act.
Performance evaluation	• No performance evaluation measures / KPIs have been outlined for the CERC / SERCs. Absence of such measures act as an impediment to unbiased evaluation of performance of the regulators.
Skill development	• There is a major concern amongst the State Regulators in terms of talent retention and development of resources by providing them adequate trainings. In absence of such skilling initiatives, there is lack of clarity on career growth for personnel entering the organization. Moreover, there is a general lack of sound technical expertise amongst the regulatory cadre.

Several amendments to the existing Electricity Act, 2003 have been proposed in the Electricity Amendment Bill, 2014 which are directed towards much needed regulatory reforms. Following aspects have been covered under the amendments:-

a) *Mechanism for Independent Performance Review of Regulatory Commissions:* through creation of an Independent Committee at the level of the Forum of Regulators.
b) *Increased transparency and consumer orientation in appointment of Regulators* through change in structure of selection committee for appointment or regulators and automatic appointment of nominated Members in events of delays in appointment by State.
c) *Improve enforcement of Regulatory Orders:* Stringent provisions and penalties for non-compliance to regulatory directives and orders.

d) *Strengthening of Cost Recovery Mechanisms for Distribution Utilities*through
- Mandatory compliance to National Tariff Policy framed by the Centre
- Introduction of No Revenue Deficit in tariff approvals by ERCs; and
- Strengthening of the provisions for automatic pass through of fuel & power purchase costs in retail tariffs.

A section on the international regulatory practices has been presented below such that any learnings from these countries could be used as a recommended way forward for the ERCs in India.

6.1.1. LEARNINGS FROM THE UNITED STATES

Akin to India, U.S. also has a federal and state structure where the activities of interstate transmission and wholesale power sales are federally regulated by the FERC (Federal Electricity Regulatory Commission) whereas retail rates and distribution service, are state-regulated by PUCs (Public Utility Commissions). The US Constitution mandates FERC regulation for any subject that involves interstate commerce, whereas provides the mandate for setting standards of lower-voltage retail distribution facilities, quality of service standards, and the prices and terms of service for electricity provided by investor-owned utilities in the respective states to the PUCs. In some states, the PUCs also regulate consumer-owned (i.e., cooperative and municipal) utilities, but in most states this is left to local governmental bodies and elected utility boards.

APPOINTMENTS AND DISMISSALS

Central regulator**:** FERC is composed of up to five commissioners who are appointed by the President of the United States with the advice and consent of the Senate. Commissioners serve staggered five-year terms and have an equal vote on the orders through which FERC takes action. The President appoints one of the commissioners to be the Chairman of FERC who acts as the administrative head of the agency. FERC is a bipartisan body; no more than three commissioners may be of the same political party. All these factors ensure that there is no bias or undue influence of the political machinery on the various decision-making and day-to-day activities of the regulatory commission.

State regulators**:**In the majority of states, the State Governor who is appointed by the President of the US appoints the commissioners. In few states, commissioners are elected by the legislature. Most state commissions consist of three or five appointed or elected commissioners and a professional staff. Moreover, the respective State Governor appoints one of the five to serve as Commission President.

*Most commissioners serve terms of four to six years.*In some states there are limits to how many consecutive terms a commissioner may serve. Staff of the commission is fairly represented through a mix of economists, engineers, accountants, lawyers, and safety specialists.

PLANNING AND KPI FORMULATION

The Commissions develop their Strategic Plan for each year which in turn leads to formation of KPIs based on the strategic plan framework. Formulation of strategic plans and governing KPIs aid the central and state commissions towards measuring the progress of activities and ensuring accountability.

The strategic plan for State PUCs clearly outlines, in understandable terms, what results the governing body wants the organization to achieve and is usually clubbed under broadly 3 goals as defined below. The Strategic directives are usually organized in categories reflecting the major areas of focus for the organization, for example, customer service, reliability, market development, and financial performance.

Goal 1: Ensure that the electricity rates and terms and conditions are just, reasonable and not unduly discriminatory or preferential.
- *Objective 1.1: Establish Commission rules and policy that will result in just, reasonable, and not unduly discriminatory or preferential rates, terms, and conditions of jurisdictional service.*
- *Objective 1.2: Increase compliance with Commission rules; detect and deter market manipulation.*

Goal 2: Promote the development of safe, reliable, secure, and efficient infrastructure that serves the public interest.
- *Objective 2.1: Foster economic and environmental benefits for the nation through development of cleaner fuel based power projects*
- *Objective 2.2: Minimize risks to the public*

Goal 3: Achieve organizational excellence by using resources effectively, adequately equipping the Commission employees for success, and executing responsive and transparent processes that strengthen public trust.

- *Objective 3.1: Manage Commission resources effectively and efficiently.*
- *Objective 3.2: Empower Commission employees to drive success.*
- *Objective 3.3: Facilitate public trust and understanding of Commission activities by promoting transparency, open communication, and a high standard of ethics.*

PERFORMANCE ASSESSMENT

Performance of state commissions is assessed on the following parameters for every year:-

TABLE 7: PARAMETERS FOR PERFORMANCE ASSESSMENT

Parameter	Performance results
Proceedings	Decisions Adopted Days of Evidentiary Hearings and Prehearing Conferences Public Participation Hearings Advice Letters Processed Resolutions Adopted
Reports	White Papers and Staff Reports
Complaints	Consumer Complaints and Questions Received
Investigations	Electrical Incidents Investigated
Audits	Audits completed
Inspections	Power Plant Outage Inspections
Fines and Penalties	Staff Citation Penalties Levied Against Energy Utilities Fines and Penalties Levied for Energy Utilities
Refunds	Refunds to Consumers from Informal Complaints

In addition to this, the State Commissions also require to assess the performance of key officials. For instance, the criteria by which the Executive Director's (reporting to the President of the Commission and in charge of overall operations of the Commission) success is evaluated at the end of the year is reproduced below:-

1) Increased compliance with state rules
2) Effective business systems that meet and exceed the standard expected of concerned state agencies:
    a. Increased agency compliance with external audit recommendations
    b. Creation of an audit compliance tracking system
    c. Bringing contracting, procurement and fiscal processes into compliance with state controls
3) Dissemination and embodiment of adopted Core values
4) Progress towards becoming a "learning organization"
5) Compliance with the Commission's adopted Strategic Directives.
6) Progress towards an effective records retention program
7) Progress towards developing a safety culture
8) Increased public and legislative confidence in the Commission

ADMINISTRATIVE POWERS OF STATE COMMISSIONS

To ensure that state commissions are independent as well as fair and just in their decision making process, their administrative powers & decisions are subject to appeal to the respective state courts, generally pursuant to the state administrative procedure act, or federal court, in the case of FERC.

In a few states, the State Commissions also have the authority to promulgate rules for the utilities that may cater to how the managerial operations should run as well as compliances to be done. Orders of the commission are regarded as the force of law and the respective courts will normally not interfere in the same.

In addition to this, additional key measures by which the FERC / State regulator ensures its accountability, independence and transparent operations are highlighted below:-

TABLE 8: KEY MEASURES BY FERC/STATE REGULATOR FOR ENSURING ACCOUNTABILITY, INDEPENDENCE AND TRANSPARENCY

Category	Particulars
Customer involvement	• State commissions conduct periodic conferences to involve utilities, consumer groups and other stakeholders on less formal and general matters through **"Ex Parte communications".** This is done with a view to bring in expertise from all quarters and decide on the course of action by widespread involvement. • FERC / State commissions promote opportunities for public participation in decision-making processes through a variety of interactive sessions throughout the various commission program offices
Independence	• Many state commissions have the authority to consider and approve / reject proposed power plants if the same have any negative impact on the entire ecosystem. • Most state regulators have independently adopted policies and principles that set criteria for making investments in energy efficiency measures and devised penalty / rewards for under / over achievement of the same. • Many state commissions independently adopt service quality indices (SQI) to measure the quality of utility service, such as the frequency and duration of outages, the speed with which companies respond to telephone inquiries, the speed with which they respond to unsafe conditions, etc. Utilities are penalized for non-conformance to the same
Performance evaluation	• FERC holds monthly meetings to review and make decisions on policies and regulations.
Financial management	• FERC / State Commissions are self-funding agencies. They are authorized to raise revenue to reimburse the United States treasury for its appropriations, through annual charges to the natural gas, oil, and electric industries which they regulate. • Internal budget approvals for the FERC are obtained by the Board of Directors from the President. Then it requires recommendation by the President and authorization by Congress through annual and supplemental appropriations
Compliance by utilities	• In an effort to increase compliance with rules and to deter market manipulation, the Commissions promote internal compliance programs and self-reporting of violations by regulated entities.
Employee development	• Commissions have brought out, employee learning and development measures to retain talented employees.
Others	• State Commissions have the power to team up with adjacent states to review issues that concern more than one state • The President and Congress do not generally review FERC decisions, but the decisions are reviewable by the federal courts

Formulation of strategic plans and KPIs, Performance assessment as per defined goals and independence in decision making and are key characteristics of US regulatory bodies

6.1.2. LEARNINGS FROM THE UK

The Office of Gas and Electricity Markets (Ofgem), is the independent National Regulatory Authority for electricity and downstream gas markets in UK. Ofgem is a non-ministerial government department that works effectively with government, the energy industry and other stakeholders within a legal framework determined by the UK government and the European Union.

APPOINTMENTS TO THE BODY

Appointments to the Authority are made by the Secretary of State for Business, Energy and Industrial Strategy (BEIS), which is a cabinet position in the United Kingdom government.

For all Non-Executive appointments, the final decision rests with the Secretary of state, who is assisted by an advisory panel consisting of an official from the BEIS, a representative from OFGEM and an independent member. This ensures that the appointments to the regulatory body are not biased and the decision making process is independent, fair and transparent
Non-executive members have fixed term appointments, normally up to five years. These appointments are renewed at the discretion of BEIS. Executive members of the Authority are appointed in line with the Civil Services Management Code subject to maximum tenure set out in the EU's Third Energy Package.

PRACTICES FOR ENSURING INDEPENDENCE, TRANSPARENCY AND ACCOUNTABILITY

TABLE 9: PRACTICES FOR ENSURING INDEPENDENCE, TRANSPARENCY AND ACCOUNTABILITY

Category	Details
Information dissemination and consultations	• Undertaking consultations, briefings and seminars for interested parties explaining their approaches towards reaching a particular decision, including the Parliament and the Press • Publishing the minutes of Authority meetings regularly
Performance evaluation	• The Authority meets at least 10 times a year, carrying out timely evaluation of activities undertaken by its internal committees. The MoMs regarding the same are issued for public reference. • The performance of the Chairman is reviewed by the non-executive members every year • The regulator maintains performance metrics for law enforcement cases viz. number of cases opened and closed, average time taken to initiate the settlement procedure and average time taken to address cases etc.
Consumer involvement	• A dedicated Consumer Insight and Engagement team has been created which undertakes consumer and market research. They have a 'Consumer First' Research Program that helps to better understand consumers' viewpoint on their policies / operations through regular surveys and workshops. The consumers can raise concerns and complaints regarding any initiative and can give feedbacks to any policies voluntarily by writing or over calls.
Financial management	• Costs for Ofgem are recovered from the utilities as a part of the Annual License fee. • To ensure transparency with regard to budget and spend, a breakdown of costs along with any savings or over spending is provided in the Forward Works Programme along with a budget for 5 subsequent years. This acts as a transparent mechanism to portray their activities and works over a 5 year period.
Tariff setting independence	• Ofgem is totally independent to set price controls for the regulated companies • They do not approve the charges set by DNOs (Distribution Network Operators) themselves, but rather evaluate and approve the methodologies used to calculate the charges levied on consumers.
Transparency	• It creates a Forward Work Programme which outlines the key projects planned to be undertaken in the forthcoming year along with a brief account of their financials and information on their planned projects. • Collaborates with National Competition Authorities to encourage policies which promote competition in the energy sector • Undertakes continuous monitoring of financial and non-financial activities and publishes expenses of senior management in public domain

Independence in appointment of officials, continuous performance review, dedicated team for consumer research and market studies, independence in tariff-setting processes and transparency are key features of UK regulatory bodies.

6.1.3. KEY LEARNINGS FOR ERCS IN INDIA

Taking into account the various international best practices and inherent shortcomings in the Indian power sector, key learnings and way forward for the strengthening the regulators and governance processes have been described below:-

1) **Appointments**: Independence of SERCs can be enhanced by ensuring appointment of Chairpersons and members by respective state Governors (appointed by President of India) or through a panel comprised of representatives from Central Ministry, Cabinet and State Government. This would ensure significant distance between the SERCs and the concerned state governments who currently appoint the Chairperson and members of the respective SERCs.
2) **Increasing transparency in the regulatory process**: This would entail the following key actions:-
    a. Holding open hearings, with agendas and minutes of the proceedings published in a timely fashion
    b. Undertaking consumer research studies which would help to better understand consumers' viewpoint on various policies / operations through regular surveys and workshops; publishing the result of such studies
    c. Publishing annual budget and accounts on the website regularly.
    d. Creation of work programmes or plan for the ensuing year/ 3-5 years with details of key tasks and activities and estimated budget requirement each year will also be essential to ensure that SERCs adhere to their plans and are evaluated against them/ KPIs formed from the plan
    e. Declaration and monitoring of financial interests for each Member of the Commission to ensure no conflict of interest/ independence (every Audit company has a requirement that the Directors and Partners need to self-declare their financial interest so that these could be monitored at the firm level on a continuous level)
3) **Ensuring Financial autonomy:** Financial autonomy of regulatory agencies could be enhanced by charging an Annual fee to the regulated utilities to cover the expenses so that SERCs have a dedicated source of funding which is independent of the state budgetary process.
4) **Performance evaluation and reporting:**Based on the Annual/ Multi-year work plan prepared by the ERCs, the KPIs could be developed by FOR for each ERC. An annual performance monitoring and evaluation of ERCs can be done by the FOR based on the KPIs developed. Results of the evaluation could be published in public domain for suitable corrective actions.

    Moreover, SERCs should mandatorily assess the performance of the key officials of the board through suitable and elaborate performance criteria
5) **Strict enforcement of regulations and orders on regulated entities:**Increase oversight on utilities by collecting data on service quality (outages by circle, technical fault rates, system interruptions, etc.) and enforce penalties on not maintaining minimum required standards. SERCs in association with the utilities should also involve themselves to carry out consumer satisfaction surveys (preferably by third parties) and collate the results for analysis and suitable actions.
6) **Employee development and retention:** A well-developed policy for recruiting of personnel as well as retaining and developing a separate cadre for technical staff needs to be in place for SERCs in India. This will ensure a streamlined and dedicated talent pool for regulatory bodies in the country and will enable the SERCs to be technically more competent and accountable to their decisions.

Additional measures which can ensure increased accountability and independence of SERCs in India are as follows:-

1) **Promoting regulatory independence**: A committee could be formed under the Ministry of Power to explore the various options for improving regulatory independence and test several proposals including the proposal for creating 4-5 Regional Regulators and deliberating their roles and limitations.
2) **Specialized staff for ERCs**: A common pool of technically specialized regulatory staff that could work across states and regulatory commissions is an option so as to ensure sound technical expertise. It could be a permanent national cadre of staff, who can work under the aegis of the Forum of Regulators (FoR).The terms and conditions of deputation of such staff to the SERCs and cost recovery could be reviewed by a Committee, formed under FOR.

Chapter seven

Distribution Operations and Retail Competition

Key amendments to the existing Electricity Act, 2003 have been proposed by the Union Cabinet, through the Electricity Amendment Bill, 2014. A key feature of the proposed amendment is the separation between distribution and supply functions to promote competition in the supply segment. Key features of the proposed amendments are highlighted in the box alongside.

FIGURE 12: KEY PROVISIONS OF ELECTRICITYAMENDMENT BILL 2014

Key provisions of Electricity Amendment Bill 2014
Current Discoms are to be split into Distribution (carriage) & Incumbent Supply (content)
Duties and Functions of Distribution and Supply businesses defined separately
Multiple Supply licensee allowed in a license area
Single Distribution company envisaged in a license area
Intermediary Company to be formed for taking over existing PPAs and procurement arrangements of the relevant distribution licensees
Transfer scheme to be made by state governments for segregation of content and carriage businesses
Protection of interests of the consumers by keeping one of the supply licensees as a government-controlled company

It is worthwhile to mention that different countries have embarked upon retail sector reforms in different phases of their reform trajectory. Retail competition has been more effective in UK, parts of Western Europe and Australia than in other parts of the world. The experience of retail competition in USA is a mixed bag, with only about 13 states having some form of retail competition. New York and Texas are the US states with the longest history of retail competition. It is essential to analyze the international experience in retail competition before shaping India's specific pathway towards achieving choice and competition in electricity retail business.

Key activities which are required as pre-requisites for introducing retail competition in India are elucidated below:-

FIGURE 13: PRE-REQUISITES FOR INTRODUCTION OF RETAIL COMPETITION IN INDIA

Economic	a) Requirement of adequate Wholesale market reforms with sufficient buyers/sellers, availability of untied capacity, low market power, good governance and market rules b) Cost-reflective tariffs across various voltage levels c) Reduction in cross subsidies for effective consumer involvement
Financial	a) Detailed methodology and process to be followed to determine network tariff needs to be outlined; clarity with regards to supply regulation b) Ensuring business continuity of existing distribution licensees and recovery of their investments c) Treatment of existing financial losses
Operational	a) Treatment of existing distribution losses to be clarified b) Suitable supply infrastructure needs to be in place (necessity for adequate feeder and backbone infrastructure for fulfilling supply obligation, cost sharing of new metering infrastructure, etc.) c) Clarity required amongst the stakeholders to understand how metering will be done and how responsibilities will be distributed and measured to reduce T&D losses. d) Transfer scheme needs to clearly address handpicking of consumers by the supply licensee, clearly defining the area of a supply licensee, defining the entities' functions and responsibilities, ownership, treatment of existing power procurement commitments, tariff and subsidies, transfer of resources etc.

7.1. THE UK EXPERIENCE

The United Kingdom is considered as the one of the successfully implemented models of retail competition in the electricity sector. The reforms process in UK was a long one, starting from late 1980s, and saw several transformations before retail competition was finally introduced to end consumers at the household level.

7.1.1. PHASED INTRODUCTION OF RETAIL COMPETITION

A key aspect of the introduction of retail competition in UK was that the supply market was opened up to competition in three phases, starting from April 1990 and culminating in May 1999. Customers were given the option of choosing their supplier from any of the twelve RECs (Regional Electricity Companies, who were also the public electricity supply licensees in their own area) or from other competing retailers.

TABLE 10: PHASED INTRODUCTION OF RETAIL COMPETITION IN UK

Phases	Details
Phase I: Apr'90 *Loads above 1 MW*	• Customers with peak loads of more than 1 MW (about 45% of the non-domestic market and 26% of total sales) were allowed to choose their supplier; these customers numbered around 5200 and they were predominantly major manufacturing plants and hospitals • At this stage, separation between distribution and retail services was not mandatory and hence retail services could be offered by distribution as well as independent companies. • There were two types of supply licenses. The distribution company needed a first-tier supply license for selling retail services and other companies needed a second-tier supply license.
Phase II: Apr'94 *Loads between 100 kW to 1 MW*	• In 1994 the open market was extended to some 45,000 users with a 100 kW and above annual demand • With time, there was increase in the number of consumers opting for competitive supply/ In 1999-2000, customers accounting for 80% of the 1 MW market in England and Wales chose to take their supply from a company other than their local Public Electricity Suppliers (as compared with 43% in 1990-91); • Similarly, by 1999-2000 customers accounting for 67% of the output in the 100 kW to 1 MW market in England and Wales chose to take their supply from another company
Phase III: Sept'98 to Mar'04 *All loads*	• Opening up of the domestic market (below 100 kW) to competition also met with success; • By September 2001, 38% of domestic electricity customers had switched suppliers at least once • Toward the end of this phase, falling prices due to competition forced merger and acquisition amongst the electricity suppliers

The phased model of rolling out retail competition was necessary in order to allow the market to evolve to competition-based price setting.

7.1.2. OWNERSHIP SEGREGATION

Through the Utilities Act, 2000 a provision was made for separating supply and distribution activities, requiring the separation of the supply and distribution businesses of former Public Electricity Suppliers (PES). Any company holding an electricity supply license could now sell electricity to all customers across Great Britain. This provided a mechanism by which a distribution network operator could no longer sell electricity as a retail supplier. PESs were inheritors of 3 years' long-term contracts with generators, designed to meet their obligation to supply to consumers in their license area. The rationale behind the move to segregate distribution network companies from retail supply was to allow for an effective implementation of non-discriminatory open access over distribution network. Consumer metering, at this point, was outsourced to third party service providers. A Meter Asset Provider (MAP) was appointed by the retail supply licensee for maintaining inventories and providing meters, whereas a Meter Operator (MOP) was appointed separately for installation, maintenance and data collection. In many instances, both services were provided by the same company but responsibilities were discrete and segregated.

7.1.3. DEVELOPMENT OF WHOLESALE MARKET

An important aspect of development of retail competition was the establishment of the New Electricity Trading Arrangements (NETA) for bilateral trading between generators, suppliers, traders and customers through forwards and futures markets and short-term power exchanges. Under NETA, the bulk of electricity was traded in forward, futures and short-term markets through bilateral contracts. Contracts in these market were drawn up over a scale of time ranging from within-day to several years ahead. NETA allowed for new suppliers to flexibly form their own wholesale procurement portfolios to supply to their licensed retail areas. This mapped well with the phased introduction of supply competition, as new suppliers only signed on to wholesale contracts to meet obligations to supply large consumers in the first phases and then when all long-term contracts (including those inherited by PESs for 3 years) became contestable, they could flexibly form their own portfolios competitively to supply to low voltage retail consumers.

On April 2005, NETA changed its name to the British Electricity Trading Transmission Arrangements (BETTA), and expanded to become the single Great Britain electricity market of England, Wales and Scotland. The arrangements under BETTA arebased on bilateral trading between generators, suppliers, traders and customers across a series of markets operating on a rolling half-hourly basis. The wholesale market evolved into a highly developed mechanism with financial tools and instruments being devised for trading of power. This, coupled with the energy surplus scenario in the UK, was significant in assisting retail side reforms. Due to these reforms, it was observed that there was a gradual reduction in the electricity prices to consumers.

OTHER ASPECTS

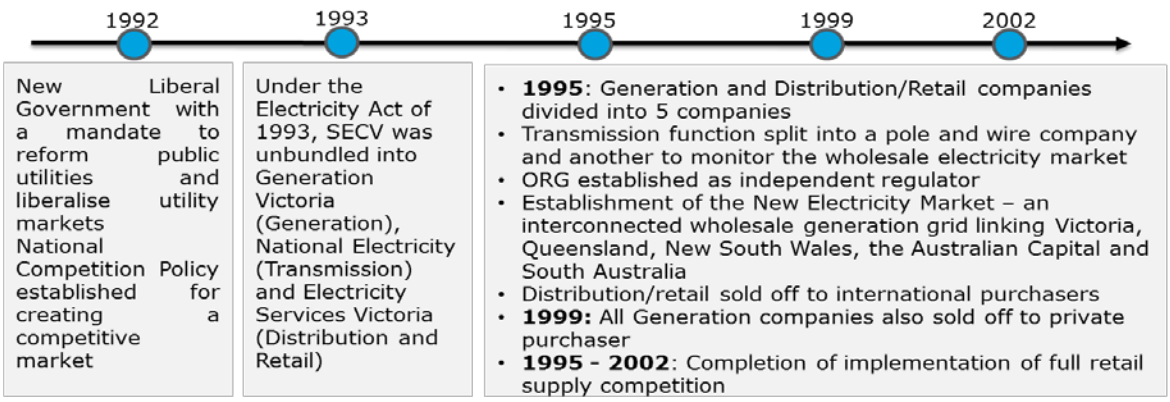
TABLE 11: OTHER ASPECTS FOM UK EXPERIENCE

	Details
Electricity pricing	The regulator OFGEM administers a price control regime that ensures that efficient distributors can earn a fair return after capital and operating costs
Consumer switching	Within 5 years of introduction of competition, 72% of British consumers have switched their gas and / or electricity supplier during the last five years.
Last resort provider	It is important to ensure consumer interests in retail competition and thereby their electricity supply was made secure by way of the universal service obligation wherein Last Resort Supply direction may be given to the incumbent retail supply licensee under certain conditions. Moreover, the distribution network operator has the "Duty to Connect‟ i.e. make available the distribution network on request, whereas the incumbent licensee as well as competitive retailer(s) both have the "Duty to Supply‟ i.e. to meet all reasonable demands for supply of electricity made by customers within their supply areas on reasonable/approved terms.

7.2. THE AUSTRALIAN EXPERIENCE

Victoria is the first state in Australia where retail competition was introduced. At present, Victoria is the second largest electricity market in Australia with approximately 2.1 million residential customers and 300,000 business customers. A vertically integrated State Electricity Commission of Victoria (SECV) existed in 1980s which was responsible for the generation, transmission and delivery of electricity to all Victorians. The electricity sector was chosen as the most priority sector for undertaking reforms post 1992, when a new Liberal Government came to power. The primary motive was to liberalize the power utility markets and create an openly competitive electricity market for the sale of electricity to consumers. The anticipated result was lower prices and improved services.

FIGURE 14: TIMELINE OF AUSTRALIAN EXPERIENCE



7.2.1. PHASED INTRODUCTION OF RETAIL COMPETITION

The rollout of retail competition was implemented in the following phases:-

TABLE 12: ROLLOUT OF RETAIL COMPETITION IN AUSTRALIA

Time period	Category covered	Load	No of consumers
Dec 1994	Large industrial consumers	> 5 MW	47
July 1995	Large commercial consumers	1 – 5 MW	330
July 1996	Medium industrial / commercial users	750 MWh – 1 MW	2000
July 1998	Small industrial / commercial users	160 – 750 MWh	>8000
Jan 2002	Domestic; Small business consumers	Under 40 MWh	2,000,000

The phased introduction of competition was extremely successful in Victoria, with the first phase targeting only consumers with load above 5 MW, with progressively bigger (in terms of number of consumers affected) segments being deregulated over time.

7.2.2. SEPARATION OF BUSINESS

After due consideration it was decided that the retail and wires distribution functions would be retained under the distribution business where low risk cash flows from the wires function would provide financial backing to the business. However, this structure increased the sectors susceptibility to cross-subsidization. To overcome this, distribution businesses were required to maintain separate accounts for regulated and unregulated businesses which would facilitate better monitoring by the regulatory bodies.

The responsibility of metering was given to the Retail Supplier who could, in turn appoint the Distribution company or a third party for providing meters.

7.2.3. SETTING UP OF MAXIMUM UNIFORM TARIFF

The Government of Victoria laid down a Maximum Uniform Tariff which would put a ceiling on the maximum tariff that can be charged. This ensured reduction in tariffs in real terms and brought about a certainty with respect to retail electricity prices. This also acted as a useful step towards reducing cross-subsidies.

7.2.4. REDUCTION IN CROSS SUBSIDIES

Under the pre-reform regime, the retail prices were complicated due to a complex set of cross subsidies including inter and intra class distortions along with a uniform tariff structure for urban and rural consumers. In order to resolve this, the Victorian approach involved capitalisation of cross subsidy as a one-time adjustment but enable, over time, distribution prices to gradually become cost reflective. The distribution businesses were free to unwind inter-class cross subsidies, but the Tariff Order limited the speed at which this could be done by capping any individual maximum increase to CPI +2%; an increase, which has generally been fully utilized by the distribution utilities since the privatization occurred. This was an important step in ensuring full implementation of retail competition

7.3. PROPOSED WAY FORWARD FOR INDIA

Taking into account the current scenario of the electricity sector in India as well as international best practices, it is important that there should be a phased approach for full implementation of retail supply competition in India. The Forum of Regulators has proposed the following phase wise approach for operationalizing the retail competition in the country taking into account the several challenges:-

7.3.1. PHASE 1: INITIATION (0-3 YEARS)

The starting phase of the approach will comprise of the following tasks:-

SEPARATION OF WHEELING AND RETAIL SUPPLY BUSINESS WITH SAME OWNERSHIP

The distribution and retail supply business is proposed to be segregated under the same ownership. Key tasks to be performed in this phase include the following:

- Maintenance of separate accounts for the two businesses
- Asset valuation and segregation of assets
- Allocation of employees between the two functions, which would help in assessing the employee cost of the distribution business at the time of regulatory tariff setting.
- Separation of technical and financial losses.
  a) Allocation of technical and commercial losses: Allocation of technical and commercial losses between the distribution and retail supply business is essential because normative loss targets shall be set for the distribution business at the time of regulatory approval of distribution tariff.
     Technical losses can be allocated to the incumbent distribution licensee whereas the commercial losses can be tied up to the retail supply business
  b) Allocation of financial losses: Since retail supply business would necessarily get divested and transferred to a separate owner in due course of time, therefore it is essential that financial losses are clearly booked to the accounts of distribution business and retail supply business separately.

In due course of time, the ownership is proposed be separated between the distribution and retail businesses

- CERC/SERCs may be encouraged to direct distribution utilities to carry out segregation of feeders and/or achieve 100% metering so that distribution losses may be accurately estimated.
- Distribution utilities also need to be directed to start maintaining voltage-wise asset registers to determine voltage wise losses.
- For dealing with accumulated financial losses and regulatory assets of Discoms, a Special Purpose Vehicle (SPV) may be created to take over all existing financial losses of the Discoms, and a Regulatory Surcharge can be levied on all consumers (of incumbent Discom as well as competitive supply retailers) which would go towards the SPV.
- Establishment of correct baseline values of existing distribution losses is necessary because after separation of the two functions, achievement (and over/under-achievement) of distribution loss targets would form one of the components of tariff for the DNO as well as for the regulated segment of the retail supply market

REDUCING CROSS-SUBSIDIES

Currently, although the cost of supply and technical and incidental commercial losses is lesser for industrial consumers than the other category of consumers, they end up paying more than the others in order to compensate for affordability across other categories. Implementation of phase wise approach would entail the consumers with load 1 MW or above obtaining the benefits of competition who would in turn move to other retailers and hence lead to substantial revenue loss for the incumbent distribution licensee.
In such a case, following actions can be taken:-

- Cross subsidies can be introduced for competitive market consumers in the initial few years
- Alternatively, a Universal Charge (UC) (similar to UK) may be imposed on all consumers before rolling out the first phase of retail competition. This UC would be an identical charge imposed on per-unit basis on sales to all consumers of incumbent distribution companies and collection of UC would go towards a state-wide/national fund to reduce the extent of cross subsidy in retail supply.
- The Government may provide some sort of a viability gap funding in order to compensate incumbent Discoms for the loss of high-tariff consumers, in case retail tariffs are not increased

Huge political will is essential for reduction of cross-subsidies for domestic consumers. Inference needs to be taken from the case of Victoria, Australia wherein gradual phasing out of cross-subsidies was carried out. Moreover, based on detailed Cost of Supply calculation for each consumer category, the tariffs need to be realigned every year.

SEGREGATING EMPLOYEES BETWEEN THE TWO FUNCTIONS

To correctly ascertain, the operating cost burden on the two functions, it is important the manpower segregation is done accurately between them. A manpower requirement / optimization study may be required to help the utilities in this activity.

PRELIMINARY OPERATIONALIZATION

SEPARATE LICENSES FOR BOTH BUSINESS

This step will entail both businesses acquiring separate licenses for their operations with clear demarcation of roles and responsibilities, which would inter-alia include:-

TABLE 13: ROLES & RESPONSIBILITIES FOR DISTRIBUTION NETWORK BUSINESS AND RETAIL SUPPLY

Distribution network business	Retail Supply
• Network planning (up to the consumer meter) • Capital expenditure on building and augmentation of the distribution network • Operation and maintenance of the network • Fault restoration	• Power procurement and management of existing contracts • Existing power trading • Supply to consumer • Meter reading and meter-related operations • Consumer billing • Collection of revenue from consumers • Credit contracts • Customer care for meter, billing, collection and technical issues

TRANSFERRING EXISTING PPAS TO SUPPLY LICENSE

Post the separation of licenses and responsibilities, procurement of power would become the supply licensee's responsibility which would necessitate that all existing PPAs signed between generators and the previous discom shall be transferred to the incumbent supply licensee of the area. ***Very long-term vested PPAs and introduction of supply competition are incompatible with each other***. A mechanism may have to be derived whereby long-term PPAs are converted into shorter-term contracts for vesting, with PPAs becoming contestable after the end of the vested term.

Defining the area, tenure and nature of supply license

Key aspects of the supply license needs to be worked out viz,

TABLE 14: KEY ASPECTS OF SUPPLY LICENSE

Area	Tenure
Demarcation of area of license should be done in such a way to generate interest among private players. Key factors include regarding revenue potential, consumer mix and loss levels.	A comparatively shorter tenure of say 3-5 years may not be in the interest of private players who would need cheaper power procurement through long term contracts

- In the initial stages, the entire state could be treated as one contiguous area of license
- Competition can be ensured by issuing licenses to several entities for the same license areas
- Licences may be provided for an initial period ranging from 10-25 years, unless revoked, after which re-demarcation of supply areas may be considered

RETAIL PRICING

Their needs to be separate tariff determination for the distribution and the supply business. While the distribution business will earn a regulated tariff, the supply business can be tied to a regulated tariff with a margin depending on the level of loss reduction achieved, similar to how it was done in the UK wherein efficient distributors can earn a fair margin. This shall contribute to increased efficiencies in operations.

ADEQUATE GENERATION CAPACITY MARKETS AND GENERATOR SHARE

Wholesale market reforms as well as availability of untied generation capacities are important for ensuring flexibility for consumers to avail supply. A competitive and well defined wholesale market is expected to provide sufficient checks and balances to ensure supply of power to consumers at the most economical price.

- As observed in UK, development of a wholesale market is essential for enhanced trading between generators, suppliers, traders and customers
- A medium term capacity market may work well in the Indian context for contracts of duration 1-3 years. Capacities that are untied or released can participate in this market. National Load Dispatch Centre may be enabled to act as the operator for this market.
- It is also worthwhile to observe that for a truly competitive electricity market, the significant market shares of mammoth entities such as NTPC, etc. should be monitored and preferably reduced otherwise these entities could possibly exert monopoly pressure on power procurement rates due to their sheer size.

INVITING SUBSEQUENT SUPPLY LICENSEES

After the aforementioned steps have been undertaken, second / subsequent supply licensees can be invited. Considerations such as requisite Authority, area and tenure of the licensee, eligibility criteria and conducting public consultations need to be observed and taken care of adequately.

7.3.2. PHASE 2: OPERATIONALIZATION (3-6 YEARS)

SEPARATION OF OWNERSHIP

Separating the ownership of the distribution wire and retail supply businesses will be required once all the aforementioned tasks have been carried out to ensure zero conflict of interest between both the businesses. Ownership separation would ensure that the distribution network licensee cannot be in the retail supply business any longer.

Key challenges in the same include:-

1) Divestment of loss making entities
2) Action plan in case there are no takers for a particular area of license
3) Modalities for separation

IMPLEMENTING TECHNOLOGICAL IMPROVEMENTS

Improvements in technology viz. introduction of AMR and smart meters will become necessary in this phase since there needs to be clear distinction between the incumbent distribution licensee customers as well as subsequent suppliers in case of load shedding, load restriction cuts imposed by incumbent licensee.

As has been observed in UK and Australia, metering activity can be outsourced to third parties who can provide the assets as well as install and maintain the same.

LAST RESORT PROVIDER

This provision would entail an obligation of offering electricity against some specified tariff to any customer, irrespective of load characteristics when any default by the supply licensee happens in providing power supply. This should comprise of a ‘Duty to Connect’ which would rest with the Distribution network operator who would be obliged to make available the distribution network on request and would be obliged to connect any person to the network as well as a ‘Duty to Supply’ would rest with both the incumbent Discom as well as competitive retail supplier(s) who would be obliged to meet all reasonable demands for supply of electricity.

7.3.3. PHASE 3: FURTHER COMPETITION (BEYOND 6 YEARS)

Similar to scenarios as observed in UK and Australia, the retail supply business shall be opened for more and more consumer segments, with competition being introduced in phases.

- Deregulation of less than 500 kW to 1 MW segment
- Deregulation of less than 100 kW to 500 kW segment

A phase wise approach for introducing retail competition in India would be apt considering learnings obtained from international markets.

Segregation of wheeling and retail supply business, reduction of cross subsidies and employee segregation between wheeling and retail supply should be carried out at first. Separation of licenses between the two businesses, transfer of PPAs to supply license, demarcation of areas of supply licenses, tariff determination and participation by subsequent supply licensees etc would be the subsequent step. Separation of ownership of wheeling and retail supply, technological advancements and last resort provider should be done thereafter. Focus should be on including consumer with load 1 MW or above. Subsequently, the retail supply business could be opened for more and more consumer segments

Chapter eight

Annexures

LIST OF FIGURES

LIST OF TABLES

List of Abbreviations

Abbreviations	Full Form
AGC	Automatic Generation Control
BETTA	British Electricity Trading and Transmission Arrangements
CAISO	California Independent System Operator
CEA	Central Electricity Authority
CEGB	Central Electricity Generation Board
CEM	Capacity Electricity Markets
CERC	Central Electricity Regulatory Commission
CFD	Contracts For Differences
DAM	Day-ahead Market
EOM	Energy Only Market
EPS	Electric Power Survey (published by the Central Electricity Authority)
ERCOT	Electric Reliability Council of Texas
FERC	Federal Electricity Regulatory Commission (USA)
GW	Giga Watts
IEGC	India Electricity Grid Code
IPP	Independent Power Producers
ISO	Independent System Operator
ISO-NE/NEISO	New England Independent System Operator
LMP	Locational Marginal Pricing
LOLE	Loss of Load Events
LOLP	Loss of Load Probability
LSE	Load Serving Entities
MISO	Midcontinent Independent System Operator (USA)
NETA	New Electricity Trading Arrangements (UK)
NYISO	New York Independent System Operator (USA)
OFGEM	Office of Gas and Electricity Markets (UK)
OTC	Over the Counter
PGCIL	Power Grid Corporation of India Ltd.
PJM	Pennsylvania-Jersey-Maryland Independent System Operator (USA)
POSOCO	Power System Operation Corporation Limited
PPA	Power Purchase Agreement
QF	Qualifying Facility (in reference to USA)
RE	Renewable Energy
REMC	Renewable Energy Management Centre
RTO/ISO	Regional Transmission Operator / Independent System Operator (in reference to USA)
SAMAST	Scheduling, Accounting, Metering and Settlement of Transactions in Electricity
SECI	Solar Energy Corporation of India
SERC	State Electricity Regulatory Commission
SO	System Operator
SPP	South West Power Pool
URS	Un-requisitioned Surplus
VRE	Variable Renewable Energy
WEM	Wholesale Electricity Markets

I. DATA TABLES

Table 15: ALL INDIA- INCREMENTAL PEAK MET / EPS TARGET VS CUM. CAPACITY ADDITION (MW) OVER FY11 BASE

Year	Incremental Peak Demand as per 18th EPS	Incremental Peak Met	Coal based capacity addition
FY 12	10398	5935	18104
FY 13	21680	13038	36302.51
FY 14	33921	19559	51355.01
FY 15	47204	30904	70717.5
FY 16	61615	38207	91254.5
FY 17	77253	46678	98244.5

TABLE 16: SYSTEM PEAK AND ENERGY DEFICIT (%)

Year	Peak Deficit	Energy Deficit
FY10	12.7%	10.1%
FY11	9.8%	8.5%
FY12	10.6%	8.5%
FY13	9.0%	8.7%
FY14	4.5%	4.2%
FY15	4.7%	3.6%
FY16	3.2%	2.1%
FY17	1.6%	0.7%

Table 17: INSTALLED CAPCITY - 334 GW

Year	Sales (GW)
Coal	193
Gas / Diesel	26
Hydro	45
Nuclear	7
RE	63

Table 18: TIED-UP CAPACITY - 291 GW

Year	Capacity Tied-up (GW)
Coal	165.68
Gas / Diesel	20.027
Hydro	42.689
Nuclear	5.865
RE	57.244

TABLE 19: DEMAND PROJECTIONS - PFA AND 19TH EPS

Year	Demand (Power for All)	Demand (19th EPS)	Deviation (%)

Year	Demand (Power for All)	Demand (19th EPS)	Deviation (%)
FY17	183838	161834	12%
FY18	199568	176897	11%
FY19	217245	188360	13%
FY20	238947	200696	16%
FY21	253541	213244	16%
FY22	269066	225751	16%
FY27		298744	

TABLE 20: PEAK DEFICIT TO BE BRIDGED (%)

Year	UP	Gujarat	Tamil Nadu	MP	Punjab	Karnataka	Haryana	Rajasthan	W. Bengal
2018	11%	0%	3%	0%	0%	-2%	1%	6%	0%
2019	3%	4%	8%	-7%	8%	10%	6%	0%	5%
2020	4%	5%	5%	-10%	8%	12%	6%	-2%	9%
2021	2%	9%	8%	-11%	10%	14%	8%	-2%	4%
2022	-2%	12%	10%	-4%	12%	16%	10%	1%	1%

Table 21: AVERAGE DEFICIT TO BE BRIDGED (%)

Year	UP	Gujarat	Tamil Nadu	MP	Punjab	Karnataka	Haryana	Rajasthan	W. Bengal
2018	11%	0%	3%	0%	0%	-2%	0%	0%	0%
2019	2%	3%	6%	-9%	7%	7%	3%	-8%	1%
2020	1%	3%	-1%	-14%	6%	8%	2%	-11%	-1%
2021	-5%	5%	2%	-15%	6%	10%	2%	-11%	-9%
2022	-14%	8%	3%	-8%	7%	11%	3%	-9%	-14%

II. EXIT CLAUSES IN POWER PURCHASE AGREEMENTS

a. REVIEW OF POWER PURCHASE AGREEMENTS OF NTPC

TABLE 22: REVIEW OF PPAS OF NTPC

Clause Description	Singrauli, Rihand-I, Anta, Auraiya, Dadri-I, Dadri Gas * Unchahar-I With NT States and Rajasthan BPSA dated 31.01.1994	Kahlgaon STPS-II With Bihar PPA dated 12.06.2003	Vindhyachal STPS-IV with Madhya Pradesh PPA dated 12.09.2008
Validity & Extension	The agreement may be mutually extended/ renewed. In case bulk customers continue to get power from the NTPC Station even after expiry of the agreement then all the provisions shall continue to operate	From the date of signing to 25 years from the date of commercial operation of last unit. Provided the agreement may be mutually extended/ renewed. In case bulk customers continue to get power from the NTPC Station even after expiry of the agreement then all the provisions shall continue to operate.	From the date of signing to 25 years from the date of commercial operation of last unit. Unless it is specifically extended on mutually agreed terms.
Exit Clause	Not present	Not present	Not present

It appears from a preliminary study that in the current structure of NTPC PPAs, there is neither an option to exit the contract nor provisions for review or renegotiation of terms and conditions.

b. REVIEW OF PPAS OF IPP PROJECTS

TABLE 23: REVIEW OF PPAS OF IPP PROJECTS

	BALCO Limited	Lanco Babandh Power Limited	PTC India Limited
State	Tamil Nadu	Uttar Pradesh	Uttar Pradesh
Capacity	100 MW	6000 MW	6000 MW
Early termination	The agreement shall be terminated before the expiry date, if the Procurer or Seller exercise a right to terminate pursuant to: • Non-fulfilment of conditions by Seller by giving seven days' notice to the Seller by the Procurer. • Sellers' inability to fulfil conditions upto the extended period of force majure, either Seller or Procurer may terminate a contract giving seven days' notice to either party • Inability of Procurer to fulfil the conditions specified upto the extended period of force majure - either Seller or Procurer may terminate the agreement with a prior notice of seven days.	The Agreement shall terminate before the Expiry Date: if either all the Procurers (jointly) or the Seller exercises a right to terminate, in such other circumstances as the Seller and all the Procurers (jointly) may agree, in writing.	The Agreement shall terminate before the Expiry Date: if either all the Procurers (jointly) or the Seller exercises a right to terminate, in such other circumstances as the Seller and all the Procurers (jointly) may agree, in writing.
Penalty	If Procurer terminates the agreement due to non-fulfillment of claim by seller, the seller is liable to pay an amount of Rs.40 crore as liquidated damages. In the event of Seller's termination due to non-fulfilment of conditions by Procurer, the Procurer shall release the contract performance guarantee to Seller. In addition, the Procurer shall pay a Seller's liquidated damage (10% of the	Liquidated Damages for delay in commencement of supply of power (formula for calculation has been specified) Liquidated Damages for delay due to Procurer Event of Default-the Procurers shall make payment to the Seller of Capacity Charges in proportion to their Contracted Capacity, calculated on Normative Availability of Contracted Capacity for and during the period of such delay. In case of delay due to Indirect Non Natural Force Majeure Event or	Liquidated Damages for delay in commencement of supply of power (formula for calculation has been specified) Liquidated Damages for delay due to Procurer Event of Default-the Procurers shall make payment to the Seller of Capacity Charges in proportion to their Contracted Capacity, calculated on Normative Availability of Contracted Capacity for and during the period of such delay. In case of delay due to Indirect Non Natural Force Majeure Event (or Natural

	BALCO Limited	Lanco Babandh Power Limited	PTC India Limited
	Contract Performance Guarantee	(Natural Force Majeure Event affecting the Procurer(s)), the Procurers shall make payment to the Seller for Debt Service, subject to a maximum of Capacity Charges calculated on Normative Availability of Contracted Capacity, which is due under the Financing Agreements for the period of such events in excess of three (3) continuous or non-continuous Months.	Force Majeure Event affecting the Procurer(s)) or Procurer Event of Default, the Procurers shall be liable to make payments as mentioned above, after commencement of supply of power, in the form of an increase in Capacity Charges
Events of default	**Seller Event of Default** Failure to commence supply of contract capacity, interruption of supply for a period of two months and not rectification within another 30 days, failure to achieve normative availability for a period of 12 months Notice to be given by Procurer with a copy to appropriate commission. 90 days of consultation period is allowed and if held, termination can be done by giving 30 days' notice within seven days of consultation period expiry, etc. **Procurer's even of Default:** Seller free to sell contracted capacity to the third party, payment of capacity charge by Procurer for maximum 12 months, etc.	Right to terminate the clause on account of procurer and seller events of default. **Seller event of default**: Failure to commence supply of contracted capacity, interruption of supply for a period of two months and not rectification within another 30 days, failure to achieve normative availability for a period of 12 months, assigns, mortgages or charges or purports to assign, mortgage or charge any of its assets or rights related to the Power Station in contravention of the provisions of this Agreement, seller becoming bankrupt. Seller repudiates this Agreement and does not rectify such breach within a period of thirty (30) days from a notice from the Procurers in this regard etc. Notice to be given by Procurer with a copy to appropriate commission, 90 days of consultation period and if held, termination to be done after 30 days' notice within seven days of consultation period expiry to the Seller, etc. **Procurer event of default: F**ails to meet any of its obligations, fails to pay an amount exceeding fifteen (15%) of the undisputed part of the most recent Monthly/ Supplementary Bill for a period of ninety (90) days, repudiates the Agreement and does not rectify such breach even within a period of thirty (30) days from a notice from the Seller, seller becomes bankrupt, etc. Notice to be given by seller, 90 days of consultation period, Seller shall be free to sell the Contracted Capacity and corresponding available capacity of the Procurers to any third party of the Seller's choice, after 7 days of cease of consultation period if default is not remedied. Procurer shall have the liability to make payments for Capacity Charges based on Normative Availability to the Seller for the period upto the Expiry Date, subject to maximum of three (3) years from the eighth day after the expiry of the Consultation Period.	Right to terminate the clause on account of procurer and seller events of default. **Seller event of default**: Failure to commence supply of contracted capacity, interruption of supply for a period of two months and not rectification within another 30 days, failure to achieve normative availability for a period of 12 months, assigns, mortgages or charges or purports to assign, mortgage or charge any of its assets or rights related to the Power Station in contravention of the provisions of this Agreement, seller becoming bankrupt. Seller repudiates this Agreement and does not rectify such breach within a period of thirty (30) days from a notice from the Procurers in this regard etc. Notice to be given by Procurer with a copy to appropriate commission, 90 days of consultation period and if held, termination to be done after 30 days' notice within seven days of consultation period expiry to the Seller, etc. **Procurer event of default: F**ails to meet any of its obligations, fails to pay an amount exceeding fifteen (15%) of the undisputed part of the most recent Monthly/ Supplementary Bill for a period of ninety (90) days, repudiates the Agreement and does not rectify such breach even within a period of thirty (30) days from a notice from the Seller, seller becomes bankrupt, etc. Notice to be given by seller, 90 days of consultation period, Seller shall be free to sell the Contracted Capacity and corresponding available capacity of the Procurers to any third party of the Seller's choice, after 7 days of cease of consultation period if default is not remedied. Procurer shall have the liability to make payments for Capacity Charges based on Normative Availability to the Seller for the period upto the Expiry Date, subject to maximum of three (3) years from the eighth day after the expiry of the Consultation Period.

There is significant variability in existing PPAs with IPPs. However, PPAs which were signed in compliance with the competitive bidding guidelines of the Ministry of Power, GOI, have followed the standard bidding documents and they have similarity in termination provisions. There are no exist clauses in these PPAs. However, there are specific termination provisions in the case of specified events of defaults which provides rights to the non-defaulting party to seek termination. As far as termination payment is concerned, the party initiating termination due to default by the other party, is liable to get liquidated damages / risk purchase for a fixed term depending on the status of the power project, i.e., whether it is under construction or operation. For example, operation projects have capacity charges for 3 years as penal payment for the defaulter party

c. REVIEW OF PPAS OF RE PROJECTS IN ANDHRA PRADESH, TELANGANA AND TAMIL NADU

TABLE 24: REVIEW OF PPAS OF RE PROJECTS

	Orange Urvakonda Wind Power Pvt Ltd	Acme Nizamabad Solar Energy Pvt Ltd	Adani Green Energy (Tamil Nadu) Ltd
State	Andhra Pradesh	Telangana	Tamil Nadu
Type	Wind	Solar	Solar
COD	30/Nov/2016	26/Sep/2017	11/Mar/2016
PPA date	31/May/2016	26/Feb/2016	04/Jul/2015
PPA term	25 years from COD	25 years from COD	25 years from COD
PPA tariff	Rs 4.84 / kWh + taxes	Rs 5.5949 / kWh (50% of tariff, for CUF over 25%)	Rs 7.01 / kWh
Exit clause(s)	By DISCOM a. COD not achieved within 2 years of PPA signing b. On default – Notice of 30 days to be given. Preliminary Termination Notice may be issued if default continues for 30 days or more. Termination possible 30 days after issue of Preliminary Termination Notice, if default is not cured within the period. c. Cancellation of wind power project by Nodal Agency, NREDCAP. By Developer: d. On default – Similar to (b) above	By DISCOM a. Failure to commission within 15 months from PPA signing b. 21 days after issue of Termination Notice, for failure to submit document c. On default– Preliminary Default Notice to be followed by 60 day Conciliation Period. 7 days after Conciliation Period of 60 days, Lenders' Cure Period of 90 days follows. On expiry of Lenders' Cure Period, Termination Notice with wait period of 30 days to be issued. (Process terminates if default is cured any time before issue of Termination Notice) By Developer: d. On default- Similar to (b) above, except no issue of final Termination Notice. Preliminary Default Notice to be followed by Conciliation Period of 60 days. 7 days after Conciliation Period, SPD may after selling power to 3rd party. Three months later PPA may be terminated.	Either party a. After three months' notice, for violation of any of the clauses of the PPA
Penalty for delayed COD	PPA liable for termination for delay over 2 years	Progressively increasingly BG encashment, corresponding to delay:- Delay period - 1 month: Rs 3 lac / MW / day - 2 – 3 months: Rs 7 lac / MW / day - 4 – 5 months: Rs 10 lac / MW / day - > 5 months: Rs 10,000 / MW / day - Max permissible delay of 21 months, after which only installed capacity to be considered	Not mentioned
Renegotiation	Not mentioned	Not mentioned	Not mentioned
Extension / Shortening beyond tariff term	Extension possible: Subject to Commission's approval on mutually agreed terms and tariff. APSPDCL has first right of refusal.	Extension possible: Subject to Commission's approval on mutually agreed terms and tariff Project has to be handed over to	Not mentioned

	Orange Urvakonda Wind Power Pvt Ltd	Acme Nizamabad Solar Energy Pvt Ltd	Adani Green Energy (Tamil Nadu) Ltd
		DISCOM at depreciated value, as approved by Commission, in case PPA is not extended or project is shut.	

III. REGION WISE DEMAND-SUPPLY SCENARIO

FIGURE 15: REGION WISE DEMAND SUPPLY SCENARIO

IV. STATE WISE DEMAND-SUPPLY PROJECTIONS

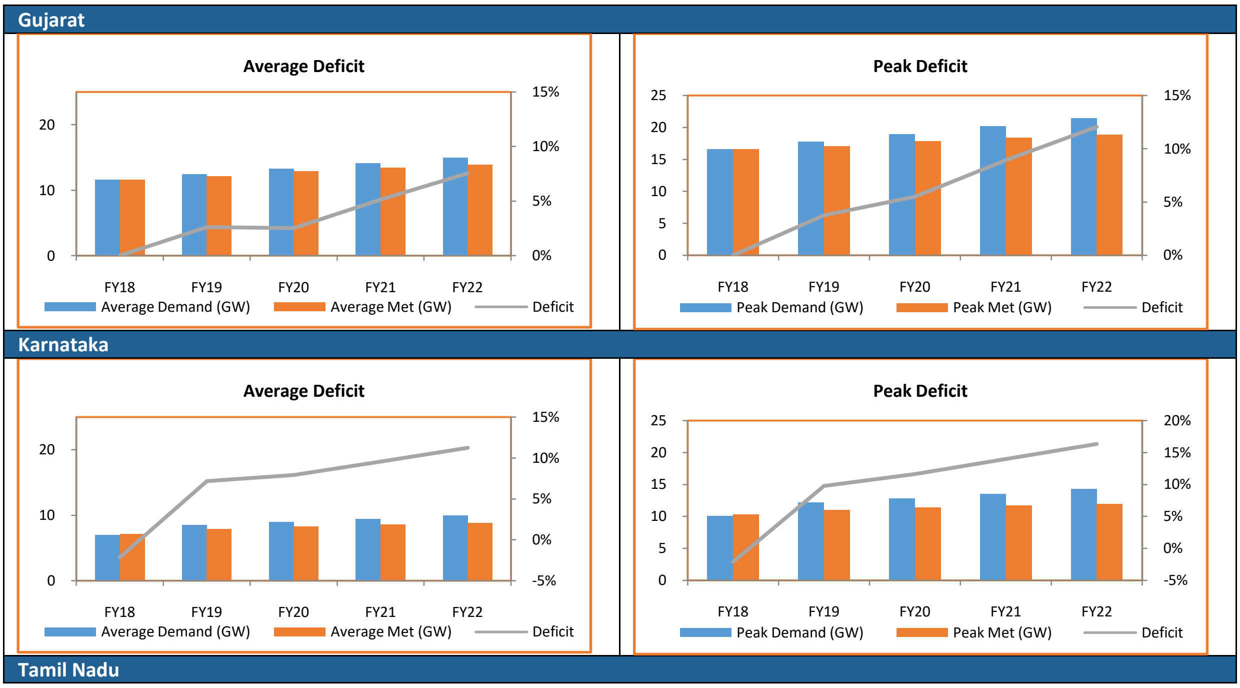
TABLE 25: STATE WISE PEAK (DEFICIT)/SURPLUS TO BE BRIDGED (%)

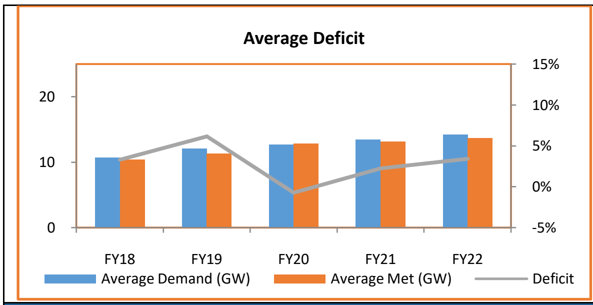
Peak (deficit) / surplus (%)- to be bridged	2018	2019	2020	2021	2022
Uttar Pradesh	-11	-3	-4	-2	2
Gujarat	0	-4	-5	-9	-12
Tamil Nadu	-3	-8	-5	-8	-10
MP	-	7	10	11	4
Punjab	-	-8	-8	-10	-12
Karnataka	2	-10	-12	-14	-16
Haryana	-1	-6	-6	-8	-10
Rajasthan	-6	-	2	2	-1
West Bengal	-	-5	-9	-4	-1

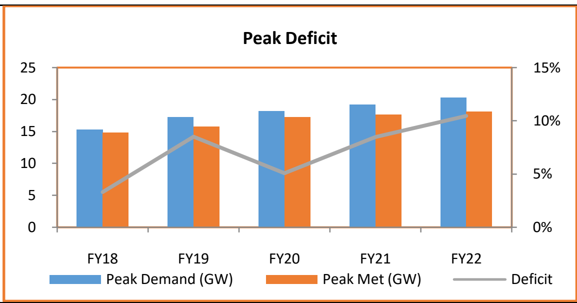
TABLE 26: STATE WISE AVERAGE (DEFICIT)/SURPLUS (%) TO BE BRIDGED

Average(deficit) / surplus (%) - to be bridged	2018	2019	2020	2021	2022
Uttar Pradesh	-11	-2	-1	5	14
Gujarat	-	-3	-3	-5	-8
Tamil Nadu	-3	-6	1	-2	-3
MP	-	9	14	15	8
Punjab	-	-7	-6	-6	-7
Karnataka	2	-7	-8	-10	-11
Haryana	-	-3	-2	-2	-3
Rajasthan	-	8	11	11	9
West Bengal	-	-1	1	9	14

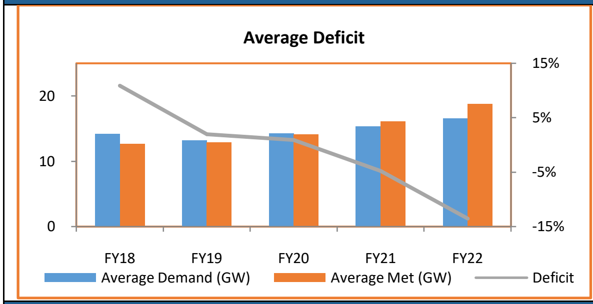
FIGURE 16: STATE WISE AVERAGE AND PEAK DEFICIT

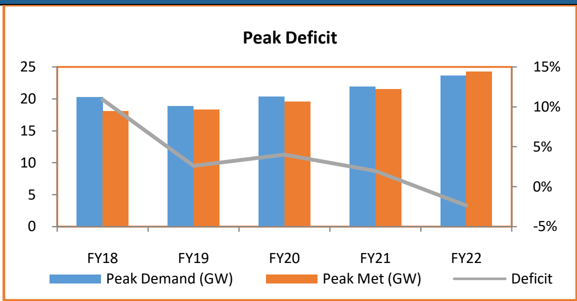




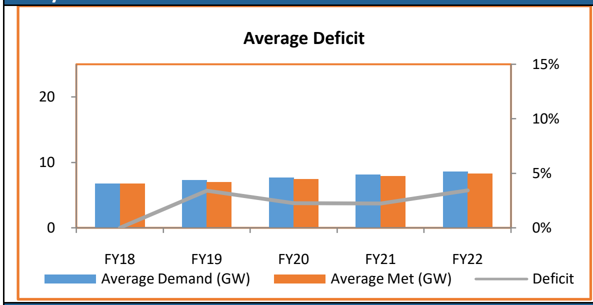


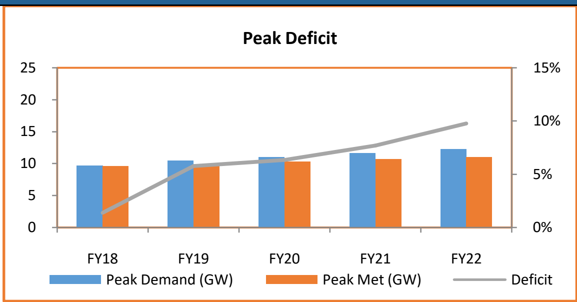
Uttar Pradesh



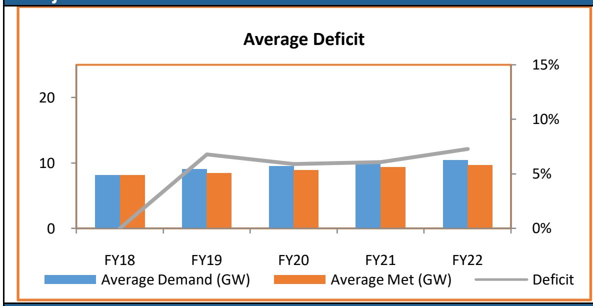


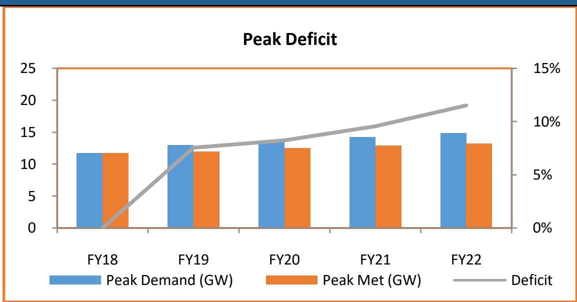
Haryana



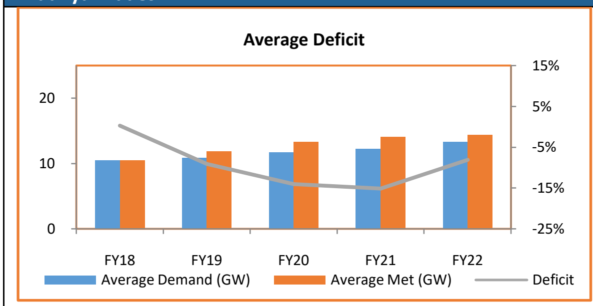


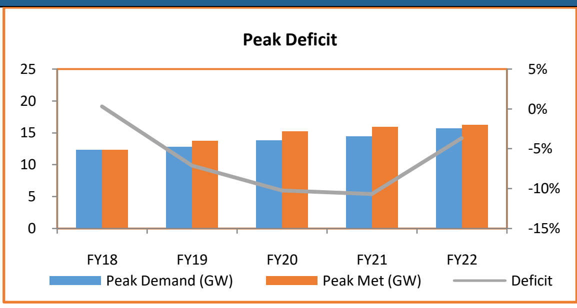
Punjab



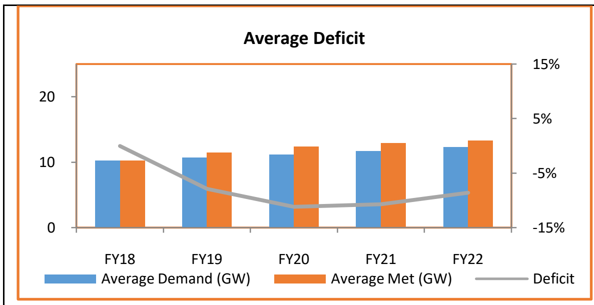


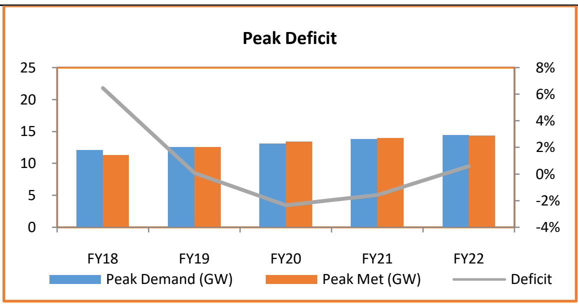
Madhya Pradesh



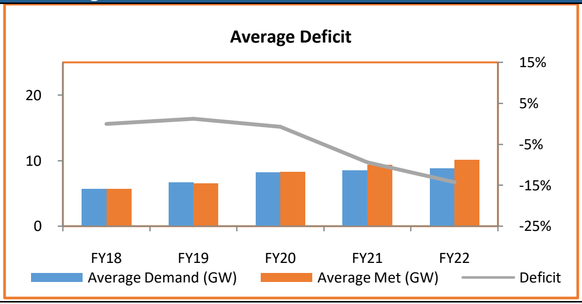


Rajasthan


Average Deficit
20
10
0
15%
5%
-5%
-15%
FY18
FY19
FY20
FY21
FY22
Average Demand (GW)
Average Met (GW)
Deficit


Peak Deficit
25
20
15
10
5
0
8%
6%
4%
2%
0%
-2%
-4%
FY18
FY19
FY20
FY21
FY22
Peak Demand (GW)
Peak Met (GW)
Deficit

West Bengal


Average Deficit
20
10
0
15%
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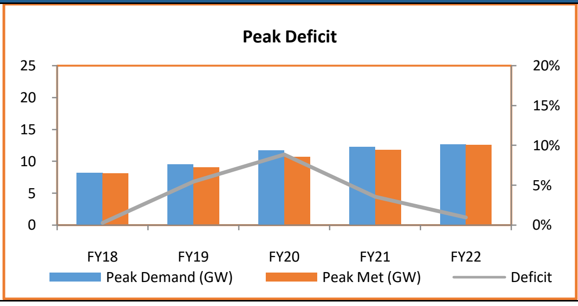
-25%
FY18
FY19
FY20
FY21
FY22
Average Demand (GW)
Average Met (GW)
Deficit


Peak Deficit
25
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20%
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10%
5%
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FY18
FY19
FY20
FY21
FY22
Peak Demand (GW)
Peak Met (GW)
Deficit

V. LIST OF THERMAL PLANTS UNDER CONSTRUCTION (EXPECTED TO BE COMMISSIONED BY FY 22) – SELECT STATES

TABLE 27: LIST OF TEHRMAL PLANTS UNDER CONSTRUCTION - SELECT STATES

Power Plant	Sector	State	Fuel	Capacity (MW)	Expected CoD
Wanakbori TPS Extn. U8	State	Gujarat	Coal	800	Oct-18
Yelahanka CCPP	State	Karnataka	Coal	370	Apr-18
Shri Singhaji TPP U-3	State	MP	Coal	660	Jun-18
Shri Singhaji TPP U-4	State	MP	Coal	660	Oct-18
Ennore exp	State	Tamil Nadu	Coal	660	Sep-18
Ennore SCTPP U1	State	Tamil Nadu	Coal	660	Sep-18
Ennore SCTPP U2	State	Tamil Nadu	Coal	660	Mar-19
North Chennai TPP	State	Tamil Nadu	Coal	800	Jul-19
Chhabra-6	State	Rajasthan	Coal	660	Mar-19
Suratgarh-7	State	Rajasthan	Coal	660	Feb-18
Suratgarh-8	State	Rajasthan	Coal	660	Mar-18
Hganj	State	Uttar Pradesh	Coal	660	Dec-20
Jawaharpur U1	State	Uttar Pradesh	Coal	660	Nov-21
Jawaharpur U2	State	Uttar Pradesh	Coal	660	Dec-22
Obra-1	State	Uttar Pradesh	Coal	660	Sep-20
Obra-2	State	Uttar Pradesh	Coal	660	Dec-20
Meja U1	Central	Uttar Pradesh	Coal	660	Jun-20
Meja U2	Central	Uttar Pradesh	Coal	660	Aug-20
Ghatampur U1	Central	Uttar Pradesh	Coal	660	Nov-20
Ghatampur U2	Central	Uttar Pradesh	Coal	660	May-21
Ghatampur U3	Central	Uttar Pradesh	Coal	660	Sep-21
Tanda U1	Central	Uttar Pradesh	Coal	660	Dec-19
Tanda U2	Central	Uttar Pradesh	Coal	660	Jun-19
Lara TPP	Central	Madhya Pradesh	Coal	100	Jan-18
Lara TPP	Central	Madhya Pradesh	Coal	100	Dec-18
Gadarwara TPP U1	Central	Madhya Pradesh	Coal	800	Jan-18
Gadarwara TPP U2	Central	Madhya Pradesh	Coal	800	Sep-18
Khargone TPP U1	Central	Madhya Pradesh	Coal	660	Mar-19
Khargone TPP U2	Central	Madhya Pradesh	Coal	660	Sep-19
Neyveli New U1	Central	Tamil Nadu	Coal	500	Jul-18
Neyveli New U2	Central	Tamil Nadu	Coal	500	Aug-18
Solapur TPP	Central	Haryana	Coal	83	Dec-18
Kudgi	Central	Karnataka	Coal	800	Mar-18
Barsingsar TPP	Central	Rajasthan	Coal	250	May-20
Bithnok TPP	Central	Rajasthan	Coal	250	May-20
Barh STPP U1	Central	Madhya Pradesh	Coal	160	Mar-19
Barh STPP U2	Central	Madhya Pradesh	Coal	160	Dec-19
Barh STPP U3	Central	Madhya Pradesh	Coal	160	Jun-20
North Karanpura	Central	Madhya Pradesh	Coal	160	Jun-20
Barh STPP U1	Central	West Bengal	Coal	660	Mar-19
Barh STPP U2	Central	West Bengal	Coal	660	Dec-19
Barh STPP U3	Central	West Bengal	Coal	660	Jun-20
Nabi Nagar TPP U3	Central	West Bengal	Coal	31	Oct-18
Nabi Nagar TPP U4	Central	West Bengal	Coal	31	Oct-18
New Nabi Nagar TPP U1	Central	West Bengal	Coal	83	May-18
New Nabi Nagar TPP U2	Central	West Bengal	Coal	83	Jun-18
New Nabi Nagar TPP U3	Central	West Bengal	Coal	83	Dec-18
Ind Barath TPP	Private	Tamil Nadu	Coal	350	Jan-18
Tuticorin TPP	Private	Tamil Nadu	Coal	525	Mar-19

VI. STATE WISE FUTURE PROCUREMENT DATA

Madhya Pradesh

TABLE 28: MADHYA PRADESH FUTURE PROCUREMENT DATA

Particulars	Unit	Coal	Gas	Hydro		Renewable		
				ROR	Storage	Wind	Solar	Others
Central	MW	6274	-	-	-	-	-	-
State	MW	2228	-	-	-	-	-	-
IPP	MW	1757	-	-	-	0	-	21
UMPP	MW	198	-	-	-	-	-	-

Punjab

TABLE 29: PUNJAB FUTURE PROCUREMENT DATA

Particulars	Unit	Coal	Gas	Hydro		Renewable		
				ROR	Storage	Wind	Solar	Others
Central	MW	200	-	-	-	150	-	-
State	MW	-	-	-	-	-	-	-
IPP	MW	-	-	200	-	-	125	76.7*

* MHP 8.2 MW+Cogeneration 24.5 MW + Biomass 44 MW = 76.7 MW

Rajasthan

TABLE 30: RAJASTHAN FUTURE PROCUREMENT DATA

Particulars	Unit	Coal	Gas	Hydro		Renewable		
				ROR	Storage	Wind	Solar	Others
Central	MW	804	-	-	492	-	-	-
State	MW	6850	990	-	-	-	-	-
IPP	MW	500	-	100	-	-	765	15

* 1. State - Work has not been started for 4210 MW Coal and 990 MW Gas power projects.
2. Center - PPAs are being reviwed for 650MW Coal power and hydro projects of 197 MW are on hold.
3. IPP- 500MW Coal Power is under litigation.

Uttar Pradesh

TABLE 31: UTTAR PRADESH FUTURE PROCUREMENT DATA

Particulars	Unit	Coal	Gas	Hydro		Renewable		
				ROR	Storage	Wind	Solar	Others
Central	MW	804	-	-	492	-	-	-
State	MW	6850	990	-	-	-	-	-
IPP	MW	500	-	100	-	-	765	15

West Bengal

TABLE 32: WEST BENGAL FUTURE PROCUREMENT DATA

Particulars	Unit	Coal	Gas	Hydro		Renewable		
				ROR	Storage	Wind	Solar	Others
Central	MW	1768	-	423	-	-	-	-
State	MW	1620	-	-	2000	-	-	80
IPP	MW	350	-	222	-	-	-	-

VII. PHYSICAL AND FINANCIAL CONTRACTS

FORWARD CONTRACT - EXAMPLE

Consider an LSE and a generator with a 3 Rs/kWh forward contract. If the spot market price is 2 Rs/kWh, the generator will find it profitable to not operate and buy power at 2 Rs/kWh from the spot market and resell it to the LSE at 3 Rs/kWh, earning 1 Rs/kWh

Thus, system operator real-time dispatch will converge on lowest marginal costs rather than contract costs. In practice, because not all market participants are profit maximizing or may have other incentives, real-time dispatch may diverge somewhat from least-cost (CAISO self-scheduling example).

CONTRACTS FOR DIFFERENCES (CFDS) – EXAMPLE

Consider an LSE and a generator with a 3 Rs/kWh CfD. If the spot market price is 2 Rs/kWh, the market operator pays the generator 2 Rs/kWh and the LSE pays the market operator 2 Rs/kWh. The LSE pays the generator (PCFD – PMARKET), or in this case 1 Rs/kWh. If the spot price were 4 Rs/kWh, the generator would pay the LSE 1 Rs/kWh.

With CfDs generators and loads offer/bid into the market separately. CfDs perfectly hedge market transactions if there is no congestion. If there is congestion, both buyers and sellers face locational risk. Locational marginal pricing (LMPs) and financial transmission rights (FTRs) reduce some, but not all, of this risk.

TOLLING AGREEMENTS - EXAMPLE

Consider an LSE and a solar PV generator with a 3.25 Rs/kWh PPA that is set up as a 10-year tolling agreement. The LSE schedules the solar PV generator in the real-time market via its forecast. If the hourly average real-time market price is 2.275 Rs/kWh, the LSE will earn 2.275 Rs for each kWh of PV generation through the market and pay 3.25 Rs/kWh for the PPA, for a net cost (market premium) of 0.975 Rs/kWh in that hour.

In California, most common tolling agreements are effectively leases: utilities sign contracts with generating companies to schedule and operate specific units or an entire power plant, which for natural gas plants usually includes buying the fuel. The market settlement from a tolling agreement is similar to a CfD, but they differ in contracting and risk allocation.

FUTURES CONTRACT - EXAMPLE

Consider an LSE that signs 10 400-MWh (standard size) NP-15 (Northern California) day-ahead peak daily futures contracts on the Intercontinental Exchange (ICE) for 2.3 Rs/kWh to hedge against high peak prices in the CAISO market. The LSE's peak demand that day is exactly 4,000 MWh. The average peak day-ahead price in the CAISO (NP-15) market for that day is 2.6 Rs/kWh. The LSE pays 10,400 Rs (= 2.6 Rs/kWh * 4,000 MWh) to the CAISO. The LSE is credited 1,200 Rs (= [2.6 – 2.3 Rs/kWh] * 4,000 MWh) to its ICE account for its futures contract. Its net cost will be 2.3 Rs/kWh (= [10,400 – 1,200 Rs] / 4,000 MWh).

Unlike forwards, futures are standardized products traded through exchanges, with greater liquidity and price transparency. Exchanges offer a variety of futures contracts: average daily or weekly peak and off-peak day-ahead and real-time, fixed price (monthly) peak and off-peak day-ahead and real-time, etc.

OPTIONS CONTRACT – EXAMPLE OF A REVENUE PUT

Consider a 300-MW merchant natural gas generator that enters into a 5-year revenue put option with a financing entity ("put provider") that guarantees a minimum 3,600 Rs per kW per year (Rs/kW-yr) fixed net revenue, for an upfront premium payment of 1,000 Rs/kW

If actual net revenues are 3,300 Rs/kW-yr for a given year in the contract, the put provider will pay the generator 90,000,000 Rs (= 3,600 Rs/kW-yr – 3,300 Rs/kW-yr * 300 MW). If, in the next year, net revenues are 3,601 Rs/kW-yr, the put provider will not pay the generator anything.

Financial markets differ from physical markets in that no physical delivery occurs. This does not mean financial markets contain only investors and speculators; physical market participants can also enter the financial market to hedge themselves. Physical and financial markets are often closely intertwined and use the same market mechanisms.

Financial products can be traded through the following routes:-

1) Exchange: Trading on exchanges is subject to the rules of the exchange as well as relevant electricity laws and regulations. Exchange-traded contracts have standardized specifications and the product's quality, quantity, and location are established in advance by the exchange. Trading in exchanges is conducted through electronic platforms, websites on which traders can buy and sell, or through trading points where traders actively call out orders to buy and sell
2) Over The counter: OTC transactions are conducted through direct negotiations between parties or through brokers. Unlike an exchange, an electronic brokerage platform matches specific buyers and sellers, and is not anonymous. The entire process of negotiating the completion of a purchase or sale lies solely with the two market participants

Clearing of financial contractstakes places through a Clearing house, which steps into the middle of the transaction and becomes the counterparty to each buyer and seller. The Clearing house assumes the risk that either the buyer or seller will fail to perform its obligations. Post this, settlement occurs at the end of a trading period, when the contract expires. At this time, delivery is to be made for a physical contract (physically settled) or a financial payout made for a financial contract (financially settled). Settlement occurs both in exchanges and in OTC trades. In OTC transactions, settlement occurs under the terms agreed upon by the parties. On exchanges, settlement occurs in a documented process and timeframe established by the exchange.

For instance, in the case of futures contract, Mark-to-market settlement covers profit or loss from day-to-day changes in the daily closing price of each contract. Final settlement, which begins at delivery, covers the difference between the final closing price of the futures contract and the system price in the delivery period. Throughout the final settlement period, which starts on the expiry date of the futures contract, the member is credited/ debited an amount equal to the difference between the spot market price and the futures contracts final closing price.

VIII. CAPACITY AUCTIONS IN THE US

PJM – MANDATORY CAPACITY AUCTION

PJM Interconnection LLC (PJM) provides transmission service in all or parts of 13 eastern states. In 2004, FERC found that PJM's electricity market design (which had price caps on certain generators and a day-ahead capacity requirement) was not offering adequate compensation for generators to recover costs, thus raising concerns about future generation adequacy. After extensive stakeholder discussions, FERC in 2006 approved of PJM establishing an electric capacity market called the Reliability Pricing Model (RPM) to address resource adequacy.

Under RPM, an annual May auction for capacity is held three years before each June-to-May Delivery Year, and incremental auctions are held closer to the Delivery Year. The auction establishes capacity prices that will be paid to resources committed for the Delivery Year, including localized prices for transmission-constrained delivery areas.

The auction prices are generally valid for the Delivery Year only, but certain new generation can get a two-year price commitment. Owners of most generation resources located within PJM are required to offer their capacity into the auction, and load-serving entities (LSEs) are assigned a capacity obligation by PJM based on their loads. There is an exception from auction participation for certain LSEs that plan to serve their entire load with identified resources.

Offers in the auction are accepted based on where they fall with respect to a downward sloping line on a graph known as a "demand curve." The vertical axis of the graph represents a price range for supplying capacity expressed in $/MW-day. The horizontal axis represents the quantity of capacity PJM needs for the Delivery Year to serve load and a reserve margin. The sell offers are stacked until they reach a point on the demand curve that represents PJM's capacity need. All offers that clear receive the clearing capacity price for the Delivery Year. PJM is the counterparty to sellers in the auction and bills the LSEs for their capacity obligation at the auction-clearing price. PJM calculates a value called the "cost of new entry" (CONE), which is an estimate of the cost of installing a new combustion turbine, and is a significant parameter used to establish both a price ceiling and a price floor for the auction.

MISO – CAPACITY REQUIREMENTS PLUS A VOLUNTARY AUCTION

The Midwest Independent Transmission System Operator Inc. (MISO) operates the transmission system in all or parts of 11 Midwestern states. MISO's resource adequacy construct establishes a reserve margin for each LSE for each zone the LSE serves. Based on an LSE's forecasted peak demand, demand-side resources, and reserve margin, MISO annually establishes the Planning Reserve Margin Requirement (PRMR) that each LSE must have during the next Planning Year. Those owning resources convert the capacity value of such resources into Planning Resource Credits (PRC) in MISO's capacity tracking system. A PRC represents one MW-month of capacity for a specified month during the Planning Year.

LSEs must demonstrate on a month-ahead basis during the Planning Year that they have acquired sufficient PRCs to meet their PRMR obligation. LSEs may self-supply their PRCs, buy them through bilateral transactions, or obtain them in MISO's voluntary capacity auction. In the event that an LSE does not obtain enough PRCs to cover its PRMR for a month, it is subject to a deficiency charge that is paid to MISO, which then distributes it among LSEs that were in compliance.

IX. ANCILLARY SERVICES

Ancillary services maintain electric reliability and support the transmission of electricity. These services are produced and consumed in real-time, or in the very near term.

Regulation services:Regulating reserves instantaneously provide the power difference between supply and demand required during the lag period while generation is catching up to supply or while generation is decreasing in response to lower demand

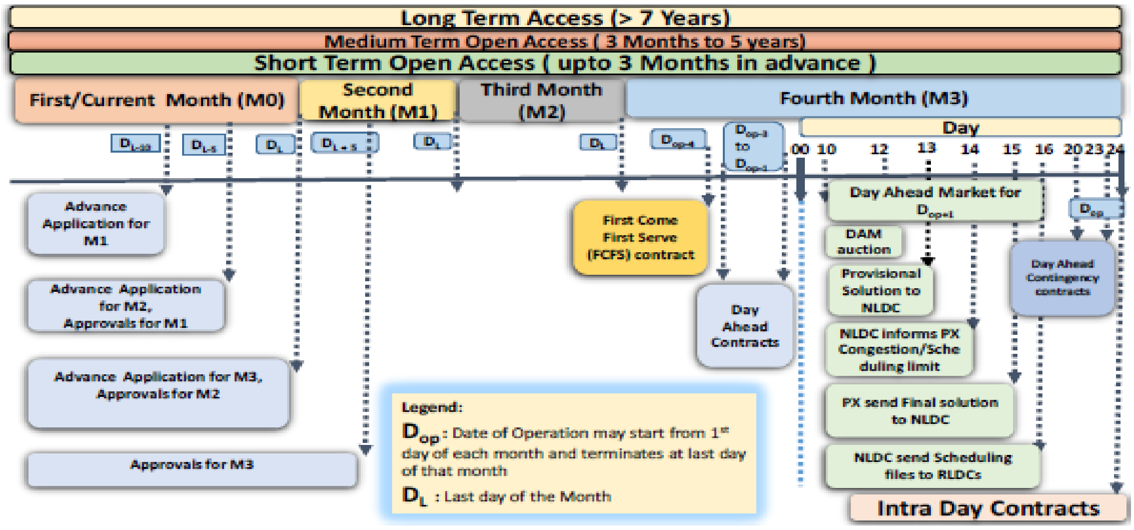
Operating reserves: Operating reserves are used to maintain the balance of supply and demand when an unexpected system event occurs. These reserves provide capacity the System Controller can call on with short notice to correct any imbalance. These reserves can come from the supply side or from the demand side. There could be minimum of three types of operating reserves:

1) Spinning reserves: To provide spinning reserve a generator must be on line (synchronized to the system frequency) with some unloaded (spare) capacity and be capable of increasing its electricity output within 10 minutes. During normal operation, these reserves are provided by increasing output on synchronized equipment or by reducing load on pumped storage hydroelectric facilities.
2) Nonspinning reserves: These come from generating units that can be brought online in 10 minutes. Nonspinning reserve can also be provided by demand-side resources.
3) Supplemental reserves: These come from generating units that can be made available in 30 minutes and are not necessarily synchronized with the system frequency. Supplemental reserves are usually scheduled in the day-ahead market, allowing generators to offer their reserve energy at a price, thus compensating cleared supply at a single market clearing price. This only applies to ISO/RTOs, and not all reliability regions have a supplemental reserve requirement.
4) Black start generating units: These units have the ability to go from a shutdown condition to an operating condition and start delivering power without any outside assistance from the electric grid. Hydroelectric facilities and diesel generators have this capability. These are the first facilities to be started up in the event of a system collapse or blackout to restore the rest of the grid.
5) Reactive power: Power plants can produce both real and reactive power, and can be adjusted to change the output of both. Special equipment installed on the transmission grid is also capable of injecting reactive power to maintain voltage limits

X. Contracting and scheduling in Indian market

India predominantly follows de-centralised self scheduling practise to meet power demand by individual discoms. The distribution companies in India self-schedule (i.e. requisition power from) the generating stations with which they have long term contracts. Currenty, there is no requirement specified for such distribution companies to intimate the price for such transactions.

Presently, more than 90% of the power demand is met under self scheduling with long term contracts and remaining through other means like Power Exchanges and other short term mechanisms. Following is a highlight of the contracting structure prevalent in India:-



Source: Based on Regulations of CERC

Share of Market Segment in Total Electricity Generation in FY2016-17	
Long Term Transactions	90%
Bilataral Transactions through Traders	2%
Bilateral Transaction between Discoms	2%
Transactions through PXs	**4%**
Transactions through DSM	2%

Self Scheduled

Day-ahead transactions via PXs follows gross pool based centralized economic dispatch model. Suppliers and the Buyers submit bids in the centralized pool (of power exchange) post which the market clears a price based on marginal cost of generation and inter-section of aggregate demand and supply curves. This is a market based operation where a generator gets dispatched if the price quoted by him is less than or equal to the Market Clearing Price (MCP), whereas a buyer gets cleared if it has quoted a price equal to or more than MCP.

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