Chapter 3


3.1. Introduction

The Indian Power Sector has its existence since 1897. The first Hydel Project was commissioned in 1897 and Steam Plant of capacity of 1000KW in 1899. Before Independence (1947), the total capacity was around 1340 MW in fragmented small entities owned by the small private players. After the enactment of Electricity (Supply) Act in 1948, local grids were formed barring a few licensees in some urban areas. By 1960, the power sector was mostly owned by State Governments and was largely managed by vertically integrated State Electricity Boards. The distribution continued to remain with State Electricity Boards (SEBs) as a monopoly business. The five Regional grids i.e. Northern, Western, Southern, Eastern & North-Eastern grids were formed in 1970. Central Generating stations (CGS) were developed on regional basis for distribution of bulk powers from central stations to the different beneficiary states in the respective region. The electrical power sector at that time was operated as a single entity i.e. vertically integrated structure. At that time all electric power utilities throughout the world were operated with an organizational model. The controlling authority is
the utility, it operated the generation, transmission, and distribution systems located in a fixed geographic area.

The Central Electricity Authority (CEA) notified the shares in the CGS units to beneficiary states in the respective regions. The CEA evolved the shares in the CGS by keeping aside 15% generation towards unallocated power. This power is allocated from time to time to the deficit states in proportion by taking deficit of condition the state at that time.

The remaining CGS generation is allocated as follows:

a) Certain percentage of generation is allocated to the states, which provide infrastructure facilities such as land, water coal, gas etc to establish CGS.

b) The remaining percentage is distributed proportionally to all beneficiary states by considering the maximum demand met at that time etc.
The shares in the CGS units of Southern Region (SR) are given in the Table 3.1.

<table>
<thead>
<tr>
<th>State</th>
<th>NTPC</th>
<th>NLC-I</th>
<th>NLC-II</th>
<th>MAPS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Andhra Pradesh</td>
<td>580</td>
<td>97</td>
<td>180</td>
<td>40</td>
</tr>
<tr>
<td>Karnataka</td>
<td>345</td>
<td>84</td>
<td>115</td>
<td>30</td>
</tr>
<tr>
<td>Kerala</td>
<td>245</td>
<td>63</td>
<td>90</td>
<td>25</td>
</tr>
<tr>
<td>Tamil Nadu</td>
<td>520</td>
<td>241</td>
<td>280</td>
<td>355</td>
</tr>
<tr>
<td>GOA</td>
<td>100</td>
<td>50</td>
<td>50</td>
<td>-</td>
</tr>
<tr>
<td>UN. ALLOC</td>
<td>310</td>
<td>95</td>
<td>125</td>
<td>20</td>
</tr>
<tr>
<td>TOTAL</td>
<td>2100</td>
<td>630</td>
<td>840</td>
<td>470</td>
</tr>
</tbody>
</table>

### 3.2. Transmission and Grid Management

Transmission and Grid Management are essential functions for smooth evacuation of power from generating stations to the consumers. The Central Transmission Utility (CTU) has established 400 KV Transmission Network to cater to the CGS power in all respective regions of India, i.e. India is divided into five (5) grids geographically, i.e., the East, West, North, South and Northeastern. All the states and union territories in India fall in either of these regions. The Central Transmission Utility (CTU) of India is also responsible for implementing inter-state, inter-regional and national level transmission schemes in
addition to implementation of evacuation schemes for central sector generation projects. The main function of CTU is to operate the transmission system effectively in regional level. The CTU caters Shares of CGS power through established inter-state transmission system to beneficiaries and plans and coordinates the transmission system in secured way.

The Regional Load Despatch Centers (RLDC) were set up so as check the integrated operation of power system in that particular region. The system operator of RLDC calculates entitlements of states by considering the actual generation of CGS in proportion to their shares. The beneficiaries drew power from the pooled ex-bus generation of CGS units. The payments are based on actual drawals and actual generation. The main job of the grid operator is to give operating instructions to the engineers in the field and ensure moment-to-moment power balance in the interconnected power system. Grid management involves taking care of the over all reliability, security, economy and efficiency of the power system.

3.3. Peculiarities of operation of Indian Grid

During these periods, inter-state transmission lines were established to develop regional grids. But this regional planning served only in a limited way the efficient use of the facilities in meeting the growth in demand. Also there were large deviations in frequency from the rated
frequency of 50.0 Hz. Low frequency situation results when the total generation is less than the consumer load at any given time. High frequency is a result of insufficient backing down of generation when the total consumer load comes down during off-peak hours. A typical pattern of frequency during this period is shown in the figure 3.1. There was no incentive for either backing down the generation during off-peak hours or reducing the consumer load /enhancing the generation during peak-load hours. There was no incentive in those days for generating at a high level even during peak times. In other words, there was no encouragement for grid discipline. There is also a general inadequacy of the transmission network, causing low voltage phenomenon.

The main problems during that period are identified as:

- Large frequency fluctuations
- Low frequency (≈ 48Hz) operation for most of the time.
- Over drawl during low frequency and under drawl during high frequency periods by the state grids from the regional pool.
- Low voltage operation (i.e., below 0.8p.u).
- Physical location of power stations (sources) and loads requiring long transmission lines.
- Frequent grid disturbances due to lack of grid discipline and weak Transmission networks.
Fig 3.1: Frequency variation of a typical day during earlier period.

3.3.1 Tariff Mechanism Prior to 2000 AD.

The tariff mechanism during this period was uniform throughout India. The Total ex-bus generation of all CGS was taken as a pool. The beneficiaries drew the power from this pool and paid for actual energy drawls at weighted average pooled rate. The generating stations received their total sale amount from this pool. The beneficiary paid to each station in proportion to its drawls in this way.

Two-part tariff structure was used for the Generation tariff of CGS based on coal and gas. The components of the tariff are fixed charges and variable charges of generator units. Fixed charges (Rs/year) are calculated based on total annual fixed costs, comprising of interest on loan, operation and maintenance expenses, return on equity, taxes, duties, interest on working capital etc. They are recovered in twelve equal
monthly installments through tariff in proportion to drawls. The CGS fully recovered its fixed charges at PLF 68.5% and at PLF over and above 68.5%, CGS received incentives at the rate of one paisa/Kwh. But if the PLF is below 68.5%, whether it is due to non-availability of generation or due to backing down instructions of the utility, the generation gets proportionally lesser amounts towards fixed charges.

Variable charges (Rs/Kwh) were recovered as per ex-bus generation of each power station. They were payable as per actual drawls.

The main drawback observed is, that the schedules did not form a component in final energy billing based on actual drawals by utilities. It had been difficult to trade between states without prior knowledge of interchanges. Moreover the payments were as per actual drawls, actual generation and they could not impose planning on day-ahead or hour-ahead basis. All the above had given improper signals for system operation. This tariff mechanism encouraged generation even under high frequency conditions as incentives were linked with PLF. At the same time there were no incentives for backing down of generation at high frequencies. There was also no penalty for any deviations in drawals from entitlements of power. It is observed that this two-part tariff structure could not impose grid discipline on the individual utility and also on generator and in turn resulted in indiscipline in grid operation and poor accounting practices.
3.3.2 Transmission Losses

The total losses incurred in the 400 KV network in region were calculated at the end of month and allocated among the beneficiary states in proportion to the actual energy drawls. But either the impedance of the circuit or distance traveled by power is not taken into account in allocation of transmission losses at that time. This methodology has obvious disadvantage that the usage of the network by any utility is not taken into consideration. If one of the beneficiary states is availing its share from distant source, the transmission losses allocated should be more than a beneficiary, who is availing its share from a nearby one. For example, NTPC is a nearby source for A.P and is distant source for other states. AP has more allocation of generation from NTPC than from the other CGS units in Southern Region. But the charges paid for transmission losses are sometimes more than the actual amount to be paid due to the prevailing methodology.

3.4 Introduction of ABT

The new tariff mechanism (frequency linked Tariff) known as Availability Based Tariff (ABT) has been implemented in regional grids so as to impose the grid discipline and to regulate the wide fluctuations in the frequency, as indicated below.

- Southern Region : 01-01-2003
- Western Region : 01-07-2002
Northern Region : 01-07-2002
Eastern Region : 01-04-2003
North Easter Region : 01-11-2003

According to this, the transactions resulting in flow from or into the control areas (i.e. state grids) other than the schedules are to be linked with frequency in pricing. For example the over drawing control area has to pay @ Rs 0 to Rs 4.20 per KWH at the frequency below 49 Hz and no charges at the frequency above 50.5Hz and linear variation in between 50.5 Hz and 49.02Hz, @ Rs 0.56 with 0.02 Hz/step to the under drawing control area.

ABT mechanism mainly facilitates the grid discipline, trading in capacity and energy and merit order despatch as and when made effective. The distinctive features of ABT are to overcome the serious problems related to (i) Low frequency (48.0-48.5 Hz) during peak load hours (ii) high frequency (50.5-51 Hz) during off peak hours (iii) rapid & wide changes in frequency, i.e., 1 Hz change in about 5 to 10 minutes and many times every day.

The Availability Based Tariff is a combination of frequency based Tariff (Drawals (VS) frequency) and Reactive power based Tariff (Reactive Power (VS) Voltage). The components are given as follows during introduction.
a) Pricing for active power.

i) Capacity charges based on target availability - Full

(Fixed charges at a target availability of 80% for generators)

Capacity charge is related to “Availability” of the generating station. The payment of fixed cost to the generating company is linked to availability of the plant. Availability means the readiness of generating station to deliver ex-bus output in MW expressed as a percentage of its rated ex-bus output capability as per rated capacity. The total amount payable to the generator over a year towards the fixed cost depends on the average availability (MW delivering capability) of the plant over the year. In case the availability achieved over the year is higher than the specified norm for plant availability, the generator company gets a higher payment. In case the availability achieved is lower, the payment is also lower. Hence it is named as ‘Availability Tariff’. This is the first component of Availability Tariff, and is termed as ‘capacity charge’.

ii) Energy charges for the energy scheduled - Variable Cost.

It is variable cost (i.e., fuel cost) of the power plant for generating energy as per the given schedule for the day. It is to be specifically noted that energy charge is based on scheduled generation only, but not on actual generation and plant output.

iii) Unscheduled Interchange (UI, difference between actual drawal and schedule) charge ranges between zero to Rs 4.20, according to variations in each 15 minutes time block.
Variation in actual Generation / Drawal and Scheduled Generation / Drawal shall accounted for through U.I

UI for Generator = Actual Generation – Scheduled Generation

UI for Beneficiaries = Total Actual drawal – Total Scheduled Drawal

UI worked out for 15 minutes time block.

<table>
<thead>
<tr>
<th>Average Frequency of time block</th>
<th>UI Rate (Paise per Kwh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>50.5Hz. and above</td>
<td>0.0</td>
</tr>
<tr>
<td>Below 50.5 Hz and up to 49.02 Hz</td>
<td>5.6</td>
</tr>
<tr>
<td>Below 49.04Hz and up to 49.02 Hz</td>
<td>414.40</td>
</tr>
<tr>
<td>Below 49.02 Hz</td>
<td>420.00</td>
</tr>
<tr>
<td>Between 50.5 Hz and 49.02 Hz</td>
<td>Linear in 0.02 Hz step</td>
</tr>
</tbody>
</table>

b) Pricing for reactive power

Payable/receivable for reactive power drawals/injections at the Rate of 4 paise per KVARh for voltages below 97 % (at the 400kV interconnectivity point).

Receivable/Payable for reactive power drawals/ injections at the Rate of 4 paise per KVARh for voltages above 103 % (at the 400kV interconnectivity point).
3.4.1 Features of ABT

Capacity Charge and Energy Charge basically do not depend on PLF of the station and actual generation/drawl respectively. There is no complication w.r.t backing down generation and there are no year-end commercial adjustments. ABT encourages perpetual incentive for maximizing generation and reducing drawl during low frequency conditions. There is no incentive to over generate during high frequency conditions. There is high penalty for over drawl during low frequency conditions. Any difference between schedule and actual drawal in whatever the transaction be, is settled under UI mechanism based on the prevailing frequency. This is one of the best features of the ABT.

Subsequently the tariff was revised 4 times to implement the grid discipline and is as follows.

1) From 1-4-2004   Maximum rate at 49 Hz is Rs 6.00/unit
2) From 1-10-2004  Maximum rate at 49 Hz is Rs 5.70/unit
3) From 30-4-2007  Maximum rate at 49 Hz is Rs 7.45/unit
4) From 7-1-2008   Maximum rate at 49 Hz is Rs 10.00/unit

The UI characteristic is shown below.
3.4.2 How does ABT mechanism work

The scheduling of CGS units is done in the following manner. The CGS units first declare their output capacity for next day to the Regional Load Despatch Center (RLDC). The RLDC calculates beneficiary’s share according to this declared output capacity of CGS unit. RLDC transmits this information to the State Load Despatch (SLDC). The SLDCs work out availability from their own generating stations and requirements from CGS units. SLDCs inform their actual requirement in CGS to RLDC. However, there is a provision to revise the requirements of beneficiaries in case of contingencies. In case of any deviations from schedule value, there is a penalty linked with the prevailing frequency at that time.
3.4.3 Regional Electricity market

At present the regional electricity market operations in India are carried out through the Inter State Transmission System (ISTS). These operations are governed by the frequency-linked operation, commercial settlement mechanism through ABT and Unscheduled Interchange (UI) mechanism. The utilities have full freedom and choice to enter into long-term and short-term bilateral contracts. These contracts are incorporated in the daily interchange schedules issued by the RLDCs.

3.4.4 Settlement system

The Special Energy Meters (SEMs) are commissioned at required generating stations and interconnecting boundary points to collect the actual data for billing purposes. The day is divided into 96 time blocks and each block consists of 15 minutes time. The required data such as MW, MVAR, MVA and frequency etc are simulated dynamically and integrated for each block. SEMs are basically 3-phase 4-wire static/composite 0.2 S class accuracy meters and having time stamping facility. The SEMs are time synchronized in order to maintain uniformity in billing for entire Southern/National grid. The actual energy interchanges for every 15-minute time block, are recorded with the help of these Special Energy Meters (SEM). The actual values are then compared with the scheduled values to obtain the deviations from schedules. Real time deviations in a particular time block are priced at
the corresponding Unscheduled Interchange rate (UI rate), and settled through an account being maintained by RLDC.

In similar lines the reactive power billing is carried out. These SEMs are also capable of measuring net reactive energy exchanges over the day, during high voltage (above 103%) and low voltage (below 97%) conditions.

3.4.5 Evaluation of Transmission Prices and Losses

The total loss in Southern Regional grid is calculated by subtracting total drawal by all the beneficiaries from the total injections at all the central generators and inter-regional scheduled metering points. The loss is then obtained with respect to the net injections for each block and averaged out for the entire week. The loss thus computed for the last week is used as the estimated normative loss percentage for use in scheduling for the next week.

The megawatt-mile method is implemented in the Indian power system to allocate the transmission costs and losses. There is an important limitation of ignoring mutual interactions between different transactions in this method. The effects of reactive power flows on losses are also neglected. But transmission loss allocation became a contentious issue as it corresponds to a huge amount of money.

Now the CERC has adopted the existing postage stamp method used by the power grid for fixing transmission charges. The entire
country will be divided into zones under this mechanism. At present the transmission charges would be having three stamps in this mechanism. A proposal is under scrutiny to shift to the incremental postage stamp method where the country is divided into smaller 100 km x 100 km squares and the charge determined by counting the squares both vertically and horizontally from the source to the sink.

### 3.5. Introduction of Open Access

There are rapid changes in the Indian power sector after the implementation of Electricity ACT 2003. India has undergone various phases of development. At present, the Indian Power Utilities have been restructured as separate entities of generation (GENCO), transmission (TRANSCO) and distribution (DISCO).

The Open Access has been implemented in all regions as per regulations issued by CERC. As per CERC, the regulations are granted in two categories. They are Long Term Open Access and Short Term Open Access.

**Stipulated trading period for usage**

- One to twenty Five (25) years long term open access
- Maximum of three months at a stretch short term open access

In this juncture, Indian electrical utilities started allowing private companies to participate in competition for electrical energy delivery.
These competitive markets provide the price of energy at low rates for the customer and higher efficiency for the suppliers. They will also facilitate greater choice to offer better services with respect to power quality i.e. rated voltage, frequency and uninterrupted power supply.

Private participation in the generation by way of Independent Power Producers (IPP) and Ultra Mega Power Projects supplemented with Government investment is envisaged.

The Nodal agencies are identified to coordinate, despatch & schedule electricity and to encourage trading in India.

The Scheduling agencies are mainly one National Load Despatch Centre (NLDC) at national level, five Regional Load Despatch Centres (RLDC) at regional level and State Load Centres (SLDC), thirty four in number at state level.

The Load Despatch operator declares the anticipated power transfer capability available in transmission system to users in advance, first-come-first-served, day-ahead or same day in short term Open Access.

The EA 2003 has made a provision for a National Load Despatch Centre (NLDC) for

a) Optimum scheduling

b) Despatch of electricity across various regions

c) Coordinating cross border energy exchanges in real time
d) Information exchange and also for facilitating inter-regional transactions.

The cross border exchanges are coordinated by the RLDC of the region wherein the interconnection is situated. RLDCs act as apex body and ensure integrated operation of the power system in the concerned region as per the Electricity Act 2003 (EA 2003).

These RLDCs coordinate among themselves both offline as well as online for maintaining the security and stability for the integrated National grid. These RLDCs in India are owned, managed and operated by the Central Transmission Utility (CTU).

Similarly, SLDCs act as apex body and ensure integrated operation of the power system in the concerned state as per EA 2003 and the SLDCs in the state are owned, operated and managed by the respective State Transmission Utility (STU).

### 3.6 Present scenario of Indian Electricity Markets

CERC approved the setting up of Indian Energy Exchange (IEX), which would be the first-ever power exchange in India. IEX serves as an optional, electronic, nation-wide platform for trading in electricity. IEX promotes inter-state and inter-region power trading in a liberalized power market. In spite of the fact that India is a power-deficit country, some regions (ER & NER) are having surplus power and are able to sell their surplus power to the users of power-deficit regions through the IEX.
The initiation of IEX in India facilitates the process of forecasting demand and price for day-ahead or on an hourly basis. Another distinctive feature of IEX is maintaining bilateral transactions in electricity markets in secured way. The bids are accepted for both sale and purchase in the form of linear segments denoting price and quantity. The linear segments are aggregated into separate price versus quantity curves of supply and demand, which are matched to obtain the system price.

The system operator selects the required demand ranking the price scheduling till the demand is met. IEX basically collects bids on hourly basis (based on the available transfer capability on all inter-regional links) from RLDCs. All successful bidders will pay uniform prices. After negotiation with IEX, RLDCs/SLDCs will allocate appropriate transmission capacities, transmission loss incurred for transactions. All payments will be routed electronically through clearing banks authorized by IEX.

Generally IEX collects bids and offers from potential buyers and sellers during the bid-call period (i.e. 10:00 AM to 12:00 Noon). Each sale bid specifies the quantity and minimum price at which they are willing to supply the energy. Conversely, each buy bid specifies the desired quantity and maximum price at which they are willing to buy energy. The IEX matches supply and demand along with publishing a market-clearing prices.
3.6.1. Ancillary Services

In real time markets, important responsibilities of the ISO are to maintain the real time balance of energy and supply, to control markets and to facilitate an efficient trading of energy and ancillary services.

The important task of the operators of RLDC and SLDC is to maintain the frequency at its target value (i.e. 50 Hz). The frequency of operation of power system becomes an index in bidding of power in short term access.

3.6.2 Energy Trading in India

At present bidding price varies from Rs 0 to Rs 20 for energy trading. It is observed that presently 3-4% of total power consumed is being traded through various inter-state /inter-region traders in India. As shown in Table3.2 around 24 billion units out of 617 billion units were traded in FY 2006-07 through 5900 transactions. The short-term market size was worth Rs 7200 crores. Similarly around 30 billion units out of 663 billion units were traded in year 2007-2008 through 9600 transactions and short-term market size was worth around Rs 10000 crores. It is expected to increase about Rs. 40000 crores in coming five years.
### TABLE 3.2
Details of Bilateral Transactions carried out in India

<table>
<thead>
<tr>
<th>S.No</th>
<th>Year</th>
<th>No of Transactions</th>
<th>Billion Units</th>
<th>Traders in Number</th>
<th>Sellers in Number</th>
<th>Buyers in Number</th>
<th>Total Utilities in Number</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>2004-2005</td>
<td>800</td>
<td>17</td>
<td>5</td>
<td>34</td>
<td>24</td>
<td>45</td>
</tr>
<tr>
<td>2</td>
<td>2005-2006</td>
<td>3900</td>
<td>23</td>
<td>7</td>
<td>46</td>
<td>29</td>
<td>64</td>
</tr>
<tr>
<td>3</td>
<td>2006-2007</td>
<td>5900</td>
<td>24</td>
<td>9</td>
<td>55</td>
<td>30</td>
<td>71</td>
</tr>
<tr>
<td>4</td>
<td>2007-2008</td>
<td>9600</td>
<td>30</td>
<td>12</td>
<td>62</td>
<td>47</td>
<td>84</td>
</tr>
</tbody>
</table>

### 3.6.3 The World-Wide Deregulation Trend

The electricity market deregulation trend is in full swing worldwide. As of December 2000 there are seven countries that have deregulated their electricity markets. These countries have adopted various electricity markets models. Australia (NEMMCO) has a mandatory power market whereas countries like New Zealand (NZEM), Nordpool, BETTA (UK), PJM (USA) are examples of voluntary marketplaces. IEX established in 2008 is also a voluntary market place.

The comparisons of Indian and international power markets are tabulated in the Table 3.3.
TABLE 3.3
comparisons of Indian and international power markets

<table>
<thead>
<tr>
<th>S No</th>
<th>Dimension</th>
<th>India</th>
<th>International</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Participation and market offering</td>
<td>Compulsory for balancing market, Bilateral and day-ahead, hour-ahead</td>
<td>Compulsory for balancing market, Bilateral</td>
</tr>
<tr>
<td>2</td>
<td>Transmission. Infrastructure</td>
<td>Coordinated planning</td>
<td>Market oriented</td>
</tr>
<tr>
<td>3</td>
<td>Type of bidding</td>
<td>Double sided</td>
<td>Double sided</td>
</tr>
<tr>
<td>4</td>
<td>Pricing type</td>
<td>Ex-Ante</td>
<td>BEETA, NEMMCO and PJM Ex-Post NordPool Ex-Ante.</td>
</tr>
<tr>
<td>5</td>
<td>Type of bidding</td>
<td>Energy only</td>
<td>Capacity, Energy Ancillary Services</td>
</tr>
<tr>
<td>6</td>
<td>Losses</td>
<td>Socialized Paid in kind</td>
<td>Independent System Operator procures or included in Zonal Price or LMP</td>
</tr>
<tr>
<td>7</td>
<td>Real Time Balancing</td>
<td>Frequency-linked UI</td>
<td>Some countries adopted penalty from schedule and other through purchase of ancillary services.</td>
</tr>
<tr>
<td>8</td>
<td>Settlement period</td>
<td>15 minute time block</td>
<td>Hourly / half hourly</td>
</tr>
<tr>
<td>9</td>
<td>Settlement cycle</td>
<td>Weekly</td>
<td>Hourly</td>
</tr>
<tr>
<td>10</td>
<td>Transmission charge</td>
<td>Long-term: postage stamp Short-term bilateral: Contract path Collective: Point of connection</td>
<td>Zonal / Nodal</td>
</tr>
<tr>
<td>11</td>
<td>Trading</td>
<td>Physical</td>
<td>Physical, Financial</td>
</tr>
</tbody>
</table>

3.6.4 Procedure for Treatment of Losses

The scheduling and allocation of losses to bilateral transactions are stipulated in Open Access in Inter-State Transmission by CERC (Procedure for Scheduling, Collective Transaction as per CERC Regulations dated 25.01.2008). According to this, the losses should also be scheduled in the energy scheduling. They are as follows
1) Inter-State transmission losses would be applied separately on Buyers as well as Sellers of Collective Transaction, for arriving at the Schedules.

2) The Sellers in the Collective Transaction shall inject extra power (MW) to compensate for losses in the inter-State transmission system in addition to the contracted power. Conversely the Buyers in the Collective transaction shall draw less power (MW) than contracted power to compensate for the losses in the inter-State transmission system,

3) The average transmission losses of the respective Region would be applied along with additional losses if any. They are notified in advance by NLDC on the basis of the power flow pattern and studies carried out by the RLDCs/NLDC for particular Region(s). These additional losses would be applied only on the Sellers in the Collective Transaction of the particular Region. The sellers should have an Injection Schedule at the periphery of the Regional Entities to compensate for losses due to wheeling of power through other Region(s).

For example, the surplus generation in Southern Region (SR) during monsoon period is wheeled to Northern Region (NR) through Western Region (WR)/Eastern Region (ER) and results in increase of losses for the wheeling Region(s). In such cases, the
additional losses as notified by NLDC shall be applied on SR and credit for additional losses shall be given to WR/ER.

4) In line with the above, the intra-State transmission system losses shall also be taken care of, in the Schedules by respective SLDCs.

3.7 Case Study of Indian Power Sector: A Representative Transition Model for Developing Countries

3.7.1 Southern Regional Grid—An Overview

Southern Regional (SR) grid comprises of six constituents States viz. Andhra Pradesh, Karnataka, Kerala and Tamil Nadu, and Goa, Union Territory of Pondicherry. These constitutes are interconnected with each other mainly through 400 KV grid network and few 220 KV inter-State lines. The Southern Regional power system is supported with two major Central Generating Stations connected to the 400 KV grid. They are Ramagundam Super Thermal Power Station of capacity 2600 MW (3x200 + 4x500) in the northern part and Neyveli-I and II of capacity 2490MW (6x50 + 3x100 + 7x210 + 2x210 ) in the southern part. Two Nuclear Power Stations of 440 MW each are located at Kalpakkam (Tamil Nadu) and Kaiga (Karnataka) of Southern Region. The Thermal-Hydro mix in the SR is in the ratio of 67:33. The installed capacity of Southern Regional Grid as on 31/03/09 is around 37,372 MW. The peak demand met is 25039 MW on 27 March 2007 in the year of 2006-2007 and a maximum consumption of energy of 559.02 MU on 23rd March 2007. SR has a large component of agricultural pumping load. HVDC bi-pole link
between Talcher (Orissa) and Kolar (Karnataka) of around 1250 km. long, + 500 KV, 2000 MW was commissioned as SR-ER inter-regional link to facilitate transfer of surplus power available in ER. The 400 KV Grid Map of Southern Region is depicted in the Fig 3.3

**Fig 3.3**: 400KV Grid Map of Southern Region
3.7.2. **PRE - ABT. (FY 1990-FY 2003)**

During this period, Frequency variations caused serious damages to both generators and loads. Owing to severe shortage of power in all constituents of Southern Region, most of the time the operating frequency has been around 48.0 Hz, without any spinning reserve being maintained. The constituents draw their central sector shares from the Central Generating Stations. There have been very low inflows into reservoirs in A.P and Karnataka, which aggravated the situation during the years 2001-2003. It is observed that as many as 22 major system disturbances occurred in Southern region during January 2001-October 2002 i.e., an average of one major disturbance every month.

Some of the defensive mechanisms adopted for overcoming the situations are given below:

The under frequency schemes and Reverse Power under Frequency (RPUF) relays were implemented to safeguard the system from total collapse. A Three stage under frequency scheme is depicted in the Table 3.4.
(i). Under frequency scheme

### TABLE 3.4
Three Stage Under frequency Scheme.

<table>
<thead>
<tr>
<th>State</th>
<th>1st Stage 48.4 HZ Instantaneous (MW)</th>
<th>2nd Stage 48.2 HZ Instantaneous (MW)</th>
<th>3rd Stage 48 HZ Instantaneous (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A.P</td>
<td>320</td>
<td>320</td>
<td>200</td>
</tr>
<tr>
<td>Karnataka</td>
<td>255</td>
<td>255</td>
<td>200</td>
</tr>
<tr>
<td>Tamilnadu</td>
<td>325</td>
<td>325</td>
<td>200</td>
</tr>
<tr>
<td>Kerala</td>
<td>50</td>
<td>50</td>
<td>200</td>
</tr>
<tr>
<td>Total</td>
<td>950</td>
<td>950</td>
<td>800</td>
</tr>
</tbody>
</table>

(ii) RPUF

On Tie line of 400 KV Madras-Cuddapah: 48.0 Hz, 100 MW Export, 0.5 Sec., at Madras.

On Tie line of 400 KV Salem-Bangalore: 48.0 Hz, 300 MW Export, 1.0 Sec at Salem

With operation of the above RPUF scheme on 11.09.2001 at 12.54 hrs at 47.9 Hz., the Southern Region got split into two subsystems: a) A.P and Karnataka b) Tamilnadu and Kerala. Tamilnadu, Kerala systems only survived due to these defensive mechanisms but A.P , Karnataka system gone into black out. There was speedy restoration of systems availing power from survived systems.

It was very essential to safeguard the thermal units by implementing separate islanding schemes for each of the important thermal stations with a near matching load in Southern Region.
It is observed that some issues are still persistent in the system, they

a) Lack of grid discipline.

b) Unable to maintain proper quality of power supply by state utilities.

c) Dishonouring the contractual obligations with CGS.

**3.7.3 Availability Based Tariff (FY 2003)**

The ABT has directly addressed these issues. Firstly, by giving incentives for enhancing the output capability of the power plants, which would enable more consumer load to be met during peak load hours, Secondly, backing down during off-peak hours would not result in a financial loss to the generating station. Thirdly, the sharing of beneficiaries in the Central generating stations would be given a significant meaning, which has not been there so far. The beneficiaries have well-defined entitlements, and they would be able to draw power up to this at normal rates of the respective power plants. In case of over-drawals, they have to pay at a higher rate during low frequency periods, which should discourage them from overdrawing and pulling down the frequency further. This payment would go to the beneficiaries who received less energy than was scheduled. The improvement of frequency pattern for four years and voltage stabilization due to implementation of ABT are depicted in figures 3.4 & 3.5. It is also observed that there is no major grid disturbance during FY 2003-2009 in Southern Region because of grid discipline. As the Unscheduled Interchange rate is fixed to be higher than the rate of costliest generation in Southern Region, the dispatch of
costly atomic power such as Kiaga, naphtha plants, diesel plants and new hydro power plants such as Srisailam Left Bank, Jural Power plant also became viable.

It is observed that the merit order dispatch was facilitated to backing down generating stations due to high frequency, especially in the months of June-September. The backing down of generation is 7139.18 machine hours (727.45 MU) in the year of 2006-07 and 10227.34 machine hours (967.13 MU) in the year 2007-08.

**Fig 3.4:** Frequency Pattern for Five Years
During high frequency periods (of >50.5 Hz), surplus power was utilized by reversible pumped storage units to pump back the water into reservoir. This means when the frequency is above 50.5 Hz, any overdrawl of energy from the central generating units is at free of cost. This energy has been properly utilized for pumping the water back during the high frequencies so as to secure the system from collapses due to high frequencies and to conserve the energy. The vallies in the load curve were also properly adjusted by using non-peak energies for pumped storages. Energy Generated/Pumped (MWh) during the year 2005-2006 (MWh) under ABT is shown in Table 3.5.
### TABLE 3.5
Pumped Storage Plant Operation during 2005-2006

<table>
<thead>
<tr>
<th>MONTHS 2005</th>
<th>GENERATOR MODE (MU)</th>
<th>PUMPED MODE (MU)</th>
<th>Average frequency</th>
</tr>
</thead>
<tbody>
<tr>
<td>April</td>
<td>21.2</td>
<td>-</td>
<td>49.80</td>
</tr>
<tr>
<td>May</td>
<td>56.0</td>
<td>-</td>
<td>49.52</td>
</tr>
<tr>
<td>June</td>
<td>5.3</td>
<td>-</td>
<td>49.59</td>
</tr>
<tr>
<td>July</td>
<td>11.7</td>
<td>-</td>
<td>49.85</td>
</tr>
<tr>
<td>August</td>
<td>571.5</td>
<td>-</td>
<td>50.10</td>
</tr>
<tr>
<td>September</td>
<td>514.6</td>
<td>-</td>
<td>50.25</td>
</tr>
<tr>
<td>October</td>
<td>33.6.1</td>
<td>-</td>
<td>50.22</td>
</tr>
<tr>
<td>November</td>
<td>110.5</td>
<td>-</td>
<td>50.11</td>
</tr>
<tr>
<td>December</td>
<td>122.5</td>
<td>12.5</td>
<td>49.94</td>
</tr>
<tr>
<td>January</td>
<td>180.0</td>
<td>102.6</td>
<td>49.83</td>
</tr>
<tr>
<td>February</td>
<td>148.8</td>
<td>49.0</td>
<td>49.49</td>
</tr>
<tr>
<td>March</td>
<td>166.6</td>
<td>88.1</td>
<td>49.42</td>
</tr>
<tr>
<td>Total</td>
<td>2243.8</td>
<td>252.</td>
<td>49.84</td>
</tr>
</tbody>
</table>

Even though some issues are tackled through implementation of ABT, solutions to many issues are still required.

### 3.7.4. Present Scenario (POST ABT)

Reforms have been taken up in Indian states out of a sincere concern for the viability and growth of the power sector to meet the needs of the consumers and to promote the states’ economy as a whole in India. This reforms process has been contemplated as a sequel to liberalization of power sector by the Central Government since 1991.i.e vertically
integrated monopoly industry to a more market-oriented environment consisting of smaller specialized firms more open to competition. It is expected that the competition among generation companies together with open access to the transmission system lead to lower electricity prices and better service for customers in the new deregulated power systems.

The Indian Electricity act 2003 (EA 2003) has come into force on 10th June 2003 by which the monopolistic electrical utilities to be unbundled and Transmission Utilities (Transco) to exit from all forms of electricity trading from this date. As envisaged in the Act, Indian SEBs were unbundled and two separate companies, viz. State Power Generation Corporation Ltd. and Transmission Corporation were formed and have commenced their business operations. The Transco acted as the single buyer in the state, purchasing all generation capacity and is selling it to the Discos at the prevailing rates as determined by the differential Bulk Supply Tariff (BST). i.e AP TRANSCO played a monopolist role in the power trading scenario of Andhra Pradesh. The entire power generated by the generators in this state had to be sold to the AP Transco (Single Buyer System). Similarly, the Discos, which acted as retail outlets for the end consumers and the bulk power consumers, had to buy power from the APTransco.

Once state Transco exits from trading, there will no longer be a requirement for a BST, as the Discos will contract directly with the Generators for the capacity. Transco will derive most of its income
through a Transmission Tariff, as per the decision of the State Electricity Regulatory Commission (State ERCs). The decision was made to implement the requirements of the EA 2003 on a PPA full allocation basis to the Discos.

These Discos have been issued regular Distribution and Retail supply licenses by the State ERC. Power Purchase Agreements entered into by TRANSCO with independent power projects (IPPs) were transferred to the DISCOS. The DISCOs were given full autonomy to act independently. The Distribution Companies are to be converted as Joint Venture Companies by inducting Private Sector participation through international competitive bidding. The induction of private sector participation will enable the DISCOS to have the benefit of better management practices of Private Sector and will also facilitate greater investments in Transmission and Distribution Sector, which may provide relief to the Government. It means the role of government intervention and control has been reduced to some extent. The present system became as Multi buyer system.

3.7.5. Illustration of Real Time Practical Power System Operation

A practical example has been taken for illustrating the operation of real time power system of deregulated environment under ABT mechanism. The figure 3.6 shows the Schedule and Actual draws of constitutes of Southern grid for 2nd March 2009 at 18:01 HRs.
The power generated by the central generating stations (CGS) viz NTPC, Neyveli, MAPPS, Kaiga, Talcher are pooled up and distributed to all the six constituents of southern grid namely, AP, Karnataka, Tamil Nadu, Kerala, GOA and Pondicherry.

At that time AP was entitled for drawl of 1677 MW and its schedule was 1628 MW (after adding its purchases and deducting losses). AP was drawing 2052 MW. The frequency at this time is 49.43 Hz. This means AP was over drawing by 425 MW at this frequency. The corresponding UI rate at this frequency is Rs 6.04 and Karnataka, Kerala were also over drawing 142 MW and 15 MW during this period. Similarly it is observed that, other states such as TN were under drawing by 332 MW, Pondy by 49 MW and GOA by 18 MW respectively.

As far as CGS units in the southern region concerned all the plants were over generating. NTPC-Ramagundam was over generating by 73 MW, MAPs by 6 MW, Neyveli-II by 41 MW and Neyveli-I by 4 MW. The Total Over generation is 124 MW. Actually all these generating plants are entitled for payment of UI charges @ 604 Paise/KWH for their over generation. But there is a CAP on over generation @ 420 Paise/KWH, which is fixed by CERC. Hence all the generating plants will be paid @ 420 Paise/KWH for their over generation.

At this time northern grid frequency was 50.2 Hz. This means in northern region the generation is more than the load and power is surplus in this region. It is observed that there is a power transmission
of 26 MW from northern region to deficit southern region. (13 MW from WR through Chandrapur- Ramagundam, 13 MW from ER through Jaipore-Gazuwaka HVDC lines).

The losses contemplated for this block due to imbalance is 33 MW.

- Total Over Drawls = 582 MW
- Total Under Drawals = 399 MW
- Total Over Generation = 124 MW
- Support from ER/WR = 26 MW
- Losses = 33 MW

As per the rules of ABT, fixed charges are calculated on annual basis and they are payable in 12 monthly installments. Since all the CGS power is under long term Power Purchase Agreement with all the states of Southern Region, the beneficiaries have to pay fixed charges as per their entitlements. As this amount is fixed, it is not taken into consideration for analysis.
Fig. 3.6. Schedule and Actuals on specified day

(Source: courtesy from APTRANCO)
Regarding variable charges, all the constituents have to pay the variable charges at respective rates to the CGS plants as per schedule.

Here the situation is complex. AP, Karnataka and Kerala will have to Pay the prevailing UI charges to the pool at Rs 604 Paise/KWH for their over drawals of 425 MW, 142 MW and 15 MW respectively. The total over drawal is 582 MW. TN, Pondy and GOA will receive UI charges from the pool at Rs 604 Paise/KWH for 332MW, 49 MW and 18 MWs respectively, The under drawal is 399 MW. Since all these six constitutes are in southern region at same frequency, here the payments and receipts are balanced for 399 MW. The generating plants are to be paid @ 420ps/Kwh for their over generation of 124 MW.

There is also UI import of 26 MW from northern grid. At that point of time the northern grid frequency is 50.2 Hz. Hence SR will pay Northern grid at Rs 120 Paise/KWH for this 26 MW. The consolidated payments are as follows:

Payments for Over Drawals

Rs 582 *1000 *604/100 = Rs 3515280.

Payments for Underdrawls and over generation

Underdrawls =Rs 399*1000*604/100 = Rs 2409960

Over generation = Rs 124*1000*420/100 = Rs 520820

Payment to WR = Rs 26*1000*120/100 = Rs 31200

Payment to losses = Rs 33 *1000*140/100 = Rs 46200

Total payments = Rs 3008180
It is observed that there is a surplus amount received by the pool. This amount will be equally divided by both SR and NR regions. Part of this amount received by SR is distributed to all the six constituents on the proportionate of allocation of power to each constituent and balance amount will be utilized for system improvement in the southern region.

In this juncture, AP had purchases through the competitive bidding. The bidding price for energy in the block varies from Rs 0 to Rs 20. As UI became bench index in the trading in electricity in Open Access environment, AP is forced to bid power at around Rs 10. But the transaction was not feasible, since others have quoted higher rate.

### 3.8 Intra-State ABT under Deregulation

The Present system should allow DISCOS to evolve the new concepts of real time pricing that more closely reflect the tuning of energy use and the cost of purchasing power. At present, the meters must record consumption of energy for every 15 minutes. It is necessary to establish a suitable communication system between the unbundled systems so as to monitor the trading process on Real–Time basis.

### 3.9 Issues Requiring Attention

Issues requiring attention incase of implementation of frequency linked tariff system within states and their companies under new market structure are listed out below.
3.9.1 Central Generating Stations (CGS UNITS)

It is found that rate payable for over generation to CGS units in the frequency band, 50 Hz to 50.5 Hz, is not the same for all CGS generators as the variable cost of CGS units are different. The variable charges of CGS Units are shown in Table 3.6. The UI Charge at 50.1 Hz is Rs 1.60. In case of any deviation in the scheduled generation over and above 50 Hz, the CGS unit gets UI rate for the over generation instead of getting variable charges. This means the CGS unit gets the difference of UI charges and variable charges for the over generation. It is observed that some of generators such as NTPC, NLC, and Talcheru etc. are benefited instead of penalized for over generation even if schedule is deviated above 50Hz. Thus discrepancy is observed in the UI charges payable to CGS generating units.

<table>
<thead>
<tr>
<th>Station</th>
<th>Rate in Ps/ unit</th>
<th>Ranking as Per merit order</th>
<th>Remarks</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kaiga – 1 &amp;2</td>
<td>307.946</td>
<td>1</td>
<td>Must run</td>
</tr>
<tr>
<td>Kaiga – 3</td>
<td>307.946</td>
<td>2</td>
<td>Must run</td>
</tr>
<tr>
<td>MAPS</td>
<td>198.040</td>
<td>3</td>
<td>Must run</td>
</tr>
<tr>
<td>NTPC(Rgm) U-7</td>
<td>127.237</td>
<td>4</td>
<td>CGS</td>
</tr>
<tr>
<td>NLC-II St-1</td>
<td>126.163</td>
<td>5</td>
<td>CGS</td>
</tr>
<tr>
<td>NTPC(Rgm)U1-6</td>
<td>118.895</td>
<td>6</td>
<td>CGS</td>
</tr>
<tr>
<td>Talcher-II</td>
<td>73.754</td>
<td>7</td>
<td>CGS</td>
</tr>
</tbody>
</table>
3.9.2 Reactive Power

3.9.2.1 Lack of VAR Support

All Discos are operated in an integrated mode with Transco as well as with regional Grid. If a DISCO does not have sufficient network and sufficient reactive power sources, there may be overloading of lines and transformers which in turn causes heavy absorption of Reactive power and Voltage drops. This may affect the other areas even if they have better transmission network and VAR compensation. It compels the above DISCOs to draw VAR due to these voltage drops and overloading of lines and transformers in the said DISCO. As a result the other DISCO also become responsible for payment for the Reactive Power due to the defaulted DISCO. The same will be applicable to the States of the Region.

3.9.2.2 Gaming

It is also not mentioned in ABT about the Reactive power generation at 97 % of voltage or absorption at 103 % of voltage of Generating Stations. A generator is commonly controlled so that the active power injected into the bus and the voltage at the generator terminals are kept constant. Active power generation is determined by the turbine control and it must be within the capability of the turbine generator system. Voltage at the generator terminals is primarily determined by the reactive power injection into the node. The generator must operate within its reactive capability curve (Active Power Vs Reactive Power). The reactive capability of a generator depends on active power generation, bus voltage and other
operating conditions, stability constraints, etc. It implies that generally a
generator delivers active power along with reactive power based on its
capability curve. The generator also plays vital role in reactive power
supplements or absorptions. There is a possibility of delivering only
active power without giving the sufficient support of reactive power to the
system. It means that the generator tries to get more income by
maximizing active power scheduling and depriving the reactive power. It
may result in decreased system reliability, increased cost for others and
reduction in overall efficiency of entire market.

**3.9.2.3 Central Transmission Utility (CTU)**

The Unscheduled Interchange due to the transmission constraints (i.e. due
to break downs of CTU lines) is not properly defined in this ABT
Scheme. This means that outage of any CTU line may cause unscheduled
interchange and change in transmission losses. Market Monitoring and
Coordinating Functions such as generation and transmission outage
monitoring are not available at present. Safeguard mechanism against
contingencies should be developed.

**3.9.3 The Impact of UI Mechanism**

It is observed that the UI has lot of impact mainly on the short-term open
access-trading environment. The main idea of implementing UI
mechanism under ABT is to bring grid discipline among the beneficiaries.
Even if it produced good results, it is observed that there are some
contradictions still exist in the system. At present, the UI mechanism of
ABT became the benchmark index on which the pillars of competitive markets have been developed in India for all open access and bilateral power exchange trading purposes. Any purchase of power through the private market in short term open access became burdensome to the beneficiaries as the rate of power in trading is fixed on basis of frequency profile. The rate is floated in between Rs 7 and Rs 10.

3.9.4 Constituents and Discos

3.9.4.1 Software Tools

Validated software must be provided for checking the correctness of the regional accounts prepared by Regional Load Despatch Center and also for the accounts prepared by constituents, which are to be passed on to their DISCOS. The existing power supporting software systems are to be improved w.r.t quality, maintainability and scalability. In order to maintain competitiveness, all utilities must move quickly to capitalize on the Internet as a medium for business integration on Real-Time basis. There is a need to automate B2B (Business-to-Business) transactions.

The Discos must be supported by the Load Management, Load staggering and Load shedding softwares so as to predict the Load patterns by integrating various practical constraints and commercial implications prevailing in their systems. This implies that all elements of Business integration platform for B2B applications along with energy Management System (EMS) functions must be developed.
3.9.4.2. Losses

A special tool to study the line losses with different scenarios must be provided to the State Load Despatcher, as energy losses play predominant role in the power sector. This means that the transmission networks and distribution networks are to be reconfigured dynamically so as to achieve better voltages and reduce losses, by conducting load flow studies in both state level and Discos level simultaneously.

3.9.4.3. Generating Stations

Incentives if any should be considered for any particular station and are required to be defined properly. A suitable mechanism must be developed so as to pass the incentives/penalties of ABT to the Genco/Discos.

The variable cost of unit must be accommodated properly in the charges of Unscheduled Interchanges of ABT at different frequencies (the capacity charges already paid to the generating stations) as the variable cost of unit in the constituents spreads from 4 Rs/unit to 0.84 Rs/unit. This means a suitable characteristic must be found to accommodate drastic variation in variable charges as the Generator may bid based on variable cost in the bid-based deregulated environment.

The proper Hydro and Thermal mix must be arrived while preparing the Schedules.

3.9.4.4. Hydro Scheduling

Procedure of Scheduling of Hydro energy during surplus and non-surplus times by giving priorities to Irrigation on Real Time basis must
be evolved, i.e. the scheduling of hydel power must be done by considering the different scenarios of drought, normal and flood conditions and irrigation requirements prevailing in the state sector.

Schedule of release of water through machine for irrigation should be evolved properly. This means that they are to be treated as must run units while scheduling the hydro component.

3.9.4.5 Thermal Scheduling

In Indian, States are forced to run all the thermal machines to their full capacities. Under such conditions, all thermal units are to be treated as base load stations. During high frequency periods each machine should run with a minimum spinning reserve of at least 5% of the machine capacity which can be utilized during peak load condition.

The proper backing down of thermal units should be evaluated as every thermal unit has its own technical limits of operation. The backing down of generation will increase the auxiliary consumption percentage and heat rate etc, which in turn reflect on the increase of the variable cost of unit even if the backing down without oil support is given.

3.9.4.6 Scheduling of Gas Stations

The Government of India introduced the private power policy to bring additional resources for capacity in the electrical sector in October 1991. According to this policy, Govt. of AP and erstwhile APSEB had permitted the private developers to set up short gestation power projects to bridge the gap between demand and supply during the period 1995-
1996. The then APSEB invited Tariff based proposals through International Competitive Bidding from private promoters to set up Gas/Naphtha/Low Sulphur Heavy Stock/Furnace oil based short gestation projects during 1995. Most of the IPPs were gas based generating plants. The Power Purchase Agreements were entered into on 31.03.1997. The new concept of “deemed generation” was introduced which compensate generators, in the event of a station being available but forced to back down due to system constraints or low demand in Grid. The total fixed charges for year is payable at normative (gross) PLF of 68.5% (the actual generation + deemed generation). i.e. The utility is compelled to pay the total fixed charges under such circumstances. Due to this clause these stations became must run stations.

As per the agreement, the utility has to pay incentive when normative (gross) PLF (actual + deemed) is over and above 68.5%.

For Gas station, the natural gas is to be used as primary fuel by one or more units of project for power generation. In case of unavailability of primary fuel, Naphtha or Low Sulphur heavy stock may be accepted as secondary fuel by utility. The variable charges for a generator running with naphtha are costlier than the generators with gas.

As agreements entered into IPPs are on long-term basis, the fixed charges are calculated annually, considering the commercial operation date (COD). The PLF of generation of these IPPS is arrived on the basis of the COD. The CODs and Tariff years are tabulated in Table 3.7.
The merit order dispatch generally is carried out by considering the variable charges as the fixed charges are already paid to these stations. The effective variable charges are different for the different PLFs as indicated Table 3.7

TABLE 3.7
CODs , Tariff years and Incentives of IPPs

<table>
<thead>
<tr>
<th>Sl. No.</th>
<th>Station</th>
<th>Tariff year</th>
<th>PLF limit for incentive</th>
<th>Current variable cost</th>
<th>Incentive rate</th>
<th>Variable plus incentive</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>IPP1</td>
<td>FROM 20-Jun-08 TO 19-Jun-09</td>
<td>85</td>
<td>101.817</td>
<td>68.00</td>
<td>169.817</td>
</tr>
<tr>
<td>2</td>
<td>IPP2</td>
<td>FROM 19-Apr-08 TO 18-Apr-09</td>
<td>85-85.5</td>
<td>102.716</td>
<td>34.00</td>
<td>136.716</td>
</tr>
<tr>
<td></td>
<td>IPP2</td>
<td>FROM 19-Apr-08 TO 18-Apr-09</td>
<td>&gt;85.5</td>
<td>102.716</td>
<td>38.80</td>
<td>141.516</td>
</tr>
<tr>
<td>3</td>
<td>IPP3</td>
<td>FROM 02-Jan-08 TO 01-Jan-09</td>
<td>80-85</td>
<td>115.270</td>
<td>76.28</td>
<td>191.550</td>
</tr>
<tr>
<td></td>
<td>IPP3</td>
<td>FROM 02-Jan-08 TO 01-Jan-09</td>
<td>85-90</td>
<td>115.270</td>
<td>114.42</td>
<td>229.690</td>
</tr>
<tr>
<td></td>
<td>IPP3</td>
<td>FROM 02-Jan-08 TO 01-Jan-09</td>
<td>&gt;90</td>
<td>115.270</td>
<td>0.00</td>
<td>115.270</td>
</tr>
<tr>
<td>4</td>
<td>IPP4</td>
<td>FROM 24-Dec-07 TO 23-Dec-08</td>
<td>85</td>
<td>95.315</td>
<td>1.34</td>
<td>96.653</td>
</tr>
<tr>
<td>5</td>
<td>IPP5</td>
<td>FROM 01-Apr-08 TO 31-Mar-09</td>
<td>122.443</td>
<td>5</td>
<td>127.443</td>
<td></td>
</tr>
</tbody>
</table>

In the Year 2005, the Power Purchase Agreements with independent power projects (IPPs) were transferred from TRANSCO to DISCOS. The generation Capacities of these IPP are allocated to DISCOS. There is a need to have proper scheduling of these generators in DISCO level. DISCOS must adhere to schedules due to incentives/disincentives. The cumulative (gross) PLF for each and every 15 minutes block should be taken into account while arriving at the schedules.

Provision must be given to the despatch instructions for backing down of IPP units. IPP agreement stipulates that despatch instruction
can be given for a time period (example: @ 1600 hours/tariff year) and specified number of despatch instructions per day. Thus the DISCOS must follow these terms and conditions of agreement. IPP is eligible for deemed generation due to these dispatching instruction to the units for backing down.

During non-availability of gas, permission to run on naphtha may be defined, as running IPP units on naphtha is costlier. Even the procedure for Despatch instructions for backing down of units using naphtha must be defined properly on real time basis.

As there are different dates of commercial operations for the IPPs, a suitable procedure for scheduling their power must be evolved. As incentives are linked with the PLFs, on yearly basis, it is required to stagger the scheduling of IPPs power.

3.9.4.7 Technical Constraints

Generators, which improve the security to the grid and give better voltage profile, have to be treated separately while considering backing down procedures.

3.9.4.8 The Role of Constituents Transmission network in the ABT.

Proper tools must be developed for carrying out the Merit Order Despatch by simulating all practical conditions prevailing in the present power system grids.
3.9.4.9 Reactive Power (Disco Level)

Reactive power drawals/injections of Distribution companies must be properly evolved as agricultural component plays a predominant role.

3.9.10.4 Billing Methodologies for Real Time Trading

Proper billing methodologies must be evolved for the drawals and unscheduled interchanges between the companies.

3.9.4.11 Real Time Operation

Suitable Communication Networks must be established between TRANSCO and Discos and in-between Discos. There is a need to integrate SCADA systems along with internal applications of TRANSCO and Discos. It gives an improvement on real-time visibility in utilities for commercial operations.

The Boundary Points for drawal/injections of the power for the DISCOS need to be specified accurately, as the commercial impacts are more.

3.10 Conclusions

An attempt is made in this chapter in brining out some important issues faced by utility engineer incase of implementation of ABT within state grids. The focus is on power system operation in real time in frequency linked tariff mechanism. The evolution of transition in power system operation prevailing in developing countries with particular reference to Indian power sector scenario is described. Identification and development of solution strategies are also discussed. Issues raised in this chapter are expected to be of practical significance in the study of real time power trading. The ABT, although considered as a market based model for generators, it does not address nor give way for establishment of Competitive Electricity Markets. In developing countries like India, what is needed are the tariff reforms that are achieved through competition