Contribution of Renewable Power Towards Eliminating Shortages and Meeting Economic Growth Aspirations

SHAKTI
SUSTAINABLE ENERGY
FOUNDATION

February 2013

Contribution of Renewable Power Towards Eliminating Shortages and Meeting Economic Growth Aspirations

SHAKTI
SUSTAINABLE ENERGY
FOUNDATION

Table of Contents

List of Tables

List of Figures

Executive Summary

As India continues its progress on high economic growth (relative to developed economies), energy security in general and power security in particular remains a key concern for sustaining this economic growth. The issues in domestic fuel availability, poor financial state of distribution utilities and the environmental concerns remain the major challenges to the capacity addition in the power sector. Given the state of domestic fuel market, the volatility in prices of imported fuels and the concerns about climate change, the conventional sources alone may not be enough to offset the growing demand stress. There is a need to stimulate renewable energy (RE) sources and adopt energy efficiency measures to ensure long term energy as well as power security.

This study examines the contribution of renewable energy towards meeting the country's energy security while eliminating power shortages and meeting the economic growth aspirations over the next twenty years i.e. till 2031. This study specifically explores the possibility of adopting RE generation based on its economics vis-à-vis that of other conventional sources. Further, this study also assesses the financial impact of any subsidy or policy push provided to the RE sector with the aim of achieving energy security for the country.

A coalesced qualitative-quantitative approach based on scenario analysis has been adopted to capture the dynamics of Indian power market and address the specific objectives of the study. The approach centres around capturing various attributes of the sector in a quantitative framework under a capacity planning and economic dispatch model followed with the examination of various parameters that can affect the renewable and other conventional generation. The assumptions under these three scenarios are incorporated into India Integrated Planning Model (I-IPM®) for simulating capacity addition forecasts.

Modelling Assumptions

Demand Assumption

18th EPS figures suggest that energy demand is expected to grow at a CAGR of ~7.3% by 2031-32. Growth is expected to be higher in the initial plan period at ~8.2% during the 12th Plan while slowing down to ~6% in the long-term by the end of 15th Plan. The electricity per-capita consumption is expected to double by 2021-22 at ~1600 kWh/per person and more than three times by 2031-32 at ~2800 kWh/per person.

Conventional Energy Resources Assumptions

Natural resources both conventional and un-conventional are present in abundance and spread across the country. Coal is concentrated in Eastern and Central region, hydro is spread over the Northern and North-eastern belt and gas is available on the Eastern and Western coastlines. On the other hand, renewable energy is mainly spread over Western and Southern areas of the country.

Coal is undoubtedly one of the most common sources of energy in the country. Geological coal reserves are estimated at ~287 Billion Tonnes (BT) of which ~40% are proven reserves estimated at ~114 BT. India's total crude oil reserves (proven & indicated) are estimated as ~1201 million metric tonnes while total gas resources – (Prognostic as well as Geological in-place Reserves) are estimated at ~400 Trillion Cubic Feet(TCF) (for 15 basins) and ~114 TCF respectively. India being rich in coal possesses a huge CBM (Coal Bed Methane) potential too. CBM resources have been estimated between 1.4 TCM (Trillion Cubic Meters) and 2.6 TCM, (49.4 TCF to 91.8 TCF) mainly in the eastern region which is also the area rich in coal resources. India is endowed with rich hydro potential which is spread across six major river basins in the country. Hydro potential has been assessed at 84,000 MW at 60% load factor which translates to about 150,000 MW installed capacity. The Uranium resources are limited and estimated at ~141,000 tonnes, including undiscovered resources (prognostic and speculative) but India has huge thorium resource potential which is estimated at ~225,000 tonnes of metal.

Conventional Fuels Supply Assumptions

Though coal remains the key fuel for the country's economic growth, its production has not kept pace with the rising demand. Key challenges in the sector include inadequate exploration activities, lack of signal for market based pricing and the absence of competition and private participation. Apart from above, there are specific mining challenges that include problems of land acquisition, forestry and environmental clearances, local law and order problems and dated production technology with limited availability of local mining expertise and technology. The three possible coal supply scenarios are developed balancing the weights on timelines associated with regulatory reforms and technological improvement. The highest coal production CAGR of 6% is anticipated to be achieved during 2011-2031 in the Grey India Scenario while a lower CAGR of 5% and 4% is projected for the Blue India Scenario and Green India Scenario respectively over the same period on the coal production of 375 MT in 2011.

Given the vision on low carbon economy, gas is likely to play a key role in the power generation. However, the uncertainty on domestic gas availability, regulatory interventions in allocation and pricing and the high prices of LNG are considered to be the key challenges in the sector. The gas demand in India is also governed by other key sectors, like Fertilizers, Sponge iron, City Gas Distribution, Petrochemicals etc, the allocation to each of which is governed by Gas Allocation Policy. Thus three probable scenarios for gas supply only to power sector- under Grey, Blue and Green India are developed. The highest CAGR of 5% is anticipated to be achieved during 2011-2031 in the Green India Scenario while a lower CAGR of 4% and 3% is projected for the Blue India Scenario and Grey India Scenario respectively over the same period on the gas allocation of 67 MMSCMD for the base year 2011.

Conventional Fuel Price Assumptions

Current weighted average blended domestic prices (across subsidiary) to power sector as per current notification are ~1,200 Rs./Tonne (inclusive of royalties, various other charges and taxes). High level reforms push the prices up in the Grey India Scenario. It is assumed that starting 2021 the prices are going to be at 15% discount to imported coal in this scenario. Thus in this scenario the average prices are expected to grow at 5% CAGR till 2031-32. In the Blue India scenario, medium pace of coal sector reforms is assumed. Starting 2026 the prices are assumed to be at 15% discount to imported coal. The average price increase under this scenario is expected grow at 5% CAGR till 2031-32. In both the scenarios, Grey India and Blue India, no increase in carbon tax over the current value of 50 Rs/tonne has been considered. In the Green Scenario, environmental regulations are anticipated to push the Carbon Cess from the current value of 50 Rs./Tonne to ~1330 Rs/Tonne by 2026 and constant thereafter.

Further, starting 2026 the prices are assumed to be at 15% discount to imported coal. The average price increase is expected to grow at 7% CAGR by 2031-32 in Green India Scenario. . International coal prices will remain strong due to global trade. Assumptions on Imported coal prices are based on IEA "*World Energy Outlook (2010)*" projections.

Domestic gas prices vary across the fields and the operators. Notified APM and NELP gas price is ~4.2 $/mmbtu. APM North-East gas price is at 60% discount to APM gas price and is equivalent to ~2.5 $/mmbtu. On the other hand, Non-APM or JV gas price is not controlled by Government and is higher than APM price at ~5.2$/mmbtu. LNG prices considered are linked to Crude Oil Forecast available from "*World Energy Outlook 2010*". Current APM and NELP prices are likely to be revised by 2014. The average domestic price increases from the current value of 4.2 $/MMBTU to 8.5 $/MMBTU by 2031 in the Grey India Scenario while it reaches 16.5 $/MMBTU and 16.9 $/MMBTU in the Blue India and the Green India scenarios respectively.

Conventional Capacity Addition Assumptions

The key challenges that have impacted the conversion of the potential projects into on-ground capacities can be broadly categorized into four heads viz. Regulatory, Technical, Infrastructure and Resources. Based on the assessment of the probability and the criticality of the above constraints along with the ongoing and expected reforms and their impact on capacity additions, three possible scenarios have been developed to identify the maximum conventional capacity addition possible by 2031-32. Under all the three scenarios, it is expected that by the end of 12th Plan and /or by the mid of 13th Plan (2018-19), constraints with respect to capacity additions will ease out specifically in terms of successful implementation of land acquisition bill, well defined state policies on water allocation in place, clarity on stringent environmental clearance norms and the availability of skilled manpower and equipment supply (in terms of BoP, construction etc). Therefore, the expected capacity mix will be driven more by the fuel availability and environmental considerations in addition to other social and political interventions. In the Grey India Scenario, annual total conventional capacity addition of ~12 GW is expected during 12th Plan which will increase to annual additions of ~31 GW by 2031-32. In the Blue India Scenario, annual total conventional capacity addition of ~11 GW is expected during 12th Plan which will increase to annual additions of ~28 GW during 15th Plan. In the Green India Scenario, annual total conventional capacity addition of ~11 GW is expected during 12th Plan which will increase to annual additions of ~24 GW by 2031-32. These bounds represent the maximum capacities that can be added in any particular year; however the actual capacity addition is based on the requirement to meet the demand.

Renewable Energy Resources Assumptions

India has abundant, untapped renewable energy resources present in various forms. Solar is currently an underutilized energy resource and offers huge potential for capacity development. On an average, India has 300 sunny days per year and each day receives an average hourly radiation of 200 MW/ sq km. Unlike other renewable technologies, Solar has infinite potential and its deployment will primarily be driven by the future solar technology developments, the cost-competitiveness and the policy framework. Accordingly, solar potential has not been capped for the purpose of this study.

India has a huge wind potential too with a currently installed capacity of more than 18000 MW. However, there is a wide variation observed between the estimates provided by C-WET vis-à-vis provided by various other agencies. This variation in potential across the studies can be attributed to varied assumptions mainly on the following parameters -Wind Density and Speed, different Hub Heights, better and Efficient Technology, type and size of turbines and land requirement. Comparing the estimates as suggested by the independent studies the wind potential in the country ranges from ~50 GW to 1,500 GW. Thus the achievable potential during the period 2012-31 could be much larger and may not be regarded as a constraint, as also suggested by various recent wind potential estimation studies. After considering all the issues and constraints, in this study, a conservative assumption of 250 GW has been considered.

Small hydropower plants are generally run-of-river plants and have a capacity of less than 25 MW. These are further subdivided into micro (100 kW or less), mini (between 100 kW and 2 MW), and small (between 2 MW and 25 MW). MNRE has estimated the potential for small hydro in India at ~15,386 MW for 5,718 prospective plant sites. Bio-fuels are also an important and traditional source of energy and currently contribute ~32% of the total primary energy needs in the form of woods and cow dung. Total bio-fuel potential of 45,700 MW has been considered as a part of the study.

The three scenarios also differ to account for the different RPO trajectories. Under the Grey India Scenario, the RPOs are expected to increase to 16% by 2031 from the current levels of 6%. Under Green India Scenario which assumes NAPCCC targets, the RPO targets are thus estimated to increase to 25% by 2031. While in Blue India Scenario, the RPO targets are assumed to be the average of that of the Grey scenario and the Green scenario, increasing to 21% by 2031. Further, different energy efficiency targets are set for the three scenarios. Demand reductions of 6% and 12% are anticipated for the Blue and Green Scenario respectively.

Results

Based on the various assumptions related to energy demand, conventional/renewable capacities, fuel supply and prices, RPO trajectories and Energy Efficiency, the projections are made through I-IPM®. The table below shows the summary of results for each of the three scenarios.

Parameters	Grey India	Blue India	Green India
Total Demand (BUs)	4,279	4,279	4,279
RPO targets to be achieved by 2031 (%age)	16%	20%	25%
Total Installed Capacity (MW)	873	928	981
Total Renewable Installed Capacity (MW)	272	375	456
Total Renewable Generation (Bus)	664	858	1022
Year by which Energy Deficit vanishes	2016	2016	2016
Year by which Peak Deficit vanishes	Beyond 2031	2031	2026
Total Coal Consumption (MTs) by 2031	1,650	1,400	1,300

Total Gas Consumption (BCM) by 2031	40	50	16
Cumulative Investment Required by 2031 (000's Crore)	7,485	7,624	7,955

The RPO targets could be met by either of the two ways.

- A policy push, such as a mandatory RPO.
- By financial support, such as feed in tariffs, capital subsidies etc, to renewable to make them competitive with conventional generation.

The RE capacity addition required to meet the RPO targets, under each of the three scenarios, is first achieved through a mandatory RPO mechanism. Practically, only a part of this RE capacity can enter the system on its own without any subsidy support. Such RE capacities will typically have a better cost economics and will set up based on economic rationale.

To quantify the cost of policy push or calculate the financial support required, RPO targets are then met through providing financial support to various renewable capacities. This financial support is provided in the form of an upfront capital subsidy to various renewable capacities, resulting in an increased renewable penetration. The financial support also emulates the cost of pushing renewable in the system if India imposes a mandatory RPO. The estimation of the capital support /subsidy required to set up the RE capacity under each of the three scenarios is done using the following methodology -

- The modeling framework of I-IPM® is used to calculate the financial support requirement.
- For each scenario, an alternate case (referred as Gry II[1] for Grey World, Blu II for Blue World and Grn II for Green World) is developed. In these cases, no RPO constraint is imposed on the system.
- Further a capital support/subsidy to various renewable types is provided to make them cost competitive viz-a-viz conventional generation to meet the RPO targets.
- Among the various ways of providing subsidy, a time-varying upfront discount to the capital cost of various renewable types was provided and thus allowing the model to build only the economically feasible renewable capacity addition in each year of the study period.
- The optimum amount of capital support/subsidy is calculated through an iterative process wherein subsidies are varied across the period as well as the capacity types until the required generation from renewable, as defined by RPO targets, is attained.
- The capital support/subsidy for each renewable type is calculated as the total RE capacity additions in the subsidy case – Grey India, Blue India and Green India, achieved multiplied by the optimum amount of subsidy given per MW (which is calculated as the discount on the capital cost in each year). The optimal subsidy value is derived after performing a number of iterations in I-IPM® until the desired RPO level is achieved.

The table below shows the results of the capital support required in each of the three scenarios against the capacity added per trillion Rupees of support.

From	To	Cumulative Support (INR Trillion) – A	Cumulative RE Capacity added due to Support (GW) - B	GW Capacity added with per trillion of Support –

[1] Also referred to as Grey Conventional BAU case in the report

				(A/B)
GRY II	Grey India	2.96	251	84.8
BLU II	Blue India	4.64	354	76.3
GRN II	Green India	8.5	435	51.2

The Grey India scenario provides the least conducive environment for renewable penetration. On the other hand, in Green India the renewable gets penetrated into the system automatically due to a favourable policy environment. Therefore, to add any incremental capacity in the Green India case, more capital support is required.

Cost-Benefit analysis of an increased renewable penetration has been done for each scenario on the following variables –

- Capacity and Generation Mix
- Coal and Gas Consumption
- Variable Cost of Generation
- CO2 Emissions (MTs) and Grid Intensity
- Investment Requirement

The table below shows the comparison of results under various heads.

	From	To	From	To	From	To
	GRY II	Grey India	BLU II	Blue India	GRN II	Green India
Total Capacity in 2031(GW)	784	873	799	928	832	981
RPO Achieved	10%	16%	14%	20%	15%	25%
Cumulative Coal Consumption till 2031 (MTs)	21,598	20,221	19,300	17,935	17,846	16,774
Cumulative Gas Consumption till 2031 (BCM)	625	622	746	727	723	490
Cumulative CO2 Emissions till 2031 (MTs)	44,068	40,610	39,977	36,654	37,123	33,972
Cumulative Investments required by 2031 (Trillions)	71.83	74.85	66.74	76.24	68.95	7,955

The study has analyzed the results within each scenario and witnessed significant savings in these scenarios if renewable contribution is increased to meet the RPO targets. However, the savings reaped increases significantly in case the capital support is clubbed with conducive environment to promote renewable into the system. The table below shows summary of results of various policy shifts from conventional Grey BAU scenario (GRY II Case) to Blue and Green India.

From	To	Support (INR Trillion) – A	Net Savings (INR Trillions) – C	Net Savings per unit of Support (C/A))
GRY II	Grey India	2.96	6.5	2.20

GRY II	Blue India	4.64	12.8	2.76
GRY II	Green India	8.5	30.5	3.59

As shown above, the savings realized per unit of financial support disbursed is highest when a shift is made from Grey Conventional BAU Scenario (GRY II) to Green India Scenario. It implies that the most economically attractive case would be when the conducive environment for RE is clubbed with the capital support to promote the renewable penetration into system's capacity and generation mix.

Recommendations

- As the generation mix changes, the nature of transmission requirement changes significantly. To absorb more RE capacities, the short-distance intra-state transmission network builds may be required instead of setting up long inter-regional corridors as significant RE resources exist in states with high electricity demand. As such RE generation can be potentially absorbed by the local demand which leads to reduction in the overall transmission investments also.
- With the introduction of more renewable in the country's capacity and generation mix, there would be an increased dependence on the firming capacities like gas based capacities and storage hydro plants. Plans need to be geared up to analyze how these firming capacities can be provided to the renewable resource rich states.
- To benefit from the renewable resources, it is recommended to initiate Integrated Resource Planning (IRP) including balancing and scheduling, grid management and Demand Side Management (DSM) in the resource rich states to match the peak demand and renewable generation profiles and thus enabling increased renewable contribution to meet the peak demand of the country.
- Renewable generation can significantly affect the system's peak capacity requirement. The capacities based on wind or solar or their hybrids, having generation profiles similar to that of demand, can contribute to the peak margin requirement and hence reduce the dependence on the conventional capacities in meeting the system's peak demand.
- Technology-wise RPOs for renewable energy technologies that can provide an explicit growth path to each RE type may be explored. This would ensure optimal use of all renewable resources.
- Within renewable mix, the wind generation requires the maximum capital support in order to make wind cost competitive with other generations. This results mainly due to the increasing capital cost curve for wind technology in India while the solar cost keeps decreasing. Steps need to be taken to maintain the competitiveness of the wind sector.

1. Introduction and Objective of the Study

As India continues its progress on high economic growth (relative to developed economies), energy security in general and power security in particular remains a key concern for sustaining this economic growth. The issues in domestic fuel availability, poor financial state of distribution utilities and the environmental concerns remain the major challenges to the capacity addition in the power sector. Given the state of domestic fuel market, the uncertainty in imported fuels and the concerns about climate change, the conventional sources alone may not be enough to offset the growing demand stress. There is a need to stimulate renewable energy (RE) sources and adopt energy efficiency measures to ensure long term power security.

The study examines the contribution of renewable energy towards country's energy security while eliminating power shortages and meeting the economic growth aspirations of the country over the next twenty years i.e. till 2031. The RE generation can be increased in the country through various measures. These measures can be grouped under three buckets –

- **Policy Push:** A supportive policy framework is required to promote renewable sources of generation. Such policy support is available through the mechanism of Renewable Purchase Obligation (RPO) which mandates the certain percentage of load of a load serving entity (LSE) to be met by renewable sources.
- **Fiscal Incentives and Subsidy Support:** The renewable generation is also supported by the government through various fiscal incentives including the feed in tariffs, generation based incentives, tax and duty waivers, accelerated depreciation and any direct or indirect subsidies.
- **Superior Cost Economics over longer term:** With the cost of Renewable energy based generation expected to go down over time, the RE generation becomes economically competitive vis-à-vis the generation from other conventional sources. If the policy push and fiscal incentives can help to build volumes and encourage innovation, a superior cost economics itself can make the RE generation find its place in the merit order.

This study specifically explores the possibility of adopting RE generation based on its superior economics vis-à-vis that of other conventional sources. Further, the financial impact of any subsidy or policy push provided to the RE sector with the aim of achieving energy security is also studied.

Specifically, the study seeks to

- Estimate the generation capacity additions that can be practically realized by 2031-32 and understand the economic growth limitations on account of power shortages if any
- Understand how demand-supply gap can be bridged by greater off-take from renewable generation leading to energy security of the country
- Quantify the financial benefits of higher renewable energy vis-à-vis a system based on other conventional sources
- Cost- benefit analysis in meeting the defined RPOs i.e. a review of the cost of any policy push or explicit subsidy required to support the RE growth

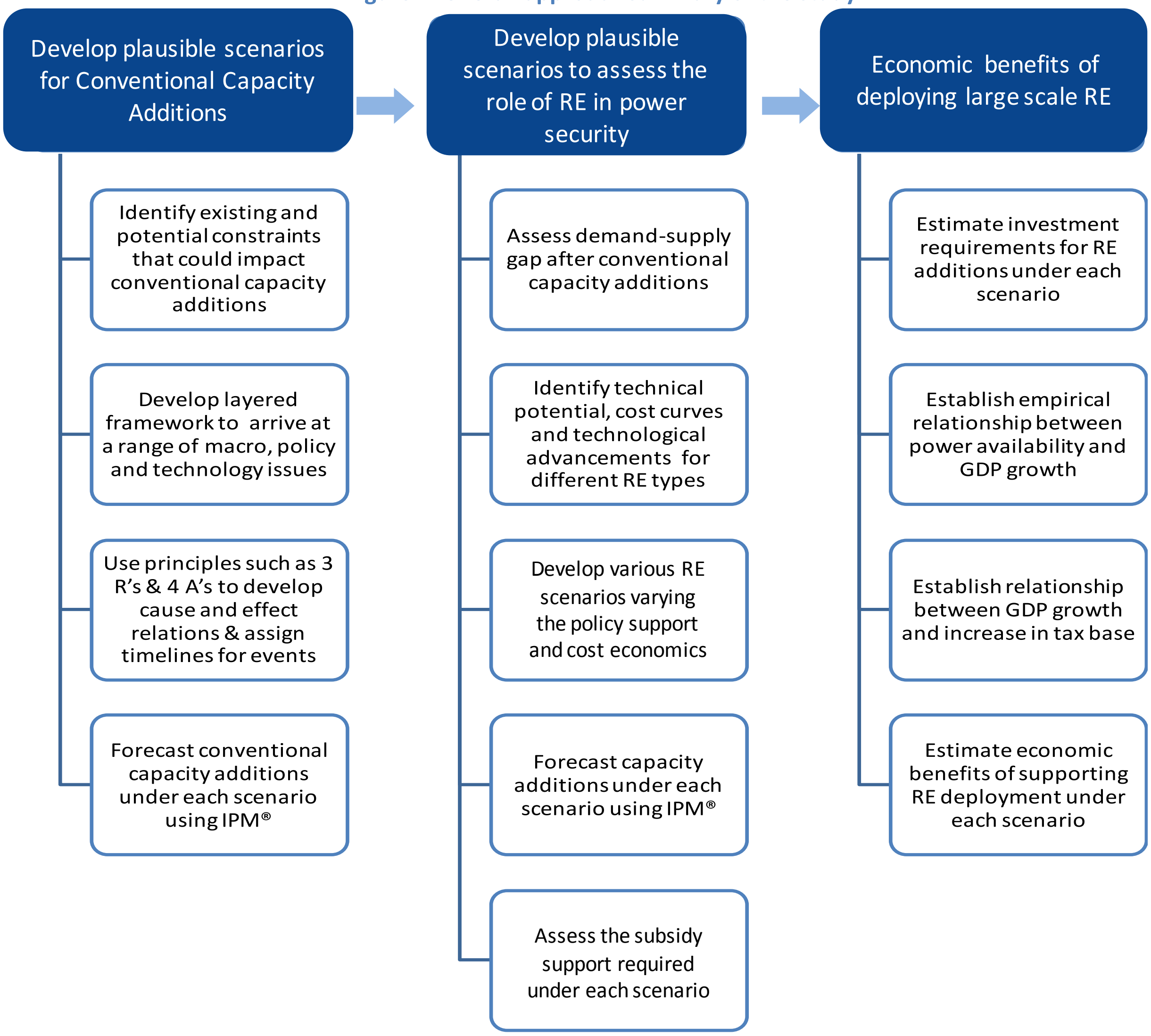
The overall approach to be followed for the study has been covered in section 2. Section 3 frames the three scenarios, which emulate the three policy paths that can be taken by the country in the next twenty years, followed by the modeling framework and assumptions in section 4 and section 5 respectively. Section 5 discusses the electricity demand projections, assumptions on conventional and renewable capacities and energy efficiency plans that the country aspires to achieve in subsequent years. The modeling results for various scenarios have been discussed and analyzed in subsequent chapters starting section 6. The quantification of policy push or financial support requirement is covered in section 7 followed by the cost-benefit analysis of having more renewable share in the country's capacity and generation mix in section 8 with the key conclusions and recommendations in Section 9.

2. Overall Approach

A coalesced qualitative-quantitative approach has been adopted to capture the dynamics of Indian power markets and address the specific objectives of the study. The approach centers around capturing various attributes of the sector in a quantitative framework under an economic dispatch model followed with the examination of various parameters that can affect the Renewable and other conventional generation.

Our overall approach towards the study is shown in the Figure 1 below.

Figure 1: Overall approach summary of the study



The study is broadly divided into three main parts; with each part involving substantial qualitative and quantitative analysis in addition to stakeholder discussions to develop deeper understanding and to achieve consensus on key issues:

1. **Develop Plausible Scenarios for other Conventional Generation Capacity addition**: Under this task, three most plausible and pragmatic scenarios for other conventional generation capacity (based on

coal, gas etc) addition forecasts are developed. The scenarios take stock of key variables arising out of macro issues (both controllable and non-controllable), which can be broadly linked to the policy developments and technological advances. The impact of each variable is incorporated by studying its cause and effect relationship and assigning its affect over a timeline. The capacity additions forecasts are available for each plan period starting 2011 till 2031. Specifically, the forecasted years are the final years of each plan period viz 2016, 2021, 2026 and 2031[2].

2. **Develop Plausible Scenarios for bridging demand supply gap with Renewable Energy**: Under this task, the ability of RE generation to meet the demand-supply gap under each scenario is assessed. Like conventional capacity forecasts, RE capacity forecasts is available for the last year of each plan period starting 2011 through 2031. RE forecasts is developed based on resource potential, technology cost curves and evolving market conditions while taking into account the key challenges and issues facing the RE sector.

3. **Estimate the Economic benefits of deploying large scale Renewable Additions:** Under this task, we estimate the costs of deploying RE generation and its benefits. This is followed by estimating the economic benefits of deploying various RE scenarios as identified in the Task 2. Various costs and benefits are measured in terms of system cost, fuel cost and requirement of subsidy besides others.

   Further we have discussed our scenario based approach followed with a discussion on the modeling framework used for this study, review of various assumptions and analysis of our results.

[2] Each year represents the Calendar year

3. Plausible Scenarios for India's Energy Security

A scenario based approach has been adopted to explore the possible conventional capacity additions and to estimate the expected mix of resources available to meet demand in different planning periods by 2031. The key differentiating variables for each scenario arise from the structural, policy and technological transformations.

Various issues are arranged in a layered structure as shown in table below. It helps to capture the key variables that can potentially influence the capacity additions in the generation sector.

Table 1: Structure for analyzing the variables for developing Scenarios

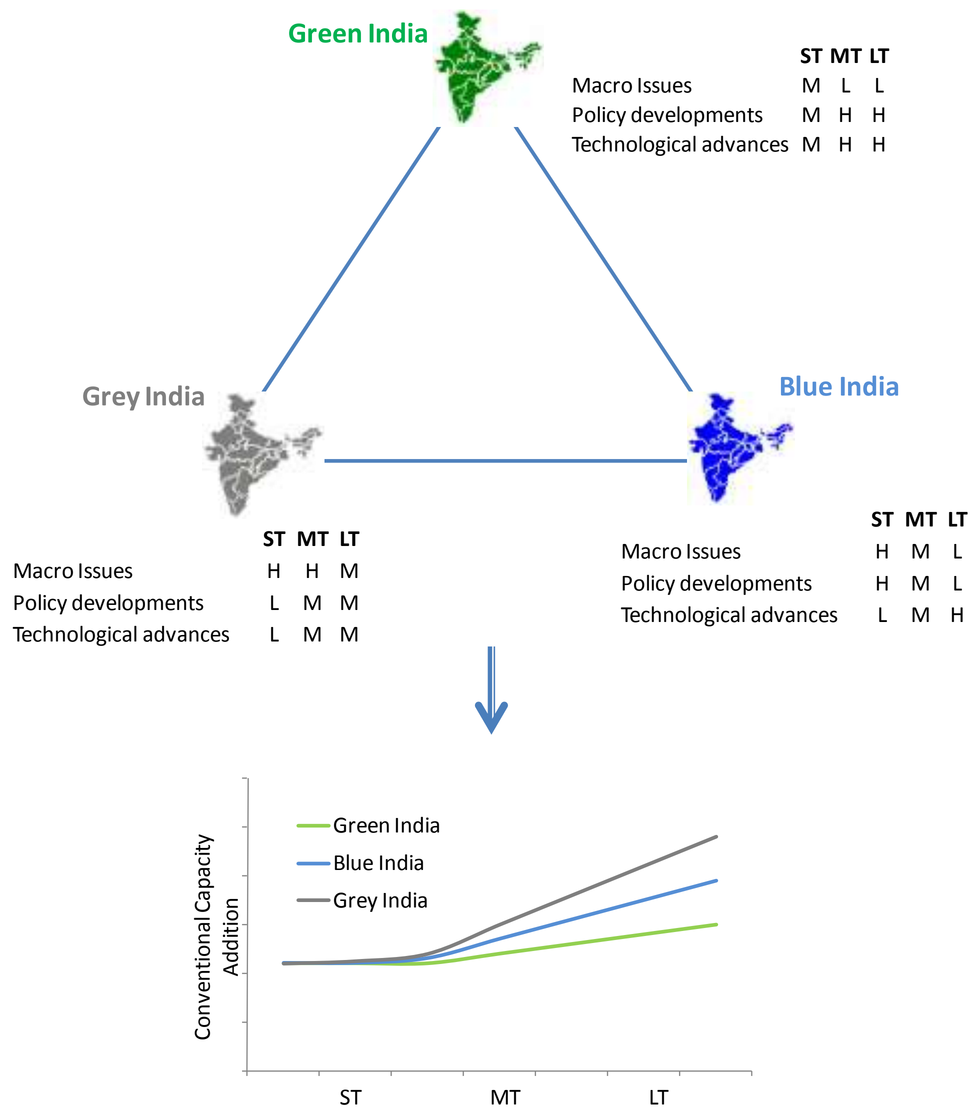
Drivers and Constraints		Associating timelines for events: ST, MT and LT
Macro Issues	a) Economic activity and demand growth b) Domestic resource availability c) Infrastructural Support d) Political and Social Issues e) Financing and Human Resources f) Project Clearance g) Energy Efficiency and DSM measures h) Energy geo-politics	o Criticality of parameter o Cause and effect relationships o Controllable and uncontrollable issues
Policy Developments	a) Electricity Markets a) Coal Markets b) Gas Markets c) Nuclear Expansion d) Land Acquisition e) Energy Efficiency & DSM markets f) Environment	o 3 R's: Level of Reforms, Restructuring and Regulations o 4 A's: Availability, Affordability, Accessibility and Acceptability o Drawing experience from other countries
Technological Advancements	a) Equipment availability and supply b) Clean Coal Technologies c) Efficiency Improvements d) Technology breakthroughs	o R & D life cycle o Pilots o Time to commercialization

The criticality of each variable is analyzed based on historic assessment and review of cause and effect relationships through the application of 3 R's and 4 A's principle. Further, the anticipated stress from each variable is assigned a timeline and a future outlook is developed. For example, the conventional capacity additions forecasts are developed while representing all the variables simultaneously i.e. generation, fuels, transmission and environment etc. The capacity addition targets are also considered to vary across scenarios due to the differential assessment of various constraints.

In order to have a broader perspective on key variables, we had consultations and discussions with multiple stakeholders which included Ministries, Regulators, Central Electricity Authority (CEA), Project Developers, Technology Providers and the Financial Institutions.

Based on above considerations, the following three scenarios are developed under this study with the following broad characteristics.

Figure 2: Three alternate possibilities for conventional capacity addition forecasts



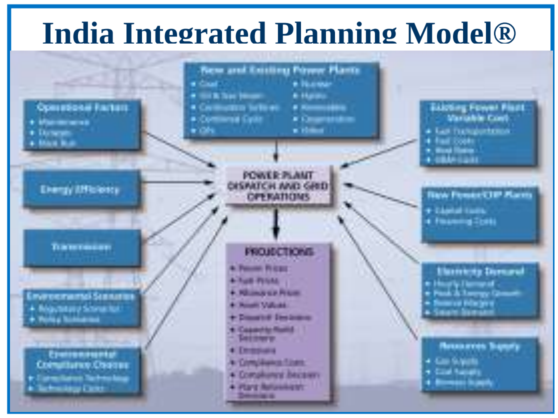
ST: Short Term; MT: Medium Term; LT: Long Term

These three scenarios emulate the three policy paths that can be taken in the next twenty years by the country. Accordingly they capture the affect of various policies as well as the impact of the cost economics of different capacity types. The Grey India scenario represents a strong coal-driven-policy scenario while the Green India scenario emulates a strong clean energy-driven-policy scenario with the Blue India scenario representing the mid-way. The scenarios differ mainly on account of different capacity additions constraints, supply and prices of various fuels, targets for energy efficiency and renewable purchase obligations (RPOs).

The assumptions under these three scenarios are incorporated into India Integrated Planning Model (I-IPM®) for simulating capacity addition forecasts. Under each scenario, the projections for renewable energy capacity deployment have been developed using the I-IPM® model.

4. Modeling Framework

We have used the India-Integrated Planning Model (I-IPM®), the flagship tool of ICF international for the generation planning, as the platform for the quantitative assessment. I-IPM® is a dynamic linear programming model that relies on a bottoms-up data structure to simulate the operations of the India power system through the entire planning horizon. The model fully captures the different states in India separately, along with their interconnections. The model has been specifically adapted to align with the India power market. Key adjustments include endogenous treatment of energy not served and forecasting of the willingness-to-pay-price for fuel shortages. The database captures all of the parameters of the India power system and is up to date. The key inputs of I-IPM® are briefly discussed below.



On the generation side, it includes data on all power plants, their costs, operation parameters and fuel capability. The database also includes all new power plants currently under construction, along with characteristics of new unplanned units. Demand is represented at the state level along with hourly demand profiles for each. Fuel supply is extensively treated with distinct supply regions and transport infrastructure. Transmission capability between states, including proposed new builds is also captured.

Projections from I-IPM® include capacity expansion, imported and domestic fuel use, generation mix, power prices, emissions, transmission flow, transmission congestion and several others. The modelling framework is flexible and can be used for a wide range of scenarios.

The modelling captures all the fundamental elements of the market such as market structure, current and future plants, demand, fuel prices, RPOs etc and provide robust and detailed estimates of short and long term capacity additions and power shortages forecasts for the required geographic and time scope. They help provide a basis for the reasoned assessment of the qualitative analysis of elements such as power shortages, pressure for structural and regulatory change, etc.

<u>Key IPM Input Parameters:</u>

1. **Demand**
   a. **Energy and Peak Demand** - State level data on unrestricted energy demand, peak demand and annual load shapes
   b. **Reserve Margin** - Percent of peak as reserve margin
   c. **Un-served Load** - Interruptible load based on willingness to pay (slightly higher than cost of a private diesel gensets)
2. **Generation**
   a. **Capacity Type** – Various capacity types modeled
      – Coal, Gas (CC & CT), Hydro, Nuclear, Wind, Solar, Diesel/Naptha/Oil and others
   b. **Existing Capacity** - All India existing installed capacity and upcoming plants (excluding islands and captives) are represented by:

– State (location), Online year (for firm builds specify future year for each unit of the plant), Ownership

c. **Operational Parameters**: For each plant unit following characteristics are considered

– Capacity, Scheduled maintenance, Forced Outage Rate, Fuel choices (if multiple fuel), Heat Rate, Seasonal / Monthly availability for renewable capacity, Pumping efficiency for pump storage, Operating Costs, Ramp-up costs, Annual or seasonal escalation in costs (VOM, FOM) or efficiency

d. **Potential** – Future plant types and characteristics are reflected

– States/Region, Type, Operational parameters, Capacity constraints, Capital Costs, Capital Recovery Factor (Hurdle Rate) (if unique to potential plant), Capacity constraints (if unique to the potential plant), Hydro: site specific option

3. **Transmission**

a. **Existing Capacity** - Inter-state exiting and firm transmission capacity modeled with

– import/export capability between states and over time

– Wheeling charges and losses

b. **Potential** – Potential transmission lines represented by

– capital cost, operation, capital recovery factor, etc

4. **Fuels**

a. **Coal** – Represented by both domestic and imported with following characteristics

– Domestic –

- Production profile and linkages by CIL subsidiaries and SCCL for existing and firm plants
- Captive coal blocks along with their production profiles and the allocation of coal from these blocks to various plants
- Commodity price inclusive of royalty, and state sales tax
- Quality of coal by grades

– Imported

- Import capacity (port handling capacity)
- Cost and quality of coal; Price includes CIF and import duties
- Regions/states served by imported coal

b. **Gas** –

– Supply curves by each pipeline (HBJ, KG, CB, South Gujarat, North Gujarat, Rajasthan, Northeast).

– Supply curve includes price and, quantity of gas available to power sector (current & future years)

– Supply also includes firm LNG imports

– Price includes commodity, royalty and pipeline transport cost

c. **Naptha and Oil** – Price of commodity with constraints on availability

d. **Fuel Transportation** –

– Rail links from coal mines to power plants. (Pit head plants explicitly treated)

– Transportation based on distance dependent rail freight charges.

– Existing link of plants to gas pipelines; sales tax by state

5. Modeling Assumptions

The approach takes into account a dynamic and blended qualitative-quantitative framework to characterize the Indian power market and understand the risks for generation capacity addition. Current power market is assessed based on the conceptual framework of:

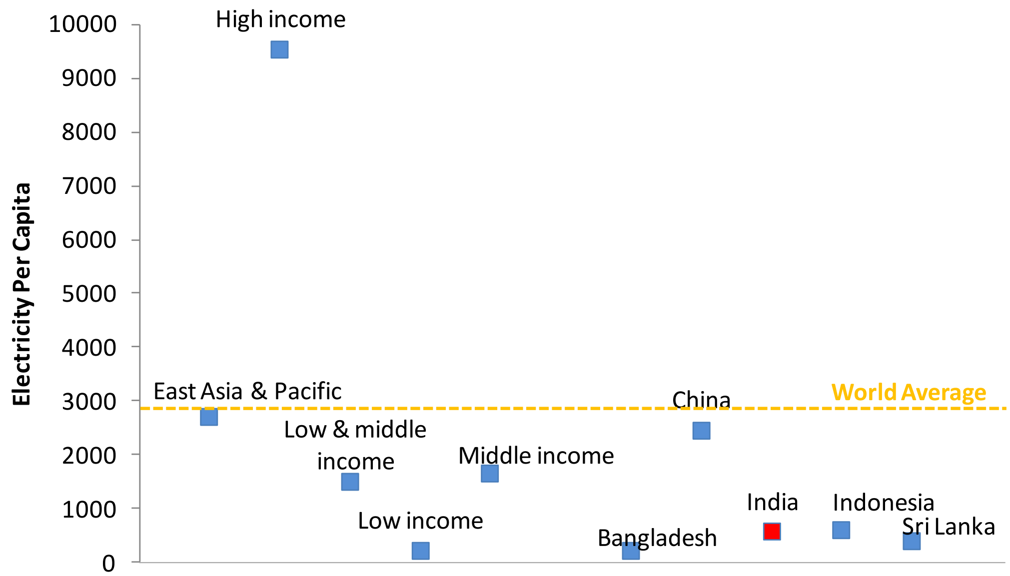
- 3R's – Review of Reforms, Regulations and Restructuring. Based on this framework, we identified the key pressure points and the expected policy initiatives that may likely impact market transformation and future developments.
- 4 A's – Assessment of the Availability and the Accessibility of energy resources. Further investigated the expected technological and market outlook to determine the Affordability and the Acceptability for each resource.

Following section describes in detail the key assumptions for the three modeling scenarios.

5.1 Electricity Demand Projections

India ranks lowest among the middle income countries in terms of per capita electricity consumption which is of approximately 750 kWh (Figure 3) currently.

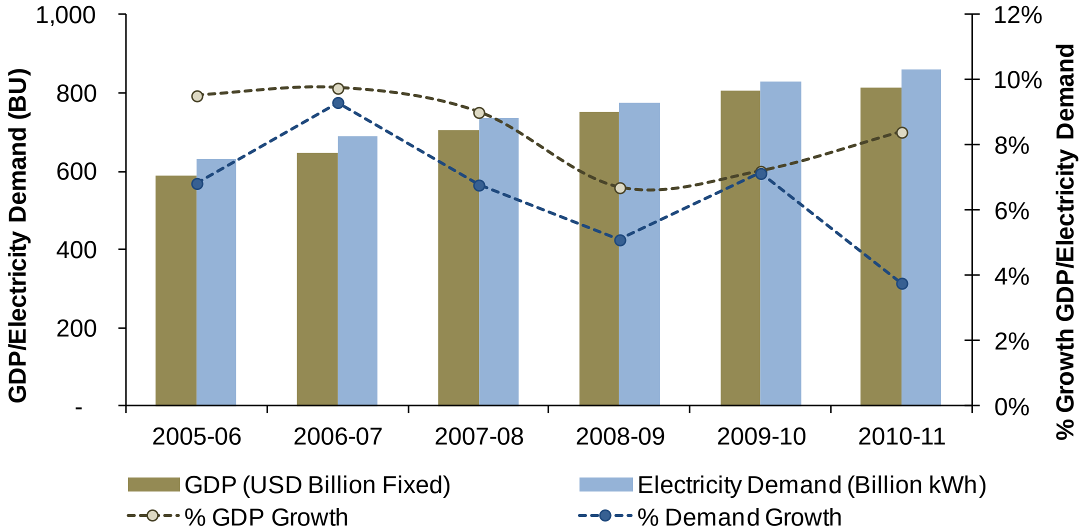
Figure 3: Global Comparison of Electricity Consumption per Capita (kWh Per Person)



Source: World Bank, 2008 stats

The electricity demand and GDP exhibits a strong correlation in the country (Figure 4). However, variety of other interrelated factors such as composition of economy growth, income levels, electricity intensity, electricity costs & availability and supply infrastructure shape the demand for electricity. The electricity demand growth has been robust with an average annual growth rate of 6% over the last decade.

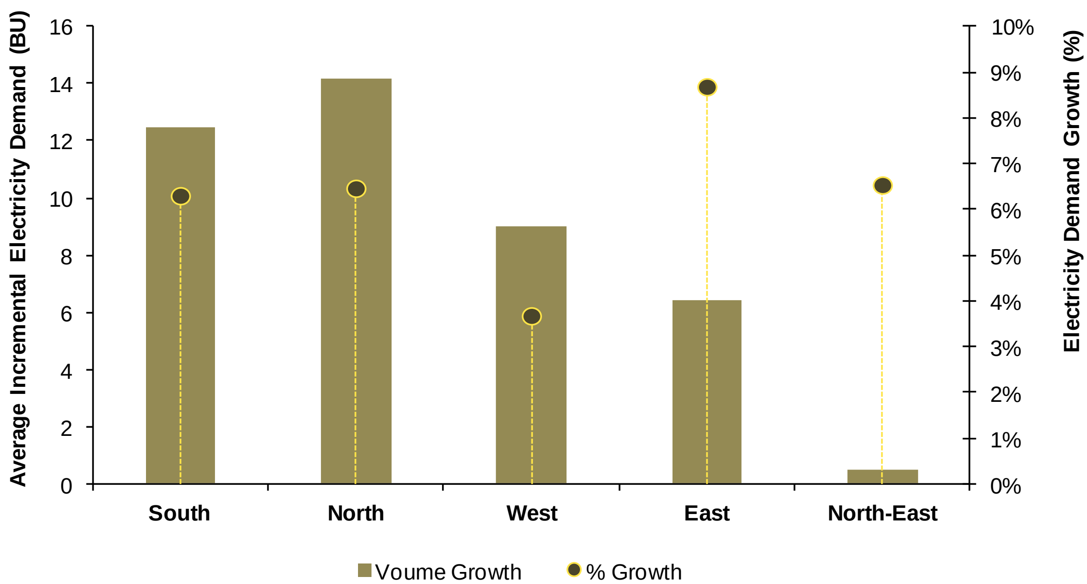
Figure 4: GDP vs Electricity Demand Growth



Despite robust growth, power sector is characterized by supply constraints and resultant high levels of latent demand. The consumer's purchase decisions are influenced by the availability/reliability of supply. Hence the demand exists beyond the simple measured unmet demand where consumers may opt for alternate energy sources, such as captive generation source or household generator. Therefore, even at a low GDP growth rate, the latent demand is likely to ensure high electricity demand growth.

The historical regional growth in demand in terms of volumes and in terms of average growth rates clearly concludes the two important underlying demand drivers' viz. - economic growth and latent demand. The average demand growth rates of West, North and South converges to the national average (~6%) due to higher volume contribution, while East and North-East demand growth rates are higher than national average with minimal volume contribution (Figure 5).

Figure 5: Regional Demand Growth



Source: CEA, 5 years average growth

This illustrates the fact that the demand growth in the West, North and South are much driven by economic growth; whereas the growth in the East and North-East are driven by the latent need with improved access and enhanced reliability. Hence the underlying demand drivers in India are, therefore, a simultaneous combination of economic growth and latent demand.

It is expected that high economic growth, 100 percent electrification of villages, high latent (unmet) demand, states energy policy and low per capita power consumption are likely to ensure that high demand growth rate is maintained going forward. However, the issues around implementation of energy efficiency measures, unwillingness of DISCOMs to supply power and high T&D losses generate an uncertainty around demand to shape in future.

Several agency/bodies provide demand forecasts however, there is no central agency that provides annual forecast on routine basis. The distribution companies do conduct annual demand forecast for their planning purposes but the demand estimates are not very robust and underlying scientific basis for these estimates remains weak. The most reliable and reference forecasts for demand are available from Central Electricity Authority (CEA), that produces state level demand forecasts once every five years and occasionally from planning commission developed for special policy report.

5.1.1 Demand Forecasts by Planning Commission

The Integrated Energy Policy (IEP) released in 2006 provides the national level demand forecast through 2031-32. The projections have been widely accepted as credible estimates and are based on falling elasticity of demand (from 0.95 in 2004-05 to 0.78 in 2031-32) at GDP growth rates of 8% and 9%.

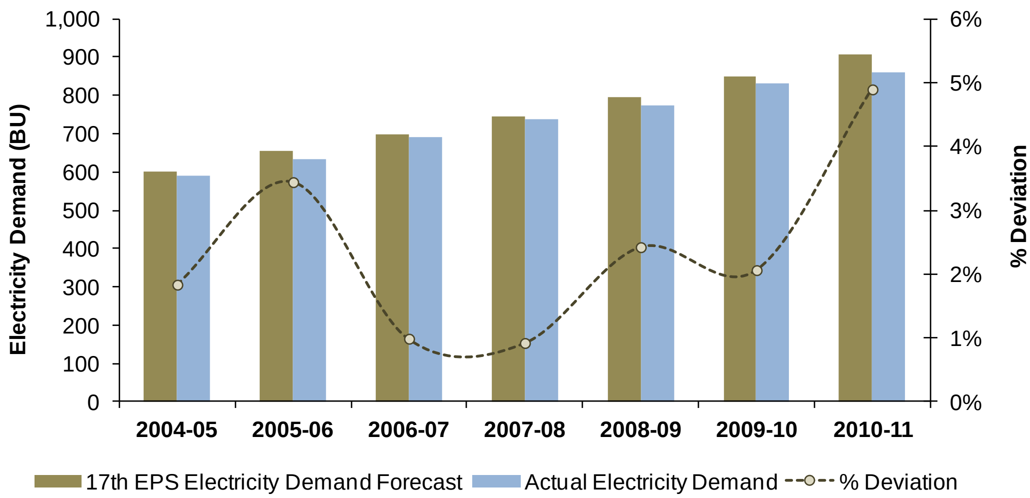
Low Carbon Strategies for Inclusive Growth (LCS) released in 2011 provides national level demand forecasts through 2020. Similar to IEP, the projections are based on elasticity of demand at GDP growth rates of 8% and 9%, however, it has assumed a constant elasticity of 0.95.

5.1.2 Demand Forecasts by Central Electricity Authority (CEA)

Electricity demand forecasts are developed every five years under the Electric Power Survey (EPS). The forecast demand is provided for national, state /union territory, urban/rural and end-consumer category level, utility connected load at the end of each plan period. The forecasts developed take into consideration the development plans and targets of state government, utilities, industries, policies and energy efficiency and T&D reduction programs. The methodology involves partial end-use method and time-series analysis, with inputs on various demand drivers, from the states through periodic electric power surveys and various stakeholder consultations. The forecasts not only serves as an important input for power sector planning, but is also used in planning exercises by all other key sectors - coal, rail, manufacturing, infrastructure and industries etc.

EPS forecast therefore serves as the most credible reference demand projections. However, historically actual demand has always been lower than the 17th EPS forecasts (latest forecast available) and the deviation has been on an average ~2%.

Figure 6: Demand Comparison - CEA Projections vs. Actual



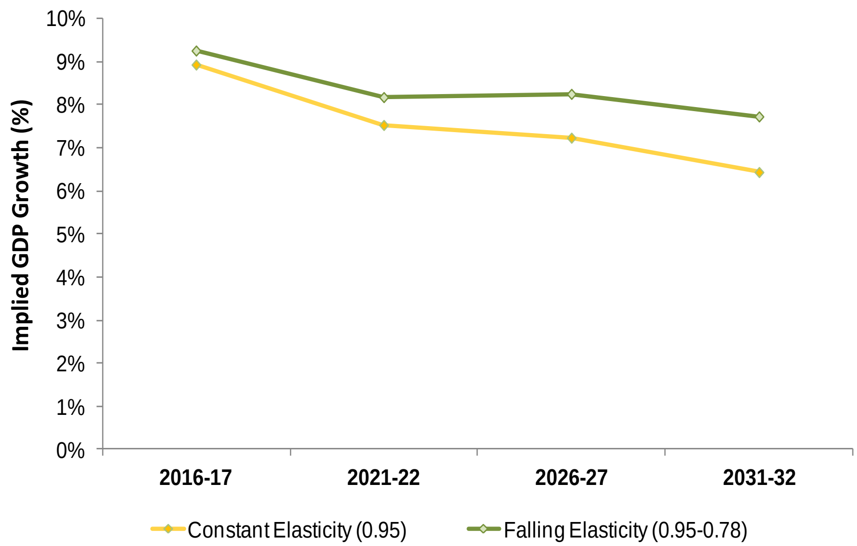
Source: CEA

Currently, CEA is in the process of releasing the 18th EPS projections. The 18th EPS has taken into account the historical deviation factor to adjust the demand and has therefore more realistic estimates. Short-term forecasts are available starting the 12th Plan (2012-13) through the end of 13th Plan (2021-22) while long-term forecasts are extrapolated to 2031-32. Moreover, in addition to utility demand forecasts, the 18th EPS also provides non-utility (i.e. Captive) demand. However, due to lack of availability of detailed data on captive power plants and generation, a broad estimate of captive demand forecasts are projected on all India level.

The 18th EPS figures suggest that energy demand is expected to grow at a CAGR of ~7.3% by 2031-32. Growth is expected to be higher in the initial plan period at ~8.2% during the 12th Plan while slowing down to ~6% in the long-term by the end of 15th Plan. The electricity per-capita consumption is expected to double by 2021-22 at ~1600 kWh/per person and more than three times by 2031-32 at ~2800 kWh/per person.

Implied average GDP assumptions for the 18th EPS demand projections (Figure 7) works out to be ~7.5% at constant elasticity of 0.95, and ~8.5% with falling elasticity (0.90 in 2016-17 to 0.75 in 2031-32).

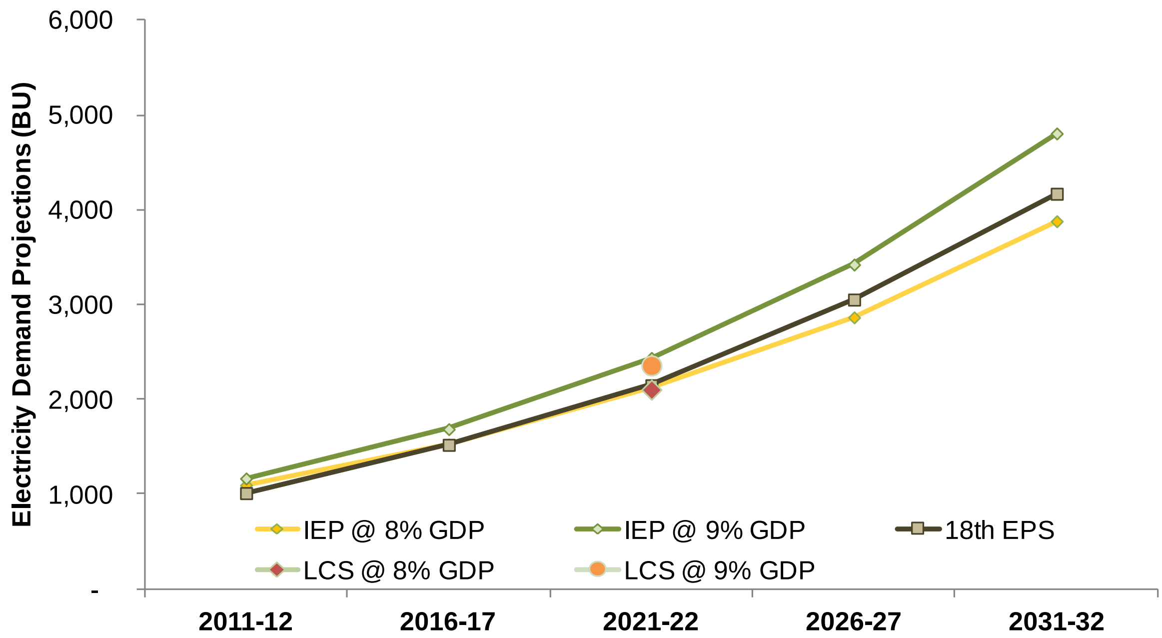
Figure 7: Implied GDP Projections for 18th EPS Demand Projections



Source: ICF Analysis

The 18th EPS demand estimate represents the most realistic business as usual scenario. Moreover, it is widely used across the industry and by the states as one of the most credible reference points. Secondly, it falls in line with the demand projections of 8% GDP growth of IEP and LCS (Figure 8).

Figure 8: Demand Projection Comparison – 18th EPS vs IEP



Source: CEA, Planning Commission

5.1.3 Demand Forecasts under the scenarios

The objective of the study is to estimate the energy mix of the country and analyze the economic impact of large scale renewable deployment; hence a single demand scenario is considered across the three expected futures viz - Grey India, Blue India and Green India that may likely emerge driven primarily by different policy environments leading to supply side uncertainties. Therefore 18th EPS demand forecast[3] are considered as base demand assumptions across the three scenarios. Table 2 provides the demand projections volumes and growth at the end of each plan period through 2031-32.

Table 2: 18th EPS Demand Projections

Scenario Name	End of 11th Plan	Energy Demand by the End of Each Planning Periods (Billion Units)				Energy Demand Growth Rates (%)				CAGR
	2011-12	2016-17	2021-22	2026-27	2031-32	2016-17	2021-22	2026-27	2031-32	2011-2031
Scenario 1 - Grey India	1,027	1,522	2,150	3,054	4,170	8.2%	7.2%	7.3%	6.4%	7.3%
Scenario 2 - Blue India	1,027	1,522	2,150	3,054	4,170	8.2%	7.2%	7.3%	6.4%	7.3%
Scenario 3 - Green India	1,027	1,522	2,150	3,054	4,170	8.2%	7.2%	7.3%	6.4%	7.3%

Source: CEA

Alternately high and/or low demand growth sensitivities can be also considered across the scenarios assuming different GDP growth or demand CAGRs or per capita electricity consumption to capture the uncertainties and other factors beyond economic growth influencing demand; however the focus of the study is primarily capturing the effects of different policy and monetary push, given the same demand,

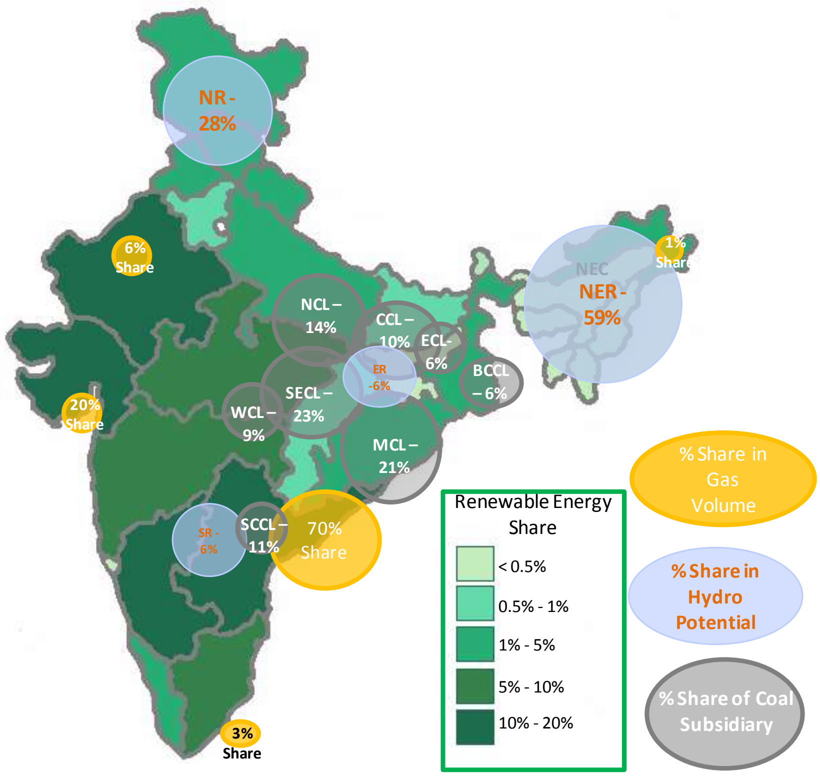
[3] The 18th EPS Demand Projections are not yet available in public domain. Draft numbers have been provided

on the renewable contribution in meeting India's energy security, hence sensitivities around the GDP growth has not been covered as a part of this study.

5.2 Conventional Energy Resources and Capacities Modeling Assumptions

Natural resources both conventional and un-conventional are present in abundance and spread across the country. Coal is concentrated in Eastern and Central region, hydro is spread over the Northern and North-eastern belt and gas is available on the Eastern and Western coastlines. On the other hand, renewable energy is mainly spread over Western and Southern areas of the country. Figure 9 below shows the spread and concentration of various energy resources.

Figure 9: Geographical spread of Conventional and Un-Conventional Energy Resources



Currently, the primary energy consumption is skewed towards fossil fuels. Domestic coal accounts for ~70% of the energy needs while remaining ~30% is met through oil and other fuels. Despite the presence of significant indigenous reserves the growing energy needs are not complemented by a similar growth in exploitation of domestic resources. Hence over the years there has been an increasing dependence on energy imports specifically on oil and recently on coal imports. As such to realize the country's economic growth aspirations, a rapid development of energy markets and deployment of alternate indigenous renewable resources become imperative.

The section below provides the potential of various conventional energy resources in the country.

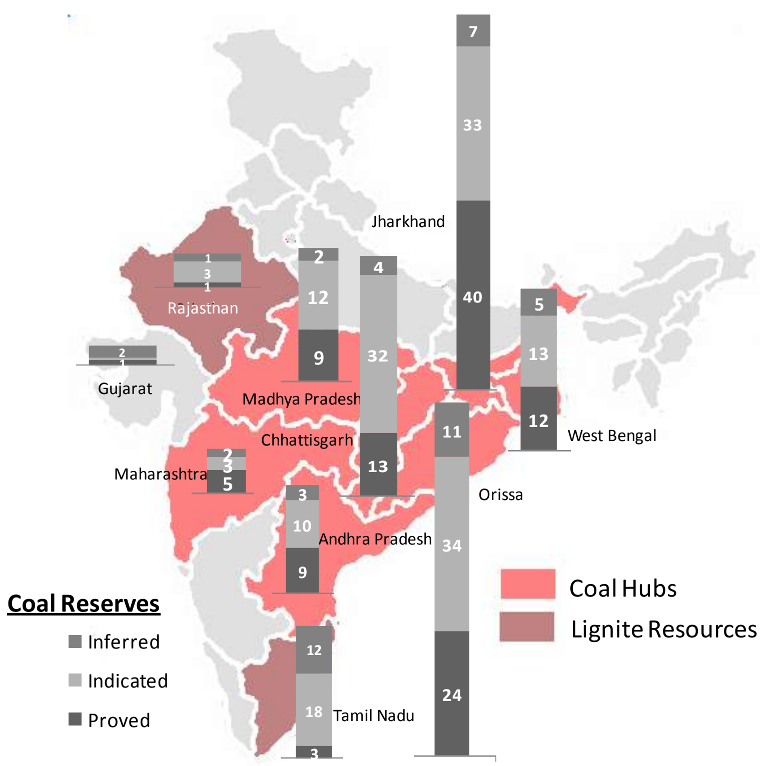
5.2.1 Resource Availability

5.2.1.1 Coal and Lignite

Coal is undoubtedly one of the most common sources of energy in the country. Geological coal reserves are estimated at ~287[4] Billion Tonnes (BT) of which ~40% are proven reserves estimated at ~114 BT However, given the current trends in demand, technology and production levels, the dwindling coal reserves has started raising concerns among planners.

Coal reserves are present in the various forms ranging from hard bituminous coal to soft brown coal (lignite). Coal reserves are mostly found in thick seams at shallow depths. In terms of quality, Indian coal is characterized with high ash content (15-45%) and low calorific value. Reserves are mostly stretched over the eastern belt with nearly 70% concentrated in the states of Jharkhand, Chhattisgarh and Orissa and rest in the states of West Bengal, Madhya Pradesh, Andhra Pradesh and Maharashtra. While the lignite deposits with estimated reserves of ~39.90[5] BT, are spread over the states of Tamil Nadu, Rajasthan, Gujarat, Kerala, Jammu & Kashmir and Union Territory of Puducherry. Figure 10 schematically represents the state-wise coal and lignite reserves.

Figure 10: Location of Coal Resources in the country



Source: Ministry of Coal

---

[4] Based on exploration carried up to the maximum depth of 1200m as of 1.4.2011
[5] As on 31.3.2010

Based on the coal quality, ash content and Useful Heat Value (UHV)[6] , coal is further categorized into coking coal (hard coking coal, semi coking coal) and steaming coal (non-coking coal). Coking coal is categorized into Steel (for steel making), Washery (clean coal beneficiated for steel making) and Semi-Coking (for coke) based on different ash and moisture content, while steaming coal is categorized in various grades from A to G based on UHV. Table 4 provides the band of calorific values for different grades of non-coking coal.

Table 3: Grades of Non-Coking Coal

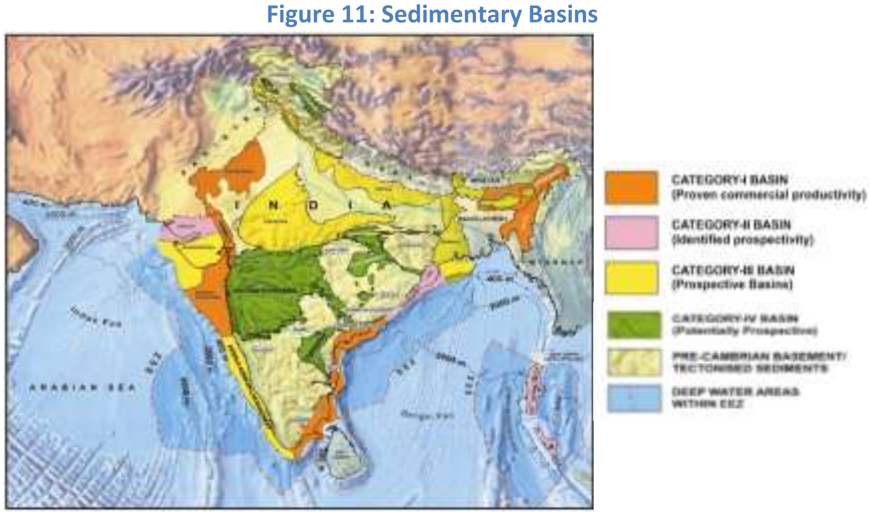
Grade	Useful Heat Value (UHV) (Kcal/Kg) UHV= 8900-138(A+M)	Corresponding Ash% + Moisture % at (60% RH & 40^{O} C)	Gross Calorific Value GCV (Kcal/ Kg) (at 5% moisture level)
A	> 6200	Not exceeding 19.5	> 6454
B	> 5600 & < 6200	19.6 to 23.8	> 6049 & < 6454
C	> 4940 & < 5600	23.9 to 28.6	> 5597 & < 6049
D	> 4200 & < 4940	28.7 to 34.0	> 5089 & < 5597
E	> 3360 & < 4200	34.1 to 40.0	> 4324 & < 5089
F	> 2400 & < 3360	40.1 to 47.0	> 3865 & < 4324
G	> 1300 & < 2400	47.1 to 55.0	> 3113 & < 3865

Source: Ministry of Coal

5.2.1.2 Natural Gas and Crude Oil

India has multitude of proven and prospective petroliferous basins from on-land, offshore to deepwater with an areal extent of 1.39, 0.4 and 1.35 million sq. km. respectively. So far, Directorate General of Hydrocarbons (DGH) has identified 26 basins in the total sedimentary area of 3.14 million sq. km. Based on the present known degree of prospectivity, basins have been divided into four categories – Category I, Category II, Category III and Category IV where in Category 1 has the highest degree of prospectivity. However, with the results of further exploration, the basins falling under higher prospectivity is further expected to increase.

Figure 11: Sedimentary Basins



Source: DGH

[6] UHV are calculated from ash content (A%) and moisture (M%) using the formula UHV = 8,900 - 138 x (A+M)

In addition to the above four categories, deep-water areas, beyond 200 m isobath and up to Exclusive Economic Zone (EEZ) form a separate category. The deepwater basins in India form 43 percent of the total sedimentary area and are considered to have higher prospectivity than onshore and offshore basins. This is due to the reason that most of the promising shallow water areas have already been explored. As a result, majority of the foreseeable production growth is expected from the deep water basins located both in the East and West coast as well as in Andaman Sea.

India's total crude oil reserves (proven & indicated) are estimated as ~1201 million metric tonnes[7] while total gas resources – (Prognostic as well as GIIP[8]) are estimated at ~400 TCF (for 15 basins) and ~114 TCF respectively. Whereas the current crude oil production was 33.69 million metric tones and gross Gas production was ~47.5 BCM[9] during 2009-10.

Most of the crude oil and gas reserves are spread across the western coast (in Mumbai High), on the offshore in Bay of Bengal (in the KG basin halfway between Chennai and Calcutta on the east coast), in the state of Rajasthan and in the northeastern parts of the country. As of today, only 20 percent of total 3.14 million sq. km. has been extensively explored and nearly 70 percent of the prognostic gas resources are not established. One of the common features of the Indian sedimentary basins is the low drilling density. East coast is particularly under-explored with an exploration density of 0.15 wells/1000 km being among the lowest in the world.

5.2.1.3 Unconventional Gas

Apart from the conventional gas resources, other unconventional alternate gas resources – Coal Bed Methane (CBM), Underground Coal Gasification (UCG), Gas Hydrates and Shale Gas are present in various forms and degrees. The high potential of these resources can be a game changer in the long-term. However, some of these are at very nascent stages of development and various initiatives have been taken/under progress to recognize the potential and commercial viability of the resources.

Coal Bed Methane (CBM): Coal Bed Methane is a natural gas (Methane) that is absorbed in coal and lignite seams. India being rich in coal possesses huge potential in this regard. CBM resources have been estimated between 1.4 tcm and 2.6 tcm[10], (49.4 TCF to 91.8 TCF) mainly in the eastern region which is also the area rich in coal resources. Table 4 details the state-wise CBM resource potential.

Table 4: State-Wise Estimated CBM Resource (TCF)

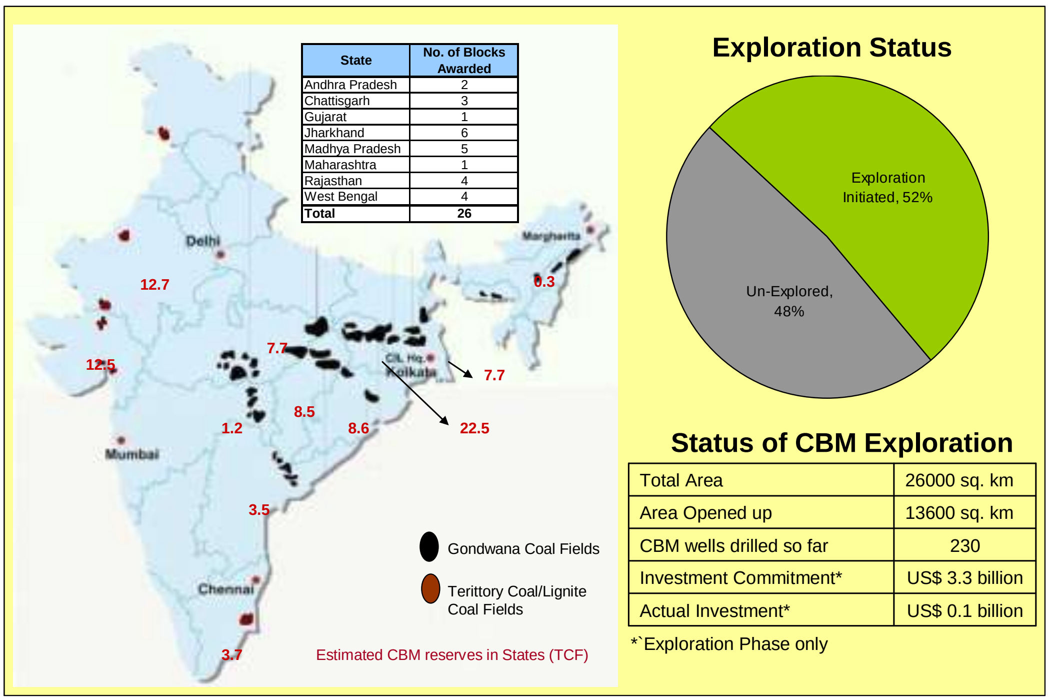
State	Estimated CBM Resources
Andhra Pradesh	3.5
Chhattisgarh	8.5
Gujarat	12.4
Jharkhand	25.5
Madhya Pradesh	7.7
Maharashtra	1.2
North East	0.3
Orissa	8.6

[7] MoPNG, as on 1.4.2010
[8] Geological in-place Reserves are discovered hydrocarbon volumes based on actual exploration activities carried out
[9] Source: MoPNG - Petstat.
[10] Source: MoPNG, estimated as on April 2008

Rajasthan	12.7
Tamil Nadu	3.7
West Bengal	7.7
Total	**91.8**

CBM policy was announced in 1997 to exploit this potential. A total of 13,600 sq km of area has been opened for CBM since 2001 under four rounds of bidding. So far, 32 contracts have been signed in 4 rounds of which 3 contracts are signed on nomination basis for exploration & production. First commercial production of CBM commenced in 2007 from Raniganj block in West Bengal and is ~72,000 cubic meters per day. As of now, CBM leads the pack in terms of achieving real possibility of production out of all Unconventional Gas Resources.

Figure 12: CBM resources in India and Exploration Status



Underground Coal Gasification (UCG): Underground coal gasification is simply the direct gasification of coal seam. It is achieved by injecting oxidants, gasifying the coal and bringing the product gas to surface. ONGC and GAIL have been exploring the possibility of exploiting coal gas by UCG technology. ONGC has signed a draft agreement with Coal India Ltd (CIL) for its UCG project.

Gas Hydrates: Gas hydrates are methane molecules trapped in ice and are found in the deep sea. Seismic data estimates 1894 TCM[11] of gas hydrate reserves in the country. National Gas Hydrate Programme (NGHP) has been launched to harness this potential. A large number of seismic data covering offshore areas has been studied including special processing of large data for identification of gas hydrates signatures. Few discoveries have been already made in KG-Basin, Andaman Islands and Mahanadi Basin.

[11] Source: DGH

Please note that at present, there is no commercial production of gas hydrates in any part of the world and the technology is only at R&D stage.

Shale Gas: Oil Shales are usually fine-grained sedimentary rocks containing relatively large amounts of organic matter from which significant quantities of shale oil and combustible gas can be extracted by destructive distillation. Shale occurs interbedded with the coal. The Damodar basin in West Bengal, Cambay basin in Gujarat, Krishna-Godavari basin in Andhra Pradesh and Cauvery basin in Tamil Nadu demonstrate favorable characteristics for shale, however, the potential reserves are yet to be estimated. In November 2010, the US and the Indian governments announced that the US Geological Survey will help India to assess its shale gas reserves. India is in the process of formulating shale gas exploration policy and is expected to auction acreages for shale gas exploration in 2012-2013.

To sum up, Table 5 below summarizes the total gas resource in the country.

Table 5: Total Gas Resource in India (TCF)

Type	Prognostic Resources	GIIP Reserves
Conventional Gas Resources	400 (15 Basins out of 26 Basins)	114
CBM Gas Resources	91 (32 Blocks)	6
Gas Hydrate	66,900	Nil
Shale	Under Evaluation	Under Evaluation

5.2.1.4 Hydro

India is endowed with rich hydro potential which is spread across six major river basins in the country (Table 6). Hydro potential has been assessed at 84,000 MW at 60% load factor which translates to about 150,000 MW installed capacity. Of this, approximately 25% of the capacity has been tapped so far.

Table 6: Basin-wise Hydro Potential in India

River Basins	Potential at 60% Load Factor (MW)	Probable Capacity (MW)
Indus Basin	19,988	33,832
Brahmaputra Basin	34,920	66,065
Ganga Basin	10,715	20,710
Central India Basin	2,740	4,152
West Flowing Rivers of Southern India	6,149	9,430
East Flowing Rivers of Southern India	9,532	14,511
Total	**84,044**	**1,48,700**

Source: Central Electricity Authority (CEA)

Further, fifty-six potential pumped storage sites with 94,000 MW installed capacity have also been identified.

In the north-eastern states (mainly Brahmaputra Basin), close to 90% of the potential is still untapped. Geological, technical, financial and managerial issues constrain the development of hydro resources. Table 7 below highlights regional split of untapped hydro potential.

Table 7: Region-Wise Untapped Hydro Potential (%)

	Northern Region	Western Region	Southern Region	Eastern Region	North-Eastern Region
Capacity Developed	27.7%	68.28%	58.95%	27.23%	1.91%

Capacity Under Construction	13.42%	4.92%	3.59%	22.08%	8.03%
Untapped Potential	58.87%	26.8%	37.46%	50.7%	90.06%

Source: CEA

5.2.1.5 Uranium

The Uranium resources are limited and estimated at ~141,000 tonnes, including undiscovered resources (prognostic and speculative). The discovered uranium resource is estimated at ~73,000 tonnes which is comprised of ~49,000 tonnes of reasonably assured resource and ~24,000 tonnes of inferred additional resource.

On the other hand, India has huge thorium resource potential which is estimated at ~225,000 tonnes of metal. But to exploit Thorium resources, the advanced nuclear technologies are required which are more complex than the uranium-fuelled Light Water Reactor (LWR) technology used in other parts of the world.

5.2.2 Fuel Outlook

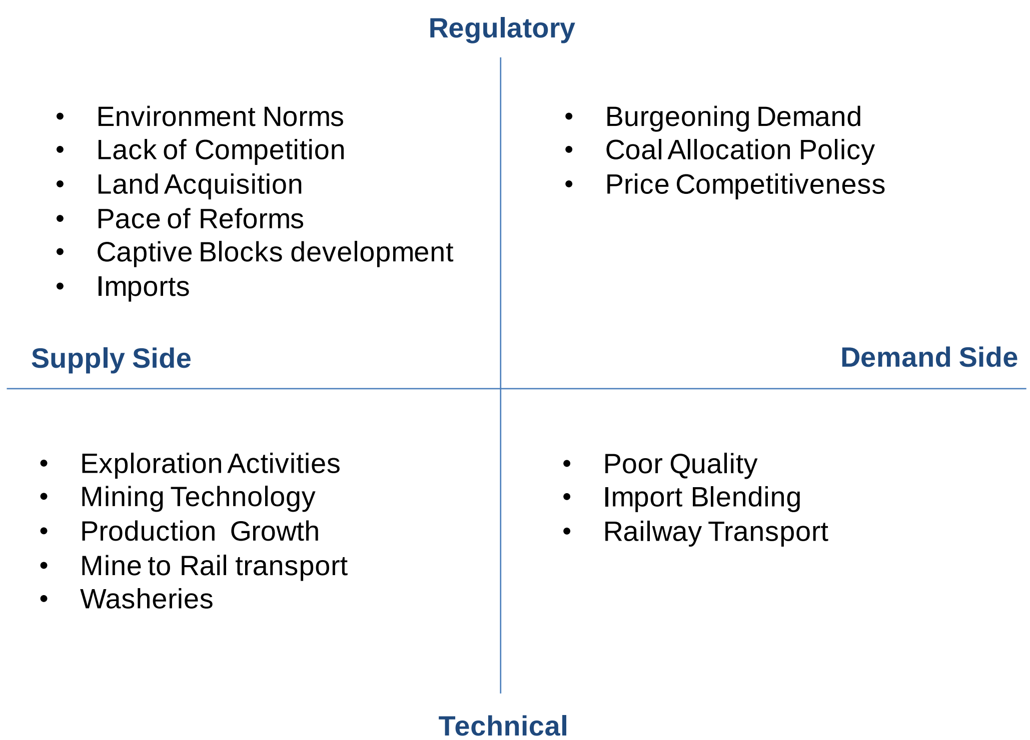
Availability and price of coal and gas are very critical input for the thermal projects. In the following section discusses in detail the current status of the sector, key pressure points and various initiatives taken/identified by the government to reform the fuel sector. Based on the review of current issues and expected constraints, the fuel supply and price outlook are developed under three scenarios.

5.2.2.1 Coal Supply

Coal is the mainstay fuel and contributes ~56 % in the total energy mix. It's dominance in the power sector is even more prominent as ~80% of the domestic coal produced is consumed by power sector (Utility + Non Utility). The dominance of coal in power sector and in the broader energy mix cannot be ignored. Coal remains the key fuel for the country's economic growth.

However, domestic coal supplies have not kept pace with the rising demand. The condition is alarming as the impact of coal deficit is clearly visible in terms of loss of generation and slowing down of capacity additions. Key challenges in the sector include inadequate exploration activities, lack of signal for market based pricing and the absence of competition and private participation. Apart from above, there are specific mining challenges that include problems of land acquisition, forestry and environmental clearances, local law and order problems and dated production technology with limited availability of local mining expertise and technology. Figure 13 highlights the existing regulatory, technical, demand and supply side constraints.

Figure 13: Demand and Supply Side Coal Market Constraints



5.2.2.1.1 Market Structure

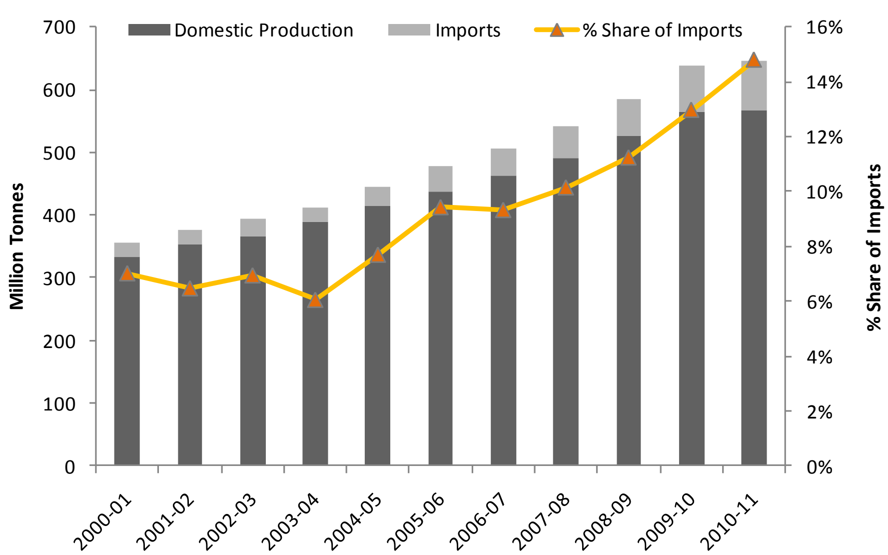
Coal industry is characterized as a highly monopolistic and government controlled with sector reforms standing at the crossroads. The market is dominated by state-controlled companies - Coal India Limited (CIL) with its seven mining subsidiaries and Singareni Collieries Coal Limited (SCCL), they together account for approximately 94% of the total coal production. Private sector companies account for the remaining part and are allowed to mine only for captive use in Power, Iron & Steel and Cement Industry.

The Government of India, through the Ministry of Coal effectively determines all matters relating to the production, supply, distribution and sale price. There have been attempts to introduce reforms and policy initiatives to liberalize the domestic coal market however the pace of reforms has been slow till date. The response to the various reform initiatives - such as sale of coal through e-auctions, outsourcing of exploration activities, third party sale for excess coal at government controlled prices and award of blocks to improve private participation - has not been encouraging and has lacked in liberalizing the coal markets.

Coal pricing in India is characterized by few unique features. Firstly, coal is sold at a heavy discount of 57% to grade-adjusted global prices. Historically there have been only five hikes in coal prices since 2002 with the average sale price increasing by ~5% CAGR over 2002-2011. Secondly, the prices are determined based on UHV (Useful Heat Value) pricing mechanism instead of GCV (Gross Calorific Value) based method which is commonly used globally. Moreover, though the coal prices have been deregulated in year 2000, they still remain under the control of Ministry of Coal (MoC) and CIL.

The coal production for the year 2010-11 has been ~480 MT (CIL+SCCL). The production has grown at ~4% CAGR over the last 5 years with almost no growth during 2010-11 (Figure 14). The coal production is mainly driven by the existing mines and the ongoing projects with a minimum contribution from new projects.

Figure 14: Domestic Coal Production and % Share of Imports



5.2.2.1.2 Technology

There is a significant uncertainty in the amount of geological reserves available in the country and the corresponding lifespan of the coal as a fuel. Better energy planning, technical support and geological surveys are extremely important for reducing the uncertainties about the coal reserves. Moreover, historically the policies have always focused on promoting the surface mining which was intended to meet the immediate coal requirements. This has definitely led to higher production rate but has severely impacted the sustainability and quality of coal produced. Currently, ~86% of the Indian coal production is dominated by open cast mines, while the remaining 14% percent is yielded through underground mines. Consequently, huge investment and technical advancement are required to enhance the domestic coal production and provide a sustainable solution to coal shortages.

5.2.2.1.3 Environment

Stringent norms on environment and forest clearances for coal mining and the imposition of carbon cess on coal production, underline the country's environment concern. Already the fourth largest emitter of Green House Gas (GHG) at 1.5 billion tonnes, India is in an alarming situation regarding the climate change. Over 60% of the emissions are contributed by coal mining and fossil fuel power generation. The pace of current emissions growth is likely to continue. Under the vision of low carbon strategies for inclusive growth, coal remains highly vulnerable to climate change. Therefore a new dimension on future environment policy framework has also been woven in the energy security concerns of India.

5.2.2.1.4 Policy and Regulatory Uncertainty

Policy and regulatory poses a big challenge in anticipating the coal supply in future. Although Captive coal blocks were allocated during past few years for increasing the production, their performance has not inspired much confidence. There has been a sharp increase in captive coal block awards over the last 4 years, raising expectations of sharp increases in coal production. But the recent Comptroller and Auditor General of India (CAG) report on coal block allocation has raised doubts over this volume of coal production. The allocation of coal blocks during the period 2004-09 got under the scrutiny of the Comptroller and Auditor General of India (CAG) office and as per their report, the Government of India allocated coal blocks in an inefficient manner. As per the report, the Government had the authority to allocate coal blocks by a process of competitive bidding, but chose not to and as a result both public sector enterprises (PSEs) and private firms paid less than they should have otherwise. The CAG estimated that the "windfall gain" to the allocatees was Rs 1.86 lakh crore. At the end of June 2012, coal ministry decided to form an Inter-Ministerial Group (IMG), to decide on either de-allocation or forfeiting the Bank Guarantees (BG) of the companies that did not develop allotted coal blocks. As of 26 September 2012, the IMG reviewed 31 coal blocks, out of these, it has recommended de-allocation of 13 coal blocks and encashment of bank guarantees of 14 allottees. This would have an adverse impact as any power projects which are dependent on captive coal blocks from the allocation, are likely to get delayed without assured supply of coal. Thus, it would halt projects under development/construction, and turn thousands of crores of bank loans into non-performing assets.

5.2.2.1.5 Coal Supply Projections

Given the current scenario, the heart of the challenge remains to streamline the sector and bring new reform initiatives to enhance the current production levels and meet the increasing demand. However, several of the following reforms/initiatives are being discussed at various forums:

- Setting up a Coal Regulator - Ensure transparency and competition
- Auctioning of Coal blocks through competitive bidding – Encourage competition and private participation
- Relaxation of Environment regulations (Go & No-Go Area) – Enhance exploration and production
- Rationalization of coal linkages – Enhance the efficiency
- GCV based pricing – Better price signals
- Setting of Washeries – Better quality
- Commercial mining – Encourage competition
- Technological Initiatives

To develop a long-term view on coal availability, the timelines of the events/reforms with lag time have been drawn to assess the future production plans. To capture the level of uncertainty around each of the above reform initiatives and likely pace of progress, three possible coal supply and price scenarios are designed with expected probabilities of growth in production. The three possible coal supply scenarios are developed balancing the weights on timelines associated with regulatory reforms and technological improvement. (Table 8-10, Figure 15).

These scenarios are defined as Grey India, Blue India and Green India as discussed below.

Scenario 1 - Grey India: *Coal centric policy with fast pace implementation*

In this scenario, it is assumed that all key reforms will be in place by the end of 12th Plan (2016-17). Markets will be more competitive and accelerated coal production will be achieved through a number of reforms including introduction of commercial mining and support for coal auctioning. A coal production CAGR of 6% will be achieved during 2011-2031 with expected CAGR of 5% and 14% by CIL and Captives respectively (Table 8).

Table 8: Grey India - Coal Supply Projections to Power

Coal Source	End of 11th Plan	Coal Supply to Power Sector (MT)				Growth Rates (%)				CAGR (%)
	2011-12	2016-17	2021-22	2026-27	2031-32	2016-17	2021-22	2026-27	2031-32	
CIL	350	480	661	775	880	7%	7%	3%	3%	5%
Captive	25	70	196	273	370	23%	23%	7%	6%	14%
Total	**375**	**550**	**857**	**1,048**	**1,249**	**8%**	**9%**	**4%**	**4%**	**6%**

Scenario 2 – Blue India: *Business As Usual*

In this scenario, underlying assumptions on coal reforms are expected to continue at medium to low pace. CIL is expected to meet its targets and will maintain the current average production growth of 4%. The coal production expected to be mainly driven by captive coal blocks growing at CAGR of 13%.

Table 9: Blue India - Coal Supply Projections to Power

Coal Source	End of 11th Plan	Coal Supply to Power Sector (MT)	Growth Rates (%)	CAGR (%)

	2011-12	2016-17	2021-22	2026-27	2031-32	2016-17	2021-22	2026-27	2031-32	
CIL	350	466	601	674	733	6%	5%	2%	2%	4%
Captive	25	68	172	218	280	22%	20%	5%	5%	13%
Total	**375**	**534**	**773**	**892**	**1,013**	**7%**	**8%**	**3%**	**3%**	**5%**

Scenario 3 – Green India: *Climate Change high on Agenda*

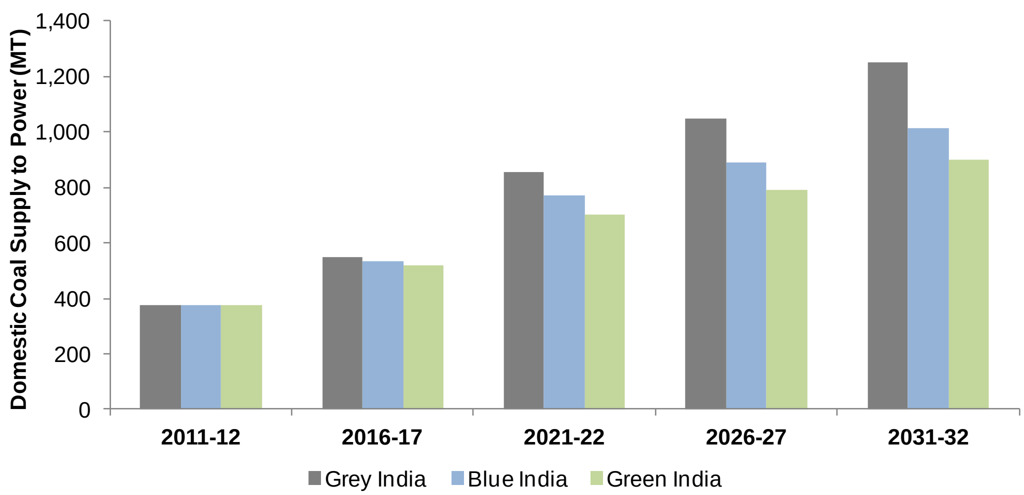
In this scenario, the coal reforms will continue at the current growth, without any further policy push. However, the low carbon strategy and climate change will be the key focus areas of all the policy initiatives. This results in more stringent environmental constraints in terms of forest clearances, land acquisition, lack of investors' confidence in coal markets and slow progress in captive block development. A coal production CAGR of 4% will be achieved during 2011-2031. CIL expected to miss the targets and grows at a CAGR of 3% during 2011-2031.

Table 10: Green India - Coal Supply Projections to Power

Coal Source	End of 11th Plan	Coal Supply to Power Sector (MT)				Growth Rates (%)				CAGR (%)
	2011-12	2016-17	2021-22	2026-27	2031-32	2016-17	2021-22	2026-27	2031-32	
CIL	350	452	553	606	660	5%	4%	2%	2%	3%
Captive	25	64	151	186	238	21%	19%	4%	5%	12%
Total	**375**	**517**	**704**	**792**	**898**	**7%**	**6%**	**2%**	**3%**	**4%**

In the Figure 15 below, the domestic coal supply projections are compared under grey, blue and green scenarios.

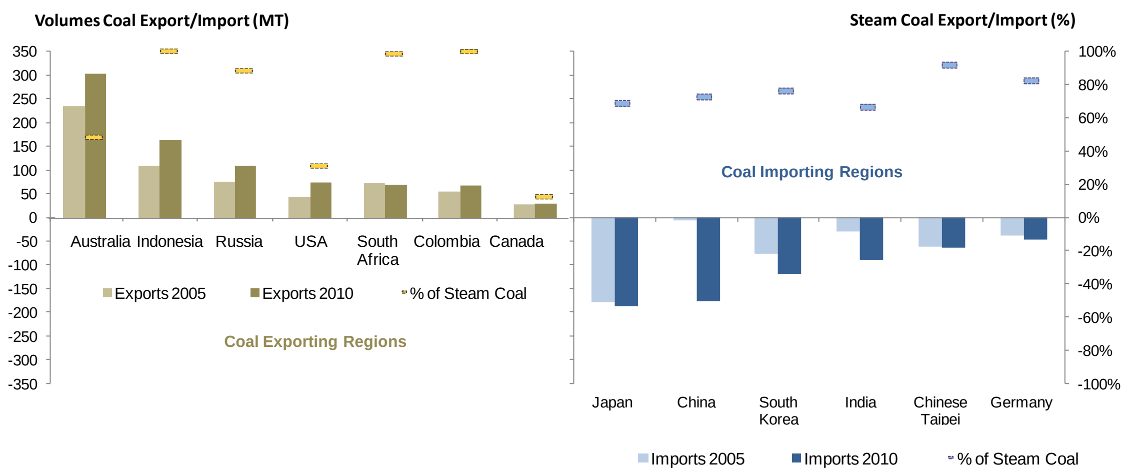
Figure 15: Scenario - Domestic Coal Supply Projections



5.2.2.2 International Coal Markets

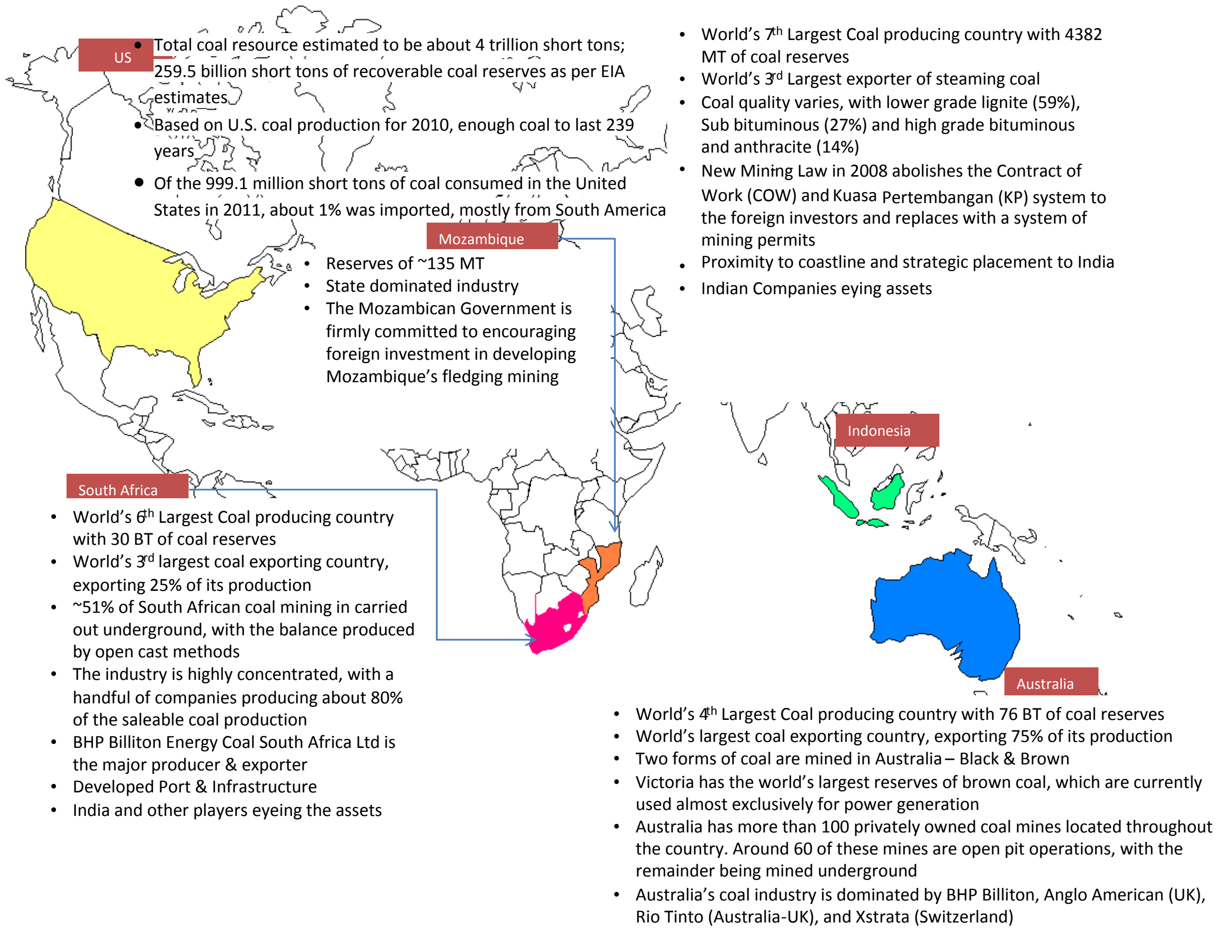
The global coal trade crossed the threshold of 1 BT in year 2010. Australia, Indonesia and Russia are the main exporting countries contributing to almost 61% of the total global trade. Australia exports a mix of coking and steam coal with almost equal percentage in export volumes for both coal categories. However countries like Indonesia, South Africa, Columbia and Russia export mostly steam coal. On the other hand Asian countries have clearly dominated the imports market. Over the last few years, China and India have been among the top coal importing countries and the increasing demand in these countries have put tremendous pressure on the global coal supply and trade scenario. Figure 16 illustrates the historical coal trades across countries and Figure 17 provides a brief snapshot of the coal assets/reserves and trade opportunities across the key international coal markets – Australia, Indonesia, South Africa and Mozambique.

Figure 16: Global Coal Import/Export with Share of Steam Coal



Source: World Coal

Figure 17: International Coal Markets Snapshot



Besides being a key importer of coal, India is also leading a wave of mergers and acquisitions in overseas coal assets. CIL is pursuing two alternative routes viz. participation in Joint Venture of PSUs (Coal Ventures International Limited (CVIL)) for formation of a Special Purpose Vehicle (SPV) to secure coal resources abroad and the acquisition of coal mines/blocks.

The private power developers are also exploring options for sourcing cheaper imported thermal coal through long term contract with overseas coal producers and acquiring partial /minor ownership interests in captive coal blocks and mines abroad. For example, companies like Reliance Power, Tata Power, Essar Group, JSW Steel, Lanco Infratech, Madhucon Projects Limited, GMR, Surana Industries, Adani and CESC have acquired coal assets abroad. The key destination has been Indonesia and Australia while interest in Mozambique, US and South Africa has also advanced. Majority of the acquisitions have been Greenfield projects. The acquisitions are driven by the coal quality, minable reserves or resources, geo-technical risk, country's regulatory environment, requirement on exploration activity, transport infrastructure and deal structure. Many of the companies are also heading for joint ventures to bring down the cost of acquisition and also to speed up the process of buying mines.

Currently, India doesn't have specific policies on imports and international acquisition of coal resources. In view of the above trade scenario along with the regulatory changes in coal exporting countries

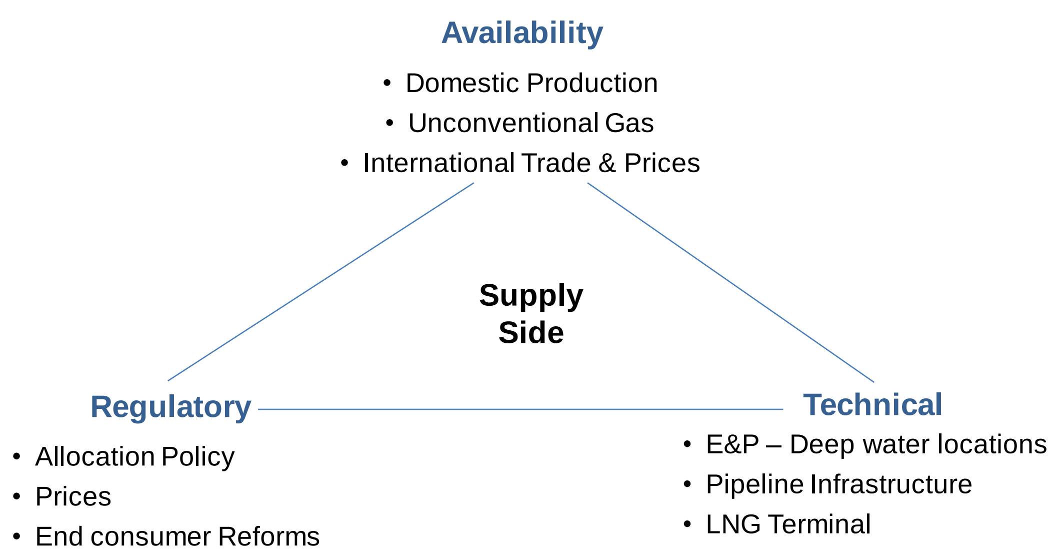
(Australia implementing new carbon policy and Indonesia's new coal mining policy aimed at increasing taxes and duties on coal export), the coal prices are expected to remain strong going forward.

Price projections for imported coal are discussed in the section to follow (Section on Fuel Price Projections).

5.2.2.3 Gas Supply

Gas plants make ~10% of the capacity mix while contributing ~11% in the generation mix. Given the vision on low carbon economy, gas is likely to play a key role in the power generation. However, the uncertainty on domestic gas availability, regulatory interventions in allocation and pricing and the high prices of LNG are considered to be the key challenges in the sector (Figure 18).

Figure 18: Supply Side Gas Market Constraints



5.2.2.3.1 Market Structure

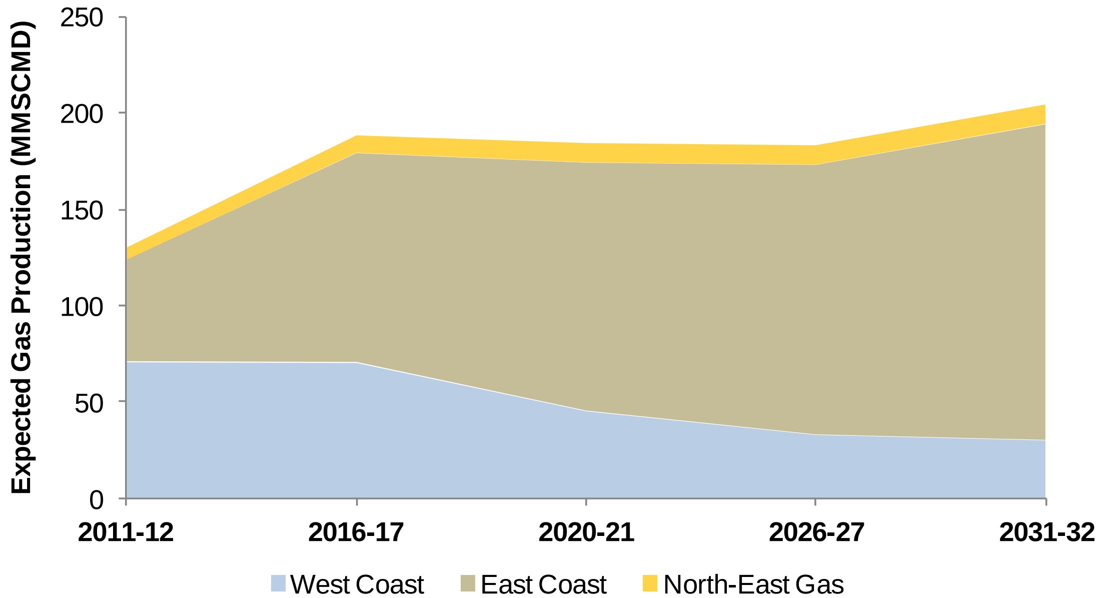
The Government of India (GoI) regulates the value chain of gas sector primarily through the Ministry of Petroleum & Natural Gas (MoPNG) assisted by three bodies, viz. Directorate General of Hydrocarbons (DGH) , Oil Industry Development Board (OIDB) and Petroleum and Natural Gas Regulatory Board (PNGRB). The sector has witnessed rapid and stable growth over the last decade and the current policy framework sets broad direction for future market development.

The number of market players has increased significantly after the introduction of NELP policy, particularly leading to the participation of the key domestic and global players such as- RIL, Essar, GSPC, Cairn Energy, BG, ENI, Niko Resources and BP. Despite the increased number of private players there is lack of competition due to various reasons. Gas utilization policy broadly controls and regulates the gas allocation to priority sectors for existing and green field projects.

The shortages in the gas supply to power sector have not only hampered the growth of new gas capacity addition but also affected the performance of existing gas plants. With the advent of gas supplies from the KG basin in 2009, the situation has improved and it was expected to get better with the ramping up of production. The production of natural gas was expected to reach 80 MMSCMD however it dropped considerably to < 30 MMSCMD from 64 MMSCMD due to problems in the performance of reservoir which has caused supply security concerns in the short term.

However in the longer term, given the on ground activities on E&P, the official estimates of production outlook remain reasonably certain through 2016. It collectively suggests that the total domestic production from the current level of ~130 MMSCMD could reach ~188 MMSCMD by the end of 12th Plan (2016-17) and could reach maximum of ~200 MMSCMD by end of 15th Plan (2031-32).

Figure 19: Expected Total Gas Production (MMSCMD)



Source: DGH and ICF Analysis

Besides the production growth and the expected availability of gas to power sector, the domestic gas pricing also remains the key driver for gas absorbability. Domestic gas prices have been significantly revised upwards over the last 10 years, however it still remains at a significant discount to the international prices. The prices are linked to JCC and are fixed for a period of 5 years with an expected revision in 2014. The government intervention in allocation and price setting has led to uncertainty and impacted investor's interest in Indian gas exploration market. With the increase in gas prices, the absorbability of gas in the power sector will reduce with the gas expected to serve more of mid-merit and peaking loads.

5.2.2.3.2 Technology

Initially, NELP was successful in attracting investment into E&P activities leading to significant development in the production. However, lately the oil and gas majors' interest has reduced mainly due to the issues in gas prices and allocation. In last few rounds, the international oil and gas majors that have the required ability, capital and technology to carry out the complex exploration, are conspicuously absent from the NELP bidding.

Going forward, as most of India's gas resources are located in deepwater, the E&P activities have to accordingly move towards these more difficult terrain and unexplored regions. Apart from technological risk, the developers also have to take risks of unsuccessful discovery of exploration effort or of time delays in completion of projects. .

To enhance the E&P activity, MOPN&G is examining the possibility of introducing Open Acreage Licensing Policy (OALP), which would allow companies to bid for a block at any time of the year. Once a bid is received, the other bids would be invited through notification to establish a transparent and competitive process.

In addition initiatives have been taken to exploit the un-conventional gas resources to enhance the domestic production. However, as discussed in section below, the outlook on gas supply from unconventional sources doesn't look very promising in the near to medium term.

5.2.2.3.3 Gas Supply to Power Sector Projections

The market uncertainties and constraints generate certain degree of gas supply risk. The gas demand in India is also governed by other key sectors, like Fertilizers, Sponge iron, City Gas Distribution, Petrochemicals etc, the allocation to each of which is governed by Gas Allocation Policy. Thus three probable scenarios for gas supply only to power sector- under Grey, Blue and Green India; are developed based on few key parameters including the technological advancements in E&P, the gas allocation and pricing policy and the exploration of unconventional supply sources. Future timelines have been drawn for these parameters along with weight-ages to estimate the likely gas supplies to power sector (Table 11-13, Figure 20).

Scenario 1 - Grey India: *E&P Technical Constraints unable to enhance production*

We assume that the current issues pertaining to technology, regulatory and market extend into the future and no likely new significant investments are expected. No major reforms in the gas allocation and pricing policy are envisaged. On an average future supplies grows at 3% CAGR with minuscule volumes from unconventional gas resources.

Table 11: Grey India - Gas Supply Projections to Power

Gas Source	End of 11th Plan	Gas Supply to Power Sector (MMSCMD)				Growth Rates (%)				CAGR (%)
	2011-12	2016-17	2021-22	2026-27	2031-32	2016-17	2021-22	2026-27	2031-32	
APM/ Non-APM	27	16	7	7	7	-10%	-14%	0%	0%	-6%
NELP	40	54	67	79	85	6%	4%	3%	1%	4%
CBM + Shale	0	0	10	15	20			8%	6%	7%*
Total	**67**	**70**	**84**	**101**	**112**	**1%**	**4%**	**4%**	**2%**	**3%**

*Over 2021-2031

Scenario 2 – Blue India: *Technological joint ventures and Policy Reforms boost Supply*

We assume that policy reforms and technological joint ventures support E&P and boost supply augmentation from new blocks. Small quantum of CBM supplies are considered to power sector by the end of 12th Plan while beyond 2020 shale production is expected to increase and the gas volumes from unconventional resources are likely to reach 50 MMSCMD by 2031-32. Total future gas supply is assumed to grow at 4% CAGR by 2031.

Table 12: Blue India - Gas Supply Projections to Power

Gas Source	End of 11th Plan	Gas Supply to Power Sector (MMSCMD)				Growth Rates (%)				CAGR (%)
	2011-12	2016-17	2021-22	2026-27	2031-32	2016-17	2021-22	2026-27	2031-32	
APM/ Non-APM	27	16	7	7	7	-10%	-14%	0%	0%	-6%
NELP	40	57	74	93	100	7%	7%	5%	5%	5%
CBM + Shale	0	3	15	30	50		38%	15%	11%	21%*
Total	**67**	**75**	**97**	**130**	**157**	**2%**	**5%**	**6%**	**4%**	**4%**

*Over 2016-2031

Scenario 3 – Green India: *Climate Change drives Reforms and Investment*

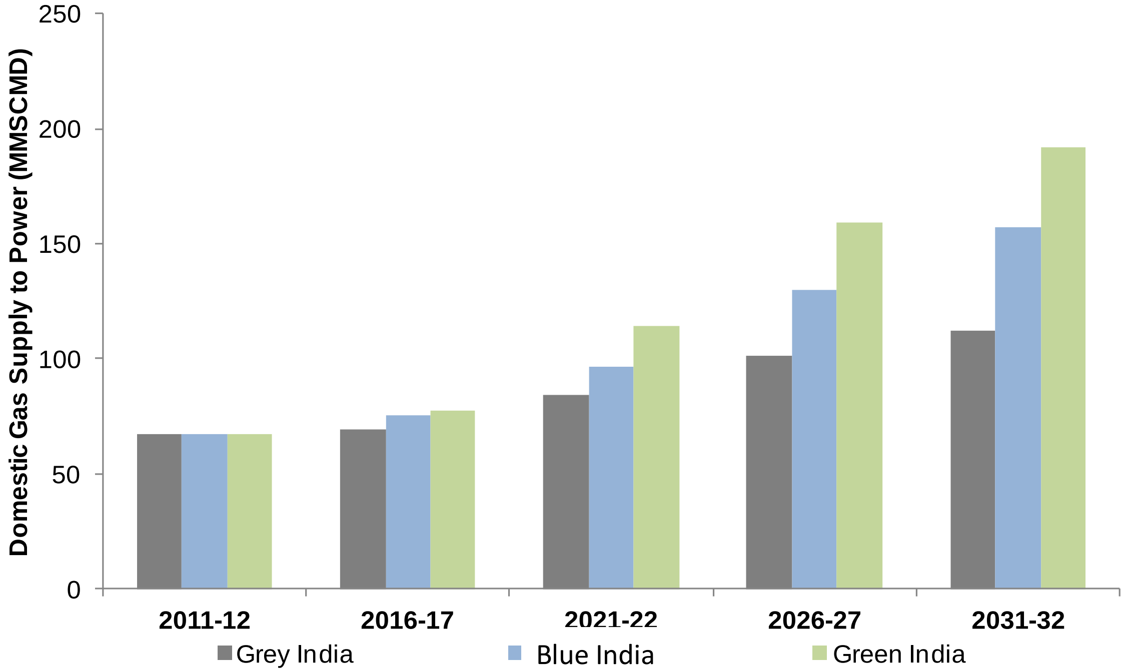
Environmental concerns as well as the expected increased role of gas in supporting renewable capacities increase the pace of reforms in gas with major investments expected in new NELP, OALP and unconventional supply sources. Power sector gets an upgrade in the priority allocation list. It is assumed the gas supply from unconventional resources to be 70 MMSCMD by 2031. Total future gas supplies are assumed to grow at 5% CAGR by 2031.

Table 13: Blue India - Gas Supply Projections to Power

Gas Source	End of 11th Plan	Coal Supply to Power Sector (MT)				Growth Rates (%)				CAGR (%)
	2011-12	2016-17	2021-22	2026-27	2031-32	2016-17	2021-22	2026-27	2031-32	
APM/NON-APM	27	16	7	7	7	-10%	-14%	0%	0%	-6%
NELP + OALP	40	56	82	103	115	7%	8%	5%	2%	5%
CBM + Shale	0	5	25	50	70		38%	15%	7%	19%*
Total	**67**	**77**	**114**	**160**	**192**	**3%**	**8%**	**7%**	**4%**	**5%**

*Over 2016-2031

Figure 20: Scenario - Domestic Gas Supply Projections (MMSCMD)



LNG supplies will be governed by the LNG terminal capacity (which is around ~30 MTPA) which will be discussed in the infrastructure section. However, LNG demand would be driven by the International LNG prices.

5.2.2.4 Fuel Price Projections

5.2.2.4.1 Coal Price Outlook

Current weighted average blended domestic prices (across subsidiary) to power sector as per current notification are ~1,200 Rs./Tonne (inclusive of royalties, various other charges and taxes). Reforms in the sector and supply outlook would influence the prices.

International coal prices will remain strong due to global trade. Assumptions on Imported coal prices are based on IEA "*World Energy Outlook (2010)*" projections. Under the three scenarios following assumptions are considered for coal price projections (Figure 21).

Scenario 1 - Grey India: *Coal centric energy policy with fast pace implementation*

High level reforms push the prices up. Coal prices are assumed to increase annually at 10% till 2020. Subsequently, it is assumed starting 2021 the prices are going to be at 15% discount to imported coal. There will be no increase in carbon tax. In this scenario the average prices are expected to grow at 5% CAGR till 2031-32.

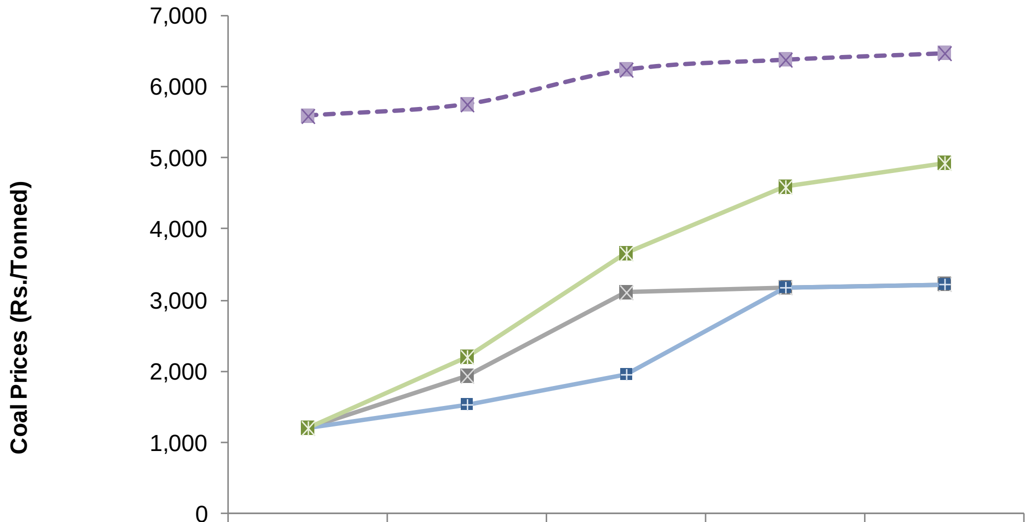
Scenario 2 – Blue India: *Business as Usual*

In this scenario, medium pace of coal sector reforms is assumed. Based on the historic price increase, the average prices are assumed to increase by 5% annually till 2025. Subsequently, starting 2026 the prices are assumed to be at 15% discount to imported coal and no increase in carbon tax. The average price increase under this scenario is expected grow at 5% CAGR till 2031-32.

Scenario 3 – Green India: *Climate Change high on Agenda*

Environmental regulations increase the Carbon Cess from the current value of 50 Rs./Tonne to ~1330 Rs/Tonne by 2026 and stays constant thereafter. In addition, an average price increase of 5% annually till 2025 is assumed. Subsequently, the price increase is capped by a maximum of 15% discount to imported coal. The average price increase is expected to grow at 7% CAGR by 2031-32.

Figure 21: Scenario - Domestic Coal Price Projections (Rs./Tonne)



	2011-12	2016-17	2021-22	2026-27	2031-32
Grey India	1200	1933	3108	3178	3224
Blue India	1200	1532	1955	3178	3224
Green India	1200	2198	3654	4588	4925
Imported Coal	5587	5750	6238	6379	6470

5.2.2.4.2 Gas Price Outlook

Domestic gas prices vary across the fields and the operators. Notified APM and NELP gas price is ~4.2 $/mmbtu. APM North-East gas price is at 40% discount to APM gas price and is equivalent to ~2.5 $/mmbtu. On the other hand, Non-APM or JV gas price is not controlled by Government and is higher than APM price at ~5.2$/mmbtu.

Given the global demand for gas it is expected that the LNG prices are likely to remain high and domestic gas prices would converge to international gas prices. LNG prices considered are linked to Crude Oil Forecast available from "*World Energy Outlook 2010*". Under the three scenarios, following assumptions are considered for gas price projections.

Scenario 1 - Grey India: *E&P Technical Constraints unable to enhance production*

Current APM and NELP prices are likely to be revised by 2014. Subsequently, the price increase in gas is adjusted to inflation. Unconventional gas prices are assumed to be ~30% higher to conventional gas prices. The average domestic price increases from the current value of 4.2 $/mmbtu to 8.5 $/mmbtu by 2031.

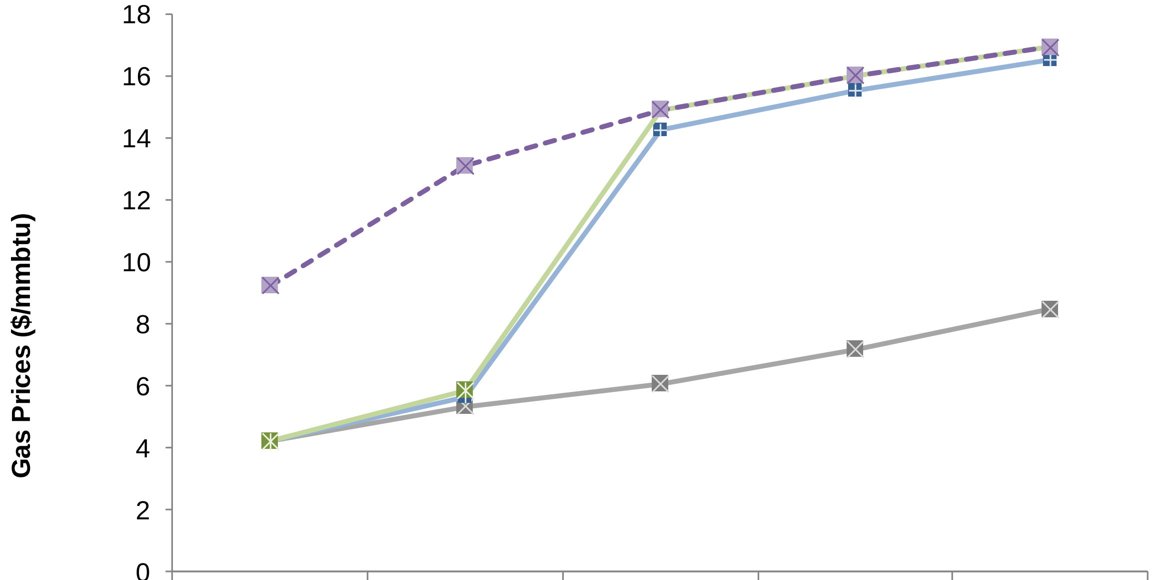
Scenario 2 – Blue India: *Technological joint ventures and Policy Reforms boost Supply*

Current APM and NELP prices are likely to be revised by 2014. Subsequently, beyond 2020, the price of existing gas supply is adjusted to inflation while new gas discoveries are assumed to be linked to LNG prices. Unconventional gases (CBM and Shale) prices are also assumed to be linked to LNG prices.

Scenario 3 – Green India: *Climate Change drives Reforms and Investment*

Current prices are likely to be revised by 2014. Further, the high demand of gas in the Green India scenario will put an upward price pressure and thus beyond 2020, all the gases are assumed to be at LNG import parity.

Figure 22: Scenario – Gas Price Projections



	2011-12	2016-17	2021-22	2026-27	2031-32
Grey India	4.2	5.3	6.1	7.2	8.5
Blue India	4.2	5.6	14.3	15.5	16.5
Green India	4.2	5.8	14.9	16.0	16.9
LNG Prices	9.2	13.1	14.9	16.0	16.9

Note: Volume Weighted Prices from different gas sources

5.2.3 Technology Development

Currently power generation is dominated by sub-critical coal technology which leads to inefficiencies in the coal usage. Various initiatives are taken towards development of new technologies that could bring in efficiencies as well as support in carbon emissions reduction. In this section, we have discussed the current status and the expected outlook on future deployment of clean coal technologies including Super Critical (SC), Ultra Supercritical, Integrated Gasification Combined Cycle (IGCC) and Carbon Capture and Storage (CCS). This is followed by the section on capital cost assumptions for different generation (conventional and unconventional) technology types.

- **Supercritical** Initiatives in the past have led to the current deployment of supercritical coal plants in India. Today, majority of the new coal plants are being planned on supercritical technology with unit size of 660 MW to 800 MW. This is a proven technology and all future capacities are likely to be supercritical and expected to dominate the coal generation. Moreover, the mega power policy specifies the use of Supercritical technology for future plant development.

- **Ultra-supercritical** coal technology is under research and development stage. The Indira Gandhi Centre for Atomic Research (IGCAR) announced the development of an advanced ultra-supercritical 800 MW coal power plant. This project is to be undertaken in co-operation with BHEL and NTPC and construction is expected to start by 2018 (IEA, 2011). Globally, two pilot projects in Australia and Japan based on ultra clean coal technology are successfully implemented; however the commercial viability of the technology is yet not proven. We expect the pilot project on ultra-supercritical technology would be operational only beyond 14th Plan. However, the large scale deployment of the technology is not likely to happen.

- Currently, a 6.4 MW **Integrated Gasification Combined Cycle (IGCC)** pilot unit developed by BHEL is operating since 1989, in Tiruchchirappalli, Tamil Nadu. This was Asia's first and world's second IGCC power plant. The plant was retrofitted with a pressurized, fluidized-bed gasification unit and began power generation in IGCC mode in March 1998. Several other initiatives have been taken to develop large scale IGCC projects in the country, however progress is slow and there is no success:

    a. A 125-MW IGCC demonstration plant at NTPC's thermal power facility at Auraiya in Uttar Pradesh by NTPC and BHEL. Nexant inc was appointed as the Owners Engineer and have submitted the detailed engineering report but NTPC is scouting for an overseas technology partner for this venture

    b. Construction of 182 MW IGCC plant in Vijayawada in Andhra by a consortium of BHEL, Andhra Pradesh Power Generation Corporation Limited (APGENCO) and the Department of Science.

    c. Other IGCC initiatives include a 1,000-MW petcoke-fired power plant proposed in January 2007 by Reliance Industries Limited for its refinery in Jamnagar, Gujarat. There is no progress as yet

IGCC technology is proven globally and countries like USA, some European countries, Japan and Singapore are operating IGCC power plants. However, there are no large scale deployments. High capital & operating cost and the non availability of standard designs & packages are the two key barriers to establish the commercial viability of IGCC plants. It is expected that the IGCC demonstrable project will be commercially operational during the 13th Plan. However large scale penetration of the technology is not expected by the end of the 15th Plan.

- **Carbon Capture and Storage (CCS)** in coal-fired generation has the benefits of CO2 reduction with no efficiency gains, so the technology is considered less suitable for India in the short term. CCS is a system of technologies that integrates three stages: CO2 capture, transport, and geological storage. India has some potential storage sites for CCS in two main geological formations: the depleted oil and gas fields, unmineable coal seams and saline aquifers in sedimentation basins; and the volcanic (basalt) rocks of the Deccan traps in west-central India. Due to available storage potential in depleted oil and gas fields, CCS can ideally be located in the areas of Gujarat, Mumbai or Chennai. However, the coal power plants with CCS are not commercially proven and not expected to commence before 2025 under Green India Initiative.

Other than for **Supercritical** technology, there is lack of any demonstrable pilot project for clean coal technology. Internationally, significant R&D efforts are in progress on these technologies. However, based on the assessment of various policy initiatives and the issues in commercial viability of the clean coal technologies, we believe that the large scale implementation of these technologies may not be possible even in long-term.

Accordingly, three probable scenarios for technology deployment are considered as below.

Table 14: Scenario – Assumptions on Clean Coal Technology

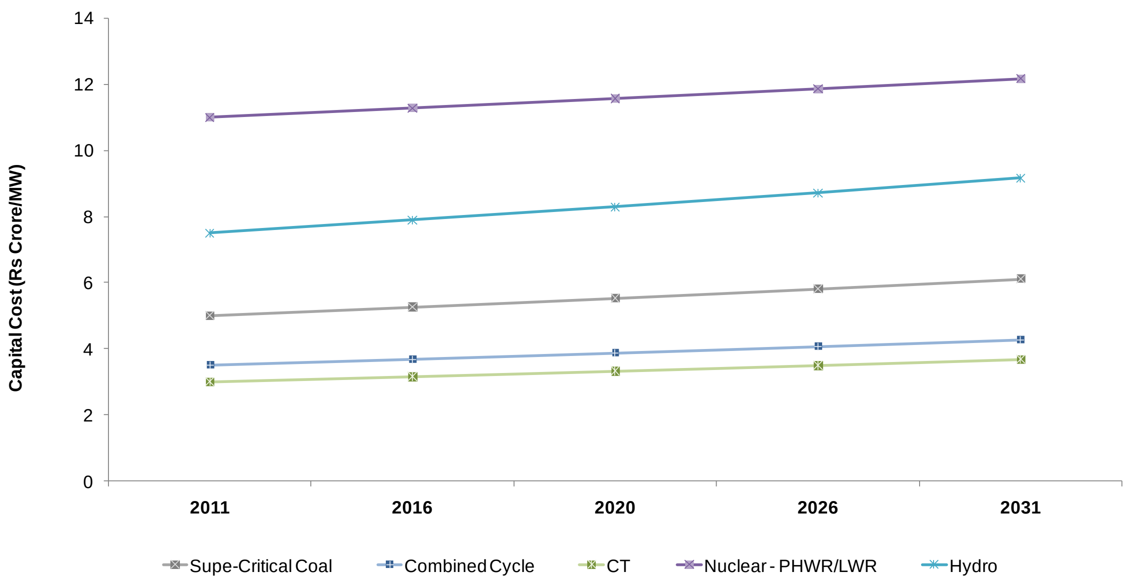
Scenario	Incremental Capacity Addition by Plan Periods (MW)				
	Technology Type	**2012-2017**	**2017-2022**	**2022-2027**	**2027-2032**
Scenario 1 - Grey India	Ultra-Super Critical	0	0	0	800
	IGCC	0	0	182	0
	CCS (Ready Power plant)	0	0	0	0
	Total	**0**	**0**	**182**	**800**
Scenario 2 - Blue India	Ultra-Super Critical	0	0	800	800
	IGCC	0	182	300	1,000
	CCS (Ready Power plant)	0	0	0	0
	Total	**0**	**182**	**1,100**	**1,800**
Scenario 3 - Green India	Ultra-Super Critical	0	0	800	1,600
	IGCC	0	500	800	1,500
	CCS (Ready Power plant)	0	0	500	1,000
	Total	**0**	**500**	**2,100**	**4,100**

5.2.4 Capital Costs Trends

The Capital cost assumptions for different generation technologies are inclusive of all capital work including plant and machinery, civil work, erection and commissioning, financing and interest during construction, and evacuation infrastructure up to inter-connection point.

Conventional generation technologies are well established globally and are expected to witness only the incremental improvement. Figure 23 provides the assumptions on expected capital cost curve for different generation technologies. Capital cost for various technologies for the base year 2012 is taken as per the CERC norms (for tariff determination purposes). For future years, the capital cost has been inflated to capture the impact of increase in cost due to land acquisition, environment cost, cost of materials and manufacturing processes and technology improvements.

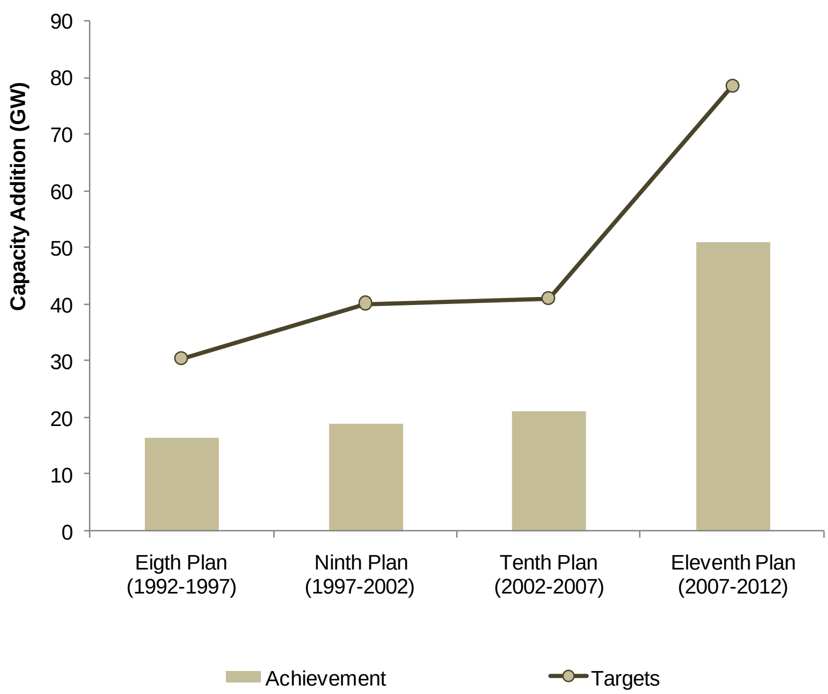
Figure 23: Capital Cost for Different Generation Technologies



5.2.5 Capacity Addition

India ranks 6th in the world in terms of installed capacity and accounts for about 4.5% of the world's total annual electricity generation. The installed capacity has grown from 63 GW during 1990 to approximately 199 GW as on March 2012. Over the last two five year Plans (X and XI), approximately 92GW (including renewable) of capacity has been added with an annual average growth rate of 7%, while the highest growth in capacity has been witnessed during FY2011-12 at 12.8%. However the sector is characterized by supply shortages with demand deficits close to 10%. Over the 8th, 9th and 10thplanning periods, a close to 50% of the target capacity was achieved and thrust has been more on State and Central sectors to add almost all the capacity. However, XI plan has witnessed a shift with private players over achieving the targets and contributing more than 45% to the total capacity addition of approximately 51 GW. It is expected that during the XII plan close to 65% capacity addition targets will come from private players. Increased private participation has helped in improving the supply position in the country. Moreover, initiatives to add Ultra Mega power projects and super critical projects with 500 unit size and above, consequently bringing in the economies of scale, have boosted the capacity addition scenario in the country (Figure 24).

Figure 24: Plan-Wise Historical Capacity Addition Targets vs Achievement



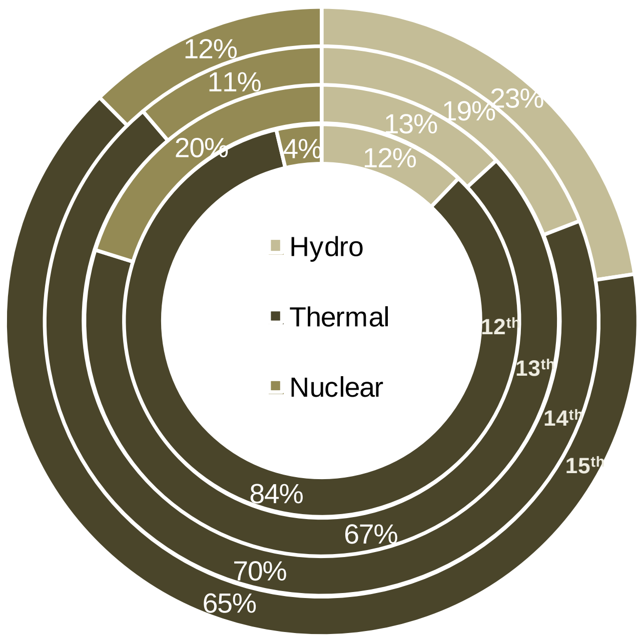
Source: CEA

The slippages arise mainly because of issues in various inputs required for the project development. Although, the impacts of constraints such as equipment availability and timely financial closures have reduced over time, others issues related to fuel and water availability have become critically important.

5.2.5.1 Capacity Addition Plans

Taking stalk of the current plans, several planning agencies have forecasted the expected conventional capacity addition. CEA has identified a shelf of ~420 GW projects for likely addition through 2031-32 (Figure 25).

Figure 25: Identified Shelf of Conventional Capacity for Plan Periods



Source: CEA

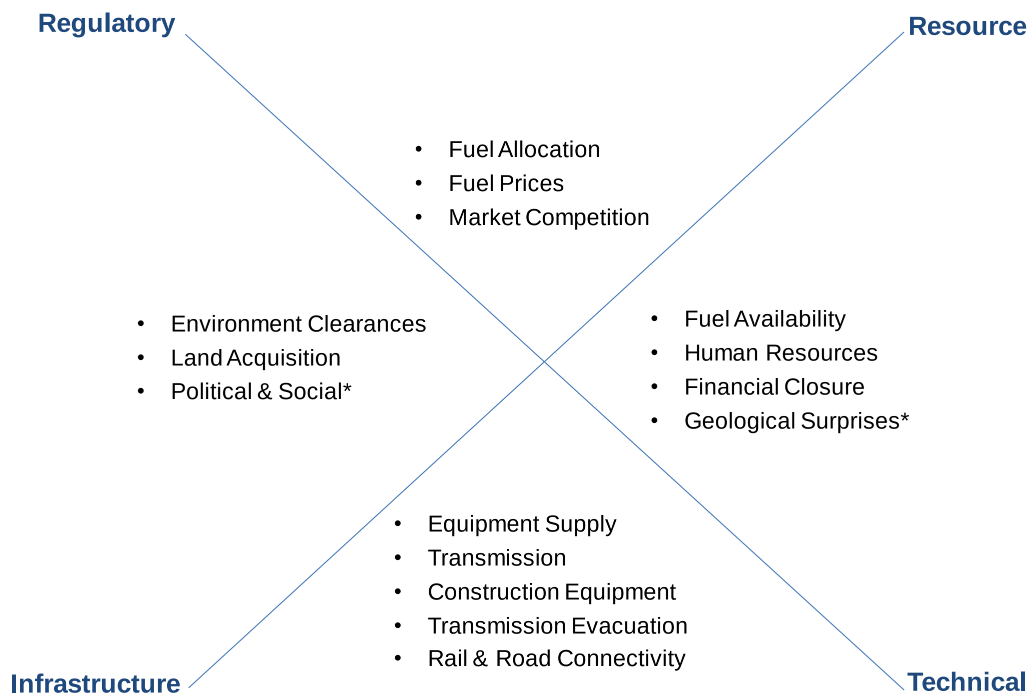
The Planning Commission report "Low Carbon Strategies for Inclusive Growth" suggests conventional installed capacity of ~300 GW and ~340 GW by 2020 under baseline scenarios with GDP growth of 8% and 9% respectively. These baseline scenarios are drawn considering the demand forecast, the committed plans, the impact of emerging technologies and the exploitation of the least cost resources.

The average annual additions have been in the range of ~3000-4000 MW (during 8th -10th Plans) and have improved to 8,000 MW during 11th Plan. Going forward, with the easing of constraints the annual capacity addition is expected to be higher. Constraints and expected timelines for the capacity addition are discussed in detail in the following section.

5.2.5.2 Capacity Addition Constraints

The key challenges that have impacted the conversion of the target pipeline into on-ground projects can be broadly categorized into four heads viz. Regulatory, Technical, Infrastructure and Resources (Figure 26). These issues can be further classified as controllable and uncontrollable constraints.

Figure 26: Identified Conventional Capacity Addition Constraints



* Uncontrollable constraints

Further in this section, we have discussed these constraints in detail while trying to quantify and determine their impact on capacity addition to the extent possible.

Land Acquisition: For the capacity planned under the 12th Plan, ~82% is already under construction and most of the land has already been acquired. In past, Land acquisition has been identified as one of the biggest challenges in executing the project on time. With growing population, industrialization and urbanization, land acquisition is expected to keep posing a challenge even in the long-term. On the other hand, to achieve targets of National Mission (NAPCC) for a Green India – the area under forest and tree cover should increase to 33% from current 23%. As such a balance is required between utilizing the land for industrial and maintaining sufficient forest cover in the country.

Land Acquisition and R&R Bill, 2011, have been framed recently and are expected to be tabled in the Parliament soon. These bills are expected to standardize the process of land acquisition and resettlement of displaced people.

Equipment Supply: The existing domestic equipment manufacturing capacity of BTG has increased over 20 GW mainly due to the initiatives taken during end of 10th and beginning of 11th Plan. Moreover, market barriers for foreign power equipment manufacturers have also been gradually removed. Many Joint ventures of Indian and foreign companies have been announced and are making progress. The removal of customs duty on imported equipments for mega power projects (1000 MW and above) and a small duty of 5% for smaller projects, has also improved the equipment availability. However, the lack of BoP equipments, construction equipments and EPC capacity still remain a serious issue.

Financial Closure: Close to ~37% of total capacity addition during 11^{th} Plan has been added by IPPs demonstrating a healthy investment climate in the sector. Current domestic debt market is characterized by several challenges that pose a roadblock for investment in the near term:

- Issues linked to the poor financial condition of SEBs and the difficulties in closure of contractual agreements under Case1 Bidding leading to delays in financial closure
- Commercial bank credits likely to hit the sector limits given the huge pipeline of projects and increasing debt funding
- Lack of maturity in Bond markets to address need of power projects
  High interest rate levels 13% - 14% coupled with high inflation

The pressure in the domestic financial market has resulted in significant competition for raising ECB (External Commercial Borrowings). However, the power market risks and current global economic scenario has also resulted in reduced risk appetite for global financial institutions. Several initiatives are being taken by Government to address the financing issues in power sector.

The financial position of the electricity distribution sector has been a concern for over a decade now. The inability of the State-owned distribution utilities to remain financially and commercially viable is putting at risk the significant investments being pumped into the electricity sector by private and public players. The accumulated loss of all State distribution utilities has been estimated at Rs 1.9 lakh crore as of March 31, 2011. In order to bail out the ailing state utilities, the government announced the financial restructuring plan. The scheme focuses attention on the short-term liabilities of discoms and requires the State Government to take over 50 per cent of these liabilities in the form of bonds duly guaranteed by it.

Approximately 50 GW of thermal capacity that is under construction and likely to be commissioned during 12^{th} plan have already achieved the financial closure. As such in the short-term, the financial constraint in the sector is not likely to have significant impact on capacity addition. It is assumed that in the long term, the reforms in financial and power sector would lead to increased liquidity and bank credit to support the power projects. In mid-to-long term, however, the financial constraint would have a medium level criticality. .

Project Clearances: Environmental and other statutory clearances present significant impediments for fast track growth of conventional capacity addition. Currently, ~700 GW of thermal projects application for clearances are pending with Ministry of Environment and Forest (MoEF). There are no major initiatives or reforms taken in this direction and with growing environmental concerns, the delays are likely to continue in the implementation of capacity additions. In terms of its criticality on capacity additions, this can be ranked in middle bracket.

Human Resources: For the construction of new plants, there is a skilled manpower requirement of ~8-10 persons/MW[12]. Similarly, for the O&M of generation projects, there is a requirement of ~2 persons/MW. Given the pipeline of projects under implementation and planning phase, there is a huge requirement of technical and educational training institutes that can cater to the manpower needs of

[12] Source: CEA

the power sector. Manpower requirement are likely to increase threefold by the end of 15th Plan from the current estimated requirement of ~16 lakh personals during 12th plan[13].

Currently there are 1,346 approved Engineering Colleges with ~4.4 lakh seats and polytechnics with ~2.65 seats and over 2 lakh trainees pass out every year[12]. Hence, a significant technical manpower is already available; however, there is lack of proper induction and training programs to match the requirements of the power sector. Several initiatives have been taken to develop skilled manpower which includes the constitution of five taskforces h to develop curriculum, roadmaps, job portals, performance indicators and distance learning programs.

Given the focus of government to develop required skill sets, the enabling environment to attract investments in the professional education and the proliferation of education sector in general in recent past, we believe that the constraint related to human resource availability will ease off in the medium to long-term.

Water Issues: One of the recent issues that have emerged and delayed the capacity additions have been the water availability to thermal power projects. Due to scarcity of water, projects are not getting timely water allocation and even the existing projects face generation issues due to unavailability of water. However, in short-term this won't be a major challenge and can be ranked lower in terms of criticality; however it is expected to move upwards in the long-term with large scale implementation of projects.

Fuel Availability & Prices: Uncertainty on domestic coal and gas availability, slow development of coal blocks and volatility in imported coal & gas prices are the biggest and important factors driving the slippages. On coal side, CIL is ready to sign the fuel supply agreement (FSA) at only 50% linkage and that too for 5 years. On gas side, new power projects are not a priority for gas allocation policy. Anyway given the high affordability of gas to other end use sectors, it is very difficult for gas projects to compete for the domestic gas. These developments have raised serious fuel security concerns for new projects and are weighing down the investment decisions in the power sector

Uncertainty in domestic fuel markets have led to increased dependence on imported fuel (coal and LNG). However, the risk associated with volatility in international fuel prices, uncertainty in the mining policies of the sourcing countries and fuel cost pass through/ risk sharing mechanism under PPA continue to influence the investment decision. In terms of criticality, this constraint is at the top of the list and would always be driving the capacity addition.

Transmission Evacuation: Delay in completion of transmission evacuation facilities for the project often has delayed the timely commissioning of projects recently. Even the projects allocated to private sector through competitive bidding have got delayed for various reasons. However, we believe that this is a short-term phenomenon and will not significantly impact the projects going forward. Moreover, with increase in private participation and the alignment of policies, this constraint is likely to ease off.

Political & Social Issues: Government Energy policies, political influence on power purchase behavior and other social issues (like law & order, R&R) are expected to hamper the capacity addition in some of the states.

[13] Source: CEA, International Conclave on "Key inputs for Accelerated Development of Indian Power Sector"

Hydro Power Issues: Hydropower has 22 % market share in the capacity mix and contributes to approx. 14 % of the total generation. Despite hydroelectric projects being recognized as the economic and preferred source of electricity, share of hydel power has been declining steadily over the course of last 2 decades from 34% to 22%. The pace of development of hydro-electric potential in the country has been slow and the target achievements have been only ~40%. The main challenges faced are technical, financial and managerial in nature. Few of these constraints are highlighted below –

- Geological risks and surprises during construction phase
- High capital costs, longer gestation periods
- Difficult or inaccessible potential sites
- Long delays in obtaining clearances – land acquisition problems, delay/non-clearance from Environment and Forest aspects, and Resettlement & Rehabilitation issues
- Rationalization of tariffs and tariff determination mechanisms
- Territorial dispute with China specially in Arunachal Pradesh

CEA expects that ~75 GW of identified hydro projects to be added by the end of 15th plan. However, given the past experience, we expect that 25-40% of the hydro capacity would face slippages for various reasons. Accordingly, we assume that a maximum of ~58 GW of capacity can be achieved under highly optimistic scenario (Green India).

5.2.5.3 Nuclear Power Plans

Current nuclear installed capacity is ~5 GW and is dominated by Pressurized Heavy Water Reactors (PHWRs). Nuclear power generation is strictly a nationalized activity and is being operated by Nuclear Power Corporation of India (NPCIL). Due to safety and social security issues the sector is not open for private participation. In past, the shortage of fuel and reported leakage in some plants, have raised a significant uncertainty for nuclear plants. However, with the international agreements with the US and NSG, the scenario on fuel availability and the import of equipment and technology has significantly improved in the country.

Based on the availability of large thorium reserves, three stage nuclear power program has been designed which consists of commissioning natural uranium fuelled PHWRs in stage 1, fast breeder reactor using plutonium in stage 2 and advanced nuclear power system using self sustaining series of Thorium in stage 3.

Energy security vision as envisaged in IEP projects to add ~ 48 GW nuclear capacities by 2030 under the pessimistic scenario, while ~63 GW under the optimistic case. The ambitious plan as projected by IEP assumes that the FBR technology is successfully demonstrated, the new Uranium mines are opened for providing fuel for setting up additional PHWRs and the country succeeds in assimilating the LWR technology through imports and develops the Advanced Heavy Water Reactor for utilizing Thorium by 2020.

However, the recent Fukushima nuclear disaster in Japan led countries with nuclear power plants to revisit safety measures and has refueled the debate over the safety of nuclear energy. Even though social activists have intensified a voice against the further expansion; the government of India has clarified its intensions to go-ahead with nuclear capacity with all the requisite safeguards. The key challenge in setting up large scale nuclear capacities remains in terms of long gestation period, land acquisition, safety and environment concerns, social problems and nuclear liability.

Various planning agencies project to add more than 50 GW of nuclear capacity by 2031-32. IEP's pessimistic scenario projects an addition of ~50 GW by 2030, Planning Commission report "*Low Carbon Strategies for Inclusive Growth*" envisages adding ~18 GW by 2020, while CEA, NPCIL and Bharatiya Nabhikiya Vidyut Nigam (BHAVANI) expect to add ~52 GW nuclear capacity by 2031-32. Given the prevailing conditions, the historical performance and the market constraints, the target plans seem to be very optimistic. Moreover, globally there has been a slowdown in nuclear capacity addition and annual average capacity additions have been in the range of only ~2000 MW. Based on the above analysis it is assumed under highly optimistic scenario India could add a maximum of ~32 GW of nuclear by 2031-32.

5.2.5.4 Expected Capacity Addition Projections

Assessing the probability and criticality of the above constraints along with the ongoing and expected reforms and their impact on capacity additions, we have developed three possible scenarios to identify the maximum conventional capacity addition possible by 2031-32.

Under all the three scenarios, it is expected that by the end of 12th Plan and /or by the mid of 13th Plan (2018-19), constraints with respect to capacity additions will ease out specifically in terms of successful implementation of land acquisition bill, well defined state policies on water allocation in place, clarity on stringent environmental clearance norms and the availability of skilled manpower and equipment supply (in terms of BoP, construction etc). Therefore, the expected capacity mix will be driven more by the fuel availability and environmental considerations in addition to other social and political interventions.

Scenario 1 - Grey India: *Coal Remain the Mainstay Fuel*

Coal being the least cost option would continue to be the main power generation source. Policy focus on coal based capacity addition and the deployment of sub-critical and super-critical capacity addition are expected. There will be clarity on regulatory framework for Case 1 & Case 2 competitive bids and the state utilities will start to plan for base-load and peak load procurement.

On Fuel side, we assume power sector reforms complemented by coal reforms, with no major reforms on gas side. Constraints in hydro in terms of law & order issues and geological challenges continue to affect the materialization and not more than ~45 GW of hydro capacity would be realized by 2031-32. Current issues with nuclear capacity additions continue in future resulting in very slow progress on projects due to technology, safety, security and social agitation issues and only ~15 GW is likely to be commissioned by 2031-32.

Annual total conventional capacity addition of ~12 GW is expected during 12th Plan which will increase to annual additions of ~31 GW by 2031-32.

Table 15: Grey India – Upper Bound Projections on Conventional Capacity Addition

Upper Bound on Cumulative Capacity Addition for each Plan Period (MW)

Capacity Type	12th Plan	13th Plan	14th Plan	15th Plan	Grand Total
Coal	50,000	66,000	92,000	120,000	328,000
Gas	5,000	10,000	15,000	20,000	50,000
Hydro	7,500	10,000	12,500	15,000	45,000
Nuclear	1,400	3,100	4,600	6,900	16,000
Total	**63,900**	**89,100**	**124,100**	**161,900**	**439,000**

Scenario 2 – Blue India: *Technology Driven Intermediate Reform Initiatives*

Coal and gas remain the mainstay fuels supported by intermediate reforms on respective fuel policies and availability. There will be focus on efficiency improvement and technology development. Successful implementation of Clean Coal Technology projects - Ultra super-critical and IGCC projects are expected to be deployed during 2021-2031. No major breakthrough in commercial deployment of CCS projects is expected before 2031-32. Hydro sector is expected to add ~50 GW primarily by exploitation of potential in North-East. In nuclear, there will be partial ease off of constraints due to – increase in global support and implementation of FBR projects. A ~20 GW of nuclear capacity is expected to materialize by 2031-32.

Annual total conventional capacity addition of ~11 GW is expected during 12th Plan which will increase to annual additions of ~28 GW during 15th Plan.

Table 16: Blue India – Upper Bound Projections on Conventional Capacity Addition

Upper Bound on Cumulative Capacity Addition for each Plan Period (MW)					
Capacity Type	**12th Plan**	**13th Plan**	**14th Plan**	**15th Plan**	**Grand Total**
Coal	45,000	60,000	80,000	100,000	285,000
Gas	5,000	12,500	17,500	25,000	60,000
Hydro	8,250	11,000	13,750	17,500	50,500
Nuclear	2,100	4,400	7,700	7,700	21,900
Total	**60,350**	**87,900**	**118,950**	**150,200**	**417,400**

Scenario 3 – Green India: *Climate Change Driven*

Policies are driven by low carbon economic growth. Stringent environmental regulations will be in place for coal based capacity and coal mining which will adversely impact the coal based capacity additions. Focus will be primarily on cleaner fuels - Gas, Hydro, Nuclear and Renewables and clean technologies. Deployment of ultra-supercritical and IGCC based capacity is expected under this scenario. Nuclear capacity additions of ~32 GW as envisaged under the most optimistic case.

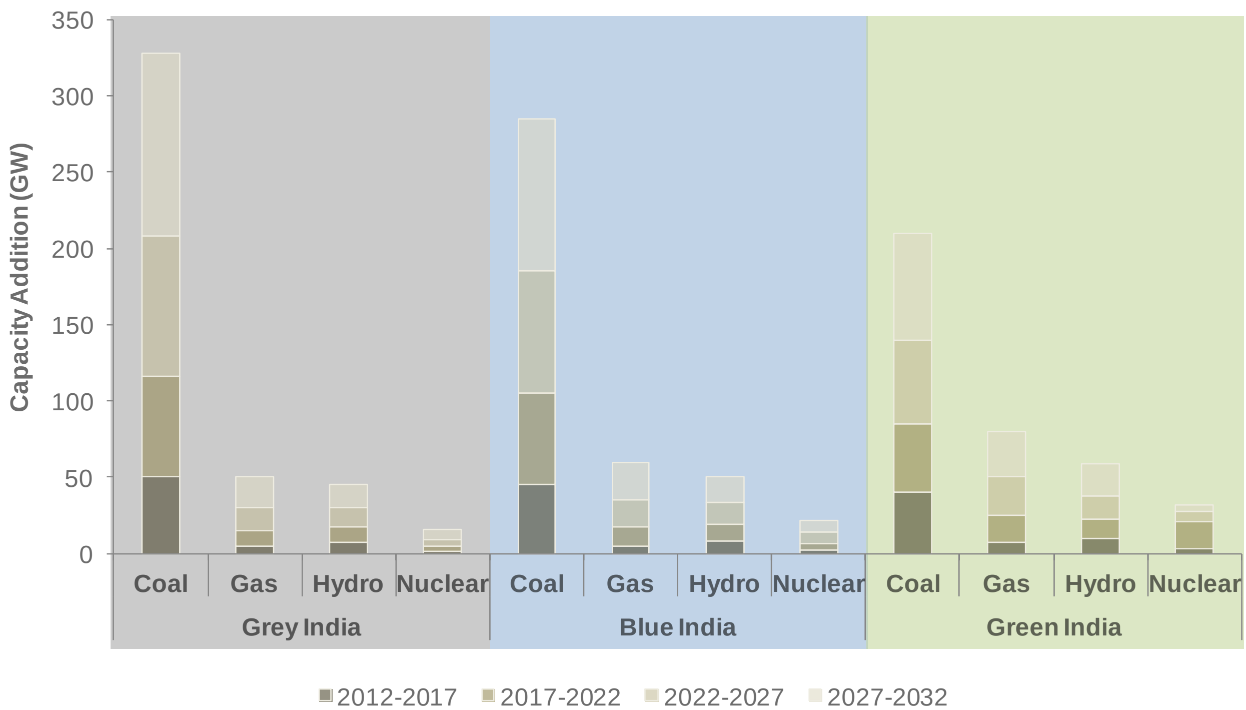
Annual total conventional capacity addition of ~11 GW is expected during 12th Plan which will increase to annual additions of ~24 GW by 2031-32.

Table 17: Green India – Upper Bound Projections on Conventional Capacity Addition

Upper Bound on Cumulative Capacity Addition for each Plan Period (MW)

Capacity Type	12th Plan	13th Plan	14th Plan	15th Plan	Grand Total
Coal	40,000	45,000	55,000	70,000	210,000
Gas	7,500	17,500	25,000	30,000	80,000
Hydro	9,488	12,650	15,813	21,000	58,950
Nuclear	2,800	18,000	7,100	4,000	31,900
Total	59,788	93,150	102,913	125,000	380,850

Figure 27: Bound Projections on Conventional Capacity Addition



5.2.6 Infrastructure

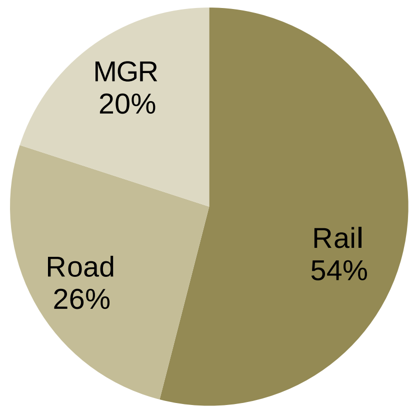
Given the spatial spread of domestic resources and demand centers, there is a need for an efficient and adequate transport infrastructure to facilitate the movement of energy resources. The fuels such as coal and gas can also be physically transferred through rail/road and gas pipelines infrastructure, however the resources like lignite, hydro and renewable which are more resource centric generation sources depends entirely on the adequate transmission systems for power evacuation. In addition, increasing dependence on energy imports requires availability of necessary ports and LNG handling infrastructure.

The development of logistics infrastructure has not been commensurate to the demand growth and hence poses a key bottleneck in the power sector development. Following section outlays the current status, the expansion plans and the assumptions on expected likely availability of infrastructure by the end of 15th Plan (2031-32).

5.2.6.1 Railways

The transport of coal is heavily dependent on rail network infrastructure - ~51% of the total coal movement is through rail other than road (-26%) and conveyer belts/merry-go-round (MGR) (~20%) (Figure 28).

Figure 28: Modes of Coal Transport



Source: CEA

Average distance travelled by coal is ~530 km, while it travels as far as 1500 km down to west from the eastern region. Due to congestion in the rail links, plants often fail to receive the desired quantum of coal. The bottlenecks in railway infrastructure have aggravated in the recent years and have led to coal shortages at power plants. Some of the key pressure points that exist in the system include:

- Inadequate loading facilities and road infrastructure from the mine head to Railway sidings
- Inadequate unloading, lack of storage capacity and unavailability of rakes at Railway sidings
- High unloading time due to transport of uncrushed and unwashed coal
- Inefficient movement of coal which is the result of irrational/un-economic allocation of coal to power plants
- Rail and road connectivity to ports

These constraints are further being studied by the Planning Commission. The Commission has formed a Working Group (National Transport Development Policy Committee) to evolve an integrated strategy for bulk transport of energy and other related commodities.

In the short to medium term, assuming coal production targets are met, the transportation constraints are expected to remain due to inadequate growth and weakened progress in railway capacity additions. Currently, Railways plan to augment new lines, double the existing networks and develop dedicated freight corridors. The achievement of these programs is likely to bear fruit in the medium to long-term only. Moreover, in the long term, besides railways, MGR & ropeways/conveyors are expected to dispatch substantial portion of coal as significant generation capacities are now being planned at mine pit head itself. The plans have been drawn for the improvement and maintenance of the railway capacity additions, the implementation of the new transport development strategy and the requisite augmentation to support the easing of constraints in the long-term.

5.2.6.2 Ports

With the growing emphasis on coal imports, port's coal handling capacity if not planned adequately may pose challenge to capacity addition. India at present has 13 major ports (for which the tariff is determined by TAMP - Tariff Authority for Major Ports) at Kolkata, Haldia, Paradip, Vishakhapatnam, Ennore, Chennai, Tuticorin, Cochin, New Mangalore, Marmugao, Mumbai, Jawaharlal Nehru and Kandla. In addition there are about 176 non-major ports (which include large size ports of Mundra and Pipavav) spread across the coast line with ~50% concentrated in Gujarat and Maharashtra. The total cargo handling capacity of all these ports is ~1.1 BT while the coal handling capacity is close to ~140 MT, which is adequate to handle existing level of coal imports. Figure 29 provides an areal view of the location of the ports in the country.

Figure 29: Location of Major and Minor Ports

Given the rising energy needs and domestic supply constraints, the volumes of imported coal and gas are likely to increase significantly over time. However, the other factors such as global economic condition and the policy and regulations adopted by the coal supplying countries would also influence the demand for future imports and correspondingly the requirement of fuel handling capacity.

Ministry of Shipping has projected coal cargo traffic to be ~1.1 BT by 2031-32. In view of the projections on cargo traffic it is estimated that by the end of 12th plan the total port capacity requirement for Coal at Major ports and Non-major Ports would be ~532 MT. The current expansion plan suggests that Major ports plan to increase the capacity by 524 MT during 12th Plan. However, the Non-major ports have drawn ambitious plan to create additional capacity of ~1,457 MT during the same period. Private sector is envisaged to fund most of these projects through PPP or BOT or BOOT basis. It is estimated by planners that likely achievement of capacity at Non-major ports will be in the range ~1000 MT by the end of 12th Plan.

The current installed port capacity and future development plans for capacity expansion, suggest adequate port capacity to handle the estimated future coal demand and hence it is not likely to be a constraint going forward. However, adequate inland transportation i.e requisite rail and road connectivity to ports needs to be improved and might pose challenge in the short-term.

5.2.6.3 Domestic Gas Infrastructure

Over the last two decades, the gas pipeline network has evolved gradually in a phased manner in tandem with the emergence of supply sources and load centers. Initially gas discovery at Bombay High drove the need for development of localized gas infrastructure. Further gas discoveries in the same region called for longer transmission pipelines across the states. The result was the first cross country pipeline - Hazira-Vijapur-Jagdishpur (HVJ) covering western and northern states. Over time, with new gas discoveries other distribution systems were developed to serve the demand. Reliance East-West Pipeline and GSPC network in Gujarat are the major distribution systems built recently.

The natural gas pipeline network in the country is made up of high pressure transmission pipelines and small regional gas distribution networks primarily located in the Western, Southern and Eastern regions. The total length of the pipelines is around approximately 10,000 kilometers with design capacity of approximately 265 MMSCMD. The network of major public and private market players are detailed in the Table 18 below.

Table 18: Existing Gas Pipeline Network Details

Owner	Pipeline	Type of Network	Design Capacity (MMSCMD)	Approx. Length (km)
GAIL	HVJ/GREP*	Trunk line	33.4	3,100
	DVPL	Trunk line	23.9	650
	DUPL/DPPL	Trunk line	12.0/12.0	750
	Gujarat & Rajasthan	Regional	19.5	1,000
	Mumbai	Regional	23.6	140
	KG Basin	Regional	15.99	835
	CAUVERY Basin	Regional	8.66	256
	Tripura	Regional	2.26	60
	Assam	Regional	2.5	9
	TOTAL GAIL		**153**	**6,800**
RGTIL	East-West	Trunk Line	100	1,440
GSPC	Gujarat Distribution	Regional	22	1,400
AGCL / OIL	Assam-Tripura	Regional	6 – 8	500
All India Total			**265**	**10,140**

The growth in infrastructure has mainly been driven by the emergence of supply sources, the location of the anchor loads and the gas allocation policy which prioritizes the order and allocation of gas to different consumer segments. Going forward, the same drivers are likely to influence the pipeline infrastructure development.

To ensure better planning and coordination, a joint study was conducted by PPAC (Petroleum Planning and Analysis Cell of MoPNG) and USTDA in the year 2010-11 with the objective of developing the blueprint of a National Gas Grid. The study was aimed at identifying the key trunk line pipeline projects that need to be set up for developing the gas grid given the huge requirement of building up gas transportation capacity across the country.

As expected, all the major pipeline infrastructure companies including GAIL, Reliance and GSPC have ambitious expansion plans to enhance the gas pipeline network as discussed below.

- GAIL plans to add ~6,500 km pipeline with capacity of ~180 MMSCMD. The construction plan involves adding new pipelines and augmenting the capacity of the existing HVJ network. The HVJ network would also be connected to the northern states of Haryana and Punjab and to the eastern region up to West Bengal. GAIL has approved an investment of Rs. 8,000 crore for these plans and various pipelines are under construction & approval stages.
- Reliance plans to develop pipelines in Southern India and also along the eastern coast. It has been authorized to add ~3,000 km of pipeline with a capacity expansion of approximately 84 MMSCMD.
- GSPC further plans to expand its network in the state of Gujarat. Expansion plans include constructing approximately 2,600 km pipeline with capacity of approximately 60-70 MMSCMD. It has also been authorized to develop Mehsana-Bhatinda-Srinagar pipeline which will link its Gujarat network to the states in Northern India. It also plans to develop a pipeline connecting Andhra Pradesh to Gujarat.

The current expansion plans of different pipeline players are under various stages of development and are likely to be achieved by 2015-16. The resultant grid is likely to affect free flow of gas from multiple sources to multiple demand centers across the country.

5.2.6.4 LNG Terminals

LNG imports have risen steadily over the years and account for ~20% of India's gas supply. The bulk of LNG imports have been sourced from Qatar under a long term contract. With the increase in natural gas demand recently, LNG has also been sourced on a spot basis from Oman, Australia, Egypt, Trinidad and Tobago, Abu Dhabi, Mayaysia, and Algeria.

Currently, two LNG import terminals are operational on the west coast at Hazira and Dahej. The combined capacity of these terminals is approximately 14.5 MMTPA (52 MMSCMD) which is sufficient enough to handle the current imports. Table 19 below illustrates the current installed LNG infrastructure.

Table 19: Existing LNG Import Infrastructure

Terminal Name, Location	Developer	Capacity (MMTPA)	Supplier
Dahej I & II, Gujarat	Petronet LNG Ltd. (PLL)	12[14]	25 Year supply contract for 7.5 MMTPA with Rasgas, Qatar, and Spot Cargos
Hazira, Gujarat	Shell/TOTAL	2.5[15]	Spot LNG purchases. Merchant sales. Operating at 70% Capacity

[14] The initial capacity was 5 MMTPA (2004) which increased to 6.5 MMTPA in 2007 due to de-bottlenecking. Commissioning of Phase II in 2009 increased the capacity to 12 MMTPA.
[15] The capacity of the terminal is expandable to 5 -10 MMTPA

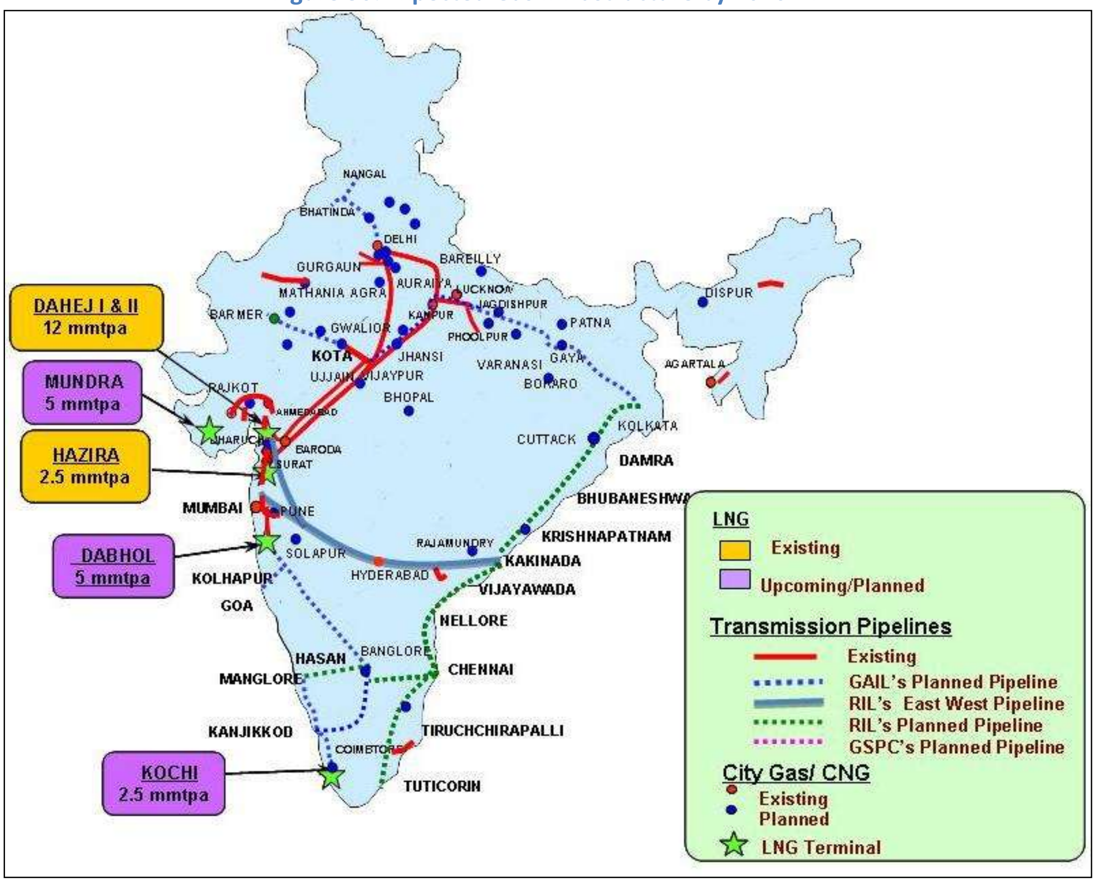
Terminal Name, Location	Developer	Capacity (MMTPA)	Supplier
Total		14.5[16]	

Source: Petronet LNG, Shell Hazira

In terms of planned expansion, two LNG terminals are under construction at Dahej and Dabhol. The Dabhol terminal was mechanically completed in December 2010, however, after several delays it is expected to be commissioned soon with operational capacity of 1.2 MMTPA. The Dabhol terminal is further expected to ramp up its capacity to 5 MMTPA by 2013-14. Additional terminals are planned at Kochi and Mundra with their expected LNG capacity to reach ~30 MTPA by 2015-16.

Figure 30 schematically represents the emerging gas pipeline network and LNG infrastructure that is planned to be operational by the end of 12th Plan.

Figure 30: Expected Gas Infrastructure by 2016-17



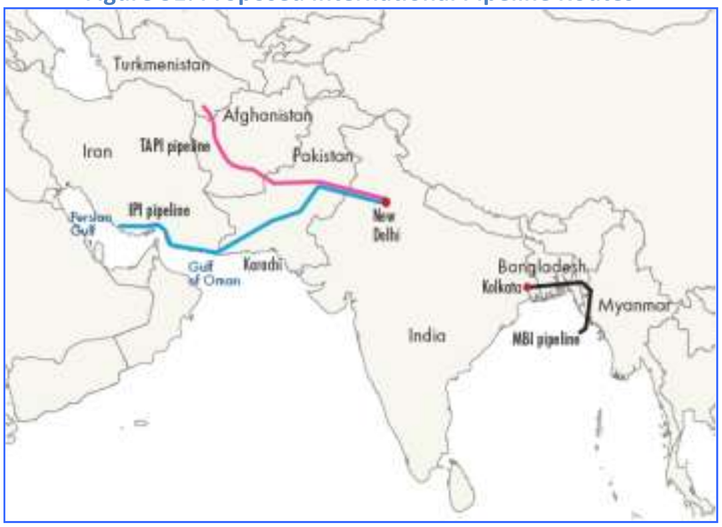
The pipelines are based on the collective plan of all the players and are either under construction or in the planning stages. The pipeline grid emerges as an integrated network that ensures gas availability and accessibility across most regions. The gas pipeline is not expected to be a constraint over the planning periods as envisaged in this study

[16] Excluding Hazira expansion plan

5.2.6.5 International Pipelines

A number of cross border pipelines from countries such as Iran, Turkmenistan, Myanmar and Bangladesh have been conceived for long. There is also a considerable support between the government and the industry for the development of these pipelines for economic and strategic reasons including the likely cost competitiveness, the positive impact on of energy security and the diversity of fuel mix leading to decrease in the fuel price volatility.

Figure 31: Proposed International Pipeline Routes



Key international pipeline initiatives along with the associated issues are discussed in detail below.

Iran-Pakistan-India (IPI): The IPI Gas Pipeline Project has been conceived as a tripartite arrangement between Iran, Pakistan and India, with the imports being divided between India and Pakistan. The proposed pipeline is ~2,670 kilometers and is expected to originate at Assaluyeh, Bandar Abbas in Iran and connect to the HBJ pipeline in India via Baluchistan and Punjab provinces in Pakistan. The initial project cost was estimated at US $ 5 billion and expected to carry ~800 MMSCFD gas. Gas would be sourced from the South Pars/North Dome gas field, which straddles the territory of Iran and Qatar in the Persian Gulf. The Iranian share of the gas field is estimated to contain around 13 tcm of gas. The volume of gas supplied by this pipeline could reach 55 bcm a year. India has sought around 37 bcm, while Pakistan's share would be around 18 bcm.

Several outstanding issues have caused substantial delays in the commencement of the pipeline. These include but are not limited to disagreements related to gas pricing between India and Iran, as well as capital cost increases. In addition, geopolitical tensions in India–Pakistan relations and concerns about terrorist activities, particularly in Baluchistan province in Pakistan, international concerns over trade with Iran, as well as domestic opposition in Iran to gas exports, have also hindered progress. All these hurdles associated with the project have the potential for further delays and heighten the uncertainty surrounding a prospective startup date. Given the uncertainties that surround the IPI pipeline, a possible startup date assumption would have high uncertainty.

<u>Myanmar-India pipeline:</u> A ~1,575 km long pipeline connecting the Shwe field in the A-1 block in Myanmar, in which both ONGC Videsh and GAIL own a stake, was expected to bring gas to India, while passing through Bangladesh. However, not much progress has happened on this front in recent times. Gas reserves of 5 TCF were discovered in the A1 gas field in Myanmar in 2001 in which GAIL holds 10% and OVL holds 20%. The Myanmar Government has a production share of 45%. Earlier the Government of Myanmar had planned to supply this gas to the Indian market for offloading it to the JV partners OVL and GAIL. But in 2006 Myanmar Government signed a contract to supply gas to China from the same field. Considering the balance reserve in place, it may not be feasible for Myanmar to transport it to India from same field.

In this case, while officials from all countries have agreed in principle to support the export of natural gas to India, the emergence of China as a foundation customer for Myanmar pipeline gas exports is likely to divert gas away from India. Considering the China play, this pipeline to India is very unlikely to proceed.

<u>Turkmenistan-Afghanistan-Pakistan-India (TAPI) pipeline:</u> This Asian Development Bank (ADB) sponsored project is likely to connect sources of supply in Turkmenistan to sources of demand in Pakistan and India. The pipeline would follow a route through Afghanistan and Pakistan to India and would be ~1,680 kilometers with a capacity of 90-100 MMSCMD. The TAPI pipeline proposal would source gas from the Dauletabad field in south east Turkmenistan.

While Turkmenistan has indicated that it supports the pipeline, once again, the project is advancing cautiously, with some headway being made in discussions. Issues regarding gas pricing, transit price and security of the pipeline in Pakistan and conflict in Afghanistan, transmission tariffs are yet to be finalized. Also, the emergence of over aggressive China as a foundation customer for Turkmenistan pipeline gas exports is likely to divert gas away from India. According to a framework agreement signed between the ministers of the four countries in spring 2008, construction was scheduled to begin in 2010 and operations to start in 2015, however given the current scenario the pipeline is unlikely to materialize soon.

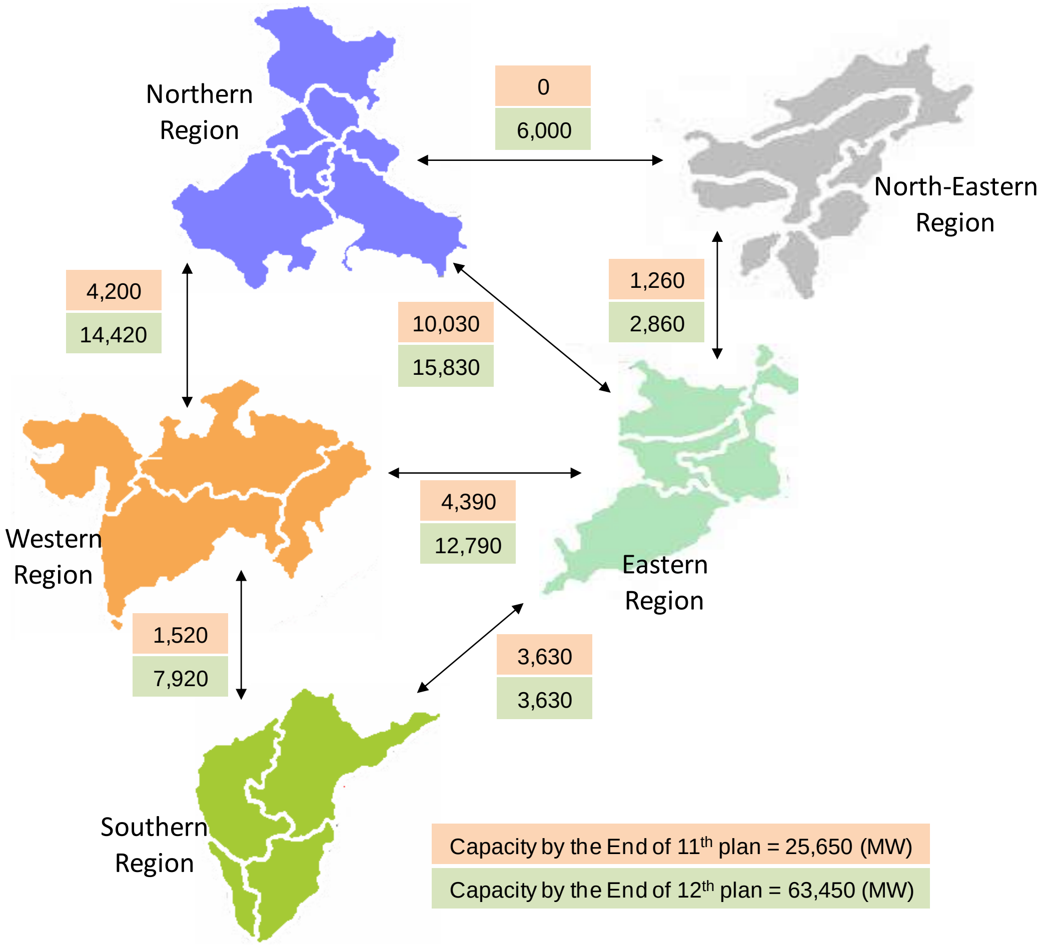
<u>Bangladesh-India Pipeline:</u> Since 2002, UNOCAL has promoted the idea of a 30”, 1,367 km pipeline, which would carry gas from its Bibiyana fields in Bangladesh to the gas markets in northern India. The pipeline’s proposed initial capacity would be around 500 MMSCFD. The project is currently stalled due to political opposition to gas exports in Bangladesh.

As discussed above, the progress on all the pipelines has been very slow. Given the current geopolitics and security concerns, it seems unlikely that these pipeline projects would takeoff even in the long term. Therefore the impact of international pipeline projects is not considered in the current study.

5.2.6.6 Transmission

Transmission planning and development in India is carried out in an integrated manner along with the generation plans. The planning philosophy for transmission is focused on integrating the scattered pockets of resources and load centers and strengthening the regional and inter-regional networks of the national grid. As of March 2011, the inter-regional transmission capacity stands at 22,400 MW and is expected to be 25,650 MW by the end of 11^{th} Plan. The strengthening of national grid is under way along with several high voltage lines under development. Private participation in the sector has also increased during the current plan and seven projects have been awarded over the last two years through competitive bids.

Figure 32: Expected Inter-Regional Transmission Capacity by 2016



There has been accelerated growth in the transmission sector that has helped in improving power supply situation in various regional grids leading to improved system reliability and better grid stability. Approximately 75% of the transmission lines targets and 90% of substation capacity have been achieved in the first four years of the 11th Plan. Table 20 below indicates the yearly target vs. achievement in transmission capacity addition.

Table 20: Transmission Plans Target vs. Achievement during Eleventh Plan

Eleventh Five Year Plan (2007-2012)	Tx. Lines (Fig. in ckt km)			Substation (Fig. in MVA/MW)		
	Target	Achievement	% Achieved	Target	Achievement	% Achieved
2007-08	5,448	4,160	76%	11,020	9,658	88%
2008-09	6,493	4,171	64%	14,943	11,235	75%
2009-10	7,103	5,139	72%	14,260	11,735	82%
2010-11	18,563	15,161	82%	27,736	31,657	114%

2011-12*	19,792	5,863	30%	27,380	6,830	25%

*Data as of August 2011. Source: CEA

Major areas of concerns in development of transmission network in the country are as follows -

- Conserving Right-of-way (Row),
- Minimizing impact on natural resources,
- Coordinated development of cost effective transmission corridor, and
- Flexibility in up-gradation of transfer capacity of lines matching with power transfer requirement.

The 12th plan envisages adding ~40 GW of inter-regional transmission capacity during 2012-2017. In view of the historical poor performance against the targets and the huge investment requirement, it is anticipated that the planned inter-regional transmission capacity would not materialize and there would be slippages. The total inter-regional capacity is expected to be ~63 GW by the end of 12th plan. Details of the expected plans and likely achievements are outlined in Table 21 below and represented in Figure 32.

Table 21: Expected Planned Transmission Inter-Regional Capacity by the end of 12th Plan (MW)

Inter-Regional Links	Capacity at end of 10th Plan	Capacity at end of 11th Plan	Capacity expected at end of 12th Plan	
	Actual	Actual	Planned	Expected Achievement
ER-SR	3,100	3,600	7,800	3,630
ER-NR	5,800	11,300	17,200	15,830
ER-WR	1,800	6,550	18,050	12,790
ER-NER	1,250	2,250	2,250	2,860
NR-WR	2,100	7,600	17,800	14,420
WR-SR	1,700	2,700	9,200	7,920
NER/ER-NR/WR	0	0	6000	6,000
Total	**15,750**	**25,650**	**78,300**	**63,450**

Source: CEA

Beyond 12th Plan, the additional transmission capacities required will be forecasted using I-IPM® and will be commensurate with the capacity additions on the generation side.

The cost assumptions for various transmission lines as considered in this study are provided in Table 22 below.

Table 22: Cost Assumptions for Potential Transmission Lines (INR)

Details of the transmission links		Cost
Voltage Level	Circuit	
400 KV	S/C	70 lakh\ km.
400 KV (twin moose)	D/C	1.05 crore\km
400 KV(quad moose)	D/C	1.8-1.9 crore\km
765 KV	D/C	2.8-2.9 crore\km
765 KV	S/C	1.5 crore\km
HVDC (+/ - 500 KV)	-	1.26 crore\km

Details of the transmission links		Cost
Voltage Level	Circuit	
400 KV (bay)	-	10 crore\bay (for two bays)
765 KV (bay)	-	12.5 crore\bay
Transformer (500 MVA) single phase	-	10 crore
Transformer (315 MVA) 3 Phase	-	9 crore
Auxiliary equipment	-	10% extra of bay cost.

Source: CEA

5.3 Renewable Energy Resources: Modeling Assumptions and Issues

India has abundant, untapped renewable energy resources present in various forms. The MNRE estimates indicate that the potential of grid connected renewable resources is ~87,000 MW[17] (excluding Solar and energy plantation on wasteland) - details provided in the Table 23.

Table 23: Renewable Resource Potential

S. No.	Resource	Estimated Potential (In $MW_{eq.}$)
1	Wind	49,130 [a]
2	Small Hydro (up to 25 MW)	15,000
3	Bio-Fuel	
	Agro-Residues	18,000 [b]
	Cogeneration – Bagasse	5,000 [c]
	Waste to Energy: - Municipal Solid Waste to Energy - Industrial Waste to Energy	 1,700 [d] 1,000
4	Solar Energy	20 MW/ sq. km. [e]

Source: MNRE, Not all of this potential may be suitable for grid-interactive power for technical and/ or economic reasons

[a] *Potential based on areas having wind power density (wpd) greater than 200 W/m^2 assuming land availability in potential areas @ 2% and requirement of wind farms @ 9 MW per sq km. The lower end of the potential might be suitable for off-grid applications.*

[b] *Based on surplus agro-residues*

[c] *Technically feasible potential with expected addition of new sugar mills and modernization of existing ones*

[d] *Technically feasible municipal waste-to-energy potential considering the expansion of urban population post census 2001*

[e] *The potential for solar power is dependent on future developments that might make solar technology cost-competitive for grid-interactive power generation applications*

However, there is a wide variation in the renewable potential estimated by different institutions especially for Wind and Solar resources. In the following sub-section, we have discussed each of the renewable resources in detail.

5.3.1 Resource Availability

5.3.1.1 Wind

The Centre for Wind Energy Technology (C-WET) has assessed the potential for grid interactive onshore wind resource at about 49,130 MW at 50 m hub-height[18]. This potential is estimated based on a comprehensive wind mapping exercise, which established a country-wide network of 1,050 wind monitoring and wind mapping stations across 25 States. The key assumptions considered in estimating the potential are as follows –

- Wind resource availability at 50 m hub height
- Wind power density (wpd) greater than 200 W/m2
- 2% land availability in all states (except Himalayan/N-E and A&N islands)
- Land requirement of @ 9 MW per square km

[17] Source: MNRE
[18] The potential has recently been revised to 102 GW at 80 m hub-height

The study shows that the onshore wind resource is concentrated mainly in Western and Southern Region viz– Gujarat, Karnataka, Maharashtra, Andhra Pradesh and Tamil Nadu with highest potential present in Gujarat (Table 24, Figure 33).

Table 24: Official Estimate of State-Wise Wind Resource Potential

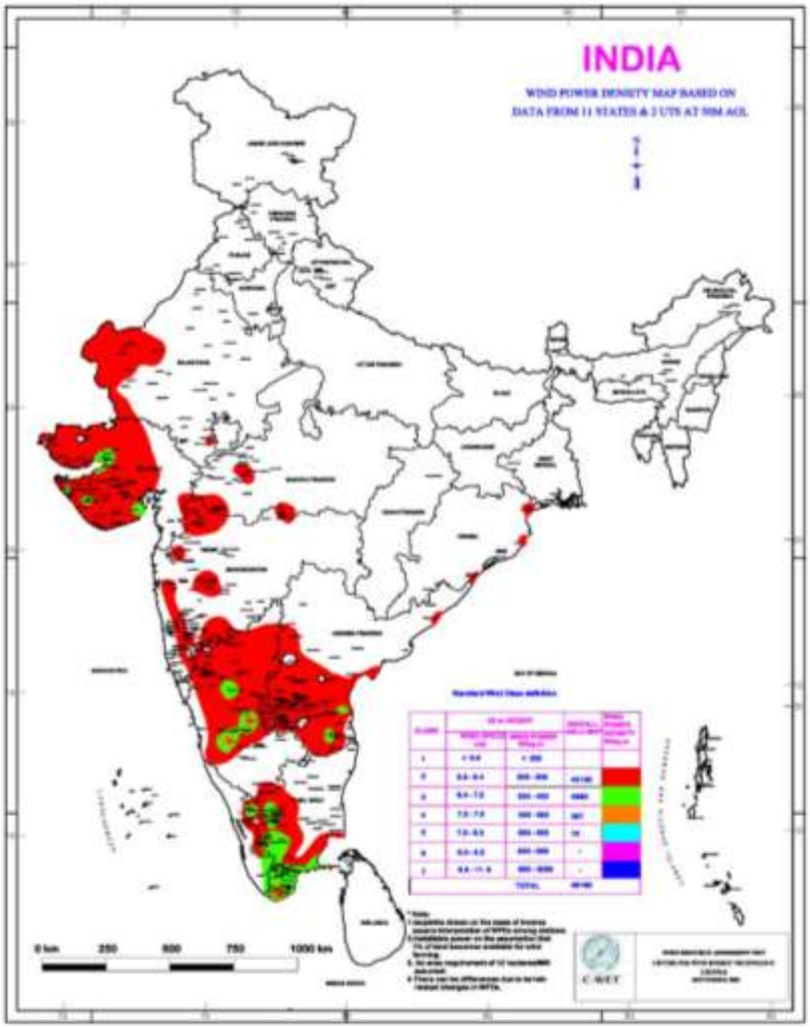
State	Potential (MW)	State (Potential yet to be validated)	Potential (MW)
Andaman & Nicobar	2	Nagaland	3
Lakshadweep	16	Manipur	7
Kerala	790	Himachal Pradesh	20
Orissa	910	West Bengal	22
Madhya Pradesh	920	Chhattisgarh	23
Rajasthan	5,005	Meghalaya	44
Tamil Nadu	5,374	Assam	53
Andhra Pradesh	5,398	Sikkim	98
Maharashtra	5,439	Uttar Pradesh	137
Karnataka	8,591	Uttarakhand	161
Gujarat	10,609	Arunachal Pradesh	201
		Jammu & Kashmir	5,311
Total	**43,054**	**Total**	**6,080**
Grand Total = 49,134			

Source: MNRE, * represents state where potential is yet to be validated

However, there is a wide variation observed between the estimates provided by C-WET vis-à-vis provided by various other agencies. This variation in potential across the studies can be attributed to varied assumptions mainly on the following parameters -:

- Wind Density and Speed
- Different Hub Heights
- Better and Efficient Technology
- Type and size of turbines
- Land requirement

Figure 33: Wind Power Density Map



Source: C-WET

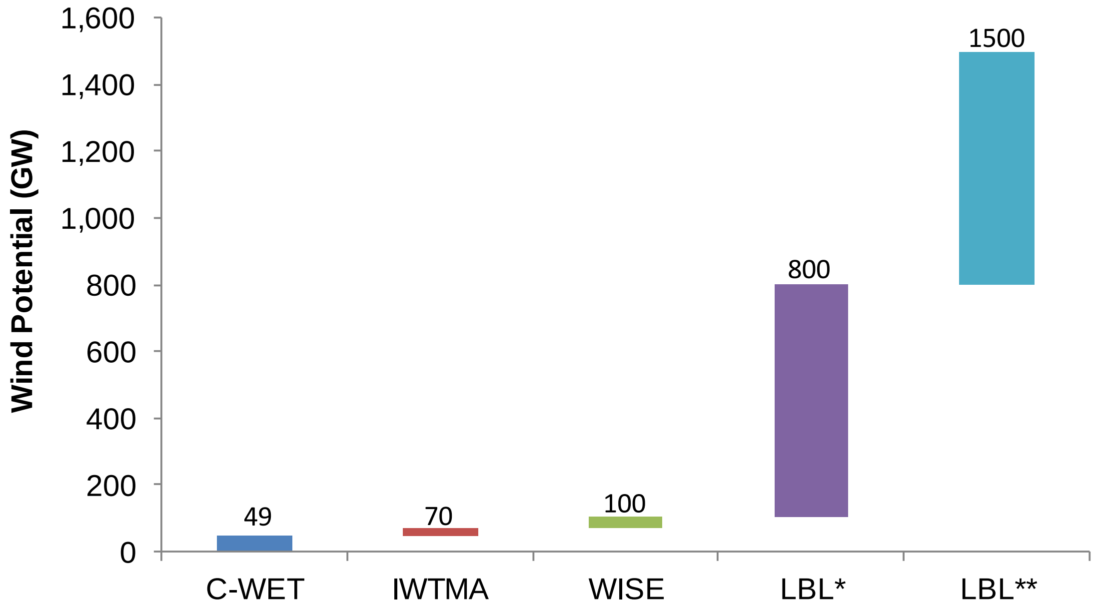
Table 25: Wind Potential Estimates by Various Agencies

S.No.	Organization/Institute	Estimated Wind Potential (GW)
1	Indian Wind Turbine Manufacturers Association (IWTMA)	65-70 GW[19] based on hub heights of 55–65 m and higher conversion efficiencies due to technology improvements
2	World Institute for Sustainable Energy (WISE)	~100 GW based on larger turbine size, greater land availability and expanded resource exploration
3	Lawrence Berkeley National Laboratory (LBNL)	These estimates are drawn based on the satellite data. The potential has been defined under two distinct scenarios – no farmland included and all farmland included. Under "no farmland included" scenario, the potential ranges from 748 GW (at 80m hub-height) to 976 GW (at 120m hub-height). Similarly, under "all farmland included" scenario, the potential ranges from 984 GW (at 80m hub-height) to 1,549 GW (at 120m hub-height) The estimates also assume the usage of better and efficient technology and of larger sizes of wind turbines.

[19] http://www.indianwindpower.com/iw_energy_economy.php

Comparing the estimates as suggested by the independent studies (Table 25) the wind potential in the country ranges from ~50 GW to 1,500 GW (Figure 34).

Figure 34: Wind Potential Assessment by Various Institutes/Agencies



* At 80 m hub-height under "no farmland" scenario, ** 120 m hub-height under "all farmland" scenario

The estimates provided by CWET seem to be on the conservative side and can be safely considered to be the minimum possible wind potential in the country. Given the higher potential established by the above studies, there is a pressure on the planning agencies to reassess the wind potential.

As such MNRE and C-WET are conducting a new study that will extrapolate the wind potential at 80 m sub height based on the results of past study (that was conducted to estimate the resource at 50 m sub height). The preliminary findings of this study suggest an on-shore wind potential of ~100 GW at 80 m hub-height.

In Off-shore Wind, C-WET is conducting feasibility studies and monitoring potential sites for off-shore projects however, no official estimates and resource map is available as yet. On the other hand, the independent study carried out by LBNL estimates off-shore developable wind potential as ~ 238 GW with capacity factor of 21 percent at 100m hub-height and <30m depth. In another research, a wind potential of 15,000 MW (<60m depth)[20] has been suggested. However, offshore wind technology is still unproven on Indian grounds. The development of off-shore wind power faces several challenges: high capital cost, lack of regulatory framework, lack of data and clarity on clearances in addition to the technical constraints associated with shallow water, sheer deep surface and cyclonic condition.

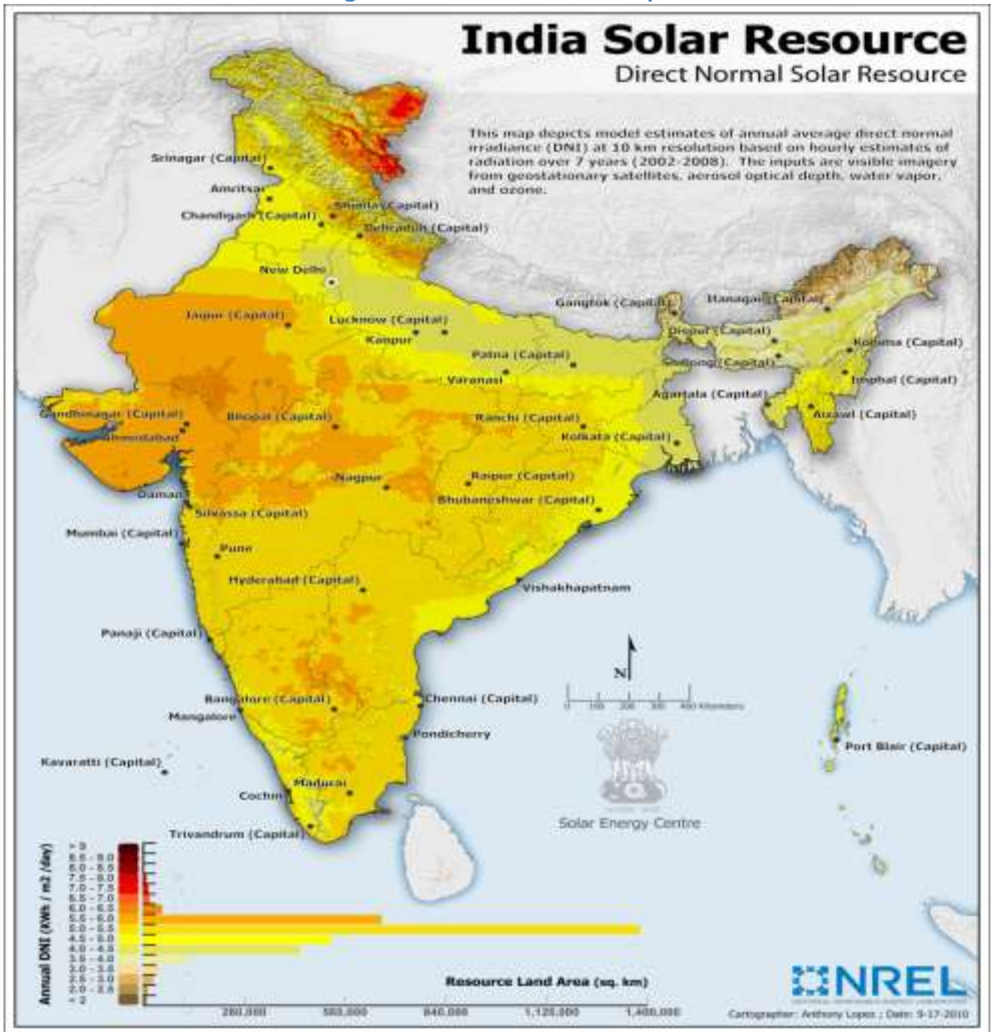
Thus the achievable potential during the period 2012-31 could be much larger and may not be regarded as a constraint, as also suggested by various recent wind potential estimation studies. However, looking at all the issues and other constraints that exist around wind power development, in this study, a conservative assumption of 250 GW has been considered.

[20] Source: MNRE, study by Dolf Gielen, Nathalie Trudeau, Dagmar Graczyk and Peter Taylor, October 2009

5.3.1.2 Solar

Solar is currently an underutilized energy resource and offers huge potential for capacity development. On an average, India has 300 sunny days per year and each day receives an average hourly radiation of 200 MW/ sq km. The following solar resource map (Figure 35) shows the geographical and topological spread of the solar resource. As shown in the figure, clearly Rajasthan and Gujarat receive the maximum solar radiation and are in fact the favorable destinations for solar investments.

Figure 35: Solar Resource Map



Source: National Renewable Energy Laboratory (NREL)

Various studies have used different assumptions on land use and technology deployed to estimate the solar potential. Table 26 below provides the details of the underlying assumptions to estimate the solar potential.

Table 26: Solar Potential Estimates by Various Agencies

S. No.	Organization/Institute	Assumptions used to measure the Solar Potential
1	MNRE	20 MW/sq km
2	India Energy Portal	Around 12.5% of India's land mass, or 413,000 sq km, could be used for harnessing solar energy and could be further increased by the use of building-integrated PV

S. No.	Organization/Institute	Assumptions used to measure the Solar Potential
3	German Aerospace Center	With the use of Concentrating Solar Power (CSP) technology the country could generate 11,000 TWh per year (~6000 GW[21])
4	Planning Commission[22]	Deploying solar on 1 percent of the land area could result in over 500,000 MW of solar power

As expected, the solar potential will vary significantly across these studies based on the combination of assumptions considered. Unlike other renewable technologies, Solar has infinite potential and its deployment will primarily be driven by the future solar technology developments, the cost-competitiveness and the policy framework. Accordingly, we have not capped the solar potential for the purpose of this study.

5.3.1.3 Small Hydro

Small hydropower plants are generally run-of-river plants and have a capacity of less than 25 MW. These are further subdivided into micro (100 kW or less), mini (between 100 kW and 2 MW), and small (between 2 MW and 25 MW). MNRE has estimated the potential for small hydro in India at ~15,386 MW for 5,718 prospective plant sites. Of this total potential, over 42% (6,592 MW) is concentrated in four northern mountainous states. The state-wise potential estimates from MNRE are indicated in Table 27 below.

Table 27: State-Wise Small Hydro Potential

State	No. of Sites	Small Hydro Potential (MW)
Andhra Pradesh	497	560
Arunachal Pradesh	550	1,329
Assam	119	239
Bihar	95	213
Chhattisgarh	184	993
Goa	6	7
Gujarat	292	197
Haryana	33	110
Himachal Pradesh	536	2,268
Jammu and Kashmir	246	1,418
Jharkhand	103	209
Karnataka	138	748
Kerala	245	704
Madhya Pradesh	299	804
Maharashtra	255	733
Manipur	114	109
Meghalaya	101	230
Mizoram	75	167
Nagaland	99	189
Orissa	222	295
Punjab	297	393
Rajasthan	66	57
West Bengal	294	662
Tamil Nadu	197	660

[21] Potential considered at 20% PLF
[22] Source: "Interim Report – Low Carbon Strategy for Inclusive Growth", 2011

State	No. of Sites	Small Hydro Potential (MW)
Tripura	13	47
Uttaranchal	444	1,577
Uttar Pradesh	251	461
A&N Island	7	7
Total	**5,778**	**15,386**

Source: MNRE

5.3.1.4 Bio-fuels

Bio-fuels are an important and traditional source of energy and currently contribute ~32% of the total primary energy needs in the form of woods and cow dung. Biomass resource is abundantly available and MNRE has developed Biomass atlas using satellite data to map the resource potential. Statistics indicated[23] that there is ~55.3 million ha of wasteland available of which ~20 million ha are currently used for agriculture, but with very low yields, ~34% land exist with or without scrub, ~20% is degraded forest, and ~10% is unsuited for cropping (barren rock, snow cover, glaciers etc.).

The draft “Bio-Energy Mission” for 12th Plan by working group suggests biomass resource potential of ~51 GW based on the revised collection efficiency. These estimates are based on 17,000 MW from agro-residue while 34,000 MW from energy plantation in waste land. However, this potential can be realized by improving the harvesting efficiency of agro-residues, better fuel management and developing policy framework for energy plantation.

Based on the biomass logistics, conversion and current harvesting efficiency (less than 50%), the biomass potential has been assessed by MNRE and is estimated as:

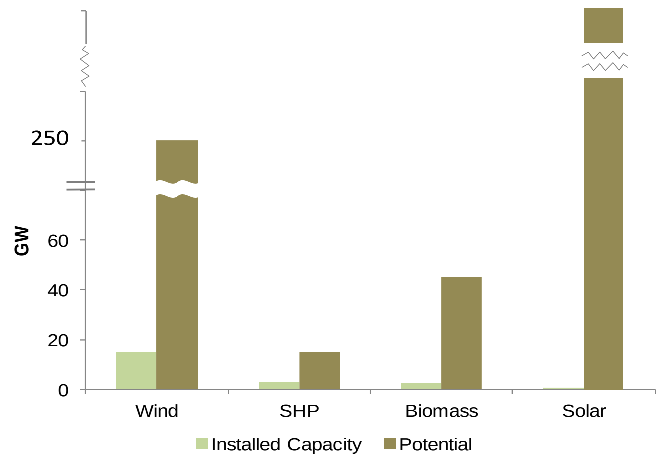
- Biomass-agri potential of ~18,000 MW[24] based on biomass fuel availability of ~500 million metric tonnes per annum and additional surplus from agricultural and forestry residues ~120 – 150 million metric tonnes per annum
- Bagasse based cogeneration potential of ~5000 MW (including existing and upcoming Sugar mills)
- Urban and industrial wastes yields ~2700 MW potential
- Energy plantation in degraded wasteland contributes ~20,000 MW. However, the wasteland energy plantation is at very nascent stages and pilot projects are being implemented in some states.

Total bio-fuel potential is thus been considered as 45,700 MW.

Figure 36: Untapped Renewable Potential

[23] Source: IEA Technology Development Prospects for India Power Sector

[24] Source: MNRE, Draft Recommendation of Sub-Group on “Bioenergy Mission” for 12th Five Year Plan (2012-17)


250
60
40
20
0
GW
Wind
SHP
Biomass
Solar
Installed Capacity
Potential

5.3.2 Capacity Utilization Factors and Generation Profiles

The Capacity Utilization Factor (CUF) for different renewable types is primarily dependent on the resource available at the location and the technology use. The CUFs norms as specified in *"Terms and Conditions for Determination of Tariff for Renewable Energy Sources (Nov 2011)"* for different renewable resources are tabulated below.

Table 28: RE Capacity Utilization Factor

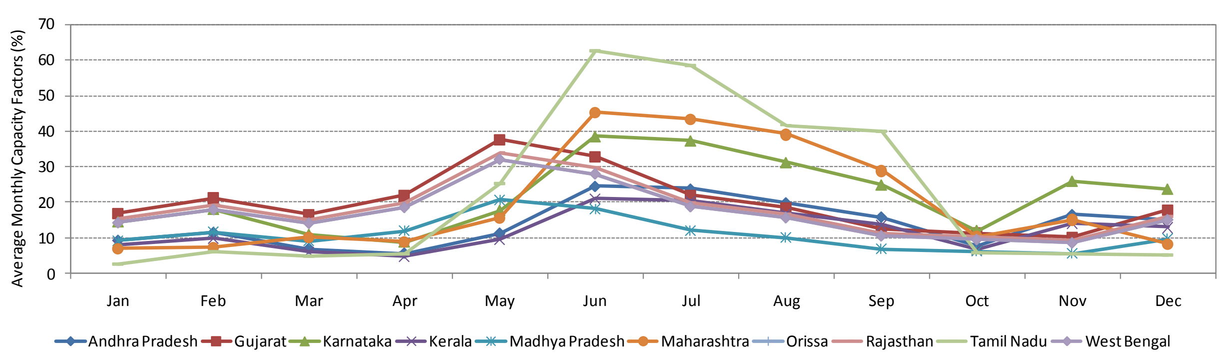
Renewable Energy Types	CUF
(A) Wind Energy (W/m^2)	
Windzone-1 (upto 200)	20%
Windzone-1 (200-250)	22%
Windzone-2 (250-300)	25%
Windzone-3 (300-400)	30%
Windzone-4 (above400)	32%
(B) Small Hydro	
HP, UT and NER	45%
Other States	30%
(C) Solar PV	19%
(D) Solar Thermal	23%

Source: CERC Tariff Norms for Renewable

The technology for setting up small hydro capacity is well established, the utilization factor for such plants is expected to remain same in future. Therefore, for small hydro capacities the CUF published by CERC has been assumed for the analysis period in this study. On the other hand, the solar and wind technology are expected to witness significant improvements which will lead to higher CUF's going forward.

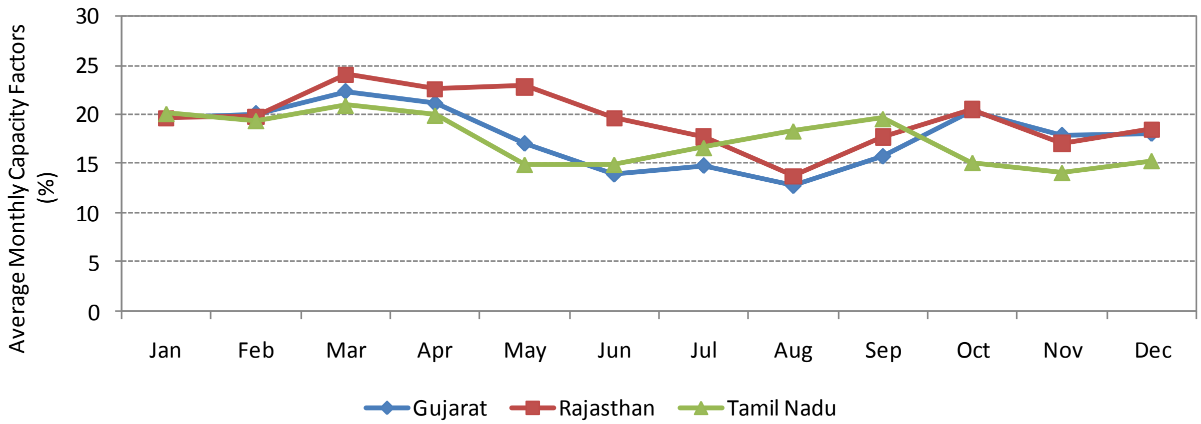
The generation profiles shown in Figure 37 have been assumed for the existing wind plants in various states. These profiles have been developed after normalizing and generalizing the generation data from some actual wind farms in various states to represent the profile for the whole state. The states, for which data is unavailable, the generation profiles have been developed based on its similarity with other states in terms of their location and resource potential. For the future wind plants that may be forecasted by I-IPM®, same profiles, escalated for their improved capacity utilization factors, have been used.

Figure 37: Average Monthly Capacity Factors for Wind



For solar PV and solar thermal, a similar analysis has been done based on the actual data obtained for some states. However, the data has been normalized to represent the generation profile for the whole state. For other states, the generation profiles have been developed based on the similarity of the state; in terms of location, altitude and potential; with other states. For the future solar plants that may be forecasted by I-IPM®, same profiles, escalated for their improved capacity utilization factors, have been used.

Figure 38: Average Monthly Capacity Factors for Solar



5.3.3 Capital Costs Trends

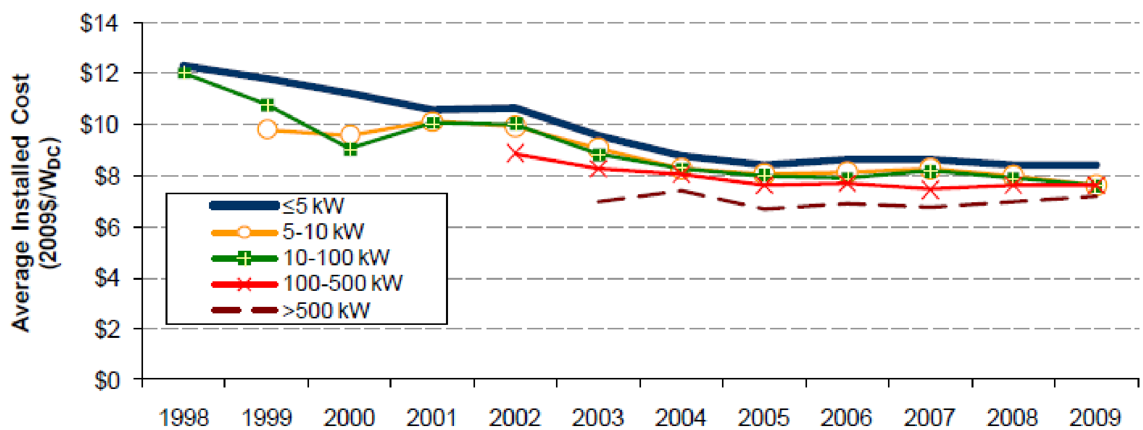
The capital cost assumptions for different renewable generation technologies are inclusive of all capital work including plant and machinery, civil work, erection and commissioning, financing and interest during construction, and evacuation infrastructure up to inter-connection point.

The key renewable resources of Wind and Solar are expected to witness significant technology improvement which will lead to increase in efficiencies and the reduction in the overall cost of generation.

Globally, the solar power industry has grown rapidly and witnessed a significant reduction in the installation costs. Approximately 60% of the solar installation cost comprises of the module costs. Due to technology improvement, the module prices have fallen sharply (Figure 39) over the years. The learning curve[25] of PV module suggests a reduction of approx 20% in module costs per doubling of capacity. This costs reduction can be attributed to following factors:

- Technological innovation
- Economies of scale
- Improved capacity utilization factors
- Extended life time of solar systems

Figure 39: Global Trends in Solar PV Installed Costs



Source: LBNL

The rate of technological improvements and global supply-demand balance will determine the future availability of cost-effective solar technology. However, IEA projects the solar costs to move to grid parity by 2020[26] globally.

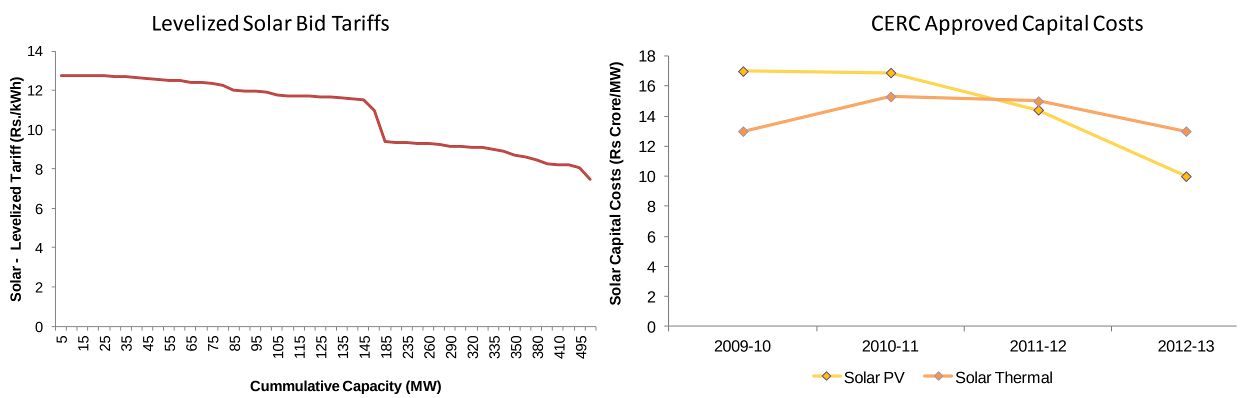
[25] Source: Research Paper – "RESEARCH AND DEVELOPMENT INVESTMENTS IN PV – A LIMITING FACTOR FOR A FAST PV DIFFUSION?" Ch. Breyer et. Al.
http://www.q-cells.com/uploads/tx_abdownloads/files/17_RESEARCH_AND_DEVELOPMENT_Paper_02.pdf

[26] Source: IEA – "Technology Roadmap: Solar Photovoltaic Energy"

India currently holds 2% share of the global solar installations and this share is expected to increase over the years. Much of the growth in solar power industry in India has been driven by the policy initiative – Jawaharlal Nehru National Solar Mission (JNNSM) launched in 2009. The three phase mission aims to add 20,000 MW by 2022, and currently ~1000 MW solar projects have been allocated till date. Given the vision, the scalable growth is expected in the sector which will lead to significant reduction in costs.

In the 2nd batch Phase 1 of bidding concluded recently, the levelized tariffs of Solar PV have already dropped to 7.49 Rs./kWh vis-à-vis the batch 1 phase 1 tariff of 12.76 Rs./kWh. Moreover, benchmark capital costs as determined by CERC over last 4 years have also witnessed a downward trend with a 12% year on year decline in PV (Figure 40).

Figure 40: Falling Trend - Solar Costs in India

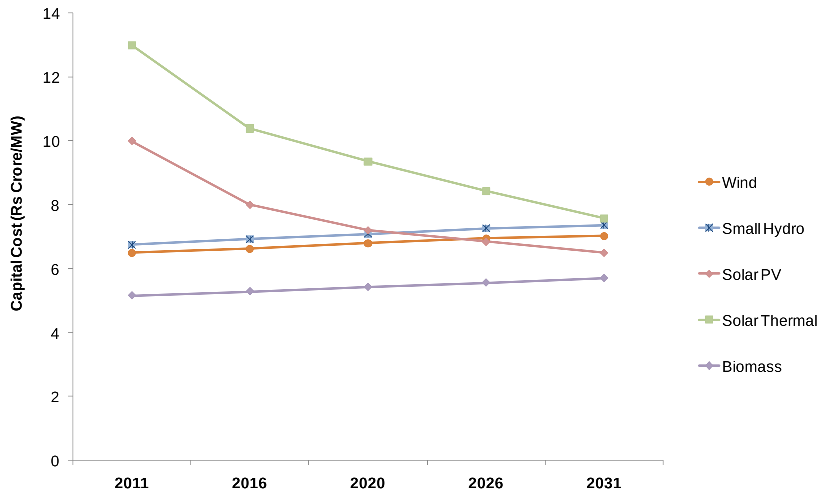


Looking at the trends and the expected research and development in solar technology, the reduction in costs is expected to be strong in the coming decade. A cost reduction of 20% by 2016, 10% by 2020 and 5% each by 2026 and 2031 is assumed. The solar capacity is expected to be competitive vis-à-vis conventional capacity by 2031.

Upcoming novel technologies (like low wind speed and high resistance turbines) will be the key driver for the reduced installation as well as generation cost of wind power plant. Globally, with the advent of technology, the costs of onshore wind turbines, which account for approx 75% of the total investment cost, have decreased by almost a factor of three since 1980s. Also globally, wind technology learning curve suggests as annual cost reduction of approx 10% in the last decade. The downward pressure on cost is also expected due to the volume growth in the capacity additions as well as and the increase in competition. But on the other hand, the raw material and land acquisition costs are likely to build an upward pressure on the wind installation cost.

In India, the existing rich potential sites have been running on poor technologies with less hub-heights. These sites may require up-gradation to improved technologies and also increase in the hug-height. The new sites, which may be developed over the study period, exist in areas with tougher terrains that have poor accessibility, environmental constraints and infrastructure bottlenecks. Considering the impact of these factors, we have assumed that the capital costs for wind will increase marginally over the study period by 2031. Figure 41 provides the assumptions on expected capital cost curve for different renewable generation technologies.

Figure 41: Capital Cost trend for Different Renewable Generation Technologies



Capital cost for other renewable technologies, like small hydro and biomass, for the base year 2012 is taken as per the CERC norms (for tariff determination purposes). For future years, the capital cost has been inflated to capture the impact of increase in cost due to land acquisition, environment cost, cost of materials and manufacturing processes and technology improvements.

5.3.4 Technology Development

Solar Technology

Solar PV technologies can be divided into four broad categories - Crystalline silicon, thin film, Concentrated PV and the upcoming Organic PV technology. The CUFs of Crystalline silicon technologies lie between 18-22%, Thin film modules have a lower CUF between 7-12%, while Concentrating PVs CUFs are between 25-30% for silicon modules and around 40% for GaA modules. The new organic PV modules has low efficiency ~6%, however, it's manufacturing costs are also very low, resulting in overall economics of the PV system (Table 29).

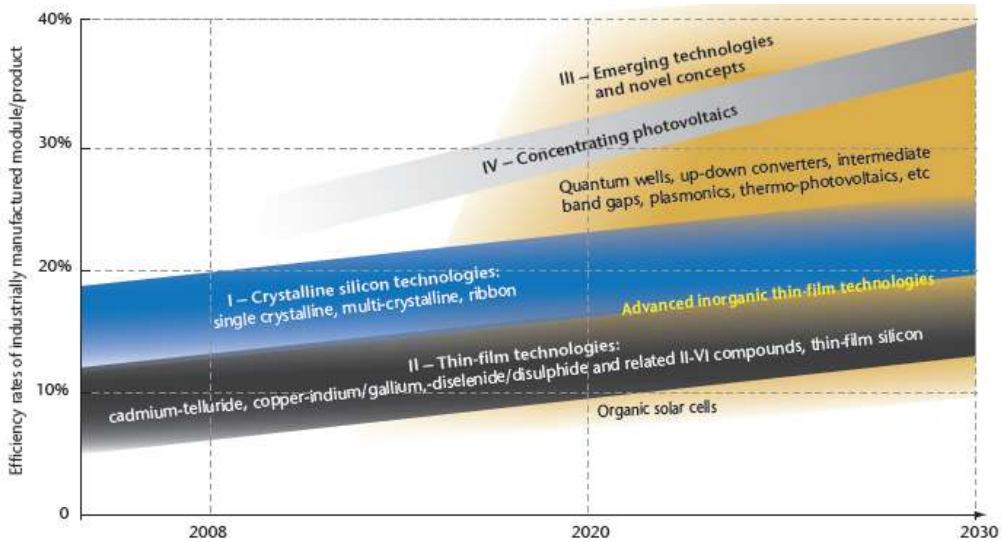
Table 29: Efficiencies of commercially available technologies

	Commercially Available Technologies	Efficiencies
Crystalline Silicon Technology	Mono (back contact)	22%
	HIT™	19.80%
	Mono (Pluto™)	19%
	Nanoparticle ink	18.90%
	Mono	18.50%
Thin Film	Amorphous Silicon(a-Si)	7-10%
	Mutlijunction Thin film(a-Si/µ-Si)	10%
	Cadmiun Telluride(CdTe)	11.20%
	CIGS/CIS	12.10%
Concentrated PV	Silicon	25%-30%
	Gallium Ascenide(GaA)	40%
Emerging	Organic Solar PVs	6%

Source: IEA

Historically Crystalline silicone technology has dominated the market but with technology development the future efficiencies are going to improve. IEA roadmap on Solar PV technology projects that market share of CPVs and upcoming new technologies will increase by 2030, and therefore the likely efficiencies are expected to be in the range of 40% (Figure 42). The expected future deployment of CPVs in India is also assumed to increase from current 20% to 30% by 2031.

Figure 42: Expected Solar Photovoltaic Technology Developments and Efficiencies

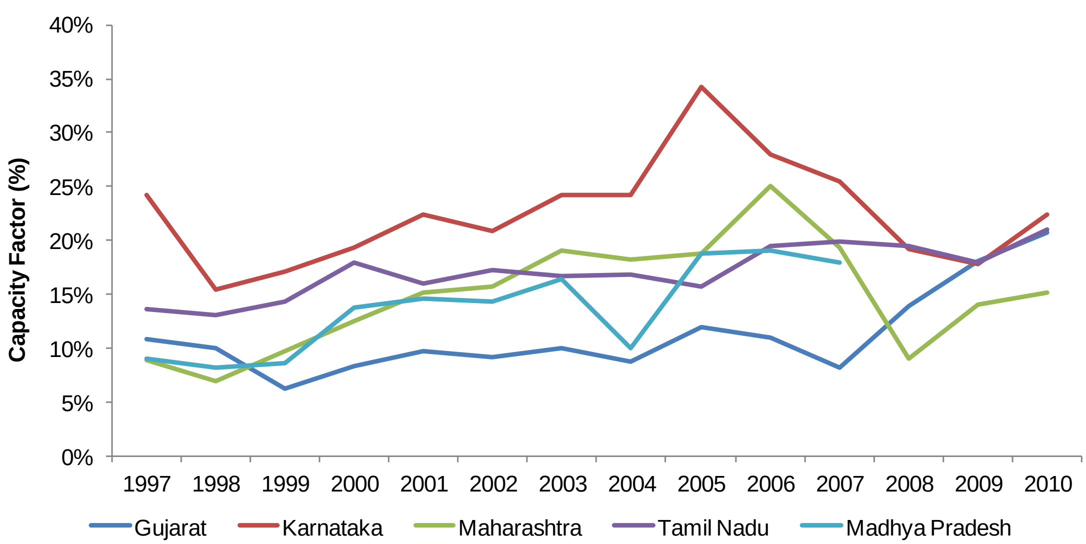


Source: IEA – "Technology Roadmap: Solar Photovoltaic Energy"

Wind Technology

Wind turbine technology in India lags the global development. The installed turbine capacity ranges from 250 kW to 2,100 kW compared to a global maximum of 5,000 kW; hub heights range from 41 m to 88 m compared to a global maximum of 117 m; and rotor diameters range from 28 m to 80 m, compared to a global maximum of 126 m. Figure 43 below illustrate historical capacity factor trend across five states that account for more than 85% of the installed wind capacity.

Figure 43: Historical Wind Capacity Factors (%)



Source: WISE

For similar locations, a considerable difference has been observed in the capacity utilization factor depending on the technology of turbine used. However, such efficient turbines have also been accordingly priced higher.

Overall, based on the available turbine size and the technologies, we have assumed an average capacity factor of ~20% in near future. Given the future technology development, the penetration into higher wind zone and the usage of large turbine size installed at higher hub-heights, the likely wind capacity factors may improve marginally. We have accordingly assumed that the average CUF will increase to 30% across the wind zones by 2031.

5.3.5 Renewable Purchase Obligation

For promoting RE, Electricity Act 2003 and the National Tariff Policy mandates states to specify Renewable Purchase Obligation (RPOs). Various State Commissions have specified the RPO for different RE types. The specified RPO varies from 1% to 14% across the states (Table 30).

Table 30: State-Level RPOs (%)

State	RE Technology	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17
Andhra Pradesh	Non-Solar	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%
	Solar	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%
	Total	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Arunachal Pradesh	Non-Solar		4.10%	5.45%	6.80%		
	Solar		0.10%	0.15%	0.20%		
	Total		4.20%	5.60%	7.00%		
Assam	Non-Solar	2.70%	4.05%	5.40%	6.75%		
	Solar	0.10%	0.15%	0.20%	0.25%		
	Total	2.80%	4.20%	5.60%	7.00%		
Bihar	Non-Solar	2.25%	3.75%	4.00%	4.25%		
	Solar	0.25%	0.25%	0.50%	0.75%	1.00%	1.25%
	Total	2.50%	4.00%	4.50%	5.00%		
Chhattisgarh	Non-Solar	5.00%	5.25%				
	Solar	0.25%	0.50%				
	Total	5.25%	5.75%				
Delhi	Non-Solar	1.90%	3.25%	4.60%	5.95%	7.30%	8.65%
	Solar	0.10%	0.15%	0.20%	0.25%	0.30%	0.35%
	Total	2.00%	3.40%	4.80%	6.20%	7.60%	9.00%
JERC (Goa & UT)	Non-Solar	1.70%	2.60%				
	Solar	0.30%	0.40%				
	Total	2.00%	3.00%				
Gujarat	Non-Solar	5.50%	6.00%				
	Solar	0.50%	1.00%				
	Total	6.00%	7.00%				
Haryana	Non-Solar	1.50%	2.00%	3.00%			
	Solar	0.00%	0.05%	0.10%			
	Total	1.50%	2.05%	3.10%			
Himachal Pradesh	Non-Solar	10.00%	10.00%	10.00%	10.00%	11.00%	12.00%
	Solar	0.01%	0.25%	0.25%	0.25%	0.25%	0.25%
	Total	10.01%	10.25%	10.25%	10.25%	11.25%	12.25%
Jammu and Kashmir	Non-Solar	2.90%	4.75%				
	Solar	0.10%	0.25%				

	Total	3.00%	5.00%				
Jharkhand	Non-Solar	2.50%	3.00%				
	Solar	0.50%	1.00%				
	Total	3.00%	4.00%				
Karnataka	Non-Solar	10% and 7%					
	Solar	0.25%					
	Total (Discoms only)	10.25% & 7.25%					
Kerala	Non-Solar	3.35%	3.65%	3.95%	4.25%	4.55%	4.85%
	Solar	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%
	Total	3.60%	3.90%	4.20%	4.50%	4.80%	5.10%
Madhya Pradesh	Non-Solar	2.10%	3.40%	4.70%	6.00%		
	Solar	0.40%	0.60%	0.80%	1.00%		
	Total	2.50%	4.00%	5.50%	7.00%		
Maharashtra	Non-Solar	6.75%	7.75%	8.50%	8.50%	8.50%	
	Solar	0.25%	0.25%	0.50%	0.50%	0.50%	
	Total	7.00%	8.00%	9.00%	9.00%	9.00%	
Manipur	Non-Solar	2.75%	4.75%				
	Solar	0.25%	0.25%				
	Total	3.00%	5.00%				
&Mizoram	Non-Solar	5.75%	6.75%				
	Solar	0.25%	0.25%				
	Total	6.00%	7.00%				
Meghalaya	Non-Solar	0.45%	0.60%				
	Solar	0.30%	0.40%				
	Total	0.75%	1.00%				
Nagaland	Non-Solar	6.75%	7.75%				
	Solar	0.25%	0.25%				
	Total	7.00%	8.00%				
Orissa	Non-Solar	4.90%	5.35%	5.80%	6.25%	6.70%	
	Solar	0.10%	0.15%	0.20%	0.25%	0.30%	
	Total	5.00%	5.50%	6.00%	6.50%	7.00%	
Punjab	Non-Solar	2.37%	2.83%	3.37%	3.81%		
	Solar	0.03%	0.07%	0.13%	0.19%		

	Total	2.40%	2.90%	3.50%	4.00%		
Rajasthan	Non-Solar	5.50%	6.35%	7.00%			
	Solar	0.50%	0.75%	1.00%			
	Total	6.00%	7.10%	8.20%			
Tamil Nadu	Non-Solar	8.95%					
	Solar	0.05%					
	Total	9.00%					
Tripura	Non-Solar	0.90%	1.90%				
	Solar	0.10%	0.10%				
	Total	1.00%	2.00%				
Uttarakhand	Non-Solar	4.50%	5.00%				
	Solar	0.03%	0.05%				
	Total	4.53%	5.05%				
Uttar Pradesh	Non-Solar	4.50%	5.00%				
	Solar	0.50%	1.00%				
	Total	5.00%	6.00%				
West Bengal	Non-Solar			3.75%	4.70%	5.60%	6.50%
	Solar			0.25%	0.30%	0.40%	0.50%
	Total	3.00%	4.00%	4.00%	5.00%	6.00%	7.00%

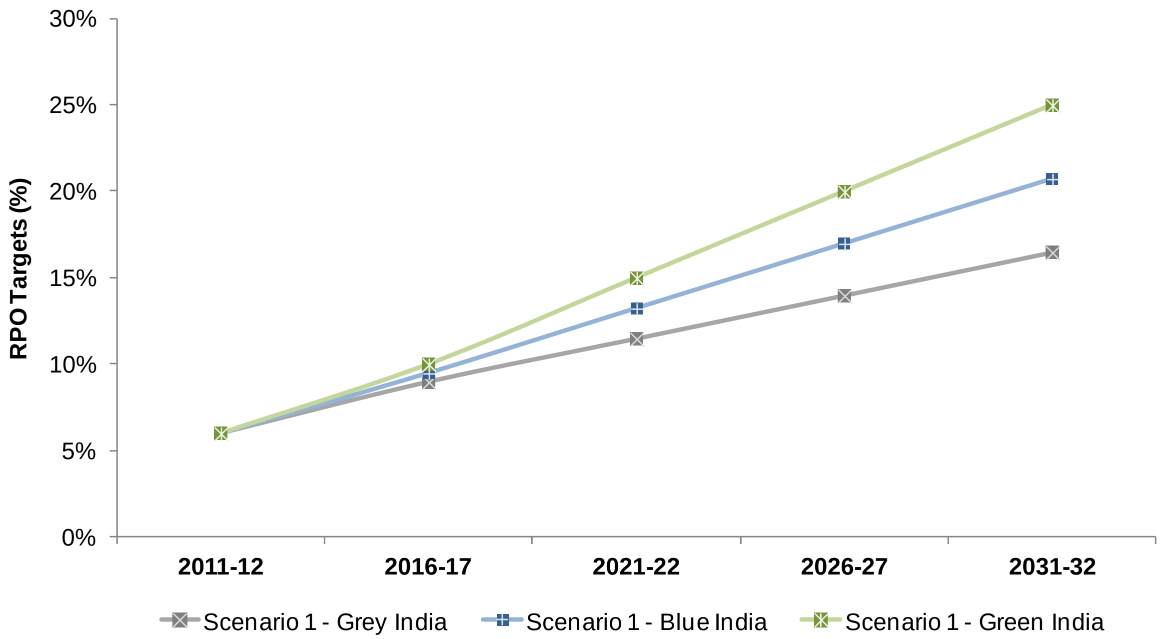
Source: MNRE

Based on similar trend, under the Grey India Scenario, the national level RPOs are determined for the other plan periods. The RPOs are expected to increase to 16% by 2031 from the current levels of 6%.

NAPCC on the other hand has specified that RPO may be set at 5% of total purchase and should be increased by 1% each year for next 10 years. Under Green India Scenario which assumes NAPCC targets, the RPO targets are thus estimated to increase to 25% by 2031. While in Blue India Scenario, the RPO targets are assumed to be the average of that of the Grey scenario and the Green scenario.

Table 31: Scenarios - RPO Projections

Scenario	Technology Type	2011-12	2016-17	2020-21	2026-27	2031-32
Grey India	State Level RPOs	6%	9%	11%	14%	16%
Blue India	Medium RPO Level	6%	9%	13%	17%	20%
Green India	NAPCC RPO Targets	6%	10%	15%	20%	25%


30%
25%
20%
15%
10%
5%
0%
RPO Targets (%)
2011-12
2016-17
2021-22
2026-27
2031-32
Scenario 1 - Grey India
Scenario 1 - Blue India
Scenario 1 - Green India

5.3.6 Challenges for Large Scale Renewable Deployment

Support in the form of legislation, policies and incentives for Renewable Energy development is available and the market also offers great opportunities for investment in renewable power projects. However, renewable energy projects face certain specific challenges, as compared to fossil fuel plants. These challenges can be broadly categorized under four heads –Regulatory, RE Resource, Infrastructure and Financing.

5.3.6.1 Regulatory Challenges

In current market scenario, it is being experienced that the existing policy and regulatory framework for renewable energy development has many limitations that are hindering speedy deployment of large scale renewable energy solutions.

There appears a lack of synchronization between initiatives by the Central and State governments. This can be attributed to non-availability of an overarching Renewable Energy Law governing the sector. For instance, Jawaharlal Nehru National Solar Mission (JNNSM) is Central government initiative, whereas RPOs and RECs come under State jurisdiction. Such a situation brings lack of cohesion between the States and the Centre as the State level RPOs do not add up to national objective as set under NAPCC. Moreover, there also exists an inconsistency between different States in implementation of Central Government RE Policies and Guidelines. As an example, renewable resource rich States are reluctant to take higher RPO due to various considerations (extra cost to be incurred due to higher feed-in-tariff) while the resource-poor States have no incentive to go for higher RPO levels. This is a paradoxical situation.

REC mechanism seeks to expand the RE market out of the resource rich states to others that should buy RE power but do not have resources available locally on a substantial scale. For example, wind resource that can be tapped for power generation is largely concentrated in six to seven states. A commercial framework for purchase of wind power by other states requires alternative mechanisms that overcome the limitations posed by resource concentration. The REC framework instituted by the Central Electricity Regulatory Commission (CERC) attempts the latter path through a framework of Renewable Purchase Obligations (RPO), which can be met either through direct purchase of RE power or through purchase of the “green component” by means of REC. The REC framework is, however, facing some practical difficulties in implementation. Most of these stem from the reluctance of the state-owned distribution companies in resource deficient states to take on binding commitments that increase cost without any corresponding energy delivery.

In view of the poor state of utility finances across the nation, the respective State regulators are also reluctant to pass on the costs of the RECs to end users. The roadblocks being encountered in the effective implementation of the REC mechanism are as follows:

- Risk of non-compliance of RPOs by cash strapped State utilities, and condoning of non-compliance by State regulators
- Even if penalties are imposed, the funds do not flow to the REC market, thus reducing certificate demand, and hence prices
- Lack of visibility on the floor and forbearance prices beyond the initial five year period of 2012-17
- Trading being restricted to the auction markets and only being on a “once-through” basis, thereby not permitting forward contracting as well as reducing liquidity.
- The double sided closed auction design for RECs does not suit the nature of the product as there is no fundamental cost basis of trading of the RECs.

- Subversion of the APPC by the host State regulator by excluding costly sources (liquid fuel, short term power) thus depressing prices
- Lack of adequate visibility of REC liquidity in the future since only non-PPA based sales are eligible for RECs

5.3.6.2 Lack of Transmission Infrastructure

Renewable energy projects are located in remote areas along the coast line, parts of Thar Desert or hilly terrains in Northern region. Therefore, renewable energy development on a large scale will require transmission strengthening.

5.3.6.3 Inadequate Financing

Sectoral Exposure Limits:
Banks have been financing power generation projects as part of their infrastructure financing, mainly for conventional power projects. In the context of the credit concentration norms stipulated for exposure to specific industry or sector(s), many banks have reached near saturation level in their exposure to the RE sector. It is worth noting that as per the RBI guidelines infrastructure sector includes, *inter alia*, the generation or generation and distribution of power based on renewable energy sources such as wind, biomass, small hydro, solar, etc. The RBI guidelines permit banks to fix internal limits for aggregate commitments to specific sectors so that the exposures are evenly spread over various sectors.

Asset Liabilities Mismatch and Cost of funding:
One of the many challenges in financing the RE sector arises from concerns of Asset Liability mismatch. Most Renewable Energy Projects generally have funding requirement for terms above 10 years. The average maturity of bank's resources is significantly lower. The resultant mismatches can expose banks to serious interest rate risk. Thus there is a need to procure long term resources for financing the sector from both domestic as well as overseas sources. In view of the capital intensive nature of the Renewable Energy projects the other major factor is the cost of funds. Consequently, lower cost of funds would provide a significant boost to the sector.

Example from Solar Sector:
Under the present system, solar power is purchased by NTPC Vidyut Vyapar Nigam (NVVN) and is sold to State Utilities after bundling with equivalent capacity of thermal power. The NVVN is expected to purchase solar power fed to 33 KV and above from the developers at a price obtained under the competitive bidding and supply it to the Utilities after bundling the solar power with equivalent capacity from unallocated quota of thermal power. Banks and financial institutions are reluctant to finance the emerging solar energy sector due to high risk perception of the sector and the apprehension that utilities may fail to honor the high tariff for the solar power as agreed in Power Purchase Agreement (PPA). The Payment Security Scheme approved by the Government is critical for achieving financial closure by the developers of the solar power projects given that the associated risks, especially pertaining to technology and performance are not fully understood under Indian conditions.

5.3.7 Key Existing Planning, Policy and Financial Measures

Renewable energy remains an integral part of the overall energy planning process in the country. The Ministry of New and Renewable Energy (MNRE) is the nodal body at the Federal level that looks after all the matters relating to new and renewable energy. It is responsible for planning and policy formulation, implementing programmes, developing and commercialising technology and providing fiscal incentives etc. The overarching laws and policies that emanate the renewable power in the country are discussed below.

The Electricity Act (2003) spurred the development of renewable power in the country and provided a basic comprehensive regulatory structure to promote renewable energy. A key feature of the Act is that it promotes RE by ensuring grid connectivity, tariff setting and electricity sale by specifying RE quota to be purchased within a distribution licensee. The Act has accorded significant responsibilities with the SERCs for providing the above provisions. Some of the important provisions in the Act related to RE development are given in Table below -

Table 32: Key Provision of Electricity Act (2003) for RE Development

Section	Provisions
3 (1)	*The Central Government shall from time to time, prepare the National Electricity Policy and tariff policy, in consultation with the state governments and the Authority for development of the power system based on optimal utilization of resources such as coal, natural gas, nuclear substances or materials, hydro and renewable sources of energy.*
4	*The Central Government shall, after consultation with State Governments, prepare and notify a national policy, permitting stand alone systems (including those based on renewable sources of energy and other non-conventional sources of energy) for rural areas.*
9 (1&2)	*A person may construct, operate, and maintain a captive generating plant based on renewable and dedicated transmission lines* *Such persons shall have right to open access to the transmission facilities, or carrying electricity from the captive plant to the destination of their own use*
61 (h)	*The Appropriate Commission shall, subject to the provisions of this Act, specify the terms and conditions for the determination of tariff, and in doing so, shall be guided by the following, namely…* *…the promotion of co-generation and generation of electricity from renewable sources of energy*
86 (1) (e)	*The State Commission shall discharge the following functions, namely:* *(a) …….* *(e) promote cogeneration and generation of electricity from renewable sources of energy by providing suitable measures for connectivity with the grid and sale of electricity to any person, and also specify, for purchase of electricity from such sources, a percentage of the total consumption of electricity in the area of a distribution*

Section	Provisions
	licensee;

Subsequently as per the provisions (section 3(1)) of the Electricity Act 2003, the Ministry of Power, notified the associated policies - National Electricity Policy (NEP, 2005) and National Tariff Policy (NTP, 2006), governing renewable power in the country. Key features of these policies are to promote competition and private participation in renewable energy technologies and encourage SERCs to fix appropriate tariffs for RE technologies and define minimum percentages of renewable purchases in the overall generation mix. Some of the important provisions of NEP and NTP specific to renewable power are highlighted in Table below –

Table 33: Key Provisions of NEP and NTP for RE Development

Policy	Section	Provisions
National Electricity Policy (NEP)	5.2.20	*Feasible potential of non-conventional energy resources, mainly small hydro, and wind and bio-mass would also need to be exploited fully to create additional power generation capacity. With a view to increase the overall share of non-conventional energy sources in the electricity mix, efforts will be made to encourage private sector participation through suitable promotional measures*
	5.12.1	*Non-conventional sources of energy being the most environment friendly there is an urgent need to promote generation of electricity based on such sources of energy. For this purpose, efforts need to be made to reduce the capital cost of projects based on non-conventional and renewable sources of energy. Cost of energy can also be reduced by promoting competition within such projects. At the same time, adequate promotional measures would also have to be taken for development of technologies and a sustained growth of these sources*
	5.12.2	*The Electricity Act 2003 provides that co-generation and generation of electricity from non-conventional sources would be promoted by the SERCs by providing suitable measures for connectivity with grid and sale of electricity to any person and also by specifying, for purchase of electricity from such sources, a percentage of the total consumption of electricity in the area of a distribution licensee. Such percentage for purchase of power from non-conventional sources should be made applicable for the tariffs to be determined by the SERCs at the earliest.* *Progressively the share of electricity from non-conventional sources would need to be increased as prescribed by State Electricity Regulatory Commissions. Such purchase by distribution companies shall be through competitive bidding process. Considering the fact that it will take some time before non-conventional technologies compete, in terms of cost, with conventional sources, the Commission may determine an appropriate differential in prices to promote these*

Policy	Section	Provisions
		technologies
	5.12.3	*Industries in which both process heat and electricity are needed are well suited for cogeneration of electricity. A significant potential for cogeneration exists in the country, particularly in the sugar industry. SERCs may promote arrangements between the co-generator and the concerned distribution licensee for purchase of surplus power from such plants. Cogeneration system also needs to be encouraged in the overall interest of energy efficiency and also grid stability*
National Tariff Policy (NTP)	6.4	*(1) Pursuant to provisions of section 86(1)(e) of the Act, the Appropriate Commission shall fix a minimum percentage for purchase of energy from such sources taking into account availability of such resources in the region and its impact on retail tariffs. Such percentage for purchase of energy should be made applicable for the tariffs to be determined by the SERCs latest by April 1, 2006.* *It will take some time before non-conventional technologies can compete with conventional sources in terms of cost of electricity. Therefore, procurement by distribution companies shall be done at preferential tariffs determined by the Appropriate Commission.* *(2) Such procurement by Distribution Licensees for future requirements shall be done, as far as possible, through competitive bidding process under Section 63 of the Act within suppliers offering energy from same type of non-conventional sources. In the long-term, these technologies would need to compete with other sources in terms of full costs.* *(3) The Central Commission should lay down guidelines within three months for pricing non-firm power, especially from non–conventional sources, to be followed in cases where such procurement is not through competitive bidding.*

Other enabling policy framework includes National Action Plan on Climate Change (NAPCC 2008), Jawaharlal Nehru National Solar Mission, and Renewable Energy Certificate Mechanism (2010). Table 34 below highlights the key features of the framework with regards to renewable power.

Table 34: Other Enabling Regulatory Framework for RE Development

Policy	Section	Provision
National Action Plan on Climate Change (NAPCC)	Paragraph 'Grid Connected Systems 4.2.2'	*The following enhancements in the regulatory/tariffs regime may be considered to help mainstream renewables based sources in the national power system:* i) *A dynamic minimum renewables purchase standard (DMRPS) may be set, with escalation each year till a pre-defined level is reached, at which time the requirements may be revisited. It is suggested that starting 2009-10, the national renewables standard (excluding hydropower with storage capacity in excess of daily peaking capacity, or based on agriculture based renewables sources that are used for human food) may be set at 5% of total grids purchase, to increase by 1% each year for 10 years. SERCs may set higher percentages than this minimum at each point in time*
National Solar Mission		Solar Purchase Obligation (SPO) to start at 0.25% by 2013, going up to 3% by 2022 – solar specific REC Mechanism To create an enabling policy framework for the deployment of 20,000 MW of solar power by 2022 in 3 Phases. Mandatory use of the renewable purchase obligation by utilities backed with a preferential tariff. Provide Payment Security Scheme to enable financial closure of the solar based projects.
Renewable Energy Certificates (REC)		Terms and conditions for recognition and issuance of Renewable Energy Certificate (REC) were notified in January 2010. REC seeks to address the mismatch between availability of renewable sources and the requirement of the obligated entities to meet their renewable purchase obligation. It allows certificate holders to sell renewable electricity at non-preferential tariff and sell the environmental attribute of renewable electricity through energy exchange to desirous entities.

Apart from the conducive regulatory environment, the Government has also been supporting renewable energy development through an attractive mix of fiscal and financial incentives. These include capital/ interest subsidy, accelerated depreciation and no/ concessional excise and customs duties and now Generation Based Incentives (GBI) or Feed-inTariff (FiT) (Figure 44, Table 35).

Figure 44: Support Mechanisms for Renewable Energy Projects

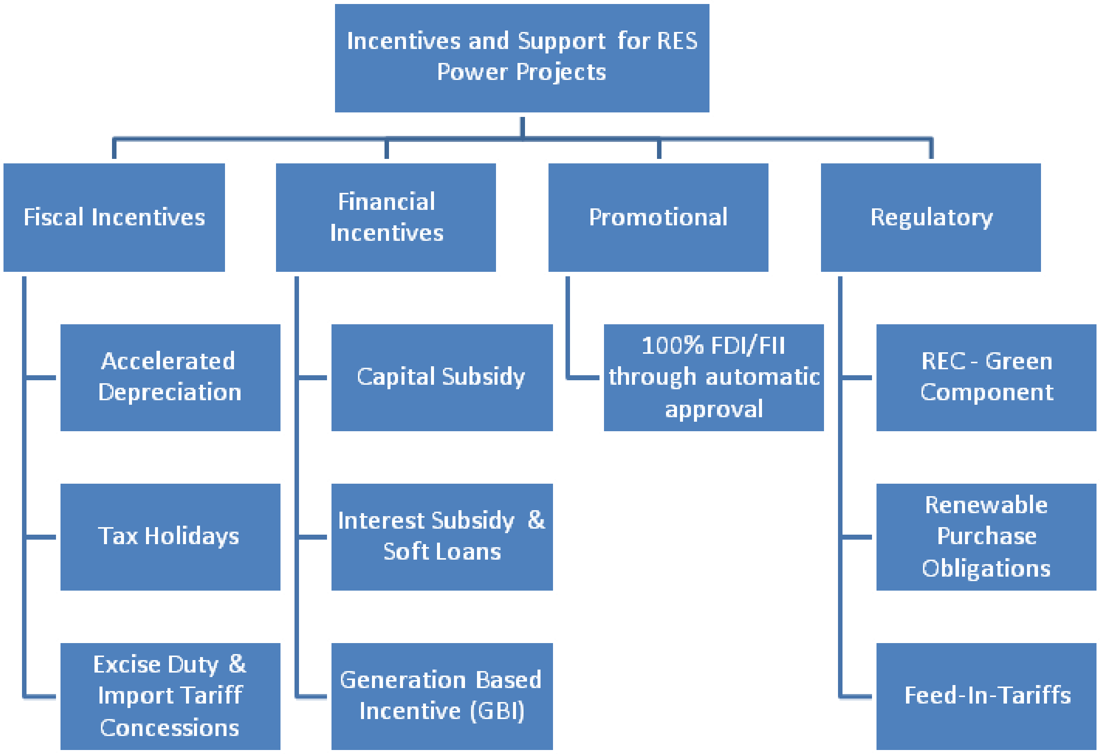


Table 35: Key Fiscal Incentives available for RE

Agency	Incentive
Central Government	• Income tax holiday u/s 80 IA of Income Tax Act, 1961 (10 consecutive years of tax holiday, Minimum Alternative Tax (MAT) applicable) • Customs duty and duty free import concessions • 100% Foreign direct investment (FDI) permitted under automatic approval route • 80% Accelerated depreciation in the first year on renewable energy equipment including solar equipment; withdrawn for wind equipment w.e.f April 1, 2012 • CERC Tariff orders ensures minimum specified level of returns for different REs • Subsidy (90% of the total decentralised energy project cost) for Decentralized Distributed Generation under Rajiv Gandhi Grameen Vidyutikaran Yojana (RGGVY) • Renewable Purchase Obligation (RPO) (solar and non-solar) and Renewable Energy certificate (REC) scheme with floor and forbearance price of REC • Renewable Regulatory Fund (RRF) support for grid interactive renewable in case it deviates from the submitted schedule(up to certain percentage of deviation (for details refer Grid code)) • Clean Development Mechanism (CDM) benefits

	• Grid connectivity Regulations relaxation – reduction in the threshold for connecting to inter-State grid to 50 MW for Hydro and other RE projects • To use domestically manufactured crystalline Photovoltaic (PV) modules for eligibility criteria under Jawaharlal Nehru National Solar Mission (JNNSM) • No transmission charges and no transmission losses applicable for the use of ISTS network to solar projects till the useful life commissioned up to 2014

State Government	• Preferential Tariffs by State Electricity Regulatory Commissions
	• Renewable Portfolio Obligation (RPO)
	• Energy buyback, wheeling and banking facilities
	• Concessions/Benefits
	  ○ Sales tax
	  ○ Electricity duty
	  ○ Exemption from Excise Duty
	• Mandatory use of Solar Hot Water Systems in certain class of buildings by Urban Local Bodies (ULBs) (e.g. Under HAREDA – Department of Renewable Energy, Government of Haryana)
	• Financial support provisions to project developers for power evacuation and for strengthening of evacuation system (like Maharashtra Energy Development Agency (MEDA) - For evacuation arrangement of wind energy project, 50% amount will be given as a subsidy through Green Energy Fund)
	• Infrastructure/ industrial status accorded to RE generation projects
	• RE Cess introduced in some states on commercial / industrial power consumers

Equipment Manufacturer	• 20% subsidy under "The Special Incentive Package Scheme" for manufacture of semiconductor material - incentives granted to a unit located in a Special Economic Zones (SEZ) can be about 20% of the capital expenditure; these incentives are over and above the incentives usually granted to any unit located in SEZs. In case of units located outside the SEZ the incentive is 25% of the capital expenditure • Manufacturing of Wind turbines & Solar Modules in SEZ with applicable incentives • Infrastructure/ industrial status accorded to RE manufacturing

5.4 Energy Efficiency

On a per-capita basis, India is one of the lowest Greenhouse Gas (GHG) emitters (1.18 tonnes of CO2 equivalent per capita in 2008) in the world. India has set voluntary emission reduction targets to address the global climate change issue. These targets aim to reduce the emissions intensity of GDP by 20-25 percent over the 2005 levels by the year 2020, through the pursuit of following policies.

- Integrated Energy Policy, 2006: key GHG related Provisions
    - Energy efficiency in all sectors
    - Emphasis on mass transport
    - Emphasis on renewable including biofuels and fuel plantations
    - Accelerated development of nuclear and hydropower Technology Missions for Clean Energy
    - Focused R&D on several climate change related technologies
- Reforms in Energy Markets (Electricity Act, Tariff policy, stress on increasing competition and efficiency)
    - Rural Electrification Policy 2006
    - Energy Conservation Act, 2001
    - Energy Conservation Building Code, 2006
    - Bachat Lamp Yojana
    - 50,000 MW Hydroelectric Initiative, 2003
- National Action Plan on Climate Change (NAPCC)
- Carbon cess on coal of 50 Rs./tonne, since July 2010

The interim report by planning commission on “Low carbon strategy for inclusive growth” forms the building block and serves as the base for all the new policy development and planning strategy. The report provides options that can reduce emission intensity. The main sectors identified for emission reduction are power, transport, industry, buildings and forestry.

In the power sector, several measures like reducing electricity demand by use of efficient appliances, introducing fuel efficient power plants and changing the generation mix are considered. It is estimated that under determined Energy Efficiency Efforts across the sectors, the emission intensity of GDP can be reduced by 23 to 25 percent over the 2005 levels, while with aggressive Energy Efficiency efforts it can be reduced by as much as 33 to 35 percent over the 2005 levels. The key pressure points to achieve the set targets –include the development of required policy framework, the financing arrangements and the implementation of various initiatives & programs.

The Energy Conservation Act 2001 (EC Act 2001) has already notified certain regulations for improving energy efficiency in the industrial sector. The EC Act provides comprehensive legal mandate for the implementation of energy efficiency measures through the institutional mechanisms of the Bureau of Energy Efficiency and the other central and state level agencies. The fifteen energy intensive sectors have been identified as Designated Consumers. Several schemes/programs on EE have been initiated. Under the National Mission for Enhanced Energy Efficiency (NMEEE) following four initiatives are outlined in addition to other ongoing programs:

- **Perform Achieve and Trade (PAT):** A market based mechanism to enhance cost effectiveness of improvements in energy efficiency in energy-intensive large industries and facilities, through certification of energy savings that could be traded.
- **Market Transformation for Energy Efficiency (MTEE):** Accelerating the shift to energy efficient appliances in designated sectors through innovative measures to make the products more affordable.
- **Energy Efficiency Financing Platform (EEFP):** Creation of mechanisms that would help finance demand side management programs in all sectors by capturing future energy savings.
- **Framework for Energy Efficient Economic Development (FEEED):** Developing fiscal instruments to promote energy efficiency

Policy development for the various EE initiatives, financing, monitoring, awareness and implementation remains the critical areas of development for EE deployment.

Based on the above discussion, three scenarios are developed while considering the optimistic and the pessimistic adoption of EE measures.

Table 36: Scenarios – Electricity Saving Projections

Scenario	Demand Reduction (%)	Electricity Savings (BU)			
		2016-2017	2021-2022	2026-2027	2031-2032
Scenario 1 - Grey India	0%	0	0	0	0
Scenario 2 - Blue India	6%	30	38	54	67
Scenario 3 - Green India	12%	59	75	108	134

Note: In Grey India Scenario, the demand assumptions by 18th EPS considers inbuilt energy efficiency and DSM assumptions hence we do not consider any additional demand reduction.

6. Scenario Results

In the last few sections, the various assumptions - related to energy demand, conventional/renewable capacities, fuel supply and prices, RPO trajectories, Energy Efficiency , and as well as the rationale behind them have been discussed. In this chapter, the projections on the following parameters for the period 2012-31 have been made. These projections have been done through I-IPM®. The following dimensions have been analysed separately for each scenario (Grey India, Blue India and Green India). At the end of the chapter, we have also provided a ready comparison of the parameters across these scenarios.

- Capacity and Generation mix of various conventional resources,
- Capacity and Generation mix of various renewable energy resources
- Peak and energy deficits
- Coal and Gas Consumption
- Investment Requirement

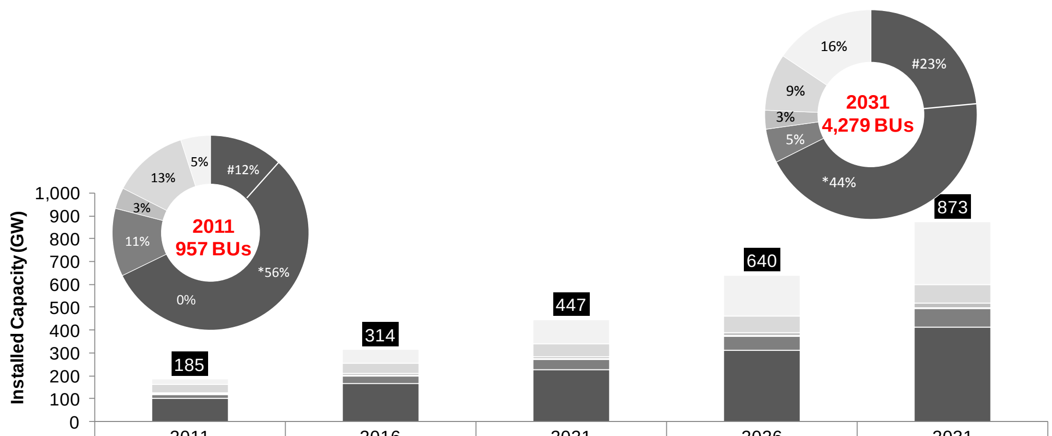
6.1 Grey India Scenario

In the Grey India Scenario, the study assumes significantly high coal generation capacity addition along with high coal supply assumptions. Figure 45 shows the summary of the capacity addition and generation mix over the 2011-2031 period.

In this Scenario, the total capacity by 2031 stands at 873 GW, approximately five times the installed capacity of 185 GW at the end of 2011. The capacity addition is dominated by coal, adding ~ 310 GW of coal capacity over the period 2012-2031, resulting in 410 GW of coal capacity by 2031. Renewable follows the lead with ~251 GW of capacity addition over the same period. However, the capacity mix undergoes a huge change viz-a-viz current capacity mix. The percentage share of the coal capacity in the capacity mix falls to 47% by 2031 from the contribution of 55% in 2011. The share of renewable in the capacity mix increases significantly from the current share of 11% to reach 31% by 2031.

The percentage share of various capacities in the generation mix does not witness a significant change by 2031 as is the case with the capacity mix. The share of coal generation in total generation mix remains unchanged from 2011 to 2031. The coal generation by 2031 still accounts for approximately 67% of total generation. The generation from gas capacity goes down to 5% by 2031 from the current share of 11%. Renewable generation share increases from the current share of 5% in the total generation to reach 16% by 2031. Though renewable accounts for 31% of the total capacity, it accounts for only 16% in the generation mix owing to the low capacity utilization factors (CUF) of the renewable capacities.

Figure 45: Grey India - Projected Capacity and Generation Mix by 2031



	2011	2016	2021	2026	2031
Total	185	314	447	640	873
Renewables	21	57	108	180	272
Hydro	39	47	57	69	84
Nuclear	5	6	9	14	17
Oil	1	1	1	1	1
Gas	18	35	45	65	86
Coal	102	168	227	311	413

- Imported Coal based generation;
* - Domestic Coal based generation

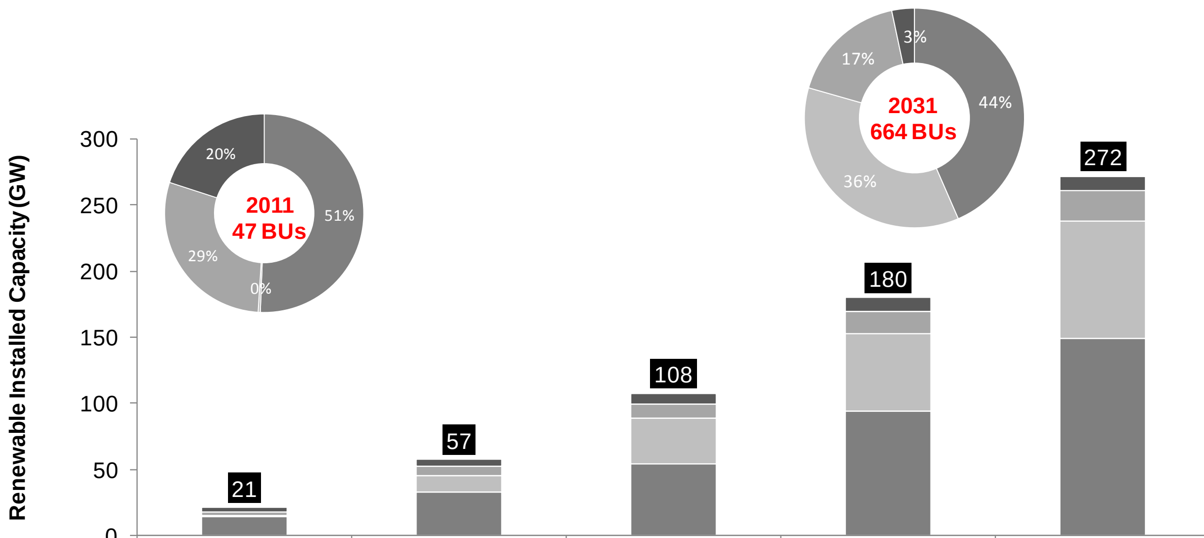
Coal Gas Oil Nuclear Hydro Renewables

Within the renewable resources, the capacity and generation mix is dominated by wind and solar on account of the huge resource availability. Figure 46 below shows the summary of capacity addition of renewable over 2011-2031.

Other types of renewable contribute lower towards the overall capacity addition due to limited potential of small hydro and biomass.

Renewable generation increases to meet 16% RPO by 2031. Solar generation contributes to 36% of total renewable generation by 2031 to meet 5% Solar RPO by 2031. The contribution of generation from wind, bio-fuels and small hydro is 44%, 17% and 3% of the total generation from renewable accounting for the achievement of Non-Solar RPO of 11% by 2031.

Figure 46: Grey India - Projected Capacity and Generation Mix of renewable by 2031

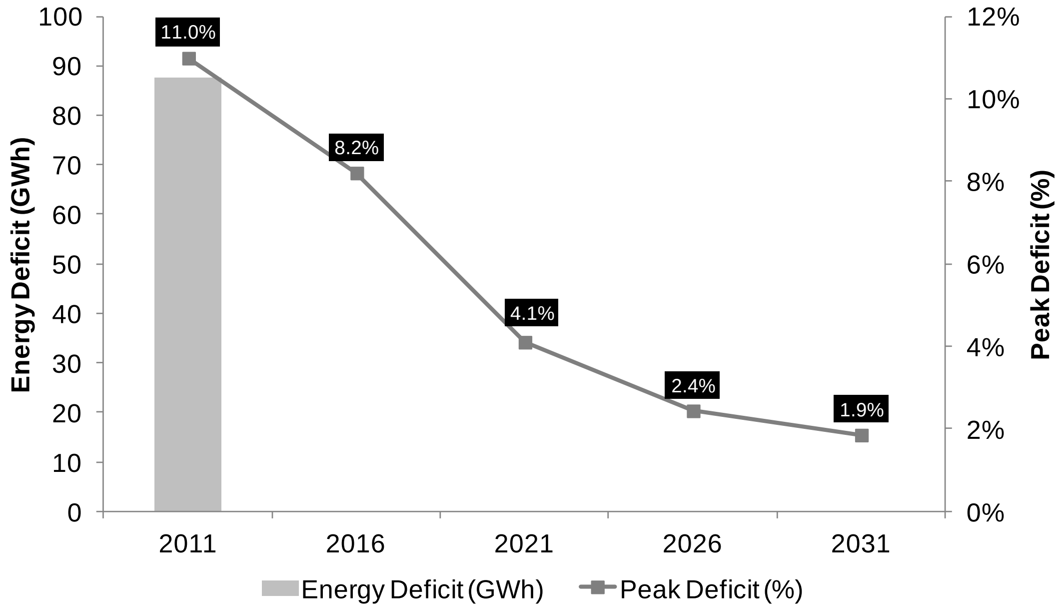


	2011	2016	2021	2026	2031
Total	21	57	108	180	272
Small Hydro	3	6	8	10	11
Bio-Fuels	3	7	11	17	23
Solar	0	12	35	59	89
Wind	15	33	54	94	149

■ Wind ■ Solar ■ Bio-Fuels ■ Small Hydro

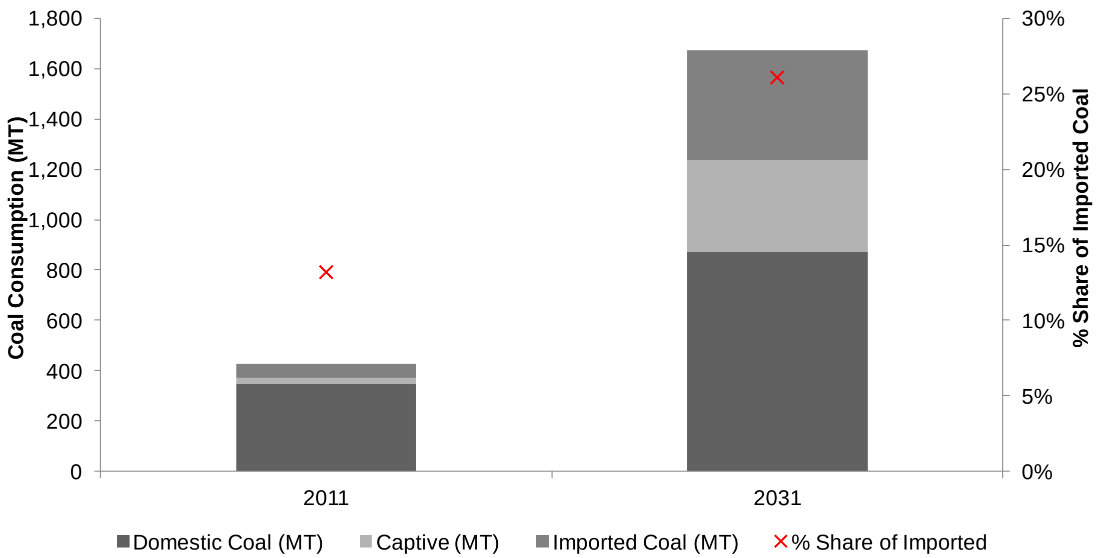
Figure 47 below shows the demand-supply position over the 2011-2031 period. Given the huge capacity addition in the 12th plan, the demand supply balance in energy is anticipated to be achieved by 2016 while peak deficits persist over the 2011-2031 timeframe. This is primarily attributed to greater emphasis on addition of base-load capacity of coal that has limited peaking capabilities, resulting in continued peak shortages throughout study horizon.

Figure 47: Grey India - Projected Peak and Energy Deficits by 2031



The reliance on coal increases significantly and total coal requirement in 2031 is ~four times the 2011 levels as shown in the Figure 48 below. The gap between domestic coal availability and requirement reaches ~120 MT by 2016 and ~440 MT by 2031. As this gap is assumed to be bridged through imported coal, the share of imported coal in total coal consumption for power generation goes up from 13% in 2011 to 26% by 2031. Thus, besides formulating exigency plans for enhancing the indigenous coal production through CIL companies and incentive driven schemes for captive block route and commercial mining, the significant logistics infrastructure needs to be build for handling the imported coal requirements.

Figure 48: Grey India - Projected coal consumption by 2031



Similarly, the gas consumption almost doubles by 2031 as shown in the figure 49 below. Apart from the contribution from the domestic gas addition, the major incremental gas supply is contributed by the unconventional gas resources while the LNG consumption stays marginal.

Figure 49: Grey India - Projected gas consumption by 2031

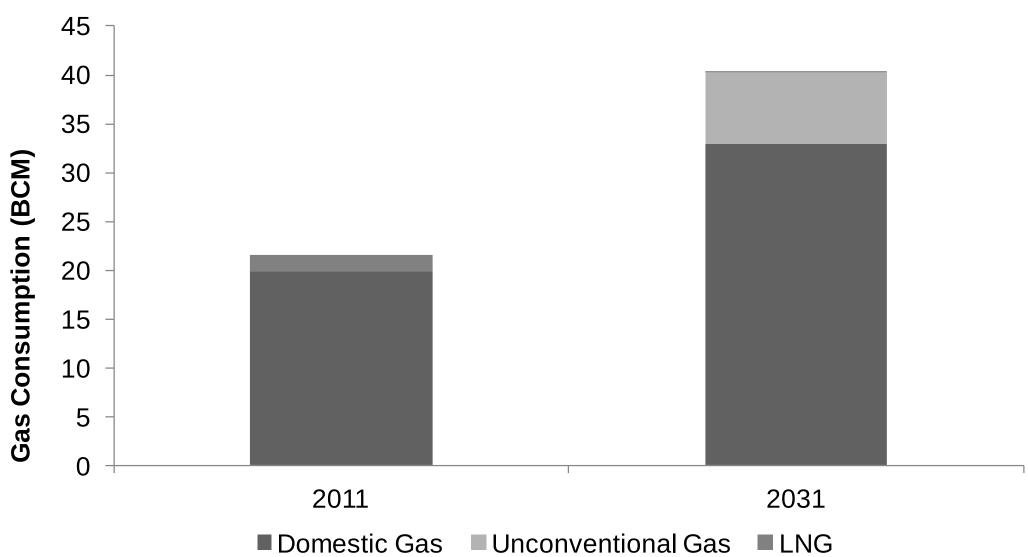
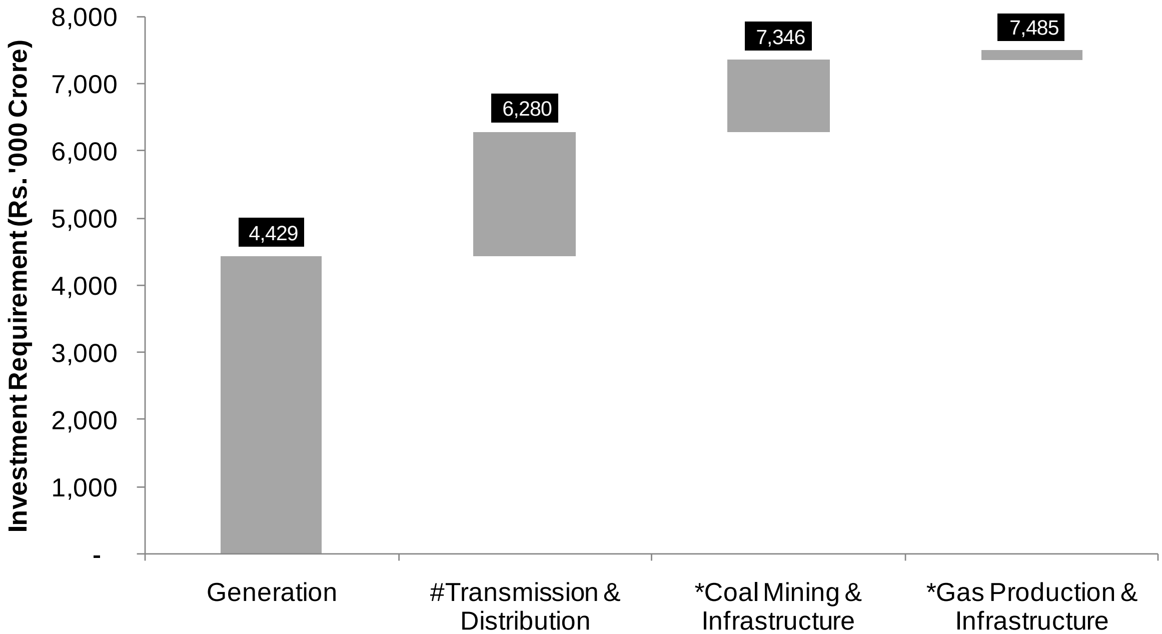


Figure 50 below provides an overview of the estimated investment requirements for the Grey India Scenario over the 2011-2031 timeframe. Besides considering the investments related to generation, transmission and distribution, the analysis also includes the investments required for the coal and gas production and the related infrastructure.

Figure 50: Grey India - Total investment requirements over the 2011-2031 timeframe



Note:

 # The T&D investment is 42% of the total investment required for generation. Refer to Annexure (notes in Figure 87: GRYII Case - Total investment requirements over the 2011-2031 timeframe)

**For Coal mining & gas production infrastructure, an average investment per MT/ MMSCMD is taken from IEA- Technology Road Map Assumption*

Overall, the power sector has a capital requirement of ~INR 75 trillion in the Grey India Scenario by 2031. While considering the cost of generation and T&D infrastructure only, an investment of INR 63 trillion is required against the new cumulative capacity additions of 687 GW expected to be set up over 2011-2031 period.

For coal supply from both domestic and imported sources, an investment of INR 10.6 trillion is required over the study period which includes investments in mining, domestic coal transport and ports. For natural gas, the investment requirement for exploration in new fields and related infrastructure is around INR 1.3 trillion, much lower than that required for coal due to relatively lower increment in gas consumption from 2011 to 2031.

6.2 Blue India Scenario

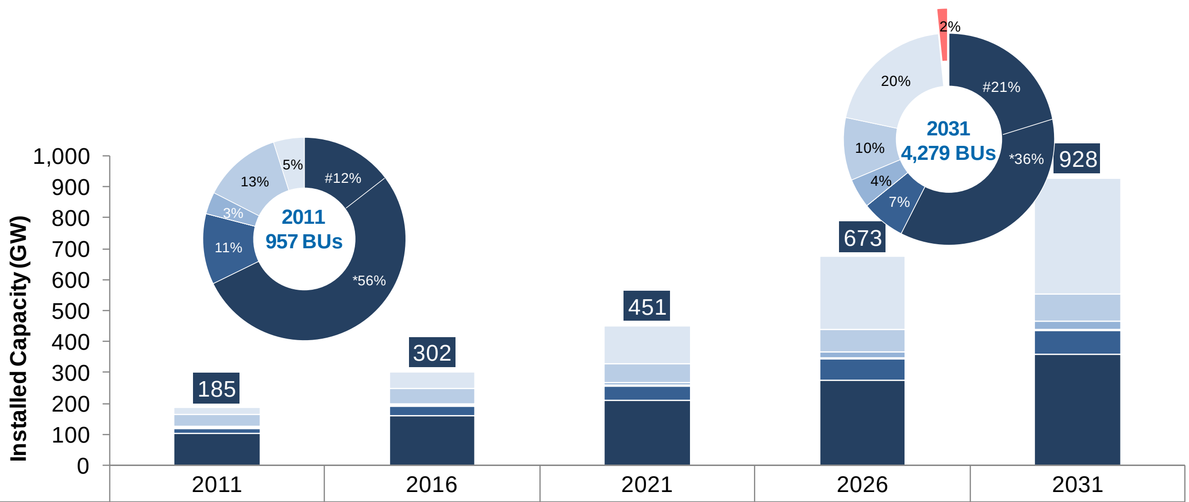
Figure 51 shows the summary of the capacity addition and generation mix over the 2011-2031 period. In the Blue India Scenario, total capacity by 2031 reaches to 928 GW, approximately five times the installed capacity of 185 GW in 2011. The capacity mix undergoes a change in 2031 relative to 2011. By 2031, the coal and renewable capacity accounts for 38% and 40% of total generation capacity. The capacity addition over 2011-2031 is shared both by coal and renewable. In the Blue India Scenario, approximately 250 GW of coal capacity is added resulting in 360 GW of coal capacity by 2031. The total renewable capacity by 2031 is 375 GW, up by 354 GW from 2011 renewable capacity.

The share of coal generation in total generation mix decreases to 57% by 2031 from current levels of 67%. The generation from gas capacity goes down to 7% by 2031 from the current share of 9%. Renewable generation accounts for 20% of total generation by 2031 mainly because of higher RPO obligation. Though the share of coal and renewable capacity in total capacity mix by 2031 is similar, the share of renewable in generation is only 20% of total generation by 2031.

Relative to the Grey India Scenario, an additional capacity of 55 GW is realized by 2031 in the Blue India Scenario. However, the incremental coal capacity over the period 2012-2031 is lower by 56 GW and the incremental renewable capacity is higher by 103 GW in the Blue India Scenario because of higher RPO obligation of 20% than that of 16% in the Grey India Scenario.

Further, the share of coal generation in total generation mix goes down to 57% in the Blue India Scenario while it remains at 67% in the Grey India Scenario by 2031. The share of gas based generation- 7% of the total generation, by 2031 is also higher than that in the grey case - 5% of the total generation, owning to the increased gas availability and increased gas based capacity addition. Also, an additional 2% of the energy demand is met through implementing energy efficiency measures in Blue India scenario. The reliance on coal generation decreases in the Blue India Scenario relative to the Grey India Scenario due to higher renewable, gas and nuclear based generation clubbed with energy efficiency measures.

Figure 51: Blue India - Projected Capacity and Generation Mix by 2031



	2011	2016	2021	2026	2031
Total	185	302	451	673	928
Renewable	21	56	125	235	375
Hydro	39	47	58	72	90
Nuclear	5	7	11	19	27
Oil	1	1	1	1	1
Gas	18	31	46	74	79
Coal	102	159	210	272	357

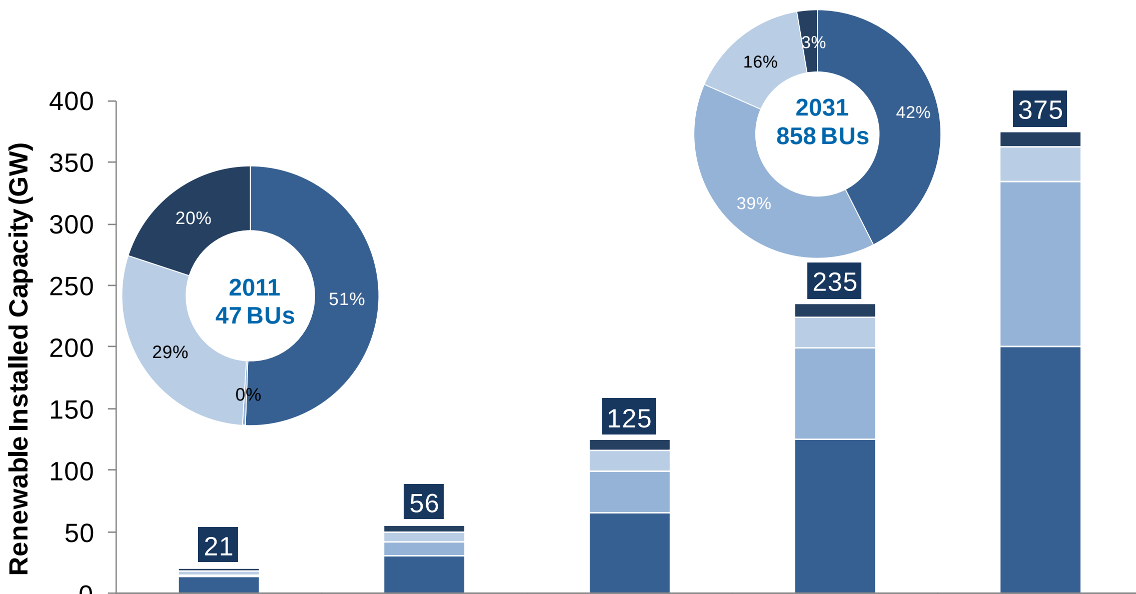
- Imported Coal based generation;
*- Domestic Coal based generation
•Energy efficiency results in ~2% reduction in demand

Figure 52 shows the summary of capacity addition of renewable in the Blue India Scenario over 2011-2031. Approximately 354 GW of renewable capacity is added, resulting in 375 GW of renewable capacity by 2031. The renewable capacity addition is primarily dominated by Wind and Solar. Other types of renewable contribute lower towards the overall capacity addition due to limited potential of small hydro and biomass. Significant capacity of solar capacity is added to meet the solar RPO of 7.5% by 2031.

Renewable generation increases to meet 20% RPO by 2031. Solar generation contributes to 39% of total generation by 2031 to meet 7.5% Solar RPO by 2031. The contribution of generation from wind, bio-fuels and small hydro is 42%, 16% and 3% accounting for Non-Solar RPO of 12.5%.

Further, a higher wind capacity is added in the Blue India Scenario to meet the Non-Solar RPO of 12.5% by 2031. This is so because both bio-fuels and small hydro power have limited potential and cannot contribute significantly in meeting the Non-Solar RPO. Higher solar capacity is also added in the Blue India Scenario to meet an additional Solar RPO of 2.5% relative to the Grey India Scenario.

Figure 52: Blue India Scenario - Projected Capacity and Generation Mix of renewable by 2031



	2011	2016	2021	2026	2031
Total	21	56	125	235	375
Small Hydro	3	6	8	11	12
Bio-Fuels	3	8	17	24	28
Solar	0	12	35	75	135
Wind	15	30	65	125	200

■ Wind ■ Solar ■ Bio-Fuels ■ Small Hydro

Figure 53 shows the demand-supply position over the 2011-2031 period in the Blue India Scenario. The demand supply balance in energy is achieved by 2016 while that for peak is achieved by 2031. The peak deficit in the Blue India Scenario is met sooner than that in the Grey India Scenario. This is primarily attributed to greater emphasis on addition of renewable capacity which shifts the gas based capacities specifically for meeting the system's peak demand and thus removing the peak deficits by 2031.

Figure 53: Blue India - Projected Peak and Energy Deficits by 2031

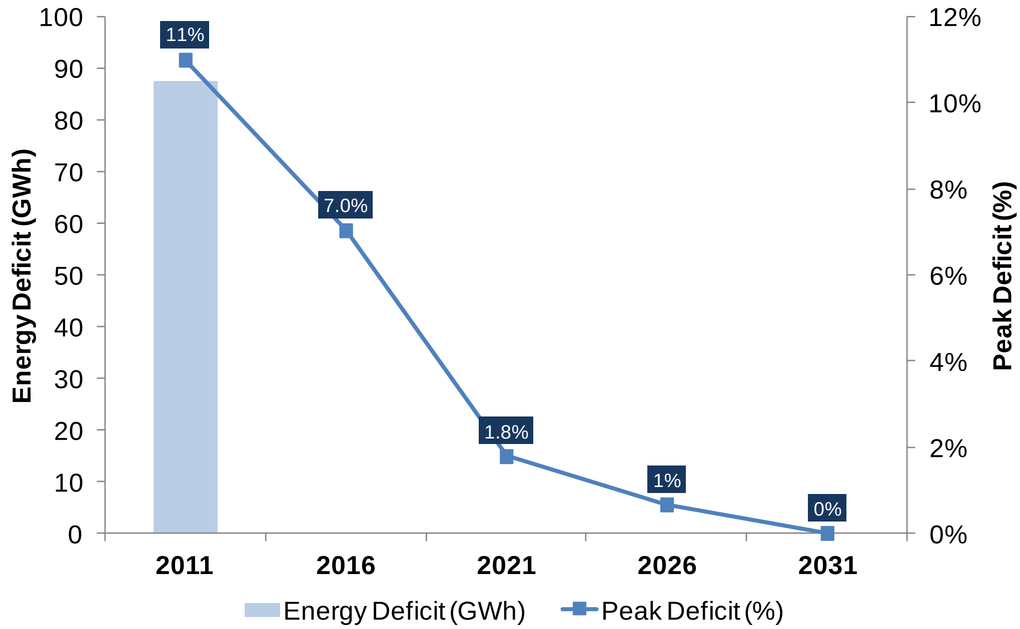


Figure 54 shows the coal consumption by 2031. In the Blue India Scenario, the total coal requirement in 2031 is ~3.2 times the 2011 levels. The gap between domestic coal availability and requirement needs to be bridged through 345 MT of imported coal. The share of imported coal in total coal consumption for power generation goes up from 13% in 2011 to 29% by 2031.

Relative to the Grey India Scenario, there is lesser reliance on coal in the Blue India Scenario due to which the coal consumption goes down by 271 MT by 2031. The lower coal consumption in Blue India scenario is due to higher renewable generation and energy efficiency measures. It has also lead to a decrease of CO_2 emissions from 0.85 CO_2 kg/kWh in 2011 to 0.71 CO_2 kg/kWh by 2031 in the blue case.

Figure 54: Blue India Scenario - Projected coal consumption by 2031

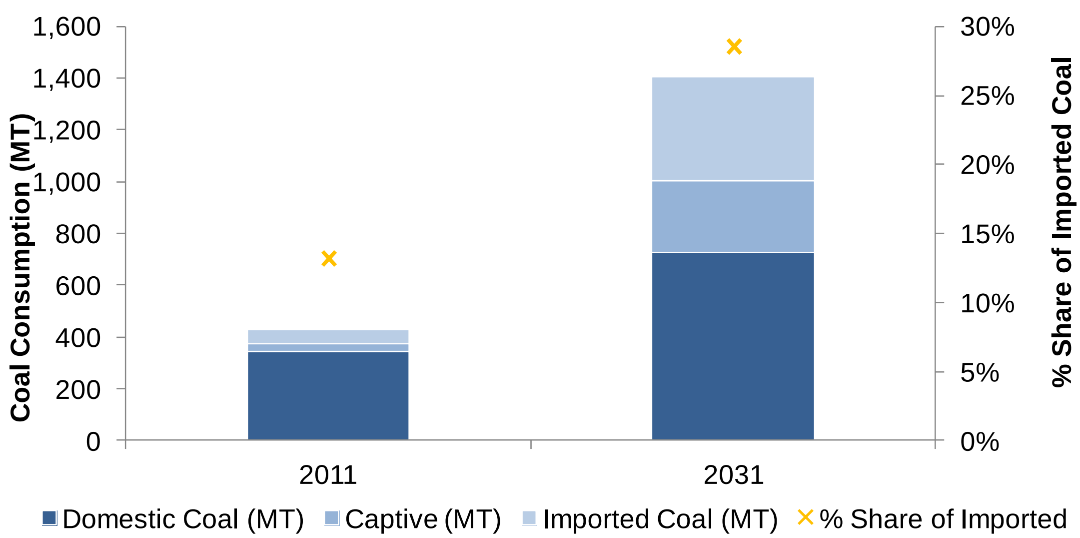


Figure 55 shows the gas consumption by 2031. In the Blue India Scenario, the gas consumption almost doubles by 2031 with the major incremental gas consumption from unconventional gas resources.

Figure 55: Blue India - Projected gas consumption by 2031

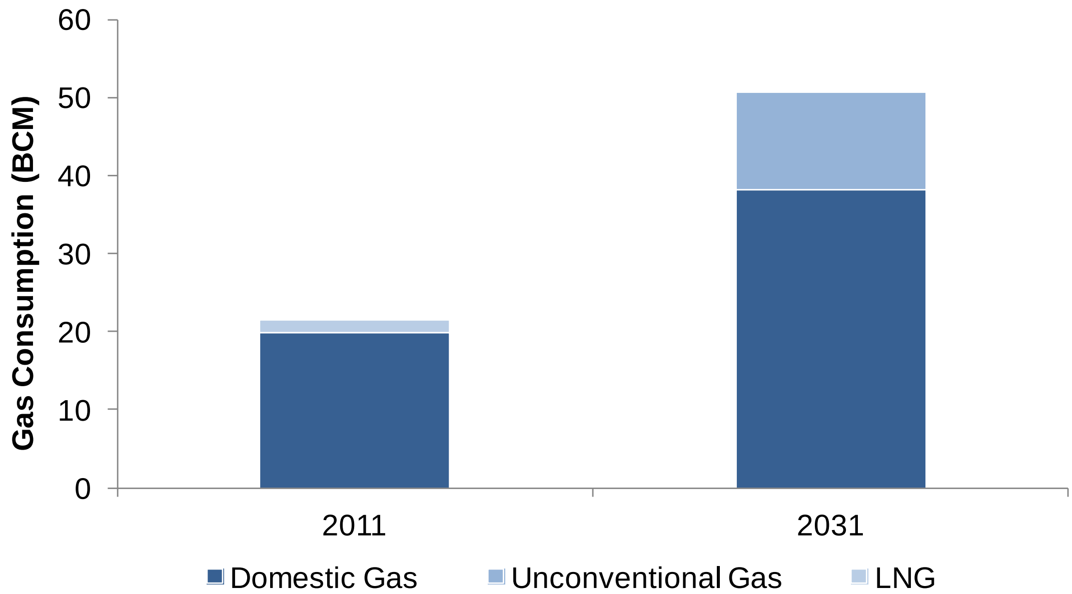
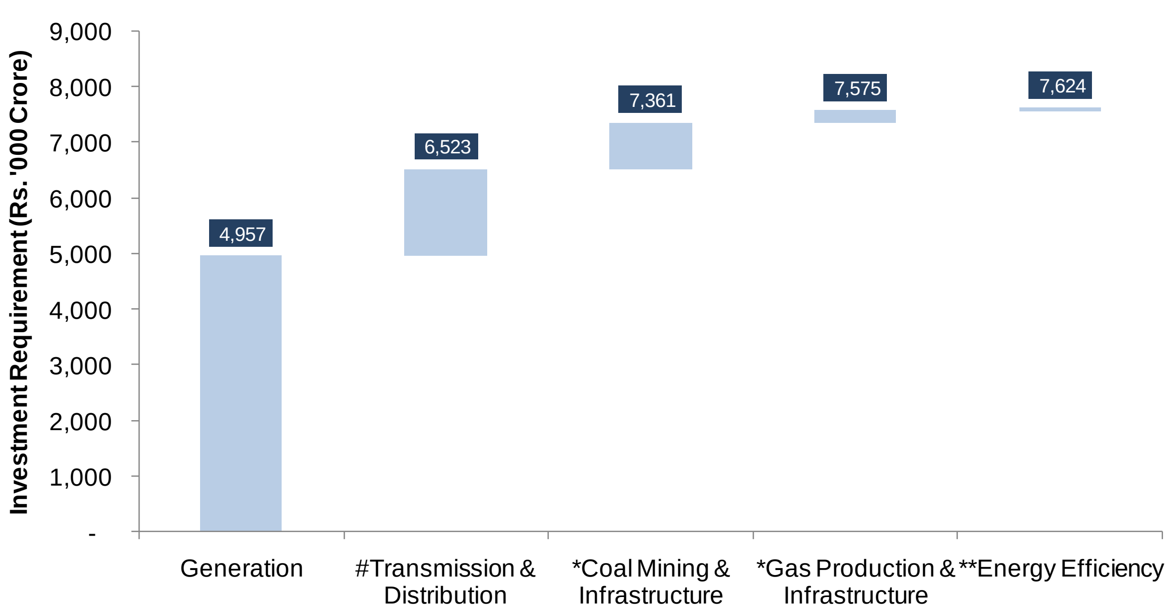


Figure 56 provides an overview of the estimated investment requirements for the Blue India Scenario over the 2011-2031 timeframe. The analysis besides the investments related to generation, transmission and distribution also includes the costs for coal and gas production and the associated infrastructure. The costs for implementing energy efficiency measures is also taken into consideration

Figure 56: Blue India - Total investment requirements over the 2011-2031 timeframe



Note:

 # The T&D investment is 32% of the total investment required for generation. Refer to Annexure (notes in Figure 87: GRYII Case - Total investment requirements over the 2011-2031 timeframe)

** For Coal mining & gas production infrastructure, average investment per MT/ MMSCMD is taken from IEA- Technology Road Map Assumption*

*** For Energy efficiency Investment Estimates, per unit cost is considered as per the National Electricity Plan 2013*

Overall, the power sector requires a capital requirement of INR 76.24 trillion in the Blue India Scenario by 2031. For meeting the cost of generation and T&D infrastructure only, an investment of INR 65.7 trillion is required against the new cumulative capacity additions of 743 GW expected to be set up over 2011-2031 period.

The total capital needs for coal supply amount to INR 8.4 trillion which includes investments required for mining, domestic coal transport and ports. For natural gas, the investment required for exploration in new fields and related infrastructure is around INR 2.1 trillion, much lower than that required for coal due to relatively lower increment in gas consumption from 2011 to 2031. An additional INR 0.5 trillion is required for implementing energy efficiency measures.

Relative to the Grey India Scenario, the Blue India Scenario requires almost the same investment. However, the investment required for generation excluding transmission & distribution investment is higher by INR 6 trillion due to higher renewable capacity added in the Blue India Scenario. Further, though higher capacity is added in the Blue India Scenario, but lower T&D investment is required. Also, the investment in exploring new gas fields and related infrastructure is higher and that required for coal mining is lower in the Blue India Scenario. This is so due to higher gas consumption and lower coal consumption in the Blue India Scenario relative to the Grey India Scenario.

6.3 Green India Scenario

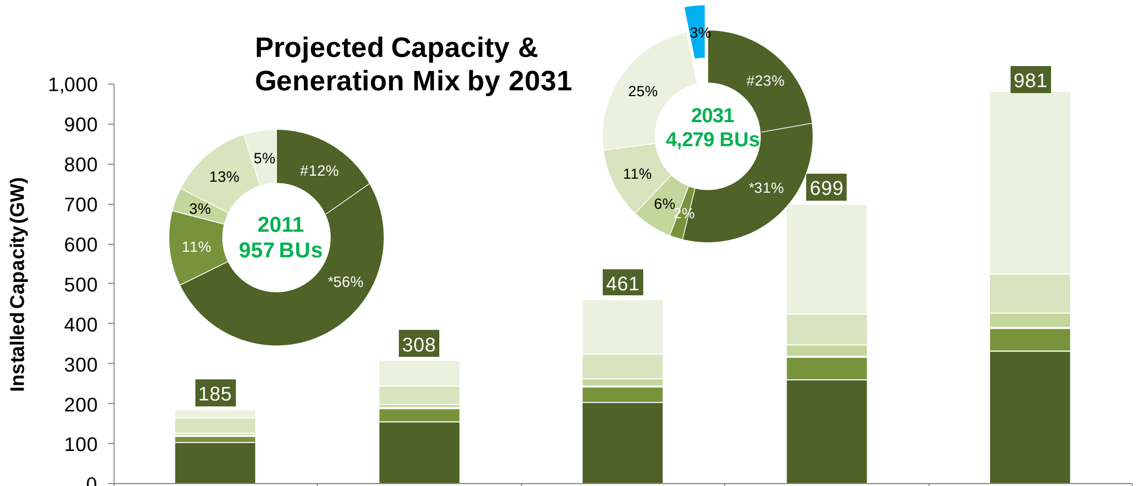
Figure 57 shows the summary of the capacity addition and generation mix over the 2011-2031 period.

In the Green India Scenario, the total capacity in place by 2031 is 981 GW, approximately 5.3 times the installed capacity of 185 GW in 2011. The capacity mix undergoes a change in 2031 relative to 2011. By 2031, the coal and renewable capacity accounts for 34% and 46% of total generation capacity. The capacity addition over 2011-2031 is dominated mainly by renewable. In the Green India Scenario, approximately 230 GW of coal capacity is added resulting in 330 GW of coal capacity by 2031. The total renewable capacity by 2031 is 456 GW, up by 435 GW from 2011 renewable capacity.

The share of coal generation in total generation mix decreases to 54% by 2031. The generation from gas capacity goes down to 2% by 2031 as more renewable in the generation mix – which are characterized with negligible variable running cost, reduces the dependence on the gas based generation in meeting the energy demand of the country. Renewable generation accounts for 25% of total generation by 2031 mainly because of higher RPO targets. Though the share of renewable capacity is approximately half of the total capacity mix in 2031, the share of renewable in generation is only 25% of total generation in 2031.

Relative to the Blue India Scenario, an additional 53 GW capacity is added by 2031 in the Green India Scenario. The incremental coal capacity is lower by 26 GW and the incremental renewable capacity is higher by 81 GW in 2031 in the Green India Scenario in comparison to that in the Blue India Scenario. Further, a share of coal generation in total generation mix goes down to 54% in the Green India Scenario while it remains at 57% in the Blue India Scenario by 2031. Also, an additional 1% of the energy demand is met through implementing energy efficiency measures in the Green India Scenario relative to that in the Blue India Scenario. The reliance on coal generation is the least in the Green India Scenario due to higher renewable generation and energy efficiency measures.

Figure 57: Green India - Projected Capacity & Generation Mix by 2031



	2011	2016	2021	2026	2031
Total	185	308	461	699	981
Renewable	21	63	138	276	456
Hydro	39	49	61	77	98
Nuclear	5	7	17	28	37
Oil	1	1	1	1	1
Gas	18	33	42	58	59
Coal	102	156	202	259	331

Coal Gas Oil Nuclear Hydro Renewable Energy Efficiency

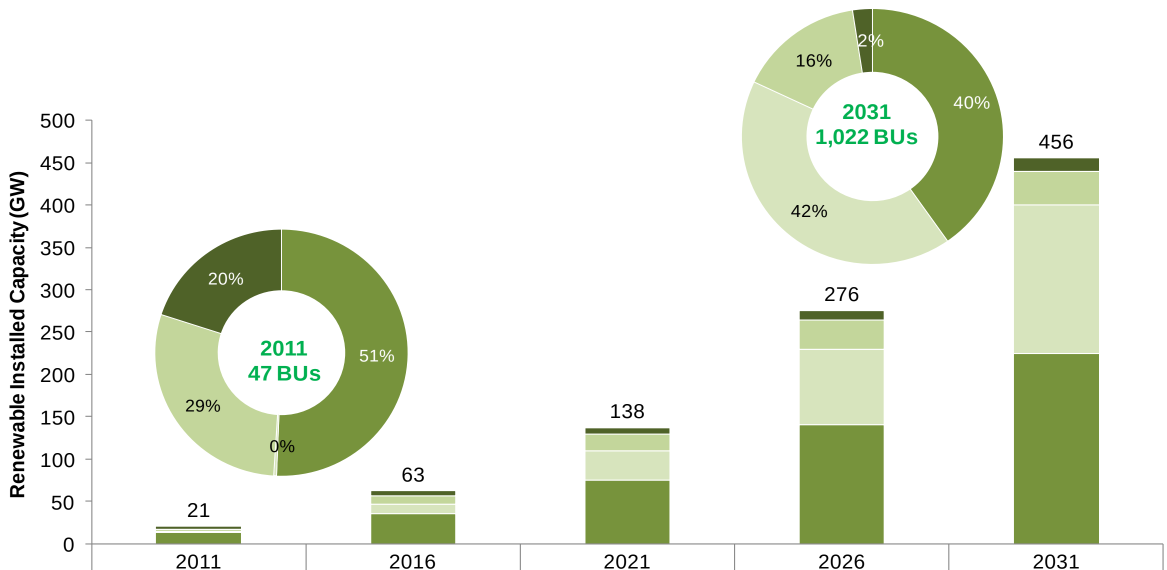
- Imported Coal based generation;
*- Domestic Coal based generation
•Energy efficiency results in ~3% reduction in demand

Figure 58 shows the summary of capacity addition of renewable in the Green India Scenario over 2011-2031. Approximately 435 GW of renewable capacity is added, resulting in 456 GW of renewable capacity by 2031. The renewable capacity addition is primarily dominated by Wind and Solar. The contribution of other types of renewable is lower towards the overall capacity addition due to their limited potential. Significant capacity of solar capacity is added to meet the solar RPO of 10% by 2031.

Renewable generation increases to meet 25% RPO by 2031. Solar generation contributes to 42% of total renewable generation by 2031. The contribution of generation from wind, bio-fuels and small hydro is 40%, 16% and 2% of the total renewable generation accounting for Non-Solar RPO of 15%.

In the Green India Scenario, an additional 81 GW of renewable capacity is added over that in Blue India Scenario which is also the highest among all the three scenarios

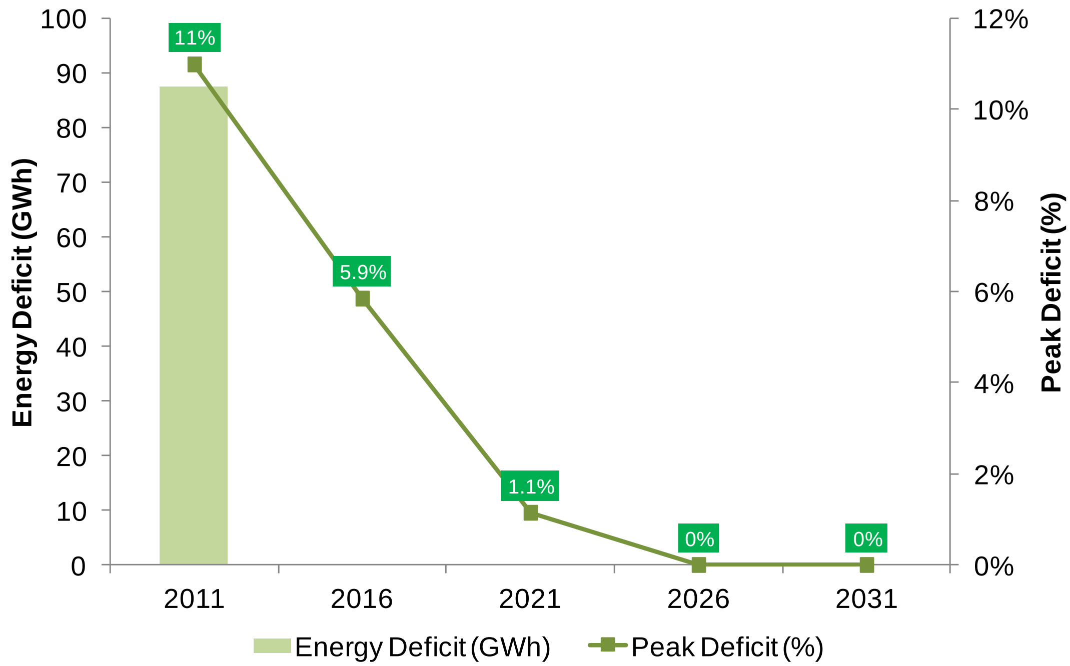
Figure 58: Green India - Projected Capacity and Generation Mix of renewable by 2031



	2011	2016	2021	2026	2031
Total	21	63	138	276	456
Small Hydro	3	6	8	11	15
Bio-Fuels	3	10	20	35	41
Solar	0	12	35	90	175
Wind	15	35	75	140	225

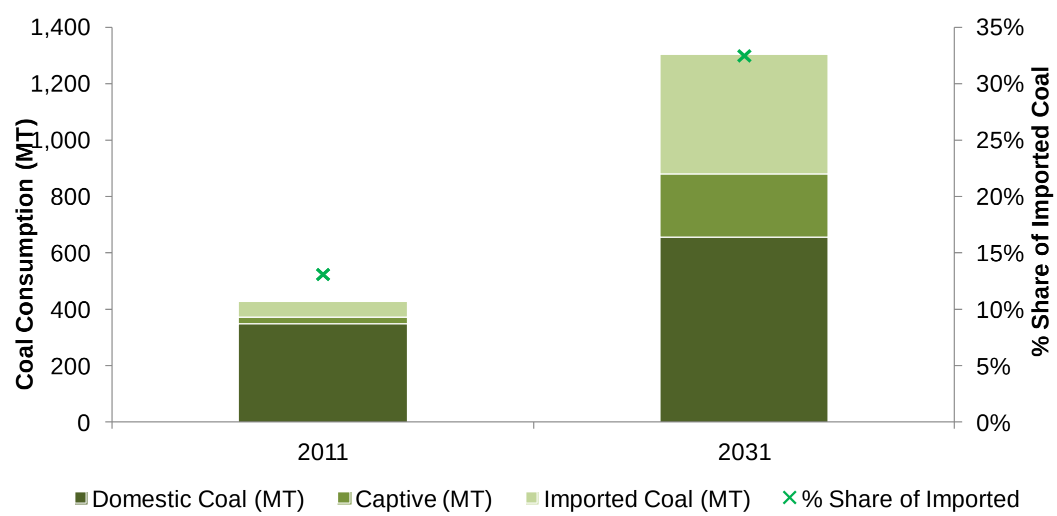
Figure 59 shows the demand-supply position over the 2011-2031 period in the Green India Scenario. The demand supply balance in energy is achieved by 2016 while that for peak is achieved by 2026. The peak deficit in the Green India Scenario is met soonest primarily due to the system's flexibility in meeting the peak demand with more renewable in the system and with dedicated gas based capacities specifically being used as peaking capacities, resulting in meeting the peak deficit by 2026.

Figure 59: Green India - Projected Energy and Peak Deficits by 2031



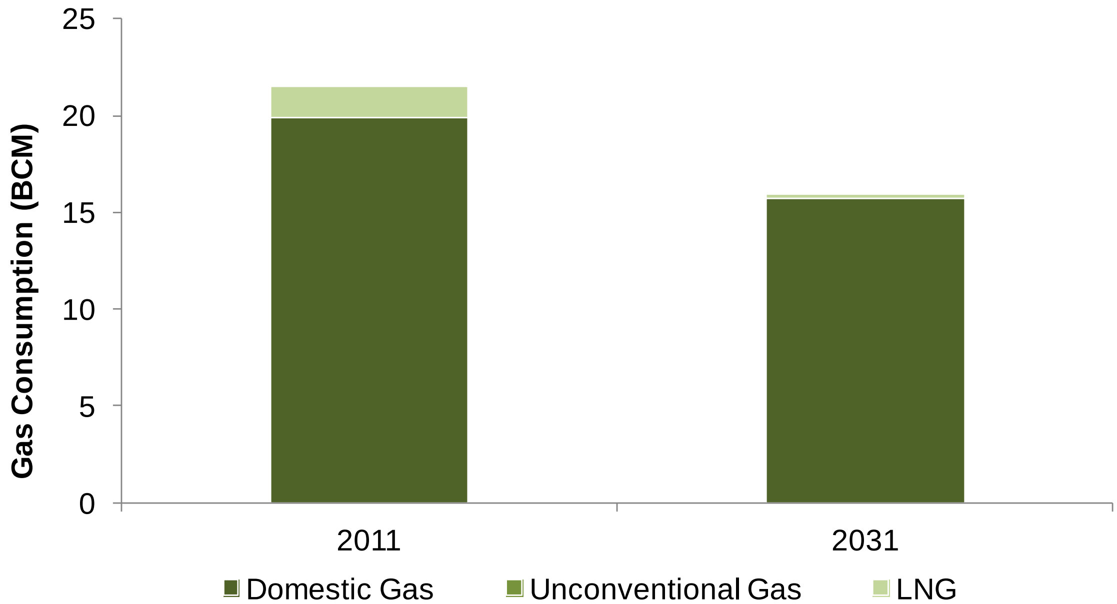
The higher renewable generation results in lowest demand for coal in the Green India Scenario relative to other scenarios. However, the reliance on imported coal continues as it is more attractive than mining new domestic coal. The share of imported coal by 2031 in the Green India Scenario is 33%, highest among all the scenarios. This is because the assumptions (discussed before) of lower imported coal prices in Green India case.

Figure 60: Green India - Projected coal consumption by 2031



The addition of renewable decreases the need for base load generation capacity. As the gas generation remains at margin for most of the time, the gas capacity is pushed out of system due to addition of high renewable capacity. The total gas demand in 2031 is lower by 26% from that in 2011. The gas demand is restricted to meeting the peak demand and responding to the variability associated with renewable generation. Therefore, sufficient flexibility would need to be built in gas infrastructure and operations to account for the induced variability in RE generation. In the Green India Scenario, the gas consumption is primarily met by the domestic available gas.

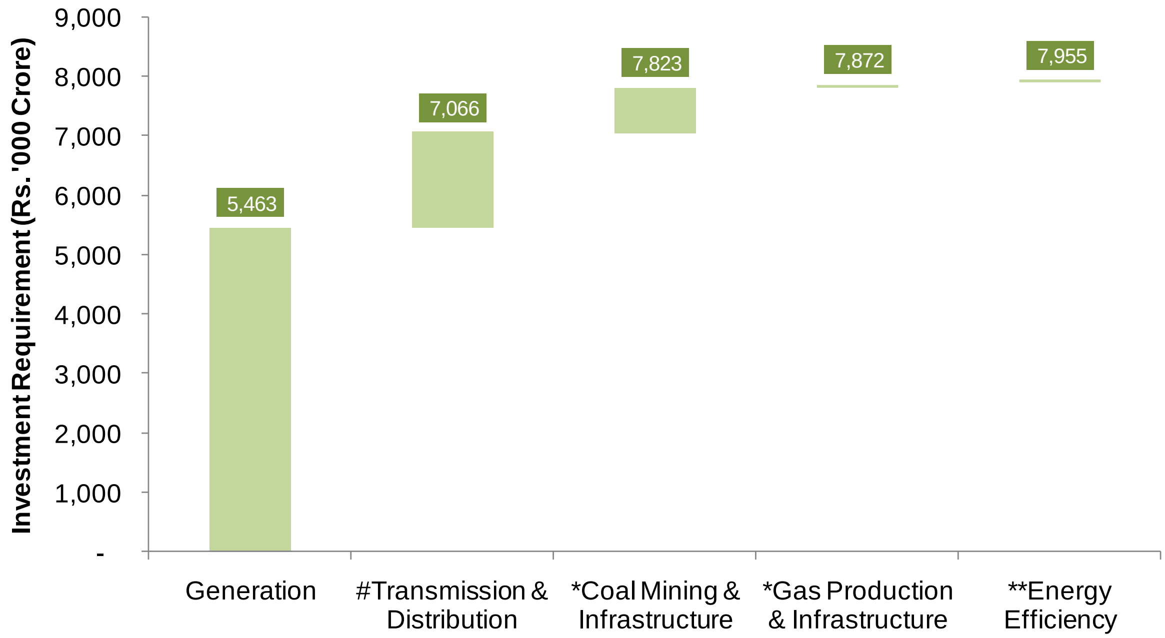
Figure 61: Green India - Projected gas consumption by 2031



The overall decrease in coal and gas consumption leads to 23% decrease in the specific CO_2 emissions from 0.85 CO_2 kg/kWh in the year 2011 to 0.66 CO_2 kg/kWh in the year 2031.

Figure 62 below provides an overview of the estimated investment requirements for the Green India Scenario over the 2011-2031 timeframe. The analysis considers the investments related to generation, transmission and distribution and also includes cost estimates for energy efficiency, coal and gas production along with their associated infrastructure. Gas capacity in Green India and in Blue India is lower as compared to Grey India scenario as gas based capacities in Green India will be used only for meeting the peak demand and supporting renewable capacities rather than serving the mid-merit system demand.

Figure 62: Green India - Total investment requirements over the 2011-2031 timeframe



Note:

 # The T&D investment is 29% of the total investment required for generation. Refer to Annexure (notes in Figure 87: GRYII Case - Total investment requirements over the 2011-2031 timeframe)

* For Coal mining & gas production infrastructure, average investment per MT/ MMSCMD is taken from IEA- Technology Road Map Assumption

** For Energy efficiency Investment Estimates, per unit cost is considered as per the National Electricity Plan 2013

Overall, the power sector has a capital requirement of INR 80 trillion in the Green India Scenario. For meeting the cost of generation and T&D infrastructure only, an investment of INR 70 trillion is required against the new cumulative capacity additions of 796 GW expected to be set up over 2011-2031 period.

However, both coal and gas require significantly less capital investments as compared to the other two scenarios. The capital required for coal and gas production along with their associated infrastructure is INR 7.6 trillion and INR 0.5 trillion respectively. The INR 7.6 trillion investments for the coal are mainly related to expansion of the domestic mining and port infrastructure. The INR 0.5 billion investments in gas are also related to the changes required in the operation and requirements for gas supply infrastructure such as enhanced line pack and gas storage facilities specifically designed for power generation. The capital requirement for gas exploration in the Green India Scenario is lowest especially because of low consumption of domestic and unconventional gas by 2031.

The total investment required in the Green India Scenario is highest among all the three scenarios. The total investment is higher by ~4% and ~6% respectively vis-a-vis that required under the Blue India Scenario and the Grey India Scenario.

Though higher renewable capacity is added in the Green India Scenario, but lower T&D investment is required. This is so because with higher renewable generation capacity added at the load centres, there is lower inter-state transmission infrastructure to be built resulting in lower investment. However, higher capital investments are needed for the expansion of the grid to connect wind and solar plants in remote areas with demand centers, and for more efficient electric equipment in the end-use sectors. As a result lower T&D is required in the Green India Scenario.

6.4 Comparison Across Scenarios

The table below summarizes the comparison of various parameters across three scenarios.

Table 37: Comparison across scenarios

Parameters	Grey India	Blue India	Green India
Total Demand (BUs)	4279	4279	4279
RPO targets to be achieved by 2031 (%age)	16%	20%	25%
Total Installed Capacity (MW)	873	928	981
Total Renewable Installed Capacity (MW)	272	375	456
Total Renewable Generation (Bus)	664	858	1022
Year by which Energy Deficit vanishes	2016	2016	2016
Year by which Peak Deficit vanishes	Beyond 2031	2031	2026
Total Coal Consumption (MTs) by 2031	1650	1400	1300
Total Gas Consumption (BCM) by 2031	40	50	16
Cumulative Investment Required by 2031 (000's Crore)	7,485	7,624	7,955

7. Estimation of the cost of Policy Push to increase Renewable Penetration

The RPO targets could be met by either of the two ways.

- A policy push, such as a mandatory RPO.
- By financial support, such as feed in tariffs, capital subsidies etc, to renewable to make them competitive with conventional generation.

The RE capacity addition, in the previous section, required to meet the RPO targets, under each of the three scenarios, is achieved through a mandatory RPO mechanism. Practically, only a part of this RE capacity can enter the system on its own without any subsidy support. Such RE capacities will typically have a better cost economics and will set up based on economic rationale.

In this section, RPO targets are met through providing financial support. This financial support is provided in the form of an upfront capital subsidy to various renewable capacities, resulting in an increased renewable penetration. The financial support also emulates the cost of pushing renewable in the system if India imposes a mandatory RPO. The estimation of the capital support /subsidy required to set up the RE capacity under each of the three scenarios is done using the following methodology -

- The modeling framework of I-IPM® is again used to calculate the financial support requirement.
- For each scenario, an alternate case (referred as Gry II[27] for Grey World, Blu II for Blue World and Grn II for Green World) is developed. In these cases, no RPO constraint is imposed on the system.
- Further, a capital support/subsidy to various renewable types is provided to make them cost competitive viz-a-viz conventional generation to meet the RPO targets
- Among the various ways of providing subsidy, a time-varying upfront discount to the capital cost of various renewable types was provided and thus allowing the model to build only the economically feasible renewable capacity addition in each year of the study period.
- The optimum amount of capital support/subsidy is calculated through an iterative process wherein subsidies are varied across the period as well as the capacity types until the required generation from renewable, as defined by RPO targets, is attained.
- The capital support/subsidy for each renewable type is calculated as the total RE capacity additions achieved on providing the subsidy multiplied by the optimum amount of subsidy given per MW (which is calculated as the discount on the capital cost in each year). The optimal subsidy value is derived after performing a number of iterations in I-IPM® until the desired RPO level is achieved.

$$\textbf{Subsidy}_{\textbf{(RE Type)(year t)}} = \textbf{Capacity Additions in Subsidy Case}_{\textbf{(RE Type)(year t)}} \textbf{ X Optimal Subsidy}_{\textbf{(RE Type)(year t)}}$$

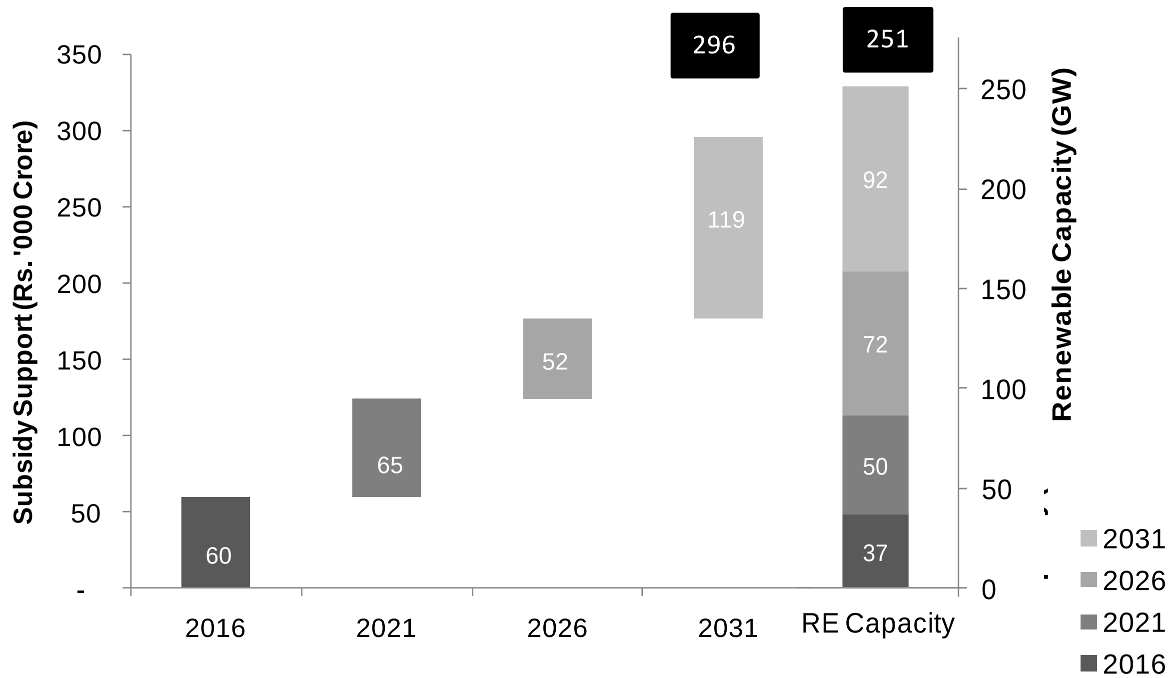
The section below presents the results of projected subsidy requirements for achieving the target RPOs in each scenario. The results of the GRY II case have been provided in the annexure.

[27] Also referred to as Grey Conventional BAU case in the report.

7.1 Grey India Scenario

The Grey India Scenario estimates that a total of INR 2,960 billion subsidy support, spread over the period 2012-2031, is required for achieving 16% RPO by 2031. This amount represents ~3% of the nominal Indian GDP in the year 2011-12.

Figure 63: Grey India: Incremental subsidy requirements and renewable additions over 2016-2031

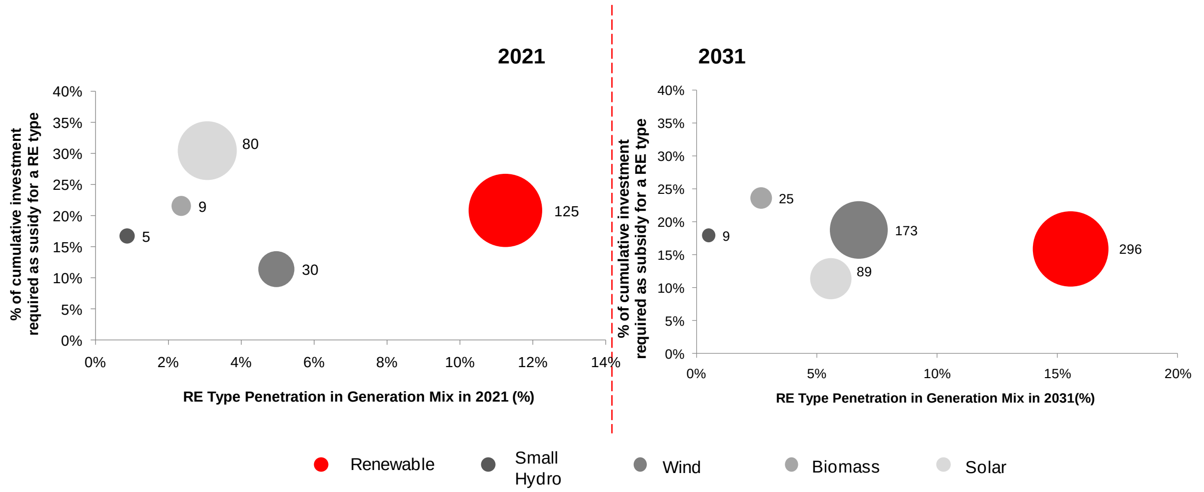


Note: *The numbers represent the subsidy requirement and capacity added over the Five-year Planning period; Also subsidy is not provided to existing projects in 2011 and 2012*

The growth in subsidy requirements declines for the period 2021-2026 before it sharply increases again. This is primarily the result of convergence of domestic fuel prices mainly coal and gas to the global market dynamics. The expected increase in fuel cost provides competitive advantage to certain renewable types. The sharp increase after 2026 is because some renewable types mainly wind requires higher support than others to meet the Non-Solar RPO of 11%. Limited potential of bio-fuels and small hydro power restrict the capacity addition from such sources, resulting in higher amount of wind capacity requirement to meet the Non-Solar RPO.

Figure 64 shows the distribution of the total projected subsidy requirements across various RE types. Over the period 2011-21, the subsidy support is heavily weighted towards solar that requires 64% of total subsidy support provided over 2011-21. However, the trend reverses from 2021 onwards and wind requires 84% of total subsidy provided over 2021-31. The other renewable types i.e. bio-fuel and small hydro are only small beneficiaries of the subsidy mainly due to the limited potential available in these resources. Solar requires INR 89 billion of subsidy support to achieve a Solar RPO of 5% by 2031. Wind requires the maximum subsidy support of INR 172 billion by 2031 to achieve a Non-Solar RPO of 11%.

Figure 64: Grey India - Renewable type wise subsidy requirements and generation mix by 2021 and 2031



Note: - Number on the bubble represents cumulative subsidy (in Rs 000'Crore) for a capacity type till that particular year from 2012 and the size of bubble is relative to the total subsidy given to renewable until that year

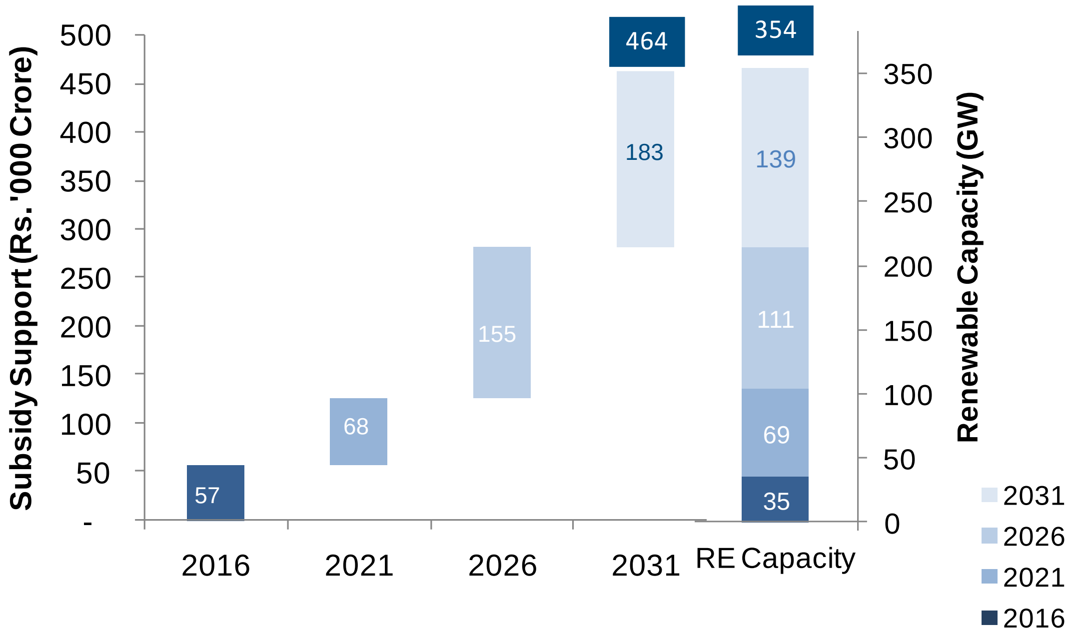
The year 2021 therefore clearly represents a key inflection point for subsidy support to be provided by the government, with solar on a downward trajectory and wind on a sharp upward trajectory. This should come as no surprise as the year 2021 marks the completion of JNNSM Phase 3 which aims to bring the cost of solar to grid parity. On the other hand, a substantial proportion of the easier-to-implement and economically attractive wind sites are expected to be exhausted by 2021, leaving mostly less-endowed wind resources to be taken up after 2021.

The above trends in the solar and wind subsidy requirements after 2021 are expected to broadly lead to two possible outcomes. First, the projected subsidy support may undergo a change as there could be strong case for government to reduce the overall subsidy requirements by promoting the solar generation only. Second, the government may continue support to wind as illustrated in the above projections. Therefore, the year 2021 is an important positioning year for subsidies as wind coming beyond 2021 may have to compete with other renewable types mainly solar which require substantially lower subsidy.

7.2 Blue India Scenario

The Blue India Scenario estimates that a total of INR 4,640 billion subsidy support, spread over the period 2012-2031, is required for achieving 20% RPO by 2031. This is a significant increase from that required in the Grey India Scenario, where the estimated subsidy support is INR 2,960 billion. This amount represents ~5% of the nominal GDP for the year 2011-12.

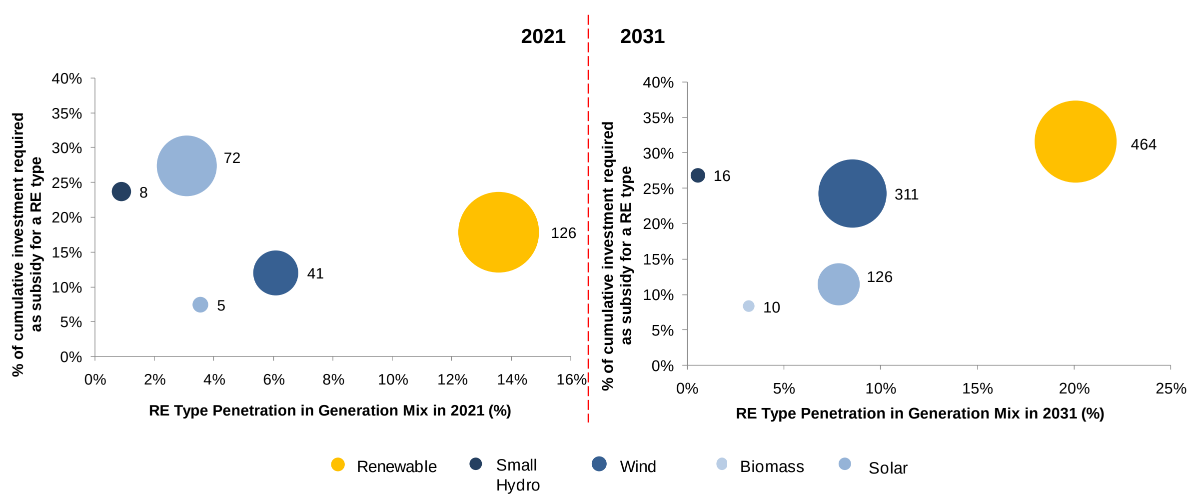
Figure 65: Blue India - Subsidy requirements and renewable additions over 2016-2031



Note: The numbers represent the subsidy requirement and capacity added over the Five-year Planning period ending in that particular year; Also subsidy is not provided to existing projects in 2011 and 2012

The Figure 66 shows the distribution of the total projected subsidy requirements across various renewable types in the Blue India Scenario. Over the period 2011-21, the solar base capacity requires approximately 57% of the total subsidy provided. However, beyond 2021, wind requires 80% of the subsidy required over 2021-31 while solar requires only 16% of the total subsidy required over 2021-2031. Solar requires INR 1,260 billion by 2031 to achieve an RPO of 7.5% while wind requires a subsidy of INR 3,110 billion to contribute to a Non-Solar RPO of 12.5% by 2031.

Figure 66: Blue India - RE type wise subsidy requirements and generation mix by 2021 and 2031



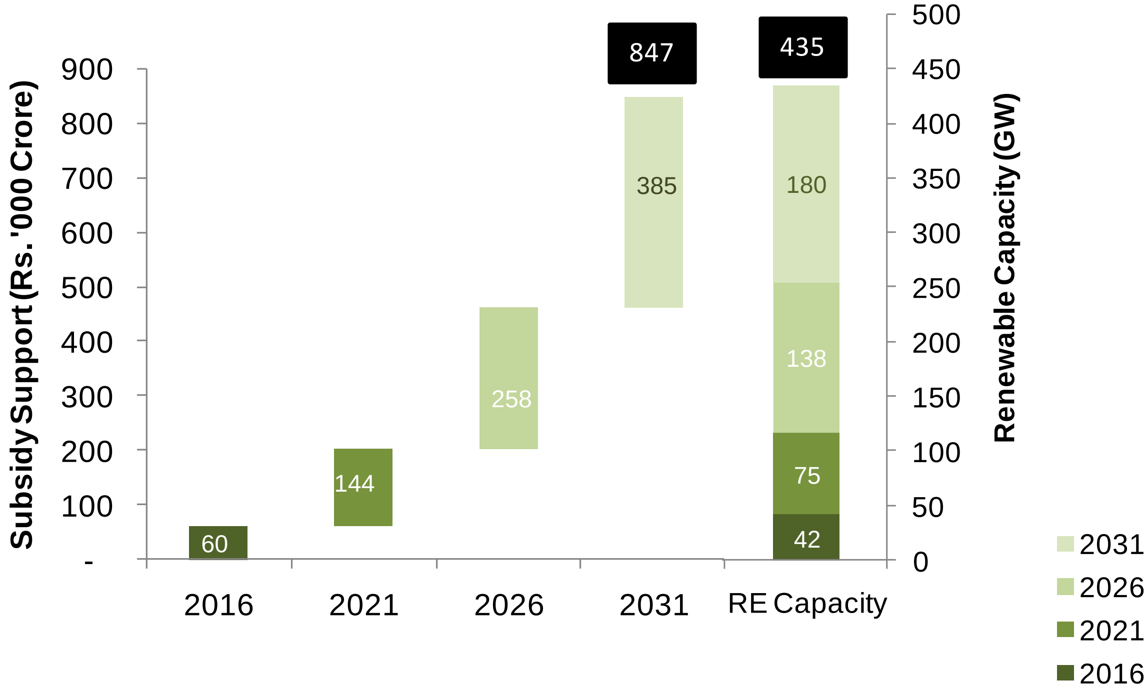
Note: The number on the bubble represents cumulative subsidy (in Rs 000'Crore) for a capacity type till that particular year from 2012 and the size of bubble is relative to the total subsidy given to renewable until that year

7.3 Green India Scenario

The Green India Scenario estimates that a total of INR 8,470 billion subsidy support, spread over the period 2012-2031, is required for achieving 25% RPO by 2031. This is a significant increase from the Grey

India Scenario and the Blue India Scenario, where the estimated support is INR 2,960 billion and INR 4,640 billion respectively. This amount represents ~9% of the nominal GDP for the year 2011-12.

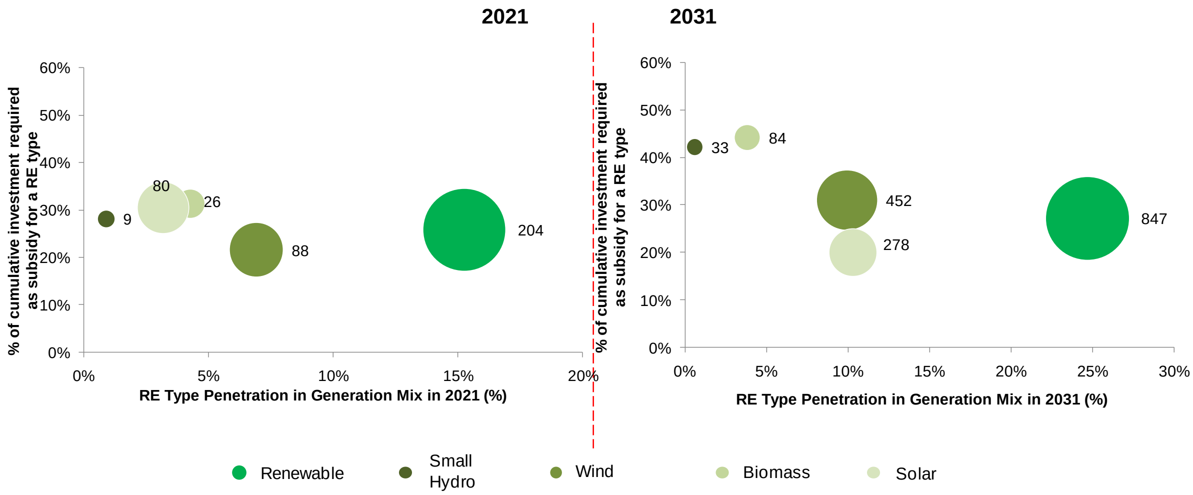
Figure 67: Green India - Incremental subsidy requirements and renewable additions over 2016-2031



Note: The numbers represent the subsidy requirement and capacity added over the Five-year Planning period ending in that particular year; Also subsidy is not provided to existing projects in 2011 and 2012

The Figure 68 shows the distribution of the total projected subsidy requirements across various renewable types. Over the period 2011-21, the subsidy support is approximately equally weighted between solar and wind. However, beyond 2021, wind requires 56% of the subsidy required over 2021-31 while solar requires only 30% of the total subsidy required over 2021-31. Solar requires INR 2,780 billion by 2031 to achieve an RPO of 10% while wind requires a subsidy of INR 4,520 billion to contribute to a Non-Solar RPO of 15% by 2031. The slightly higher reliance on subsidy continues for Solar in the Green India Scenario as assumed coal prices are lower than those in the Grey India Scenario as a result of the lower global coal demand. Other renewable types mainly bio-fuels and small hydro although do not have the potential to scale-up like solar and wind but with subsidy support become important to meet the RPO targets in Green India Scenario.

Figure 68: Green India - RE type wise subsidy requirements and generation mix by 2021 and 2031



Note: Number on the bubble represents cumulative subsidy (in Rs 000'Crore) for a capacity type till that particular year from 2012 and the size of bubble is relative to the total subsidy given to renewable until that year

8. Cost – Benefit Analysis of Higher Renewable Penetration

In this section, the results of each of the three scenarios with RPO enforcement (Grey India, Blue India and Green India) against their respective alternate scenarios without any RPO enforcement (Gry II, Blu II and Grn II) have been discussed.

Cost-Benefit analysis of an increased renewable penetration has been done for each scenario for the following variables –

- Capacity and Generation Mix
- Coal and Gas Consumption
- Variable Cost of Generation
- Grid Emission Intensity
- Investment and Net savings

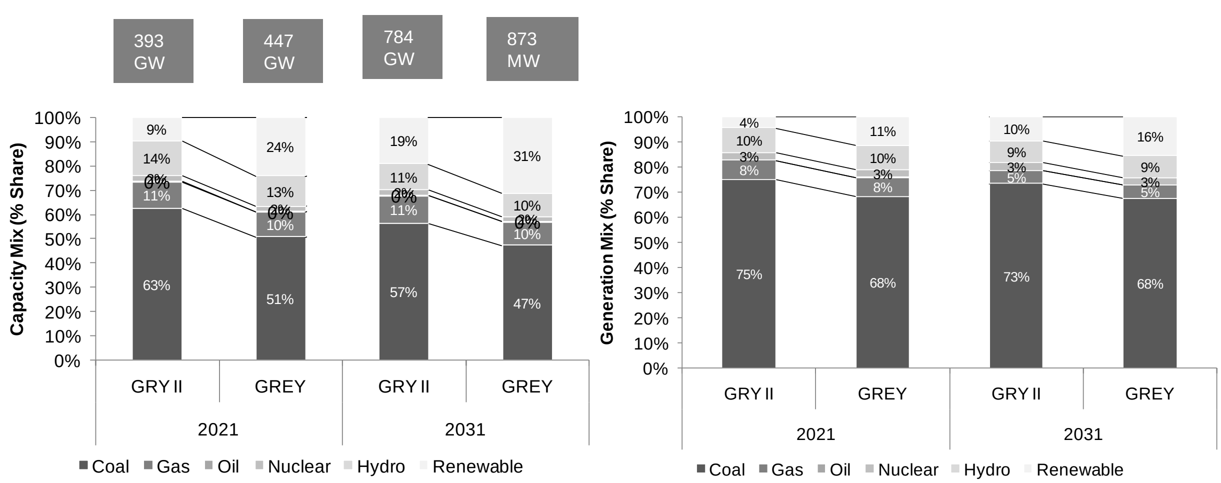
The objective of this analysis is to understand that if the high cost RE generation has achieved certain other economic benefits which can lead to sustainable development along with cost recovery of RE investments.

8.1 Grey India Scenario

8.1.1 Impact on the Capacity and Generation Mix

Figure 69 shows the breakup of capacity and generation mix for each generation type for the Grey India against its alternate Gry II Case with no RPO enforcement. The total Capacity requirement in 2031 The results indicate that subsidy support can have a significant impact on Capacity and Generation Mix.

Figure 69: Grey India: Projected impact of Subsidy on Capacity and Generation Mix

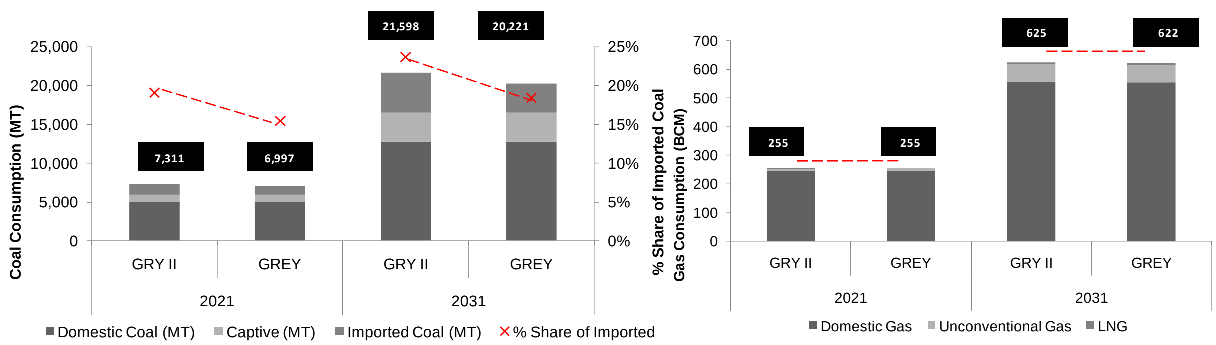


The penetration of renewable in the generation mix only based on its superior economics is limited to only 4% and 10% by 2021 and 2031 respectively as shown in the Gry II case of the above Figure. However, with subsidy support, the conventional base load capacity mainly based on high cost imported coal and gas is displaced by the RE capacity with the RPO levels reaching the levels of 11% and 16% by 2021 and 2031 respectively. The potential of renewable to replace certain amount of base-load capacity would result in eventual cost savings in the system in the longer term which has been discussed in sections to follow.

8.1.2 Impact on the Coal and Gas Consumption

The subsidy support given in the Grey India Scenario results in huge savings in imported coal consumption as shown below. This is due to the reason that renewable displaces the high cost generation based on the imported coal from the Merit-Order-Curve. The total cumulative savings in imported coal consumption during the period 2012-21 is 313 MT which is also equivalent to monetary savings of INR 1.81 trillion. During 2012-31, the cumulative savings through reduction of 1,376 MT imported coal consumption is INR 8.3 trillion. Similarly, there is insignificant saving through reduction in gas consumption as shown below.

Figure 70: Grey India: Projected Impact of Subsidy on Coal Consumption (MT) and Gas Consumption (BCM)

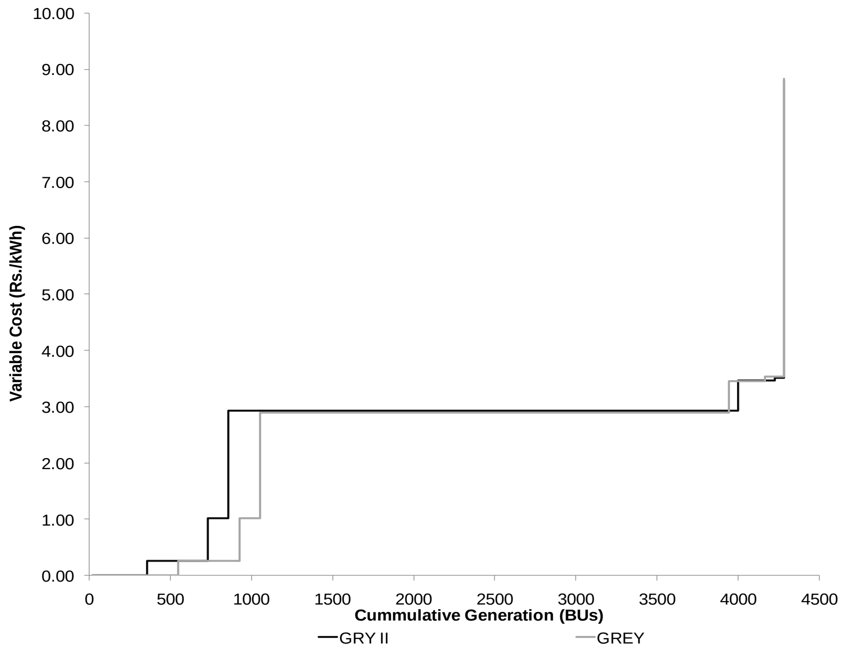


Note: -Both coal and gas consumption, stated in any year, represents cumulative consumption for each fuel type till that particular year from 2012

8.1.3 Impact on Variable Cost of Generation

The subsidy support results in lower cost of variable generation as the larger volume of RE generation is available with negligible variable cost of generation relative to that of conventional resources. This is illustrated in the Figure 71 below which depicts a representative curve for the year 2031 showing the variable cost of generation for the energy generation available. The lower cost of generation results in savings of INR 8.1 trillion over 2011-2031 period.

Figure 71: Grey India: Projected Impact of Subsidy on variable cost of generation

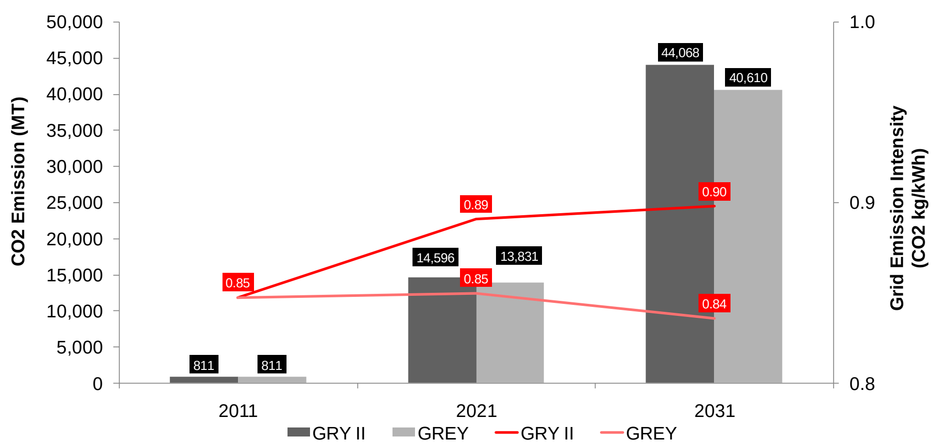


Note: The curve is representative for year 2031 only

8.1.4 Impact on Grid Emission Intensity

In the Grey India Scenario, additional revenues can be realized against the reduction in Grid Emission Intensity since the carbon emissions are reduced with the infusion of higher RE as shown in the Figure 68 below. The average Grid Emission Intensity over 2011-2031 in the Grey India scenario is 0.84 CO2 kg/kWh which is 0.06 CO2 kg/kWh lower than that in the alternate case – Gry II with no RPO enforcement. The savings of 765 MT in carbon emissions is achieved till 2021 which further increases to 3,460 MT till 2031. The total annual savings based at a price of 6 Euro/Ton of CO_2 amount to INR 0.32 trillion savings over 2011-2021 and INR 1.5 trillion savings over 2011-2031.

Figure 72: Grey India - Projected Impact on Grid Emission Intensity



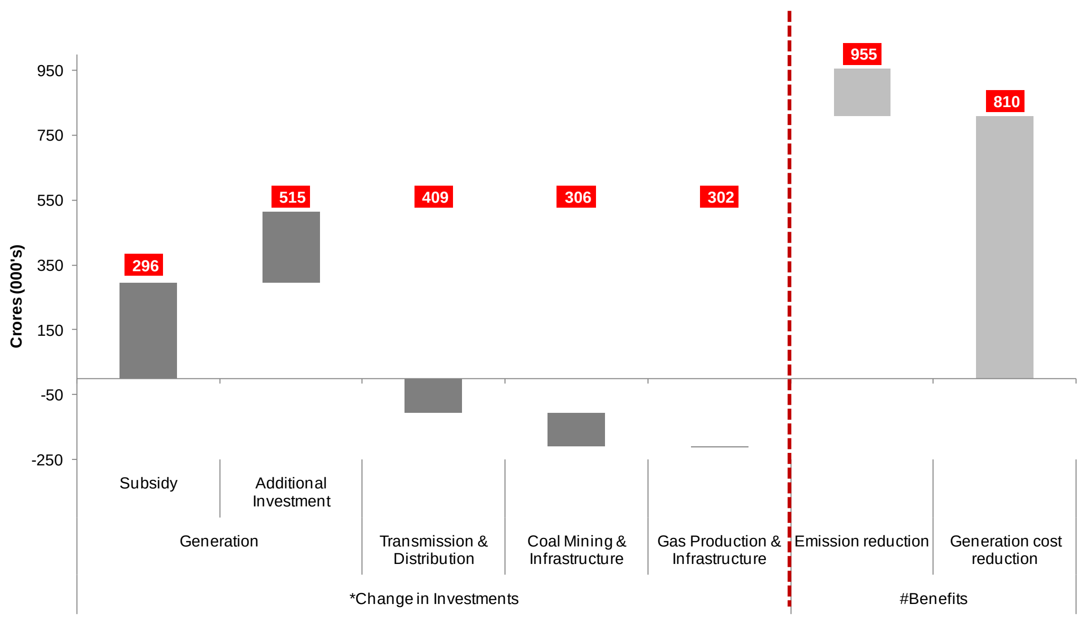
Note: -Emissions stated in any year represent cumulative emission till that particular year from 2012

8.1.5 Impact on Investments and Net Savings over 2012-31

In the Grey India Scenario, an additional investment of INR 3.02 trillion is required cumulatively over the period 2011-31 vis-à-vis that in the Gry II Case. As discussed in Section 6, total investment of INR 74.85 trillion is required in Grey India case. This implies that Grey India Scenario bears an additional price of INR 3.02 Trillion against the investment requirement of INR 71.83 Trillion (74.85-3.02) in GRY II case in meeting the RPO targets. Similarly under various investment heads shown in the figure 73, such as generation, transmission & distribution, coal mining and infrastructure etc, the differences represent the additional costs/savings the system bears/reaps in meeting the RPO targets as against the values in case the RPO targets are not met, as in GRY II Case. The time value of both investments and savings has not been considered in this analysis and thus investments and savings represent the values as realized in that particular year.

In total, INR 5.2 trillion of additional investment is required in adding the generation capacity. Out of INR 5.2 trillion, INR 3 trillion is required to be provided as capital support to promote renewable to achieve an RPO of 16%. As discussed before, this capital support also represents the cost that the system has to bear on pushing renewables through mandated RPOs. However, with the increased RE penetration, approximately INR 1.1 trillion lesser investments is required in transmission and distribution due to reduced requirement for the inter-state transmission infrastructure. Further, the coal consumption reduces by 1,376 MT cumulatively over 2011-31 which in turn leads to a decrease in the investment requirement in the coal mining and infrastructure by ~INR 1.0 trillion. Negligible savings in gas consumption in the Subsidy case result in insignificant savings in the investment required.

Figure 73: Grey India - Investment required and Net savings over 2012-31



*Note: * Change in investments represents the incremental investments incurred in the subsidy case relative to that in the base case; # Benefits take into account the incremental generation and emission costs incurred in the subsidy case relative to that in the base case*

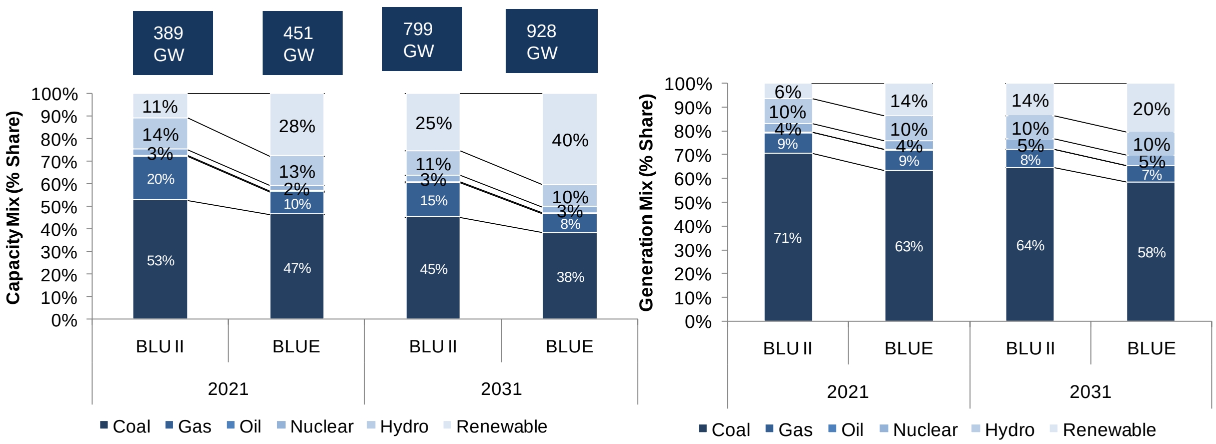
Increased renewable penetration results in savings of INR 8.1 trillion due to reduction of variable cost of generation. Further, a saving of INR 1.5 trillion is possible from the carbon emission reduction. To sum up, over the 20 years, promotion of renewable leads to an additional investment of INR 3.02 trillion, potentially resulting in gross savings of INR 9.6 trillion and hence a net savings of INR 6.6 trillion.

8.2 Blue India Scenario

8.2.1 Impact on the Capacity and Generation Mix

Figure 74 shows the breakup of capacity and generation mix for each generation type for the Blue India against its alternate Blu II Case with no RPO enforcement.

Figure 74: Blue India - Projected impact of Subsidy on Capacity and Generation Mix



In the Blue India Scenario, the coal capacity share goes down to 38% with RE Subsidy by 2031 relative to that of 45% in the Blu II case. The share of renewable capacity in the total capacity mix has increased to 40% due to RE Subsidy by 2031. Further, the share of coal generation in the total generation mix by 2031 has decreased by 6 %

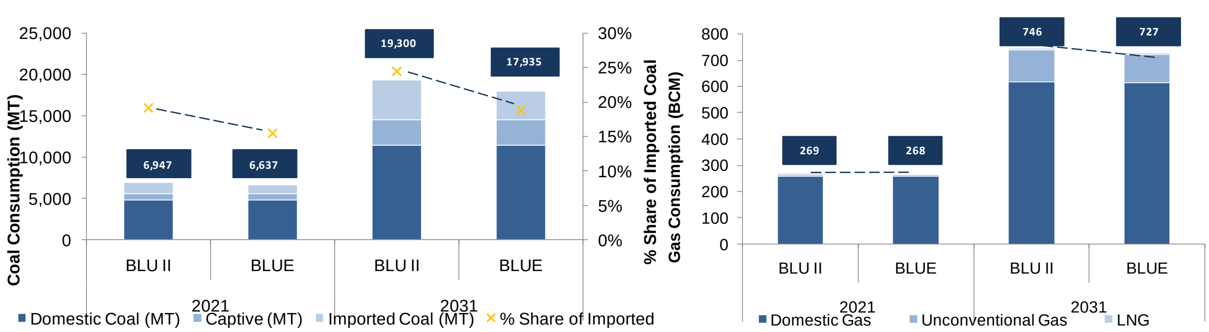
The share of coal capacity in the Blue India Scenario is 10% lower than that in the Grey India Scenario due to higher renewable purchase obligation.

8.2.2 Impact on the Coal and Gas Consumption

The subsidy support given in the Blue India Scenario results in huge savings in imported coal consumption. The total annual savings in imported coal consumption is 310 MT amounting to INR 1.77 trillion over the period of 2012-21. The total annual savings through reduction of 1,376 MT imported coal consumption is INR 7.9 trillion over 2011-31.

In the Blue India Scenario, the gas consumption worth INR 0.45 trillion is reduced, mainly due to the savings in unconventional gas.

Figure 75: Blue India - Projected Impact of Subsidy on Coal Consumption (MT) and Gas Consumption (BCM)



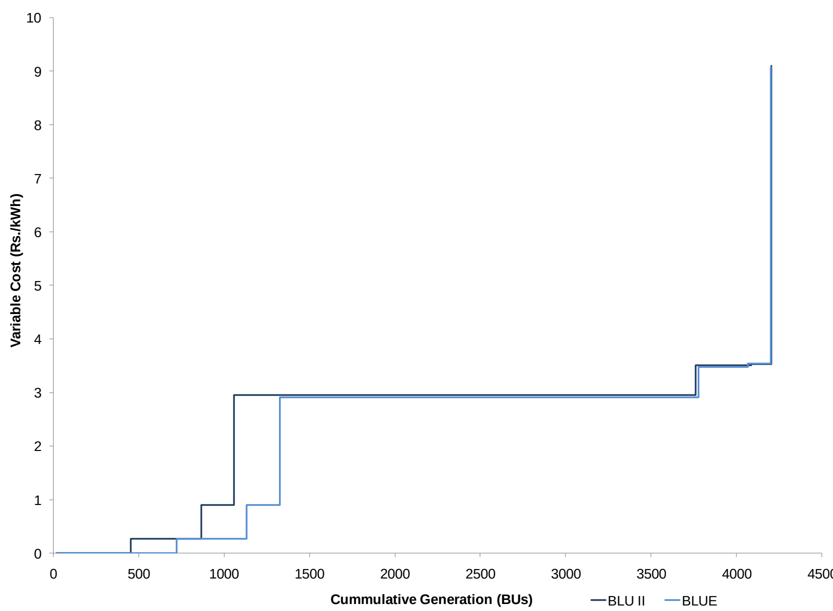
Note: -Both coal and gas consumption, stated in any year, represents cumulative consumption for each fuel type till that particular year from 2012

8.2.3 Impact on Variable Cost of Generation

Figure 76 depicts a representative curve for 2031 showing the variable cost of generation for the energy generation available in the Blue India Scenario. The lower cost of generation results in savings of INR 9.4 trillion over 2011-31.

The savings in the Blue India Scenario due to reduction in variable cost of generation is INR 1.3 trillion higher than that in the Grey India Scenario. This is due to higher penetration of renewable in the generation mix.

Figure 76: Blue India - Projected Impact of Subsidy on variable cost of generation

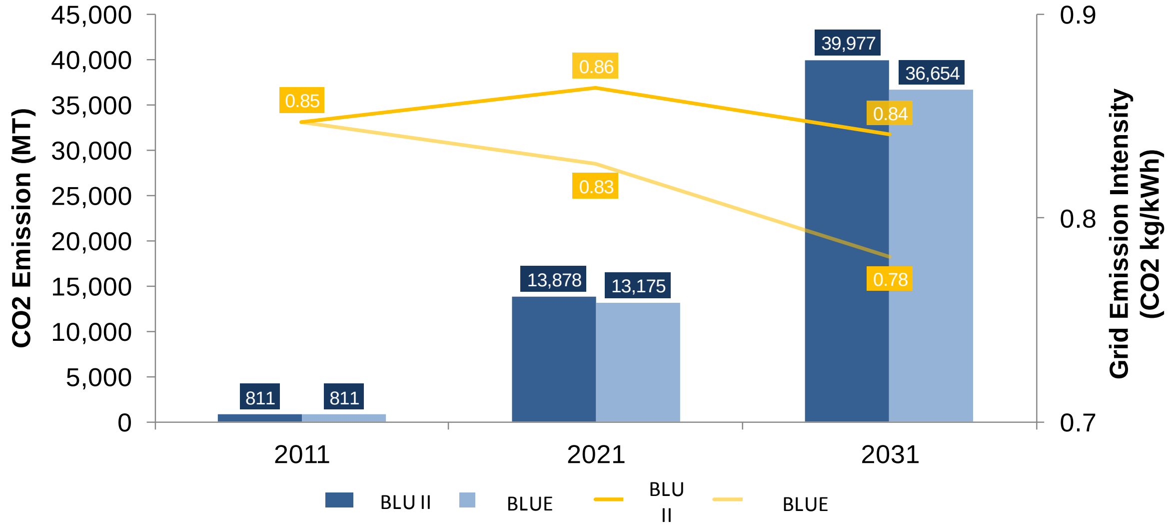


Note: The curve is representative for year 2031 only

8.2.4 Impact on Grid Emission Intensity

In the Blue India Scenario, the average Grid Emission Intensity over 2011-31 is 0.78 CO2 kg/kWh which is 0.6 CO2 kg/kWh higher than that in the alternate Blu II case with no RPO enforcement. The savings of 700 MT in carbon emissions is achieved till 2021 which further increases to 13,175 MT till 2031. The total annual savings based at 6 Euro/Ton of CO_2 amount to INR 0.3 trillion over 2011-21 and INR 1.4 trillion over 2011-31 periods.

Figure 77: Blue India - Projected Impact on Grid Emission Intensity



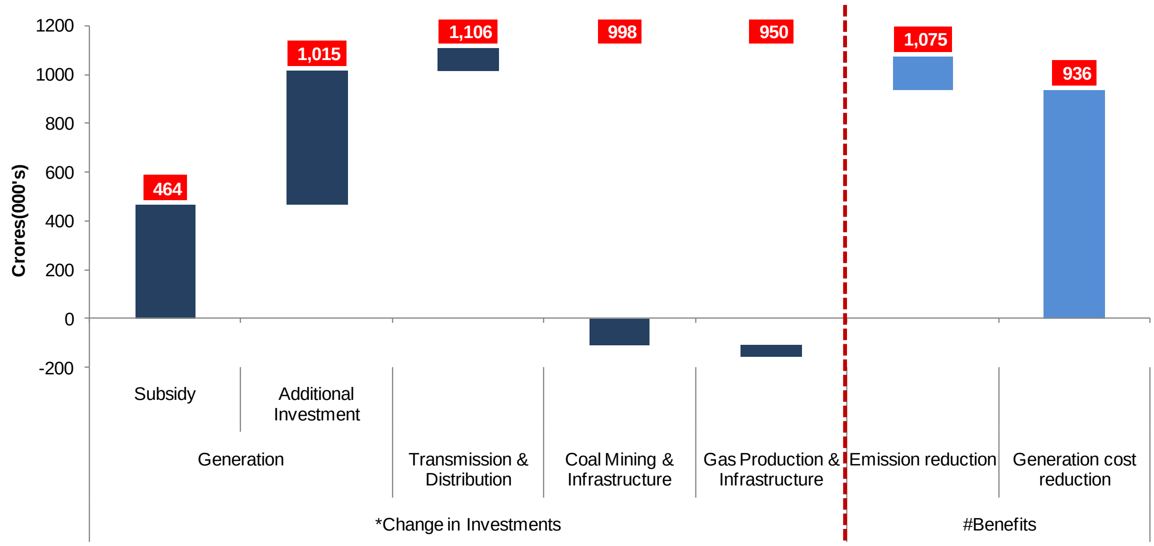
Note: -Emissions stated in any year represent cumulative emission till that particular year from 2012

8.2.5 Impact on Investments and Net Savings over 2012-31

In the Blue India Scenario, an additional total investment of INR 9.5 trillion is required over 2011-31 vis-à-vis that in the Blu II Case. As discussed in Section 6, total investment of INR 76.24 trillion is required in Blue India case. This implies that Blue India Scenario bears an additional price of INR 9.5 trillion against the investment requirement of INR 66.74 Trillion (76.24-9.5) in BLU II case in meeting the RPO targets. Similarly under various investment heads shown in the figure 78, such as generation, transmission & distribution, Coal mining and infrastructure etc, the differences represent the additional costs/savings the system bears/reaps in meeting the RPO targets as against the values incase the RPO targets are not met, as in BLU II Case.

Out of INR 10 trillion of generation investment required, INR 4.64 trillion has to be provided as capital support. As discussed before, this capital support also represents the cost that the system has to bear on pushing uneconomical renewable through mandated RPOs. There is an additional investment of INR 0.9 trillion required in T&D infrastructure because higher capital investments are needed for the expansion of the grid to connect wind and solar plants in remote areas with demand centers, and for more efficient electric equipment in the end-use sectors. Lower coal mining and gas exploration results in lower investments. Overall, an investment of INR 9.5 trillion is required additionally in the Blue India case viz-a-viz over 2011-2031.

Figure 78: Blue India - Projected Investment required and Net savings till 2031 in Subsidy vs. Base case



*Note: * Change in investments represents the incremental investments incurred in the subsidy case relative to that in the base case; # Benefits take into account the incremental generation and emission costs incurred in the subsidy case relative to that in the base case*

In the Blue India Scenario, the savings through reduction in variable cost of generation amount to INR9.4 trillion over 2011-31. Further, savings increase to INR 10.1 trillion if the savings from carbon emissions are also considered. To sum up, over the 20 years, promotion of renewable leads to an additional investment of INR 9.0 trillion, potentially resulting in gross savings of INR 10.79 trillion and hence a net savings of INR 1.79 trillion.

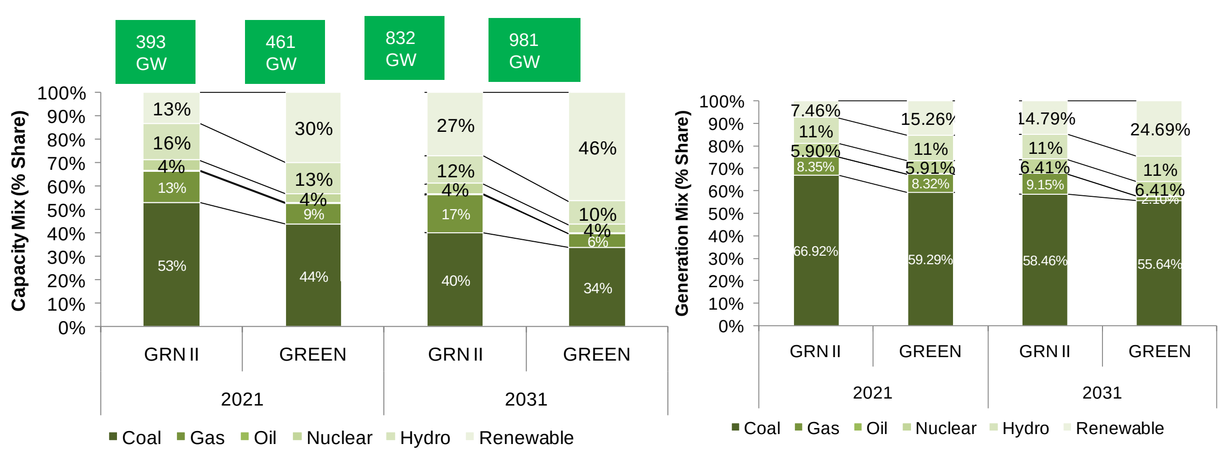
8.3 Green India Scenario

8.3.1 Impact on the Capacity and Generation Mix

Figure 79 shows the breakup of capacity and generation mix for each generation type for the Green India against its alternate Grn II Case with no RPO enforcement.

The coal capacity share in the total capacity mix goes down to 34% by 2031 while the share of renewable goes up to 46% in the same period. The share of coal generation in the total generation mix has gown down to 56% in 2031 in comparison to that in alternate Grn II case with no RPO enforcement

Figure 79: Green India - Projected impact of Subsidy on Capacity and Generation Mix

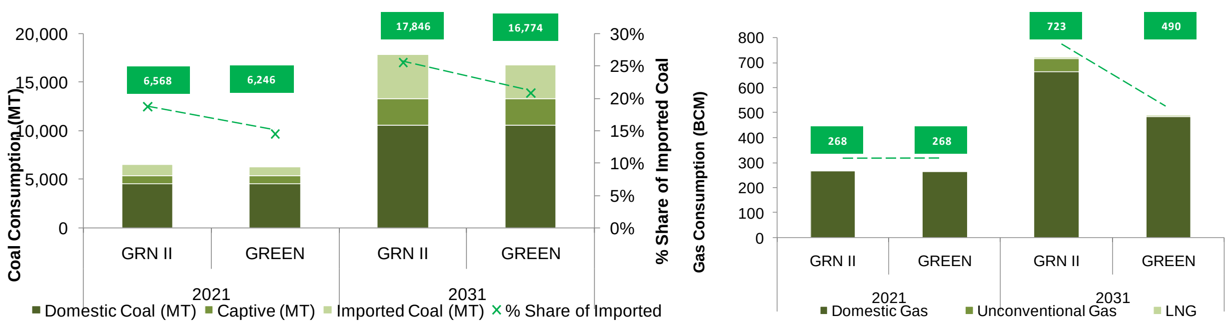


8.3.2 Impact on the Coal and Gas Consumption

As shown in the Figure 80, the subsidy support given in the Green India Scenario results in huge savings in imported coal consumption. The total annual savings in imported coal consumption is 322 MT amounting to INR 1.72 trillion over the period of 2012-21. The total annual savings through reduction of 1,068 MT imported coal consumption is INR 5.31 trillion over 2011-31.

In the Green India Scenario, there is substantial lower gas consumption in the Subsidy case relative to the Base case. There is a cumulative saving of 233 BCM of gas over 2011-31 amounting to savings of INR 4.3 trillion. Overall, there is saving of INR 9.6 trillion over 2011-2031 due to lower coal and gas consumption.

Figure 80: Green India - Projected Impact of Subsidy on Coal Consumption (MT) and Gas Consumption (BCM)



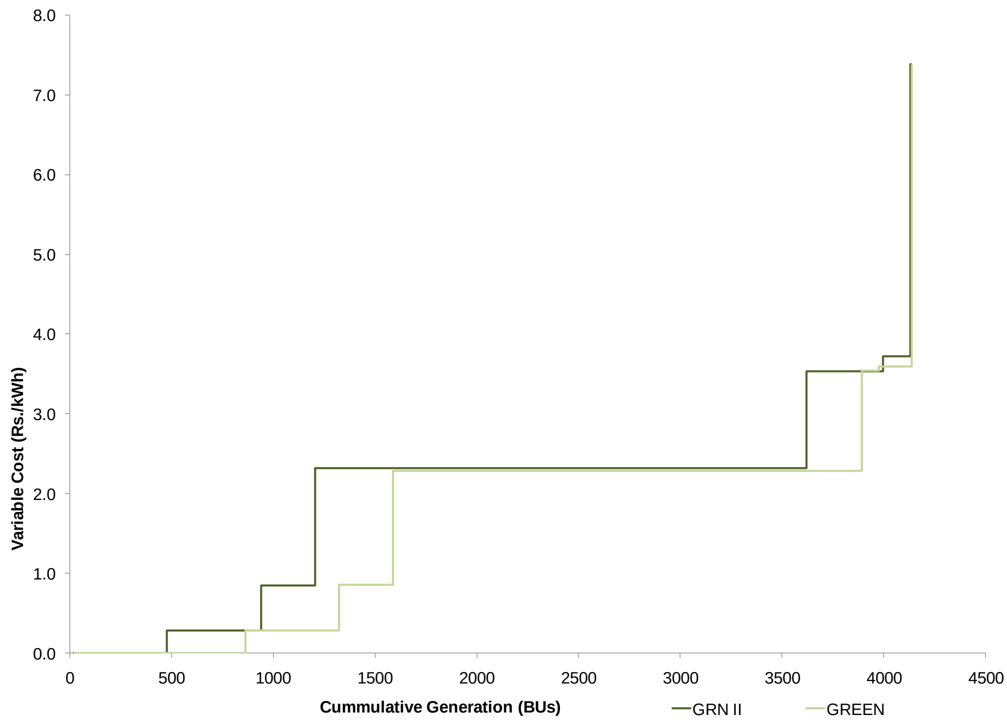
Note: -Both coal and gas consumption, stated in any year, represents cumulative consumption for each fuel type till that particular year from 2012

8.3.3 Impact on Variable Cost of Generation

Figure 81 depicts a representative curve for 2031 showing the variable cost of generation for the energy generation available in the Green India Scenario. The lower cost of generation in the Subsidy case results in savings of INR 11.2 trillion over 2011-2031 in the Green India Scenario.

The savings in the Green India Scenario due to reduction in variable cost of generation is higher by INR 1.8 trillion than that in the Blue India Scenario. This is due to higher penetration of renewable in the generation mix.

Figure 81: Green India - Projected Impact of Subsidy on variable cost of generation



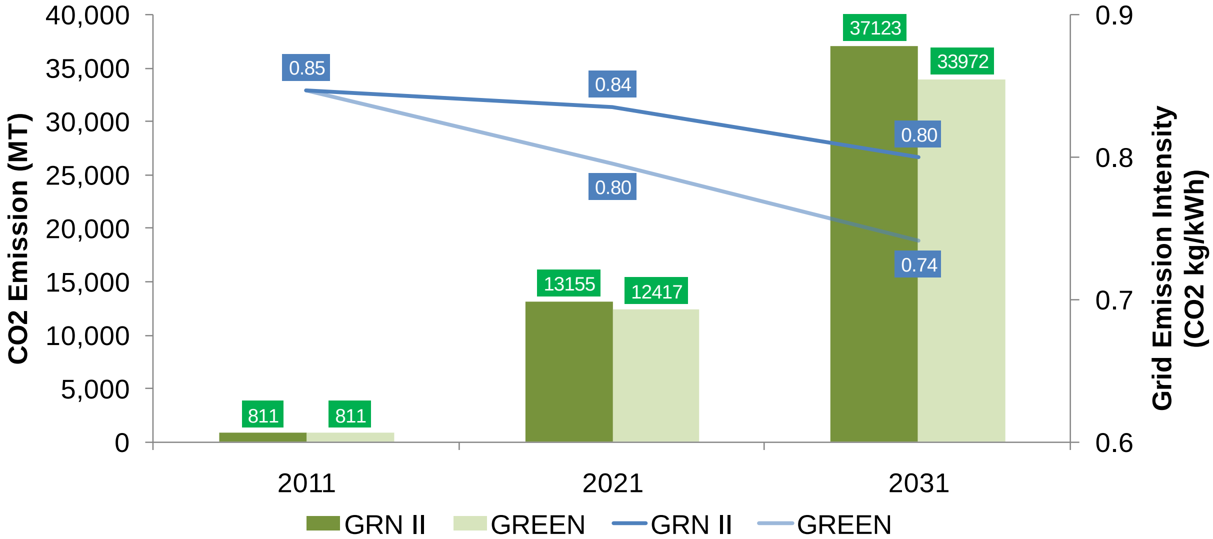
Note: The curve is representative for year 2031 only

8.3.4 Impact on Grid Emission Intensity

In the Green India Scenario, the average Grid Emission Intensity over 2011-31 is 0.74 CO2 kg/kWh which is 0.6 CO2 kg/kWh higher than that in the alternate Grn II case with no RPO enforcement. The savings of 740 MT in carbon emissions is achieved till 2021 which further increases to 12,417 MT till 2031.

The total annual savings based at 6 Euro/Ton of CO_2 amount to INR 0.3 trillion over 2011-21 and INR 1.3 trillion over 2011-31 periods.

Figure 82: Green India - Projected Impact on Grid Emission Intensity



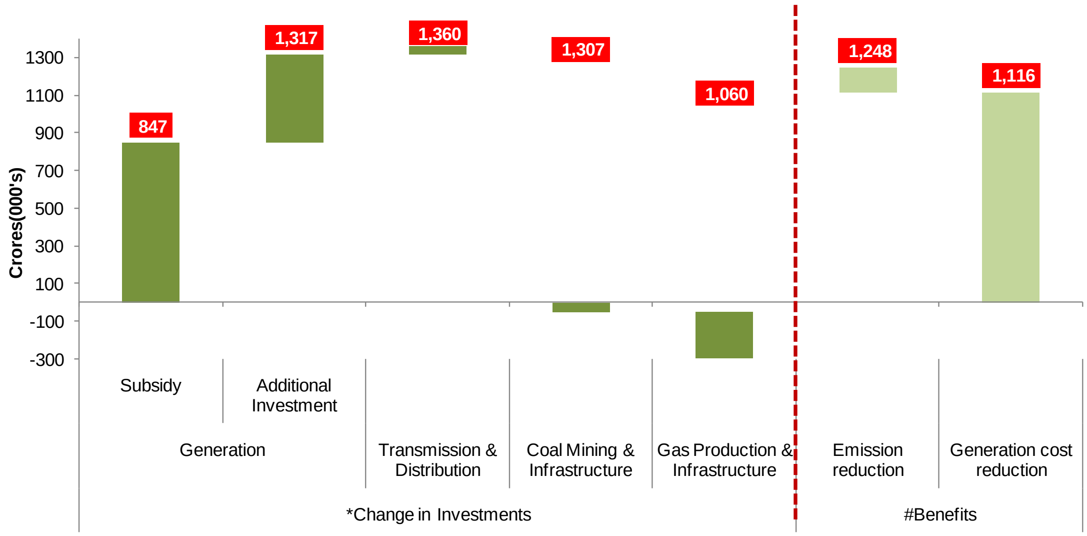
Note: -Emissions stated in any year represent cumulative emission till that particular year from 2012

8.3.5 Impact on Investments and Net Savings over 2012-31

In the Green India Scenario, an additional total investment of INR 10.6 trillion is required over 2011-2031 vis-à-vis that in the Grn II Case. As discussed in Section 6, total investment of INR 79.55 trillion is required in Green India case. This implies that Green India Scenario bears an additional price of INR 10.6 trillion against the investment requirement of INR 68.95 Trillion (79.55-10.6) in GRN II case in meeting the RPO targets. Similarly under various investment heads shown in the figure 83, such as generation, transmission & distribution, Coal mining and infrastructure etc, the differences represent the additional costs/savings the system bears/reaps in meeting the RPO targets as against the values incase the RPO targets are not met, as in GRN II Case.

Out of INR 13 trillion of generation investment required, INR 8.5 trillion has to be provided as capital support. As discussed before, this capital support also represents the cost that the system has to bear on pushing uneconomical renewable through mandated RPOs. There is an additional investment of INR 0.4 trillion required in T&D infrastructure. This is in contrast to the Grey and Blue scenarios in which there are savings on T&D infrastructure vis-à-vis that in their respective alternate cases (Gry II and Blu II) with no RPO enforcement. This is because in the Green case, the huge addition of renewable based power in resource rich states requires additional T&D transmission infrastructure for evacuation. A substantially lower investment is needed in the gas exploration and related infrastructure. Overall, an investment of INR 1.1 trillion is required additionally during the period 2011-31.

Figure 83: Green India - Projected Investment required and Net savings till 2031 in Subsidy vs. Base case



*Note: * Change in investments represents the incremental investments incurred in the subsidy case relative to that in the base case; # Benefits take into account the incremental generation and emission costs incurred in the subsidy case relative to that in the base case*

In the Green India Scenario, the savings through reduction in variable cost of generation amount to INR 11.16 trillion over 2011-31. Further, savings increase to INR 12.48 trillion if the savings from carbon emissions are also considered. To sum up, over the 20 years, promotion of renewable leads to an additional investment of INR 10.6 trillion, potentially resulting in gross savings of INR 12.48 trillion and hence a net savings of INR 1.88 trillion

The table below summarizes the key points as discussed above while comparing the results of Grey, Blue and Green scenarios with their respective alternate scenarios (Gry II, Blu II and Grn II) with no RPO enforcement.

Clearly, the investments into renewable reap significant returns as shown above. This remains true irrespective of the policy path India takes as defined under the three scenarios – Grey India, Blue India and Green India. However, as the energy deficit vanishes by 2016 in all the scenarios discussed above, these savings may not be significant. If there are slippages in the capacity addition or there is a scarcity of key fuels like coal and gas, the RE generation can fill this gap leading to even higher economic returns for the economy.

Further, the accrued benefits of renewable that extend beyond 2031 have not been considered which means that the benefits of any renewable capacity i.e. for a potential solar project coming in 2030 benefits have been considered for two years only (till 2031) rather that the actual benefits over its lifetime of 25 years. Hence the savings could be much higher than those calculated under various scenarios.

Table 38: Benefits of renewable Comparison

	From	To	From	To	From	To
	GRY II	Grey India	BLU II	Blue India	GRN II	Green India
Total Capacity in 2031(GW)	784	873	799	928	832	981
RPO Achieved	10%	16%	14%	20%	15%	25%
Cumulative Coal Consumption till 2031 (MTs)	21,598	20,221	19,300	17,935	17,846	16,774
Cumulative Gas Consumption till 2031 (BCM)	625	622	746	727	723	490
Cumulative CO2 Emissions till 2031 (MTs)	44,068	40,610	39,977	36,654	37,123	33,972
Cumulative Investments required by 2031 (Trillions)	71.83	74.85	66.74	76.24	68.95	7,955

8.4 Summing Up – Key Benefits of Increased Renewable Penetration

The study has analyzed the results within each scenario and witnessed significant savings in these scenarios if renewable contribution is increased to meet the RPO targets. However, the investments as well as the savings reaped increases significantly in case the capital support is clubbed with conducive environment to promote renewable into the system. In this section, analysis of the difference in investment and subsidy requirement between any two scenarios has been done. The effect of the change in policy is considered as the country shifts from –

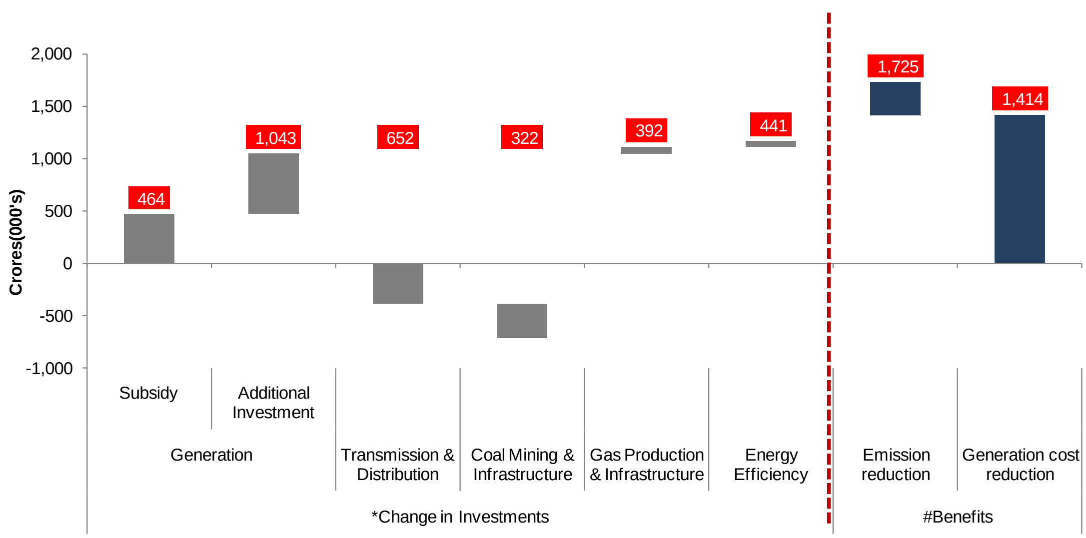
- Grey India to Blue India and
- Grey India to Green India and

8.4.1 Comparing Grey India and Blue India

Herein the results for the policy shift from Gry II case i.e. Grey India case with no RPO Enforcement to Blue India case have been compared. This shift requires an additional investment of INR 4.4 Trillion. This includes an incremental investment of INR 10.4 Trillion on generation and an additional subsidy of INR 4.6 Trillion in Blue India vis-à-vis in Grey India. Further, an additional investment of INR 0.5 trillion is required for implementing various energy efficiency measures. However, there is a significant savings of INR ~3.9 Trillion on account of lesser T&D infrastructure required in Blue India. A greater focus on renewable in Blue India leads to lesser investments on coal mining and infrastructure also.

However, compared to investments, there are huge savings on account of emissions reduction and generation cost reduction in the Blue India scenario vis-a-vis that in Grey India. The gross savings can potentially go up to INR ~17 Trillion while net savings can be up to INR ~12.8 Trillion

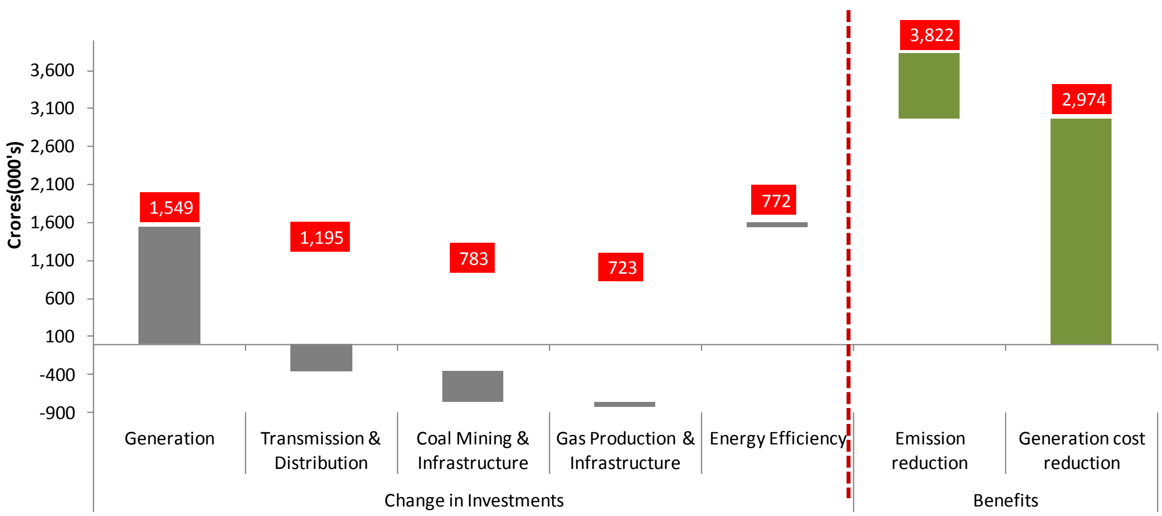
Figure 84: Grey India to Blue India – Incremental Investments and Savings Required



8.4.2 Comparing Grey India and Green India

The figure 85 highlights the additional investments and the possible savings that can be accrued if the country shifts from Grey Conventional BAU scenario to Green India scenario. In the Green India case, additional investments in generation would be required as more capital intensive RE capacities come in, while the investments in T&D network and the fuel infrastructure will reduce. An explicit subsidy support of INR 8.47 trillion[28](Fig 83) to RE generation would also be required under the Green India scenario. Thus after accounting for the change in investments (additional as well as reduced), a net additional investment of INR 7.72 trillion is required. However, these investments would lead to decrease in generation cost by INR 29.74 trillion over the study period along with the savings, in the range INR 4.24 – 8.48 trillion, due to emission reduction resulting in the total optimistic savings of INR 38.22 trillion. Overall a net savings of INR 30.50 trillion (=38.22 – 7.72) is achievable under the Green India Case vis-à-vis Grey Conventional BAU case spread over the study period.

Figure 85: Grey India to Green India – Cumulative Additional Investments and Savings over 2012-31



To summarize, results on expected subsidy and savings are provided when the country shifts between different policy paths –

Table 39: Summary – Incremental Subsidy and Savings per Rupee of Subsidy

To	From	Subsidy (INR Trillion)	Savings (INR Trillion)	Savings per Rupee of Subsidy Disbursed
Grey India	Blue India	4.64	12.8	2.76x
Grey India	Green India	8.5	30.5	3.59x

Given that the difference in policy focus under Grey India is very different from that in Green India, the subsidy requirements are also substantial. Accordingly, the impact on the savings is also considerable as the scope of realizing value through usage of RE is significant too. Therefore, the incremental savings against each rupee of subsidy disbursed to RE is 3.59x for Green India vis-à-vis a multiple of 2.76x for Blue India.

[28]The subsidy is the amount of financial support required in a renewable conducive environment as provided in the Green India Scenario

8.5 Other Tangible Benefits

The other key benefits of proving support to renewable energy sources are listed below -

- Improved availability of electrical energy and reduced peak shortages in case of fuel shortages or capacity slippages for coal and gas based projects. This would also imply a higher economic growth resulting in better tax revenue to the government.
- Lower cost of interruptions in terms of use of costly captive power and/or loss of production
- Higher economic growth due to improved availability of electricity and hence improved welfare of the society.
- Support to domestic manufacturing in case of domestic content requirement
- Lower impact on global environment due to replacement of fossil fuel for power generation
- Lower impact on local environment in terms of local pollutants like NOx, SOx and fly ash.
- Lower environmental impact due to avoided coal mining.
- Lower impact on global and local environment due to avoided transportation of fossil fuel.
- Avoided import of fossil fuel used for power generation and hence saving of foreign exchange.
- Improved energy security due to lesser dependency on fuel import.

9. Conclusions and Recommendations

9.1 Conclusions

1. Energy Shortages may disappear in India by 2016 if the minimum projected capacity addition of 105 GW is achieved against an energy demand projection of ~1,560 BUs under the Grey Conventional BAU Scenario (GRY II). However, the peak deficits persist beyond 2016.
2. Under high renewable cases, the RE generation displaces the conventional capacities (especially gas based generation) from serving the base load. The gas based capacities will be used mainly to serve the peak demand only and to support increased renewable penetration rather than contributing to meet the base and mid-merit loads.
3. Peak shortages get eliminated with more renewable in the capacity mix. Peak shortages vanish by 2026 in the Green India Scenario, exist till 2031 in Blue India Scenario and persist beyond 2031 in the Grey India Scenario.
4. Renewable can be promoted through a combination of factors including (a) providing a conducive environment for RE in terms of enforcing a mandatory RPO (b) better cost economics of RE generation over that of conventional and (c) the explicit financial support (through feed in tariffs etc) to RE. Various scenarios studied in this report represent a mix of conducive environment for RE and the cost economics of RE based generation (basically covering factors (a) and (b) as discussed above). Further in the table below, for these scenarios, the impact of financial support to promote RE is compared vis-à-vis the Grey Conventional BAU Scenario (GRY II).

Table 40: Dependence on Subsidy

From	To	Cumulative Support (INR Trillion) – A	Cumulative RE Capacity added due to Support (GW) - B	GW Capacity added with per trillion of Support – (A/B)
GRY II	Grey India	2.96	251	84.8
BLU II	Blue India	4.64	354	76.3
GRN II	Green India	8.5	435	51.2

The dependence on capital support/subsidy is maximum in Grey India Scenario with the amount of capacity added per unit of subsidy being the highest, which goes against the theory of collaborative involvement of all resources for an integrated planning approach. The Grey India scenario provides the least conducive environment for renewable penetration as against that in Green India, wherein the renewable gets penetrated into the system through a collaborative involvement of financial incentives and conducive policy environment.

Table 41: Impact of Conducive Environment and Capital Support

From	To	Support (INR Trillion) – A	Net Savings (INR Trillions) – C	Net Savings per unit of Support (C/A))
GRY II	Grey India	2.96	6.5	2.20
GRY II	Blue India	4.64	12.8	2.76
GRY II	Green India	8.5	30.5	3.59

As shown above, the savings realized per unit of financial support disbursed is maximum when a shift is made from Grey Conventional BAU Scenario (GRY II) to Green India Scenario implying the most profitable case occurs when conducive environment is clubbed with capital support to promote the renewable penetration into system's capacity and generation mix.

5. In the table below, a summary of additional investments required in the Green case over the Grey Conventional BAU Scenario (GRY II) is provided against various heads.

Table 42: Cost Benefit Analysis of more RE

Costs – benefits	Parameters	Grey Conventional BAU Scenario	Additional Investments in Green Case over Grey Conventional BAU Scenario
Investments (INR Trillions) over the period 2012-31	Generation	39.14	15.49
	Transmission & Distribution Investment	19.57	(3.54)
	Coal Mining and Infrastructure	11.68	(4.12)
	Gas Production and Infrastructure	1.44	(0.61)
	Energy Efficiency	0	0.49
	Total	**71.83**	**7.72**
Cumulative Savings (INR Trillions)*	Generation Cost Reduction	**29.74**	
	Emission Reduction	**8.48**	
	Total Savings	**38.22**	
Cumulative Net Savings (INR Trillions)*	**30.50**		

*For Green India Scenario over Grey Conventional BAU Scenario over period 2012-31

Key results are as follows –

a. A renewable contribution of 25% in the generation mix can be achieved by the year 2031 under the Green India case. In fact, it also makes immense economic sense to do so, with or without providing subsidies.
b. The "policy driven" route to go about it is to impose mandatory RPO, which will involve some additional costs on utility in initial years. However it will still make economic sense to utilities in medium to long term as fuel prices increase.
c. The "Incentive driven" route to achieve it will involve providing an explicit support (INR 8.47 trillion in Green India Scenario) over the study period, which will be paid back over the study period itself, with additional benefits and economic returns.
d. An additional investment of INR 7.72 trillion is required in Green India case over the Grey Conventional BAU Scenario as shown above. However, under the Green India case, an additional savings of INR 38.22 trillion is possible mainly because of reduced system generation cost resulting in a net savings of INR 30.50 trillion.

Based on the key findings in the study, the following recommendations are made in the following sub-section which can help in an economical renewable penetration into India's capacity and generation mix.

9.2 Recommendations

1. As the generation mix changes, the nature of transmission requirement changes significantly. To absorb higher RE capacities, the short-distance intra-state transmission network builds as well as REC (Renewable Energy Certificates) mechanism needs to be strengthened. We also need to focus on setting up long inter-regional corridors as significant RE resources exist in states with high electricity demand and better integration of high RE penetration would merit balancing at regional/national level. Further studies need to be carried out to analyse how much of resource-concentrated renewable energy can be taken care of by the REC mechanism and how much needs long transmission corridors to reach the demand centres, resulting in an optimum impetus to both REC mechanism and transmission investments requirement.
2. With the introduction of more renewable in the country's capacity and generation mix, there would be an increased dependence on the firming capacities like gas based capacities and storage hydro plants. Plans need to be geared up to analyse how these firming capacities be provided in the renewable resource rich states. Thus studies should be done to analyse the availability of firming capacity for renewable to reduce the intermittency of renewable generation, providing a reliable source of power. Further, analysis of the explicit gas demand and availability to CTs (combustion turbines) for supporting renewable should be undertaken.
3. To benefit from the renewable resources, it is recommended to initiate Integrated Resource Planning (IRP) including balancing and scheduling, grid management and Demand Side Management (DSM) in the resource rich states to match the peak demand and renewable generation profiles and thus enabling increased renewable contribution to meet the peak

demand of the country. An integrated resource planning that takes into account both conventional and renewable resources at national level will allow the system to be developed optimally, reducing the overall system costs.

4. Renewable generation can significantly affect the system's peak capacity requirement. Studies should be done to analyse if wind or solar or their hybrids, having generation profiles similar to that of demand, can contribute to the peak margin requirement and hence reduce the dependence on the conventional capacities in meeting the system's peak demand. Thus renewable should also be included in the capacity planning exercise by the country's planners.
5. Support to renewable energy, which could be either policy driven or incentive driven or a combination of both, should ensure harnessing of economic benefits out of all renewable resources. Studies need to be performed to analyse the demand profile of each demand centre clubbed with the generation profile and dispatch economics of each renewable type, for an economical-cum-equitable promotion of various renewable resources.
6. Within renewable mix, the wind generation requires the maximum amount of support - 60% in the Grey Scenario, 67% in the Blue Scenario and 53% in the Green Scenario, in order to make wind cost competitive with other types of generation sources. This results mainly due to increasing capital cost curve for wind technology in India while the solar costs show a declining trend. Detailed studies may be undertaken to analyse accurate cost trends of technologies over time. Further, introduction of competition in the renewable sector may possibly make all renewable technologies more competitive, resulting in reduced support requirement.

10.Annexure

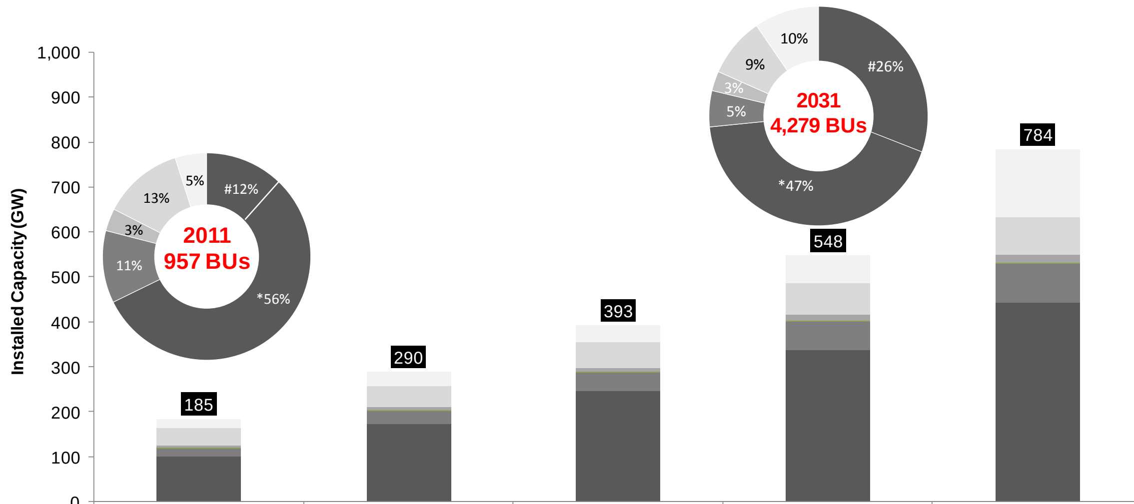
10.1 GRY II Case - Grey Conventional BAU Scenario

GRY II case represents the case where same economical and policy environment exists as that in the Grey India Scenario, leaving the obligation to meet the required RPO of 16%. This implies that no renewable has been forced into system either through policy push or through disbursement of subsidy. This case also represents the least amount of self sustainability of renewable against a coal rich policy environment. Figure 86 shows the summary of the capacity addition and generation mix over the 2011-2031 period.

In this Scenario, the total capacity by 2031 stands at 784 GW, approximately five times the installed capacity of 185 GW at the end of 2011. The capacity addition is dominated by coal, adding ~ 340 GW of coal capacity over the period 2012-2031, resulting in 443 GW of coal capacity by 2031. Renewable follows the lead with ~130 GW of capacity addition over the same period. The percentage share of the coal capacity in the capacity mix marginally increases to ~57% by 2031 from current level of ~55%. The share of renewable in the capacity mix increases from the current share of 11% to reach 19% by 2031.

The percentage share of various capacities in the generation mix does not witness a significant change by 2031 as is the case with the capacity mix. The share of coal generation in total generation mix increases to 74% by 2031 from current level of 68%. The generation from gas capacity goes down to 5% by 2031 from the current share of 11%. Renewable generation share increases from the current share of 5% in the total generation to reach 10% by 2031.

Figure 86: GRY II Case - Projected Capacity and Generation Mix by 2031



	2011	2016	2021	2026	2031
Total	185	290	393	548	784
Renewables	21	32	37	62	150
Hydro	39	47	57	69	84
Nuclear	5	6	9	14	17
Oil	1	1	1	1	1
Gas	18	31	43	65	89
Coal	102	172	246	338	443

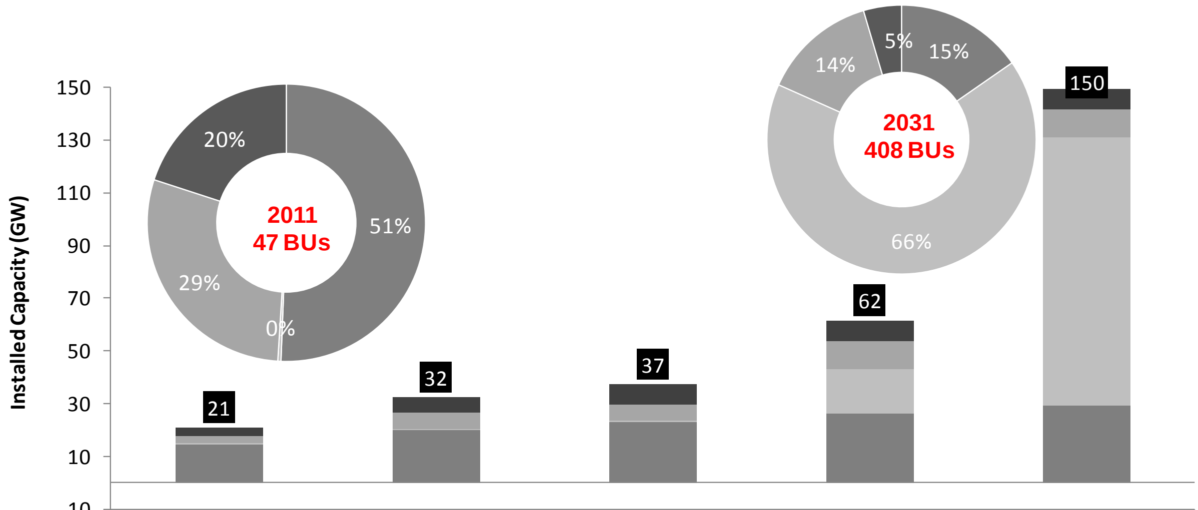
- Imported Coal based generation; * - Domestic Coal based generation ■Coal ■Gas ■Oil ■Nuclear ■Hydro ■Renewables

Within the renewable resources, the capacity and generation mix is dominated majorly by solar, followed by wind. Figure 87 below shows the summary of capacity addition of renewable over 2011-2031.

Other types of renewable contribute lower towards the overall capacity addition due to limited potential of small hydro and biomass.

Renewable generation increases to 10% by 2031 and this generation represents the self sustainability of renewable. Solar generation contributes to 66% of total renewable generation by 2031. The contribution of generation from wind, bio-fuels and small hydro is 15%, 14% and 5% of the total generation.

Figure 87: GRY II Case - Projected Capacity and Generation Mix of renewable by 2031



	2011	2016	2021	2026	2031
Total	21	32	37	62	150
Small Hydro	3	6	8	8	8
Biomass	3	6	6	11	11
Solar	0	0	0	17	102
Wind	15	20	23	26	29

■ Wind ■ Solar ■ Bio-Fuels ■ Small Hydro

Figure 88 below shows the demand-supply position over the 2011-2031 period. Given the huge capacity addition in the 12th plan, the demand supply balance in energy is anticipated to be achieved by 2016 while peak deficits persist over the 2011-2031 timeframe. This is primarily attributed to greater emphasis on addition of base-load capacity of coal that has limited peaking capabilities, resulting in continued peak shortages throughout study horizon.

Figure 88: GRY II Case - Projected Peak and Energy Deficits by 2031

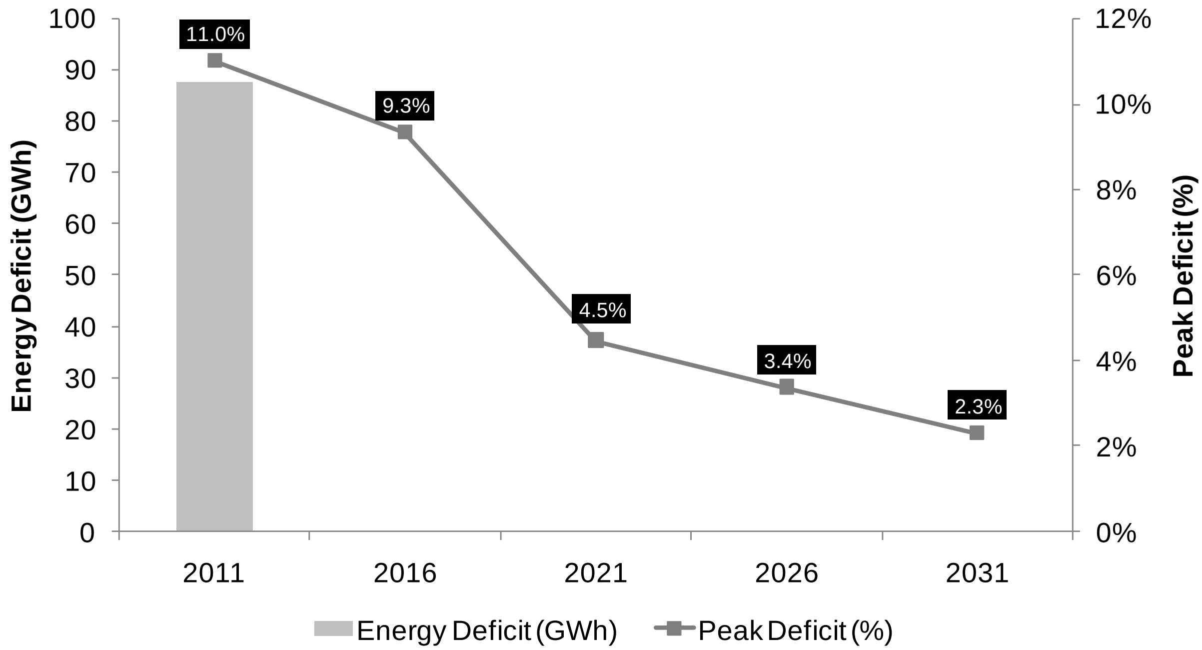
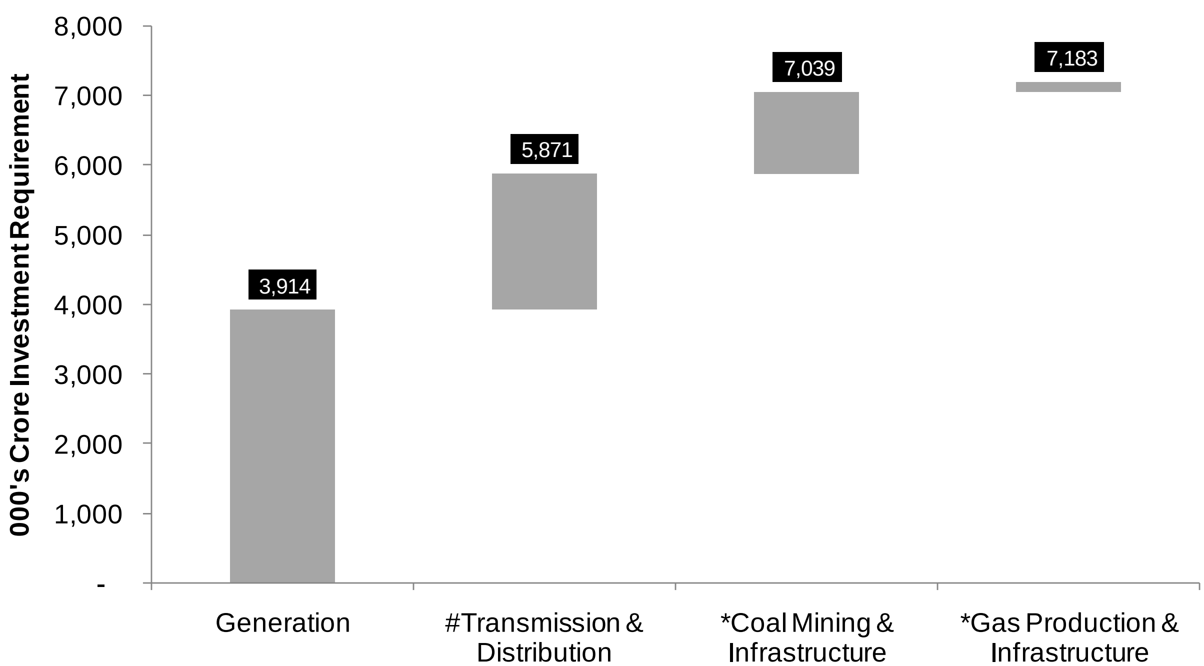


Figure 89 below provides an overview of the estimated investment requirements for the Gry II Case Scenario over the 2011-2031 timeframe. Besides considering the investments related to generation, transmission and distribution, the analysis also includes the investments required for the coal and gas production and the related infrastructure.

Figure 89: GRYII Case - Total investment requirements over the 2012-2031 timeframe



Note:

 # The T&D investment is assumed to be 50% of the total investment required in generation as assumed by CEA (Central Electricity Authority) for its investment calculation. This case serves as the basis for calculation of T&D investments for rest of the cases in the study. T&D investment for rest of cases is calculated based on the difference in transmission capacity (MW) required in any case vis-a-vis that in the GRYII case as projected by IPM. With more renewable capacity in the system, less transmission capacity needs to be built in due to its nearness to the demand centre. The percentage reduction in transmission capacity is further applied to the assumed value of 50% of the investments in generation, which has been considered for GRYII case, to get the precise percentage of investments in generation that will approximately reflect the required T&D investments for that particular case. However, accurate analysis for T&D investments requires a separate detailed load-flow/congestion analysis that is beyond the scope of this study.

**For Coal mining & gas production infrastructure, average investment per MT/ MMSCMD is taken from IEA- Technology Road Map Assumption*

Overall, the power sector has a capital requirement of ~INR 72 trillion in the Grey India Scenario by 2031. While the considering the cost of generation and T&D infrastructure only, an investment of INR ~59 trillion is required against the new cumulative capacity additions of ~600 GW expected to be set up over 2012-2031 period.

For coal supply from both domestic and imported sources, an investment of INR ~11 trillion is required over the study period which includes investments in mining, domestic coal transport and ports. For natural gas, the investment requirement for exploration in new fields and related infrastructure is around INR ~1.4 trillion, much lower than that required for coal due to relatively lower increment in gas consumption from 2011 to 2031.

10.2 India Integrated Planning Model (I-IPM)®

India Integrated Planning Model (I-IPM) ®

I-IPM® uses a linear programming formulation to select investment options and to dispatch generating and load management resources to meet overall electric demand today and on an ongoing basis over the chosen planning horizon. System dispatch - determining the proper and most efficient use of the existing and new resources available to utilities and their customers - is optimised given the security requirements, resource mix, unit operating characteristics, fuel and other costs including environmental costs, and transmission possibilities. The model incorporates innovations in several areas of generation modelling such as representing inter-regional transmission constraints, environmental constraints and ancillary service pricing algorithms in order to capture various real-world operating circumstances.

I-IPM® is used in combination with other proprietary and third-party model on transmission (Positive Sequence Load Flow, PowerWorld, GE-Maps) and fuels (coal production, gas market model) to ensure that all areas of the sector and extensively covered.

Figure: I-IPM® Analytical Framework

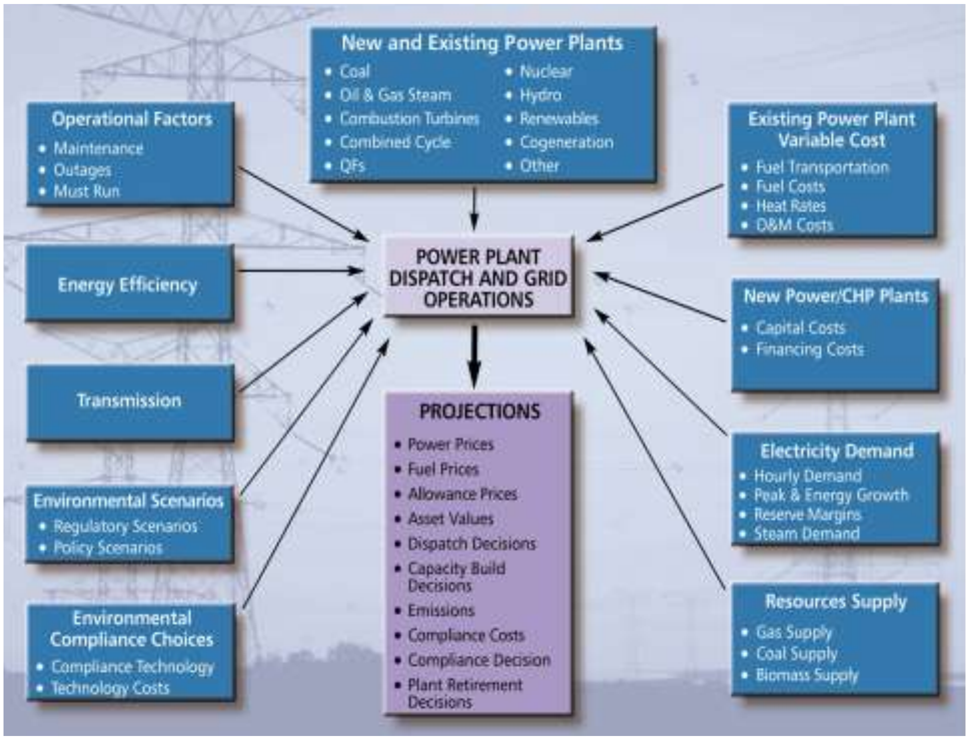


Figure illustrates the analytical framework used. Assumptions on the air pollution regulation to be simulated, compliance technology cost and performance, costs of new builds, electric market conditions, and fuel supply and transportation costs, transmission limitations can all be defined as inputs. Outputs will include optimal compliance plans for individual generation units, allowance prices, compliance costs, renewable energy premium and electricity prices, and optimal capacity expansions including mothballing, retrofits, retirements and new builds.

As a forward-looking model, the I-IPM® can easily tackle the complex task of determining the most efficient capacity adjustment path. Because the model solves for all years simultaneously, it will select the most appropriate solution to ensure that system security is not compromised (e.g. build new baseload or peaking units, retrofit or repower existing units), select units that should be retired or mothballed, and identify the timing of such events. Capacity prices are one of the results from this optimization process. Investment decisions are selected by the model by taking into account system security requirements, forecasts of customer demand for electricity, realization of electricity prices across the year, the cost and performance characteristics of available options, technical characteristics of existing power plant units and a host of other factors. By using this degree of foresight, the model replicates the approach used by power plant developers, regulatory personnel, and energy users when reviewing investment options.

Applications

Its linear programming structure makes the I-IPM® particularly well suited for a variety of applications such as assessing planning strategies or regulatory policy options. Among the types of analyses that can be conducted with the I-IPM® are:

- ***Power price forecasts*.** The I-IPM® can be used to predict wholesale power, renewables obligation certificates prices or the value of emission permits using scenarios developed through the I-IPM® database interface.
- ***Strategic planning*.** The I-IPM® can be used to assess the costs and risks associated with alternative utility and consumer resource planning strategies as characterized by the portfolio of options included in the input data base.
- ***Analysis of uncertainty*.** The efficiency of the model's computational algorithms allows it to be used with various techniques for analyzing the potential impacts of uncertain future conditions (e.g. load growth, fuel prices, environmental regulations, costs and performance of resource options) and the risks associated with alternative planning strategies. Alternative approaches that have been used for analyzing uncertainty with the I-IPM® include sensitivity analysis, decision analysis, and modeling uncertainty endogenously by incorporating specific factors that are uncertain and the associated probabilities for different values or expectations for these factors directly into the linear programming structure.
- ***Optimization of operations under system-wide constraints*.** Various approaches can be evaluated for meeting environmental constraints (e.g. limits on hourly, daily, or annual emissions), fuel use constraints (e.g. optimum allocation of limited fuel supplies to alternative plants), load management constraints (e.g. dispatch of directly controlled loads given limits on the availability and scheduling of service interruptions), and other operational constraints (e.g. "must-run" considerations and "area-protection" concerns). The model can also address optimum usage of pumped storage facilities and economic or long-term contracted power purchases from neighboring regions.
- ***Assessing the effect of multi-pollutant policies*.** The environmental modeling capabilities are extremely sophisticated, developed as they have been with a view to support the US EPA's federal emission control programs since the 1980s. Whether estimating the marginal abatement costs of NO_x, SO_2, or CO_2, or establishing the optimal operating and investment regime in the face of multi-pollutant regulations, the I-IPM allows the user to compare alternative investment programs thus minimizing the possibility of stranding investments and preparing the client to respond pro-actively to evolving environmental regulation.
- ***Options assessment*.** The I-IPM® can be used to "screen" alternative resource options and option combinations based upon their relative costs and potential earnings. By defining all plausible alternatives, the model will suggest the optimal timing for different actions on the basis that all market participants are seeking to maximize profits.
- ***Estimation of avoided costs.*** Shadow prices from the linear programming solution can be used to determine avoided costs by season or time-of-day for pricing purchases from qualifying facilities, independent power producers, or economy and/or firm power purchases from other utilities. Shadow prices also can be used to assess the economic value of relaxing a constraint (e.g. what is the marginal cost of emissions reductions for the utility?), to conduct marginal cost studies, and to determine the cost reductions of alternative options in order for these options to be competitive with those options selected by the model or the "preferred" options. This greatly enhances the capability to use the model and its outputs as a screening tool.

- ***Integrated resource planning*.** The I-IPM® can be used to perform least-cost planning studies that simultaneously optimize demand-side options (load management and conservation), fuel supply, non-utility supply, renewable options and traditional utility supply-side options. The model has been licensed to Red Eléctrica de España (REE) and Polskie Sieci Elektroenergetyczne (PSE), system operators in Spain and Poland respectively, who use it to prepare inputs into their national energy plans. We have also licensed the software to a number of private sector clients.
- ***Detailed modeling of dispatch.*** The I-IPM®'s dispatch algorithms are very accurate and have been benchmarked against detailed utility dispatch models. This includes the ability to optimize the allocation of capacity across energy, reserve and capacity markets.

About the study

The study has been supported by Shakti Sustainable Energy Foundation and carried out by ICF International (www.icfi.com).

About Shakti Sustainable Energy Foundation

Shakti Sustainable Energy Foundation works to secure the future of clean energy in India by supporting the design and implementation of policies that promote both the efficient use of existing resources as well as the development of new and cleaner alternatives. Shakti's efforts are concentrated in four specific areas: power, energy efficiency, transport, and climate policy. The organization acts as a systems integrator, bringing together stakeholders in strategic ways to enable clean energy policies in these fields. It also belongs to an association of technical and policy experts called the ClimateWorks Network. Being a member of this group further helps Shakti connect the policy space in India to the rich knowledge pool that resides within this network.

Shakti Sustainable Energy Foundation | The Capital Court | 104 B/2 Fourth Floor, Munirka Phase III
New Delhi 110067 | India | T +91 11 4747 4000 | F +91 11 4747 4043 | www.shaktifoundation.in