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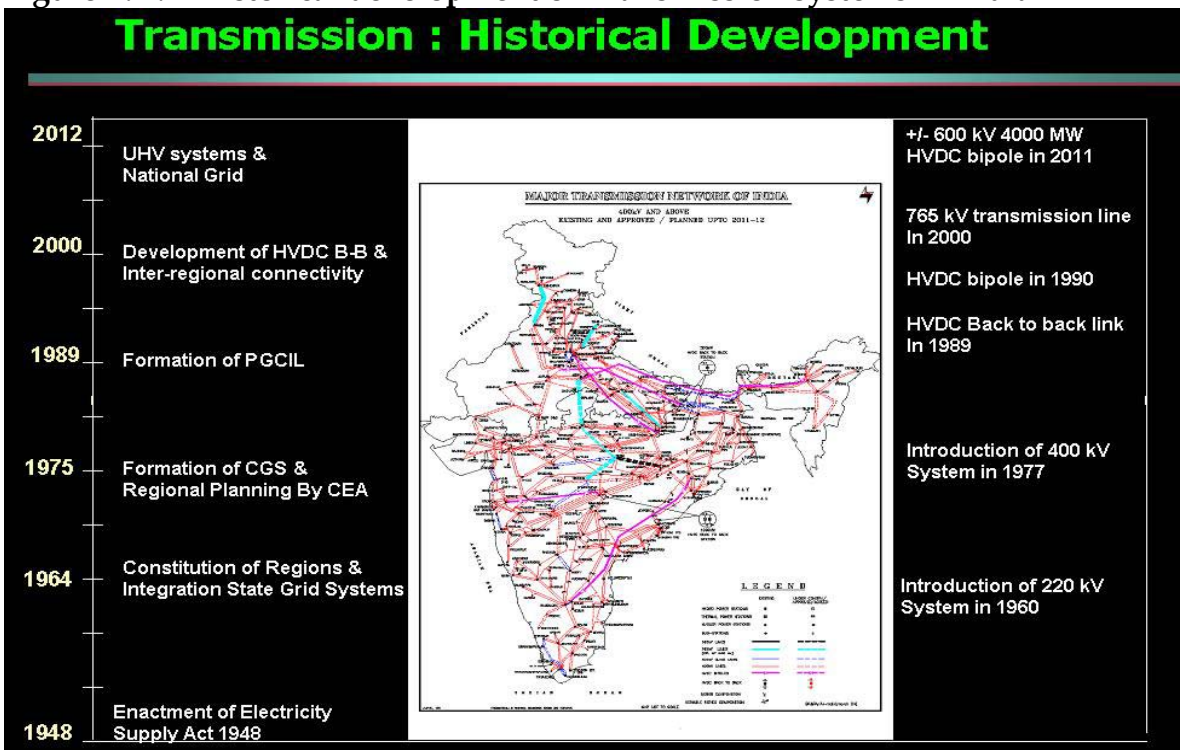
1 INTRODUCTION

1.1 Historical development of transmission systems in India

At the time of Independence, power systems in the country were essentially isolated systems developed in and around urban and industrial areas. The highest transmission voltage at the time was 132 kV. The framework for development of power sector was set with the enactment of Electricity (Supply) Act, 1948 providing for establishment of CEA for coordinated development of Power Sector. In 1964, for the purpose of coordinated power sector planning on a larger scale and integration of State Grid systems towards optimum development and utilization of resources, the country was demarcated in to five Regions viz. the Eastern Region, the North-Eastern Region, the Northern Region, the Western Region and the Southern Region, and the Regional Electricity Boards were established in each of the regions for facilitating integrated operation of state systems and encouraging exchange of power among the States.

Figure-1.1 : Historical development of Transmission systems in India



Source: CEA and MOP

1.2 Emergence of Regional Transmission Systems

During 1970s, with creation of central generating stations, the focus of planning and development in the transmission system shifted from State Grid system to Regional Grid system. In 1989, the transmission wings of these Central Generating companies were separated to set up Power Grid Corporation of India (POWERGRID) to give thrust to implementation of transmission system associated with Central generating stations and intra-Regional transmission programme based on perspective planning done by CEA. A few inter-regional links were also planned and developed to facilitate exchange among the various regions. However, these inter-regional links were planned for emergency assistance and transfer of operational surplus between the regions in a limited manner only.

In the recent past, the focus of planning generation and transmission system in the country has shifted from the orientation of regional self-sufficiency to the concept of optimization of utilization of resources on all India basis. The change in planning philosophy towards National Grid system has started showing the developments on the ground.

At present, the inter-regional transmission capacity of only 9,450 MW is available and inter-regional energy exchanges of more than 12 billion kWh in a year are taking place. The program is to achieve inter-regional capacity of 16450 MW by the end of 10th Plan and about 37,150 MW by the end of 11th Plan.

As per Section 3 of the Electricity Act 2003, the CEA has been entrusted with the responsibility of preparing the National Electricity Plan in accordance with the National Electricity Policy and notify such plans once in five years. CEA has developed such Plan titled 'Draft National Electricity Plan – Program up to 2011-12 – Transmission', which covers the National Transmission Plan up to 2011-12 based on the updated generation program.

2 ELECTRICITY MARKET DEVELOPMENT AND TRANSMISSION INFRASTRUCTURE

A robust transmission network is essential for power market operations. Experts have recommended that the market reforms should start with transmission and not generation. Transmission system issues need to be accorded the highest priority in the market development initiative. Commercial autonomy to buy and sell power may not achieve desired results if transmission network do not have adequate capacity.

2.1 Existing Transmission Infrastructure

At the end of nineth five year Plan, corresponding to the total installed generation capacity of 105 GW as on 31st March 2002 and peak demand of 73 GW, the transmission system in the country at 765/HVDC/400/230/220 kV stood at 150 thousand circuit kilometers (Tckm) of transmission lines and 178 GVA of grid substation capacity.

During the tenth plan period a capacity addition programme of 41 GW comprising 14.4 GW of hydro, 25.4 GW of thermal and 1.3 GW of nuclear was envisaged and accordingly transmission requirements at 132 kV level and above were identified. The current installed capacity of transmission network in the country is as under:

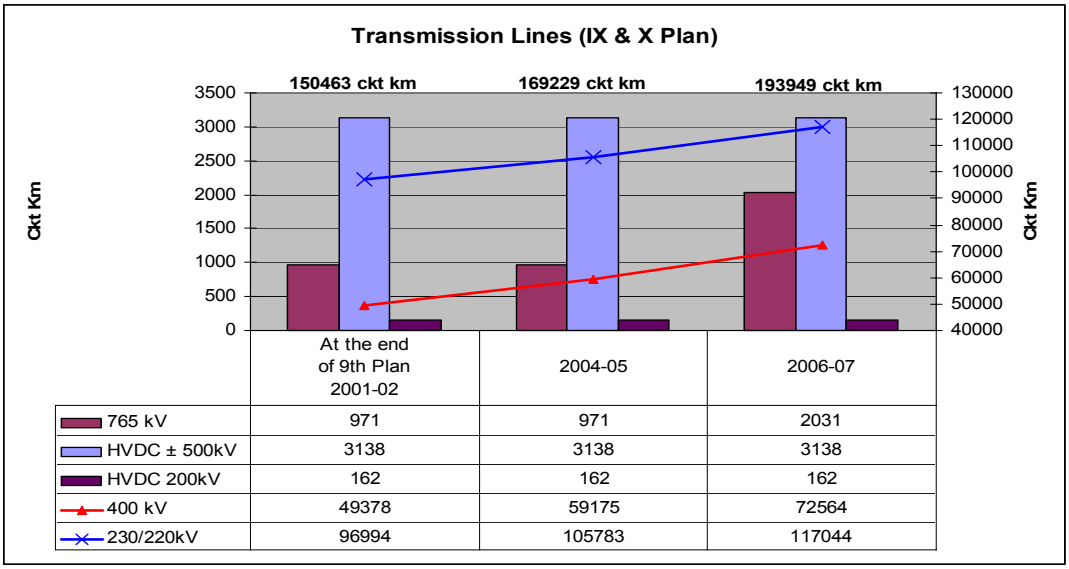
Table 2.1: Transmission Assets (above 220 kV)

Transmission Assets	Unit	9th Plan (as on 2001-02)	2004-05	10th Plan (2006-07) (est)
Transmission lines	Ckt km	150,463	169,229	193,949
Substations	MVA	177,688	212,897	248,467
HVDC capacity	MW	5,200	8,200	8,700

Source :CEA

A detailed break-up of voltagewise transmission lines, Grid Substations and HVDC capacity added during 9th and 10th Plan is presented in the following charts at Figure 2.1, Figure 2.2 and Figure 2.3.

Figure-2.1: Transmission Lines (9th and 10th Plan)

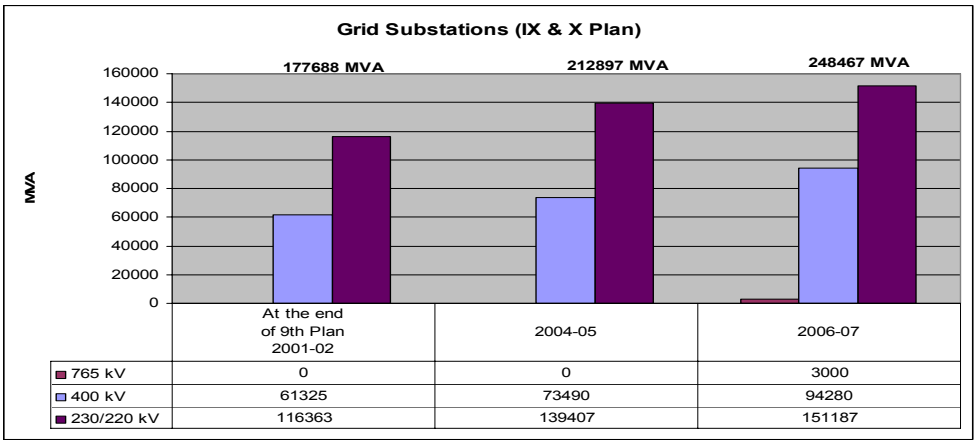


	At the end of 9th Plan 2001-02	2004-05	2006-07
765 kV	971	971	2031
HVDC ± 500kV	3138	3138	3138
HVDC 200kV	162	162	162
400 kV	49378	59175	72564
230/220kV	96994	105783	117044

Source: ABPS Research

Based on actual progress achieved during first three years of 10th Plan and updated targets for the balance two years of 10th Plan period, the **cumulative transmission lines** at the end of 10th Plan period are projected to be around 193949 ckt-km., an increase by around 43,500 ckt-km during 10th Plan period. Significant addition in transmission lines have taken place at 440 kV and 220 kV level amounting to addition of 23,200 ckt-km and 20,000 ckt-km respectively. There has also been addition of 1060 ckt-km at 765 kV.

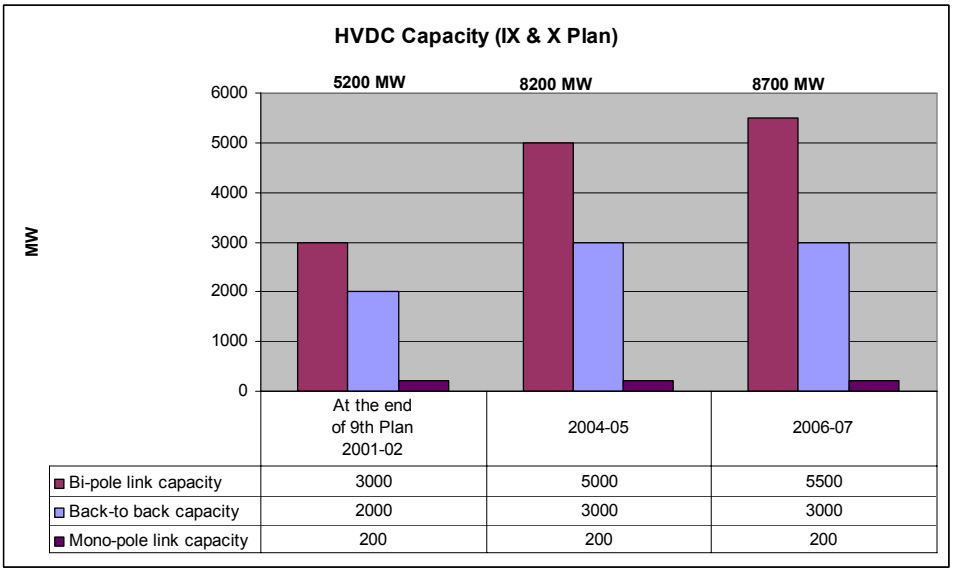
Figure-2.2: Grid Substations (9th and 10th Plan)



Source: ABPS Research

Based on actual progress achieved during first three years of 10th Plan and updated targets for the balance two years of 10th Plan period, the **cumulative Grid Substation** capacity at the end of 10th Plan period are projected to be around 248467 MVA, an increase by around 70,800 MVA during 10th Plan period. Significant addition in substation capacity have taken place at 440 kV and 220 kV level amounting to addition of 33,000 MVA and 34,800 MVA respectively. There has also been addition of 3000 MVA at 765 kV.

Figure-2.3: HVDC Capacity (9th and 10th Plan)

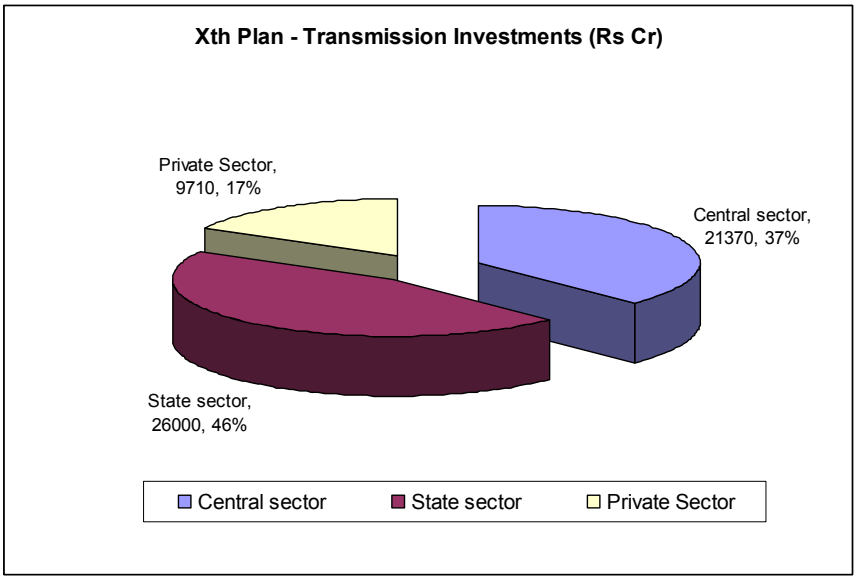


Source: ABPS Research

Based on actual progress achieved during first three years of 10th Plan and updated targets for the balance two years of 10th Plan period, the **cumulative HVDC** capacity at the end of 10th Plan period are projected to be around 8700 MW, an increase by around 3500 MW during 10th Plan period. Significant addition in substation capacity has taken place in terms of HVDC Bipole link amounting to addition of 2500 MW. There has also been addition of 1000 MW at HVDC back-to-back station capacity.

2.2 Transmission Investments and Ownership (10th and 11th Plan)

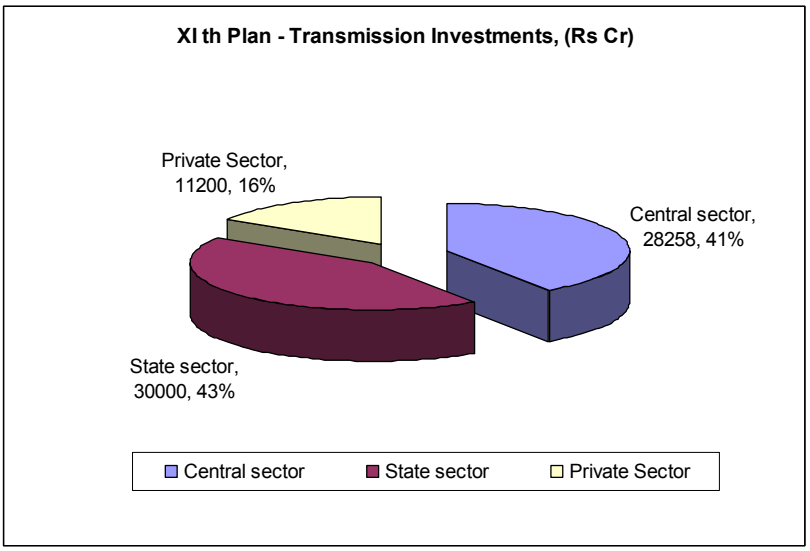
Figure-2.4: Transmission Investments (10th Plan)



Source: ABPS Research

During 10th Plan period, total investments in transmission sector for Rs 57,080 Crore have been envisaged. Out of above investment, central sector and State sector are expected to contribute almost 83% amounting to Rs 47,370 Crore.

Figure-2.5: Transmission Investments (11th Plan)



Source: ABPS Research

During 11th Plan period, total investments in transmission sector for Rs 69,458 Crore have been envisaged. Out of above investment, central sector and State sector are expected to contribute almost 84% amounting to Rs 58,258 Crore.

2.3 Indian Transmission System - Characteristic features

While looking at the issues associated with the Indian Transmission System, it is essential to understand the characteristic features as follows:

- Transmission operations are likely to continue to be overwhelmingly dominated by government owned entities (primarily the CTU and the STUs).
- The national transmission system in India is presently under development, with less than adequate interconnections existing between regions. However, given that the primary resources of power generation are unevenly dispersed in the country, the demand for regional interconnections is likely to increase. Power trading between regions is also likely to increase;
- The four main regional networks are significantly strong and are well functioning. Frequency integration of the Western, Eastern and North-

Eastern networks has been accomplished and the Northern Grid is likely to be integrated in the coming year. The Southern Grid is proposed to be integrated thereafter.

- Rules for transmission access are inadequate since in the past the State owned entities have been the only participants in the regional network and continue to dominate the networks in all States.
- Transmission pricing is in its infancy and postage stamp arrangements are followed throughout the country. Currently, transmission loss is apportioned onto all transactions on average basis.

2.4 Transmission Capacities – A pre-requisite for Open Access:

The Electricity Act 2003 has envisaged 'open access' as an important tool for introduction of competition across various segments of electricity value chain from generation to distribution and to retail consumers. However, open access transactions are dependent on or rather subject to availability of transmission capacity.

As per Open Access Regulations notified by CERC, open access transactions have been classified into two categories long term (period of 25 years or more) and short term (other than long term). The transmission capacities are allotted in case of long term OA transactions and transmission capacities are reserved in case of short term OA transactions.

In fact, currently transmission capacity reservation for short term open access transactions takes place for period of only three months at a time. Mostly, existing transmission capacities are allotted to incumbent licensees and State Utilities on long term basis, thus creating long term physical transmission capacity rights. Further, reservation of transmission capacities for short term OA transactions is subject to inherent design margins, variation in power flows or built-in spare capacities to cater to future load growth. The short term OA transactions can be curtailed and have less priorities over long term OA

transactions. Similarly, Open Access Regulations formulated by most of the SERCs have created long term transmission capacity rights in favour of incumbent State Utilities and existing licensees.

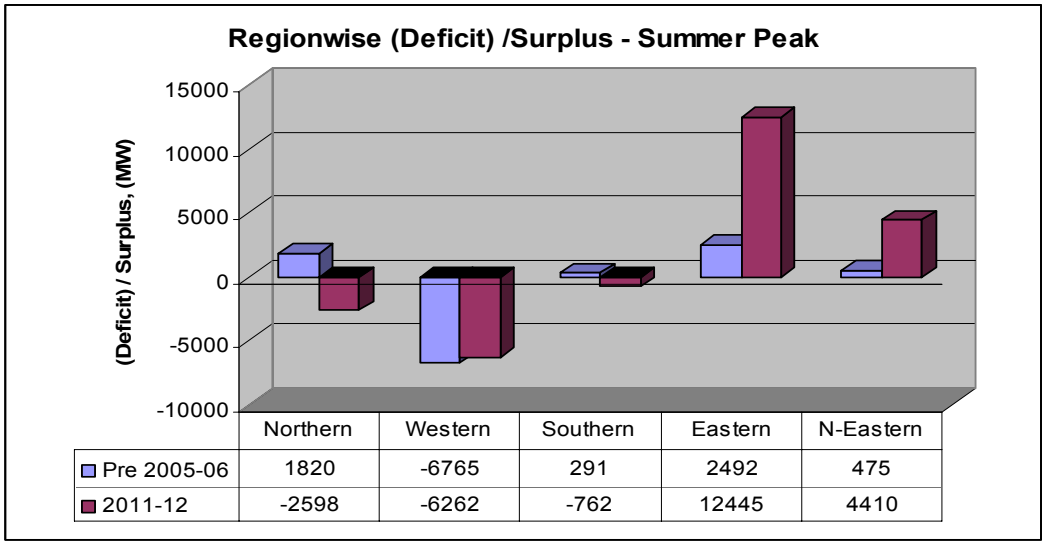
Accordingly, the model of 'physical transmission capacity right' of long term nature has put severe restrictions on the operationalisation of open access transactions limiting even short term OA transactions amongst incumbent utilities. Availability of transmission capacity is critical for effective implementation of open access across territories.

3 TRANSMISSION EXPRESSWAY – NEED OF THE HOUR

3.1 Region-wise demand-supply scenario

Development Plan for National Grid System for a perspective scenario requires determination of capacity and topology of the grid corresponding to that scenario. This in turn requires assessment of power exchange requirement based on which transmission expansion plan could be worked out. Power exchange requirement would depend upon the projected scenario of surpluses and deficits in various regions taking into account the regional plans of generation capacity additions and growths in demand. The inter-regional exchange requirement would vary from season to season as well as during the peak and off peak periods of the day. Therefore, possible scenarios of regional surpluses and deficit corresponding to various operating conditions as well as extreme dispatch conditions have been considered by CEA for determination of transmission expansion plan. The same has been presented under its proposed Draft National Electricity Plan for Transmission. An analysis of projected demand- supply scenario across various regions during **Summer peak, Monsoon Peak and Winter Peak** is presented in the following paragraphs.

Figure-3.1: Summer Peak (Projected variation from Pre 2005-06 to 2011-12)



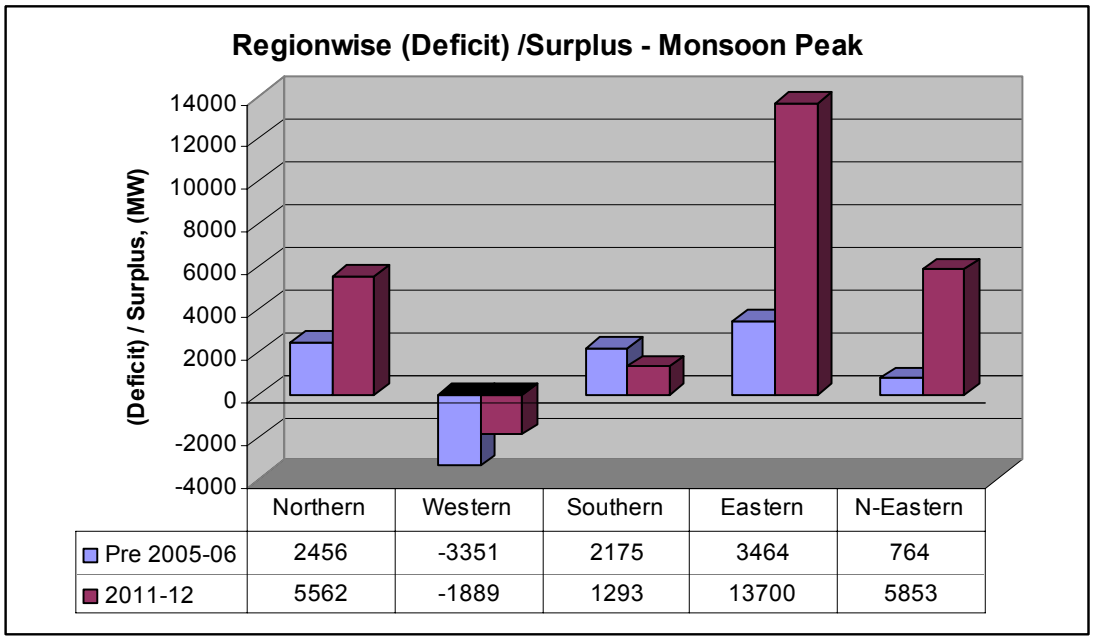
	Northern	Western	Southern	Eastern	N-Eastern
Pre 2005-06	1820	-6765	291	2492	475
2011-12	-2598	-6262	-762	12445	4410

Source: ABPS Research

Surplus in Eastern and North-Eastern region is expected to increase significantly to 16000 MW from 2950 MW as prevalent during pre 2005-06 period. Further, it has been projected that Western region shall continue to have deficit of the order of 6000 MW as was prevalent during pre 2005-06 period. In case of Northern and Southern region, it has been projected that they would move from surplus scenario during pre 2005-06 period to deficit scenario during 2011-12.

An analysis of projected demand- supply scenario across various regions during **Monsoon peak** is presented in the following paragraphs.

Figure-3.2: Monsoon Peak (Projected variation from Pre 2005-06 to 2011-12)



	Northern	Western	Southern	Eastern	N-Eastern
Pre 2005-06	2456	-3351	2175	3464	764
2011-12	5562	-1889	1293	13700	5853

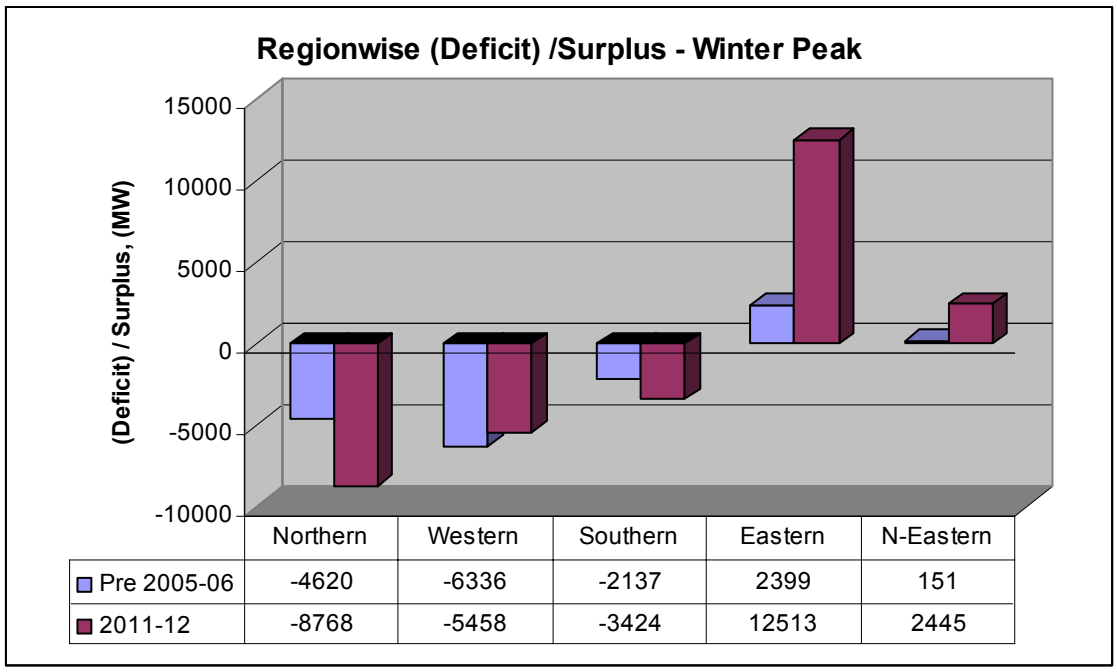
Source: ABPS Research

Surplus in Eastern and North-Eastern region is expected to increase significantly by around 19500 MW from 4200 MW as prevalent during pre 2005-06 period. Further, it has been projected that Western region shall continue to have deficit of the order of 1800 MW as was prevalent during pre 2005-06 period. However, the deficit is expected to reduce from level of 3350 MW as prevalent during pre 2005-06 period. In case of Northern and Southern region, it has been projected

that they would continue to have surplus. However, surplus in case of Northern region is expected to increase to 5562 MW from level of 2456 MW as prevalent during 2005-06 period whereas in case of Southern region, the surplus is expected to reduce from 2175 MW to 1293 MW during 2011-12.

An analysis of projected demand- supply scenario across various regions during **Winter peak** is presented in the following paragraphs.

Figure-3.3: Winter Peak (Projected variation from Pre 2005-06 to 2011-12)



	Northern	Western	Southern	Eastern	N-Eastern
Pre 2005-06	-4620	-6336	-2137	2399	151
2011-12	-8768	-5458	-3424	12513	2445

Source: ABPS Research

Surplus in Eastern and North-Eastern region is expected to increase significantly by around 14900 MW from 2550 MW as prevalent during pre 2005-06 period. Further, it has been projected that Western region shall continue to have deficit of the order of 5458 MW, a downward revision of around 900 MW from that prevalent during pre 2005-06 period. In case of Northern and Southern region, it has been projected that they would continue to have deficit. In fact, deficit in case of Northern region is expected to increase to 8768 MW from level of 4620 MW as prevalent during 2005-06 period whereas in case of Southern region, the deficit is

expected to increase from 2137 MW to 3424 MW during 2011-12. Thus, there is an urgent need to strengthen regional and inter-regional infrastructure to enable exchange of power from surplus regions to deficit regions.

3.2 Existing Inter-regional Transmission capacity

At the end of the 9th Plan that is by year 2001-02, the inter-regional transmission capacity was 5050 MW. The addition to the inter-regional transmission capacity during the year 2002-03, 2003-04 and 2004-05 had been 2500 MW, 1000 MW and 900 MW respectively and the programme for the year 2005-06 and 2006-07 is 2500 MW and 4500 MW respectively. Thus, 4400 MW transmission capacity has been added during first three years of 10th Plan and another 7000 MW is to be added during the remaining two years of the 10th Plan. Thus, total of 11400 MW would be added to the inter-regional transmission capacity during the 10th Plan period (2002-07) that would take the total inter-regional transmission capacity in the country to 16450 MW by 2006-07. The cumulative inter-regional capacities across various regions at the end of 10th Plan is presented in the following Table.

Table-3.1: Inter-regional transmission capacity

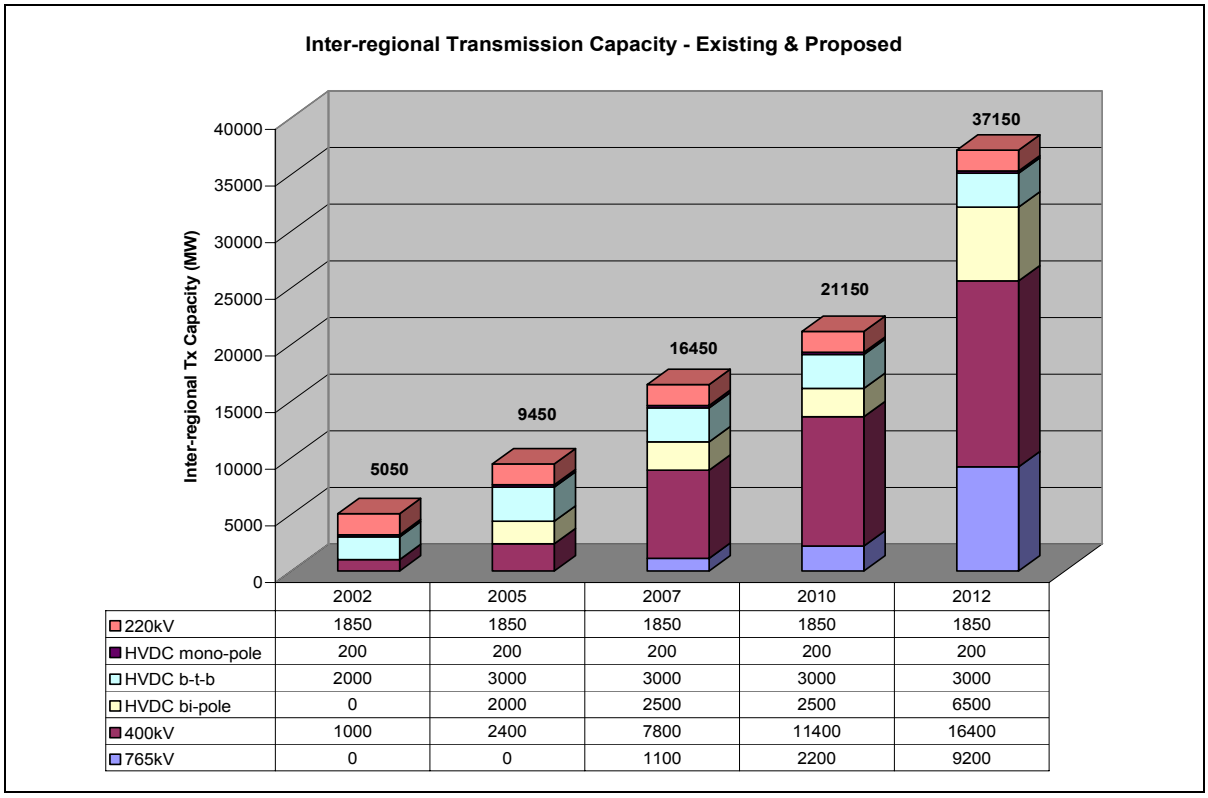
Inter-regional transmission assets	**Unit**	**Cumulative at the end 9th Plan 2001-02**	**Addition during 2002-07**	**Cumulative at the end of 10th Plan 2006-07 (est)**
ER-SR	MW	600	3,000	3,600
ER-NR	MW	100	4,900	5,000
ER-WR	MW	400	2,400	2,800
ER-NER	MW	1,250		1,250
NR-WR	MW	1,000	1,100	2,100
WR-SR	MW	1,700		1,700
NR-NER	MW			
TOTAL	**MW**	**5,050**	**11,400**	**16,450**

Source: CEA

Significant inter-regional capacity addition is expected to facilitate evacuation of power from Eastern region to other regions through above links such as ER-SR (3000 MW), ER-NR (4900 MW), ER-WR (2400 MW).

Further, as per draft National Transmission Plan, inter-regional capacity is expected to increase to 37150 MW during 11th Plan period. Significant capacity addition is expected to take place through 765 kV transmission lines (8100 MW), 400 kV transmission lines (8600 MW) and HVDC bi-pole (4000 MW). Inter regional transmission capacity expected to increase in following manner:

Figure- 3.4: Inter-region capacity addition (Planned)



	2002	2005	2007	2010	2012
220kV	1850	1850	1850	1850	1850
HVDC mono-pole	200	200	200	200	200
HVDC b-t-b	2000	3000	3000	3000	3000
HVDC bi-pole	0	2000	2500	2500	6500
400kV	1000	2400	7800	11400	16400
765kV	0	0	1100	2200	9200

Source : ABPS Research

3.3 Challenges for development of National Grid

The exploitable energy resources in our country are unevenly distributed, like Coal resources are abundant in Bihar, Jharkhand, Orissa, West Bengal and Hydro resources are mainly concentrated in Northern and North-Eastern Regions. Further, there exists significant potential for renewable energy sources such as wind – onshore and offshore, which can be harnessed. As a result, some regions do not have adequate natural resources for setting power plants to meet their future requirements whereas others have abundant natural resources. Demand for power continues to grow unabated. This calls for addition of transmission capacity through creation of National Grid for optimal utilization of generating resources across the country for sustainable development.

Further, acquiring Right of Way (RoW) for constructing transmission lines is getting increasingly difficult, especially in eco-sensitive areas like North-Eastern Region, Chicken-neck area, hilly areas in Jammu & Kashmir and Himachal Pradesh. At the same time, these areas are also endowed with major hydro potential of the country. This necessitates creation of "Transmission Super Highways", so that in future, constraints in RoW do not cause bottleneck in harnessing generating resources. Inter-connection of these highways from different parts of the country would ultimately lead to formation of a high capacity "National Power Grid".

3.4 Key issues to be addressed:

(i) Is the market model for 'open access' severely constrained by availability of transmission capacities at State level, regional level and inter-regional level?

(ii) Is the proposed inter-region capacity addition, adequate to address projected regional shortfall scenarios?

4 TRANSMISSION INVESTMENT : KEY CONSIDERATIONS

In order to accomplish ambitious plan targets of generation capacity addition of 1,00,000 MW by 2012, timely creation of adequate evacuation infrastructure and transmission facilities is extremely important.

It is estimated that around Rs 2,00,000 Crore worth of investment would be required for the associated transmission system including creation of a National Grid. Out of this, an investment of about Rs 70,000 Crore would be required in Central Sector Transmission Systems alone. POWERGRID is expected to mobilise an investment of Rs 41,000 Crore and the balance fund requirement of Rs 29,000 Crore is proposed to be mobilised through private investments.

4.1 Status of Private participation in transmission at Regional Level

Considering the scale of investment and the volume of expansion required, attracting large private investment in transmission is essential. Ministry of Power issued detailed guidelines for private sector participation in transmission as early as January 2000.

These guidelines envisage two distinct routes for private sector participation in transmission: Joint Venture (JV) Route, wherein the CTU/STU shall own at least 26% equity and the balance shall be contributed by the Joint Venture Partner (JVP) and Independent Private Transmission Company (IPTC) Route, wherein 100 percent equity shall be owned by the private entity.

Implementation of first private sector transmission project under JV route is already underway in case of Tala Transmission project involving development of 1200 km transmission lines and associated substation facilities. Private participation under IPTC route in case of 400 kV Bina-Nagda-Dehgam double circuit line is under advanced stage of tendering process.

4.2 Regulatory and Policy developments at Regional Level

Meanwhile, CERC in its Order of July 29, 2005 has highlighted need for private sector participation in 'transmission' in the matter of application filed for grant of transmission licence for development of transmission schemes in western region involving estimated outlay of almost Rs 4700 Crore. The Commission had directed some components of proposed transmission scheme (Scheme – B & C) excluding 765 kV transmission lines to be offered for 100% private participation. The tendering process for selection of private developer is currently underway and the response to the tendering process titled "Western Region System Strengthening Scheme II" has been very encouraging with as many as 28 companies - domestic and international companies have evinced keen interest in the private sector participation in the IPTC route.

Subsequently, Central Government has notified guidelines for "Tariff based Competitive Bidding for Transmission Service" on April 17, 2006. However, development of transmission projects based on these competitive bidding guidelines is yet to be initiated.

Further, 'transmission' being licensed and regulated business, the private developer would have to avail transmission license from the Appropriate Commission as per the Licensing Regulations. With qualification criteria such as experience of development, operation and maintenance of transmission lines/substations at appropriate voltage levels and financial requirement of networth, there may be limited number of domestic private players that would fulfil the qualification requirements.

4.3 State level Transmission Planning and Investment:

As outlined earlier, Rs 70,000 Crore out of Rs 2,00,000 Crore funding requirement for transmission schemes pertain to central sector schemes and development of National Grid infrastructure. This also means that funding requirement for State level transmission infrastructure at Rs 1,30,000 Crore is almost double that for

central level. The State transmission utilities are faced with this challenge to mobilise resources and attract private participants for the same.

The National Task Force (N. K. Singh Committee) constituted by Central Government has opined that GoI and appropriate State Governments should provide high priority to the development of transmission network at State level. Similarly, ERCs would need to promote investments in networks through appropriate pricing and regulatory arrangements and this aspect would need to be adequately reflected in permitted capital expenditure.

As per Clause 5.3 of National Electricity Policy notified by the Central Government, the Central Transmission Utility (CTU) and State Transmission Utilities (STU) have the key responsibility of network planning and development based on the National Electricity Plan in coordination with all concerned agencies as provided in the Act. The CTU is responsible for the national and regional transmission system planning and development. The STU is responsible for planning and development of the intra-State transmission system. The CTU would need to coordinate with the STUs for achievement of the shared objective of eliminating transmission constraints in a cost effective manner.

Over the past three years, many State Governments have notified State Transmission Utilities as per Section 39 of EA 2003, however, hardly any STU has developed detailed transmission capacity plan and sought approval of the SERC for the same. The SERCs will have to take up exercise of review and approval of 'transmission capacity addition plans' of STU on priority. STUs will have to aggressively implement transmission capacity addition to facilitate open access transactions.

4.4 National Transmission Plan : Gaps to be addressed

In view of the approach laid down by the National Electricity Policy, prior agreement with the beneficiaries would not be a pre-condition for network expansion. CTU/STU should undertake network expansion after identifying the requirements in consonance with the National Electricity Plan and in consultation with stakeholders, and taking up the execution after due regulatory approvals. However, National Electricity Plan for transmission is still under draft stage and yet to be notified by CEA.

With Ultra Mega Power Projects (UMPP) being contemplated seriously, significant quantum of resources would be required to be mobilised by CTU/STUs to evacuate and strengthen existing infrastructure, unless evacuation infrastructure is proposed to be developed by private investors. As development of transmission infrastructure and evacuation arrangement would involve significant gestation period, clarity on the role and responsibility of various agencies involved is desirable. It is preferable that an action plan for concurrent development of associated evacuation infrastructure is also initiated. The transmission schemes for UMPPs under consideration have not been featured under the Draft National Electricity Plan currently circulated by CEA for stakeholder consultation. Suitable modifications to Draft National transmission plan may need to be incorporated.

4.5 Key issues to be addressed

(i) What needs to be done to revive focus on 'transmission capacity addition' at State level by each stakeholder – Regulators, STUs, Private investors?

(ii) What are the key constraints in 'transmission planning' and implementation of transmission schemes in the Indian context?

(iii) Are STUs capable to undertake systematic long term (perspective) planning of their respective transmission systems in close co-ordination with CTU? Have STUs suitably considered planned growth

in intra-regional / inter-regional transmission systems and its operational impact on state transmission planning?

(iv) Apart from load related planning, has adequate attention been given to non-load related planning (robust telecommunication, better visibility of network at SLDC), system stability issues, high fault levels, reactive power planning etc.?

(v) Even after proper planning, will STUs be able to achieve their targets of system expansion keeping in view the critical issues like financial resource constraints, availability of right of ways (for lines) and land (for sub-stations), adequate number of equipment suppliers to meet growing demand of good quality equipment and material, availability of competent erection contractors etc?

(vi) Is tariff based competitive bidding in transmission schemes the only alternative to attract private investment in transmission sector?

5 TRANSMISSION PLANNING - RENEWABLE ENERGY PERSPECTIVE

5.1 Harnessing of Renewable energy and Grid connectivity

Section 86(1)(e) of EA 2003 requires SERCs to promote harnessing of renewable energy sources by specifying minimum percentage for procurement from renewable energy sources and also by providing suitable measures for connectivity to grid for such sources. While some SERCs have notified Regulations under this provision specifying percentage of renewable purchase specification (RPS), most of the SERCs have still not addressed the critical issue of 'grid connectivity' and evacuation infrastructure for renewable energy sources.

With advancement in technology for harnessing of renewable energy sources, the market for larger capacity RE units has emerged and concept of Wind Farm or Biomass Project schemes, etc. has found favour with investors and developers. While primary responsibility to evacuate RE generation is of distribution licensees as most of such sources are connected at distribution voltages. In fact, increased RE generation at distribution level will relieve the stress on transmission network at certain extent. However, some of these renewable energy projects such as wind energy projects are located in remote hilly or coastal locations necessitating creation of adequate evacuation infrastructure to exploit the available potential. None of the STUs have included 'evacuation infrastructure' for RE as a part of their overall transmission plan.

The resource constrained STUs are averse to invest in transmission assets and evacuation infrastructure dedicated to renewable energy sources due to its inherent nature of lower capacity utilisation factors. The problem is aggravated to such an extent that in some States like Tamil Nadu, the existing wind energy generation capacity is under utilised despite availability of wind resource due to

evacuation constraints. The developers and investors would be keen to invest in creation of such infrastructure provided there is regulatory clarity and certainty as regards recovery of costs pertaining to such investments. Appropriate market model may be necessary to address infrastructure requirement of renewable energy sources, however, transmission capacity planning by STU should recognise such evacuation infrastructure requirement in the first place.

5.2 Development of 'Evacuation Infrastructure' for renewables

There is urgent need to evolve innovative structures and schemes to develop and fund the evacuation infrastructure for renewable energy projects. Some such innovative schemes are discussed below.

a) Some Regulatory Commissions such as Maharashtra Electricity Regulatory Commission had directed that 50% of the cost of evacuation infrastructure to be funded by STU and balance 50% to be provided by renewable energy developer to STU as interest free advance to be repaid in five annual instalments from the date of commissioning of the project.

b) Government of Maharashtra has devised one such scheme by way of creation of 'Green Energy Fund' funded by levy of 'Green Cess' at 4 paise per unit on commercial and industrial consumers within State. The proceeds of Green Energy Fund are to be exclusively used for funding the evacuation infrastructure and other infrastructure requirements of renewable energy projects.

5.3 Key issues to be addressed

(i) How should requirements of grid connectivity and evacuation infrastructure for renewable energy sources be addressed under transmission capacity planning?

(ii) What are the alternatives to fund or attract investments for creation of 'evacuation infrastructure' for renewable energy sources?

(iii) What is the role of STU in developing 'evacuation infrastructure' for renewable energy projects?

6 TRANSMISSION PRICING REFORMS

6.1 Transmission Pricing : Need for Reforms

Due to integrated nature of State Electricity Boards as well as Transmission Utilities, pricing for network service alone has not been implemented until recently. Information pertaining to 'connection assets' and 'grid assets' is not available in case of most of the State Transmission Utilities.

Existing transmission pricing framework is based on postage stamp basis, with a region forming one postage stamp. Further, within a Region, the transmission charges for State level transmission system are based on 'postage stamp' derived for that State. Thus, open access transactions across territories of States and regions have become un-economical due to cascading of transmission charges (commonly known as 'pancaking' effect).

The National Electricity Policy and National Tariff Policy notified by Central Government require the CERC to devise a mechanism for transmission pricing which is sensitive to distance, direction and quantum of power flow. While CERC is yet to notify such mechanism, the SERCs are required to introduce a similar mechanism at regional level within two years of introduction by CERC. In most of the States, SERCs have issued maiden Tariff Orders for the STU or are in the process of evaluating the same.

6.2 Key challenges for reforms in Transmission Pricing

As unbundling and industry restructuring exercise has not yet been completed in some States, there is still a lack of clarity as regards intra-State transmission system. Further, systems for accounting of costs related to transmission activities at different voltages and recording of energy transactions at generation to transmission (G-T) interface and transmission to distribution (T-D) interface are still evolving.

Thus, transmission pricing reforms are evolving in many States and would need adequate time for implementation. Regulatory clarity and certainty is essential in respect of transmission pricing so as to ensure economic viability of open access transactions. Until reforms in transmission pricing framework are adopted consistently across various States, the feasibility of long term open access transactions shall remain uncertain.

Further, as per the National Tariff Policy, the ultimate objective of transmission pricing should be to get transmission system users to share the total transmission cost in proportion to their respective utilization of the transmission system. Hence, it is important to clearly identify the 'transmission system users' and establish norms for measurement of "utilisation of transmission system' in the context of the State level transmission system.

Hence, broader issues that need to be addressed are whether transmission costs should be recovered from users on 'causer pays' principle or should these be socialised across 'consumers' in proportion to drawal?

6.3 Establishing cost recovery mechanism for State Transmission System

Currently, transmission assets in most of the States are owned and operated by State Transmission Utility and there is no other transmission service provider in the State. However, pursuant to notification of guidelines for private sector participation in transmission and extent of investment requirement, there are bound to be emergence of other transmission service providers (rather, transmission licensees) in most of the States. In fact, in Maharashtra, apart from MSETCL (STU), there existed other private licensees which own and operate transmission assets due to historical reasons. Under the circumstances, following key principles will have to be strictly adhered to.

- Encouragement for free flow of power over 'intra-State transmission system'

- Enabling framework to facilitate easy access to 'intra-State transmission system' by generators, other licensees and OA consumers.
- Uniformity and parity amongst the consumers eligible for OA (EHV/HV) of different licensees.

Further, it needs to be recognised that 'recovery of ARR of transmission licensee' is distinct from 'determination of transmission tariff' to be applicable to transmission system users (TSUs) for use of transmission system. The challenge lies in terms of addressing following key concerns – (a) Clear demarcation of Intra-State transmission system (b) Composite transmission cost recovery or licensee specific cost recovery (c) Recovery of CTU related charges from State transmission system users (d) treatment of existing open access and renewable energy transactions.

6.4 Key issues to be addressed:

(i) How should 'transmission pricing reforms' be evolved to provide impetus to open access transactions and attract investments in transmission?

(ii) Whether transmission costs should be recovered from users on 'causer pays' principle or should these be socialised across 'consumers' in proportion to drawal?

(iii) How should cost recovery of multiple 'transmission licensees' be linked to transmission tariff to be recovered from Transmission System Users?

(iv) What would be an appropriate transmission pricing framework for integration of non-dispatchable renewables in grid?

(v) What are the challenges of 'capacity building' at STU for implementation of sophisticated transmission pricing mechanisms such as MW-mile method?