GIZ - India Green Energy Corridors

IGEN-GEC

Large Scale Integration of Renewable Energy

Summary of findings and key recommendations

Consortium Partners

Contents

List of Abbreviations

ACP	Area Clearing Prices
AGC	Automatic gain control
BRP	Balance Responsible Party
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Authority
CERC	Central Electricity Regulatory Commission
CSP	Concentrated solar power
DC	Direct current
DISCOM	Distribution Company
EMS	Energy Management System
ECMWF	European Centre for Medium-Range Weather Forecasts
EHV	Extra High Voltage
FRT	Fault Ride Through
FiT	Feed in Tariff
GW	Giga Watt
GFS	Global Forecast System
GFS	Global Forecasting System
GTS	Global Telecommunication System
GoI	Government of India
HPCS	High Performance Computing System
HV	High Voltage
HPSEBL	Himachal Pradesh State Electricity Board Limited
IEGC	Indian Electricity Grid Code
IMD	Indian Meteorological Department
IGEN-GEC	Indo German Energy Programme - Green Energy Corridor
IT	Information Technology
MIS	Management Information System
MCP	Market Clearing Price
MSCDN	Mechanically switched capacitors with damping network
MW	Mega Watt

MoP	Ministry of Power
NCAR	National Center for Atmospheric Research
NCEP	National Centre for Environmental Prediction
NIWE	National Institute of Wind Energy
NLDC	National Load Despatch Center
NWP	Numerical weather prediction
PV	Photovoltaic
PLF	Plant Load Factor
PX	Power Exchange
PGCIL	Power Grid Corporation of India
POSOCO	Power System Operation Corporation Limited
PHPS	pump hydro power storage capacity
PPA	Purchase Power Agreement
RLDC	Regional Load Despatch Centre
RE	Renewable Energy
REC	Renewable energy Certificate
REMC	Renewable Energy Management Centre
RPO	Renewable Purchase Obligation
RMSE	Root-mean-square error
SLDC	State Load Despatch Center
STU	State Transmission Utility
STATCOM	Static Synchronous Compensators
SVC	Static Var Compensators
SCADA	Supervisory Control and Data Acquisition
TSO	Transmission System Operators
UTC	Universal Time Coordinated
WRF	Weather Research and Forecasting

Executive Summary

The electricity system in India faces several challenges as the energy demand is expected to grow significantly within the next decades while the domestic energy resources in terms of fossil fuels are becoming increasingly limited. It is important to increase electricity production in order to keep pace with the growing demand. The primary objective of the Government of India is to build and efficiently deploy renewable energy (RE) for supplementing the energy requirements of the country. This will also enable the government to sufficiently reduce the nation's greenhouse gas (GHG) emissions. The Indian grid has a grid connected RE capacity of 42.75 Gigawatt (GW) as of 31.03.2016. Integration of Large quantities of RE power in the grid offers significant challenges which are both technical and economic in nature.

The Government of India has set an ambitious target of adding 175GW of Renewables to this portfolio by the year 2022, with 100GW from solar, 60GW from wind, 10 GW from biomass and 5 GW from small hydro. A significant component of solar and wind energy capacity addition is expected to come up in states like such as Tamil Nadu, Maharashtra, Gujarat, Karnataka, Rajasthan, Andhra Pradesh and Telangana in the form of large renewable energy farms. Keeping in mind the large capacity of such farms, it is not feasible to absorb all of this power at the local community or even at the distribution grid level. There is a pressing need for evacuation of this power from Renewable farms to power centres by integrating with the transmission network at state/region/national level/(s) and going forward, at international levels.

Unlike conventional electricity generation, renewable energy cannot be "tamed". Solar and Wind energy generation can fluctuate widely sometimes dropping to near zero within a span of a few minutes (example - passing cloud). Moreover, the behaviour of wind and, to some extent solar, cannot be predicted accurately. This makes their integration into transmission grids a major challenge as it can threaten the stability and security of the overall grid. RE plants being "must run", the grid operator is expected to be able to anticipate renewable energy generation profile to adjust conventional energy sources and load accordingly, and to be able to respond to the highly variable nature of these plants quickly. This situation is likely to get more difficult, as the penetration of renewables into the grid increases. Despatch rules are required to be redefined and conventional generation and loads need to become "flexible".

The government is already working towards redefining policies, processes and is introducing fresh tools to enable integration of large scale Renewable Energy into the transmission grid. This project is a pioneering initiative by the government to understand the key issues in integration of large scale renewable energy.

The project aims to conduct a comprehensive analysis of the current challenges that RE faces in the country and those that will arise out of significant capacity addition in RE. The Indian grid is currently the fifth largest in the world. Maintaining grid stability and power quality is a herculean task with its own legacy of issues. Variable generations from RE such as wind and solar plants together are posing significant technical difficulties in the area of grid management. The recent increase in variable wind and solar power generation, future projections of higher share of RE in the total generation portfolio and associated challenges of grid management render wind and solar power forecasting a mandatory task for the Indian electricity grid. Owing to the higher penetration of variable wind and solar resources, appropriate balancing actions are becoming increasingly complex.

This assignment has chiefly addressed the following challenges:

- Necessary measures for grid stabilization,

- Implementation of appropriate forecasting techniques and balancing capabilities, and
- Establishment of an effective control infrastructure.

The above challenges have been addressed by conducting a detailed analysis of the Indian electricity sector as a whole and on an individual basis in selected states. This analysis provides a reliable inventory of the current electricity sector and its potential to meet the needs for an accelerated RE integration. A special focus of this document is on the question of whether the state-of-the-art instruments for forecasting and balancing are appropriate for the Indian context and which specific changes should be applied to them to make them suitable for the Indian scenario.

Based on the outcomes of this analysis, recommendations for the implementation of forecasting techniques and balancing actions and for the establishment of an effective control infrastructure are provided, namely:

- A good forecast and appropriate balancing action,
- Optimum structure for renewable energy management structure,
- Ancillary market,
- A dynamic power market with short term products,
- Appropriate grid code and control mechanism,
- Adequate reserves,
- Accounting and deviation settlement mechanism,
- Flexible power system and demand responsive consumption, and
- Creating capacity for managing infirm power.

This project under consideration comprises mainly three work packages. While the first package focuses upon forecasting tool, methods to enhance balancing and the concept of Renewable Energy Management Centre (REMC), second package focusses on instrument to foster renewable energy including financial, market based instruments, ancillary services and need of capacity market. The third work package throws light on the need for appropriate grid code and control instruments. A summary of recommendations derived as a result of each of the three work packages are highlighted as follows.

- Need for scientific power generation forecasting techniques and state of the art tools at control centres. Establishment of REMCs and need for visibility of real time RE generation data at the control centre.

- An accurate load forecast (schedule) to the system operator must be availed and frame measures to incentivize DISCOMS for accurate load forecasting.

- Increase the balancing capabilities of the Indian states from a technical perspective is of high priority. Also, there is a need for regional balancing framework. Regional control reserves and regionally coordinated balancing may be introduced

- The setup of new flexible power plants and enhancing flexibility in existing power system is of high importance.

- Flexible hydro capacity with storage capability and pump storage plants have to be further developed. Effective use of hydro power with storage possibility for balancing.

- Recommended strategies to effectively increase the level of regional balancing

- Recommended for market transformation that can enable to foster large share RE including ancillary services market.

- Introduction of aggregators/balancing groups in generation and stepped progression towards a shorter term products in power market.
- Recommended to develop/update standards of some key technical factors related to RE plants such as active power reduction, ramp up/down capability, reactive power compensation, fault ride through, dynamic behaviour to fault, protection systems
- Enforce compliance with grid code regarding provision of balancing power
- Introduce and enforce compliance of effective accounting system and deviation settlement mechanism
- Technical implementation of reserve controls (primary control & tertiary control)
  - ✓ Assessment and adoption of control reserve functionalities
  - ✓ Necessary adaptation works at the generating plant
  - ✓ Revision and improvement of telecommunication infrastructure
  - ✓ Required operation details and specifications of software use at SLDC units
  - ✓ Control concept & establishment of control cooperation between different balancing areas
- Implementation of Automatic Generation control, which is a technical means for realization of secondary load-frequency control but requires the availability of the needed control power at all times
- Reserve pricing mechanism to ensure so that generators have clear visibility of price signals between energy and reserve provision.
- Trade of RE power over short-term markets and financing of difference costs by RE funds,
- Technical balancing of RE by combining RPO and real-time purchase of RE power (15-min intervals),
- Development of policy schemes for energy storage technologies and integration of the technologies in transmission system planning, and
- Dynamic system support and reactive power management at EHV and HV system.

Chapter 1: Forecasting and Balancing

1.0 Introduction:

Forecasting revolves around on the tools used and methods followed to accurately determine the amount of RE power that will be produced in a scheduling time block. Balancing of the grid lays emphasis on the tools used and methods followed (current and suggested) to mitigate the effects of wind and solar variability for one day ahead and for four time blocks ahead in a day.

Forecasting is primarily a necessity to minimize deviations between schedule and actual despatch at the State Load Despatch Centre (SLDC) level and at the Regional Load Despatch Centre (RLDC) level. Moreover, the need for forecasting for a grid operator can be different from those for farm owners/traders. For example, a grid operator from the grid balancing perspective will require forecast at a large spatial region and at smaller time frame, however farm owner/traders will require forecast at smaller spatial region and at day ahead time frame. Different approaches are preferable for differing time frames to produce the best forecast for each time period and spatial scale. However, it has been found that most accurate forecasts can be obtained by using many local and global scale models and combining them to form a single multi model ensemble. This section of the chapter is further supported by a detailed explanation on the state of the art forecasting techniques undertaken for wind and solar power across the globe along with the different kinds of accuracy or error measure techniques.

The analysis of the current forecasting scenario in the country depicts that RE generation forecasting is at its infancy. However Indian Meteorological Department (IMD) has significant resources and experience in traditional weather forecasting. Numerous multi model ensembles can be developed and adapted to wind and solar power forecasting in the country. Pilot forecasting project was implemented in Gujarat; an analysis upon the findings of that pilot is highlighted in later sections of this chapter. However, from stakeholder consultations, a strong consensus unilaterally was observed for a need of robust and reliable forecasting systems for the deployment of large RE capacities in India.

With deregulated electricity markets getting common with its high costs of over or under contracting and buying or selling power in the balancing market, load forecasting has become an integral process in the planning and operation of electric utilities, system operators and other market participants. In this respect, load forecasting methodologies prevalent and practiced globally have also been analysed. Methodology practiced in three states of the country, namely Gujarat, Rajasthan and Himachal Pradesh have been discussed along with the accuracy levels. Further, this has also been analysed with the inputs garnered from Power System Operation Corporation Limited (POSOCO). It was observed that the deviation due to incorrect load forecast and the occurrence of conventional power plants not adhering to schedule is higher than the variability due to renewable energy sources.

It is recommended that due to the extraordinarily large uncertainty in forecasting, the latter should not be carried out at the wind farm level alone unless required for commercial reason. There are two very specific reasons identified for the same; the first is spatial smothening of the prediction that occurs over large geographical areas. The second reason is the forecasting level which corresponds with the spatial scale on which decisions regarding scheduling, balancing and grid control are usually taken.

1.1 Wind Power forecasting:

Two main methodologies for uncertainty forecasting have been established:

- Statistical approaches working on single Numerical Weather Prediction (NWP) forecasts, and

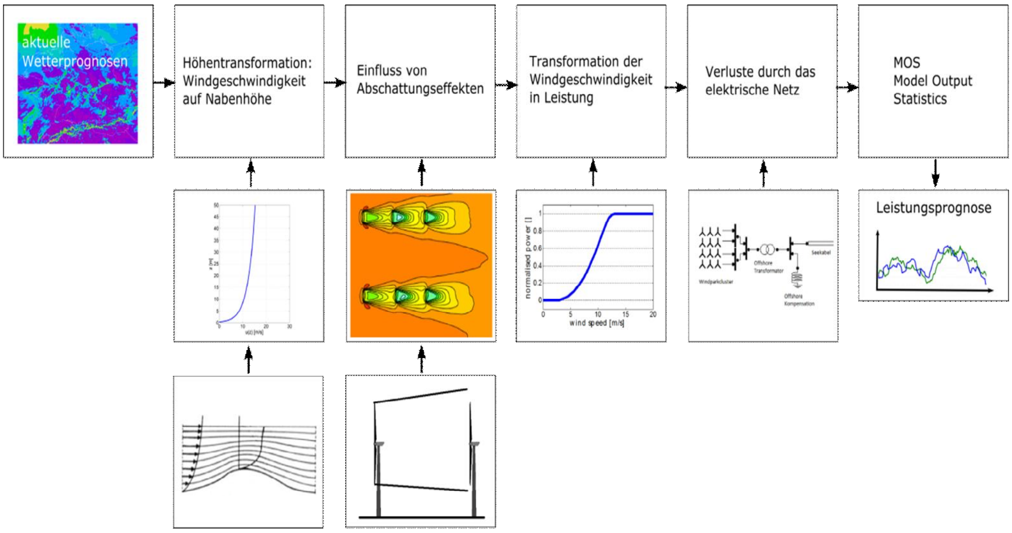
- Uncertainties derived from ensembles of predictions.

While statistical models already have an estimate of the uncertainty explicitly integrated in the method, physical models need some additional processing to yield an uncertainty result. As an appropriate tool for online assessment of the forecast uncertainty confidence intervals have been introduced. Typical confidence interval methods, developed for models like neural networks, are based on the assumption that the prediction errors follow a Gaussian distribution. This however is often not the case for wind power prediction where error distributions may exhibit some skewed characteristics, while the confidence intervals are not symmetric around the spot prediction due to the form of the wind farm power curve. On the other hand, the level of predicted wind speed introduces some nonlinearity to the estimation of the intervals; e.g. at the cut-out speed, the lower power interval may suddenly switch to zero.

1.1.1 Physical wind power forecasting

Physical wind power forecast models derive wind speeds at turbine hub height from the NWP model and use explicit descriptions of relevant physical processes to calculate the electric power output of the turbine

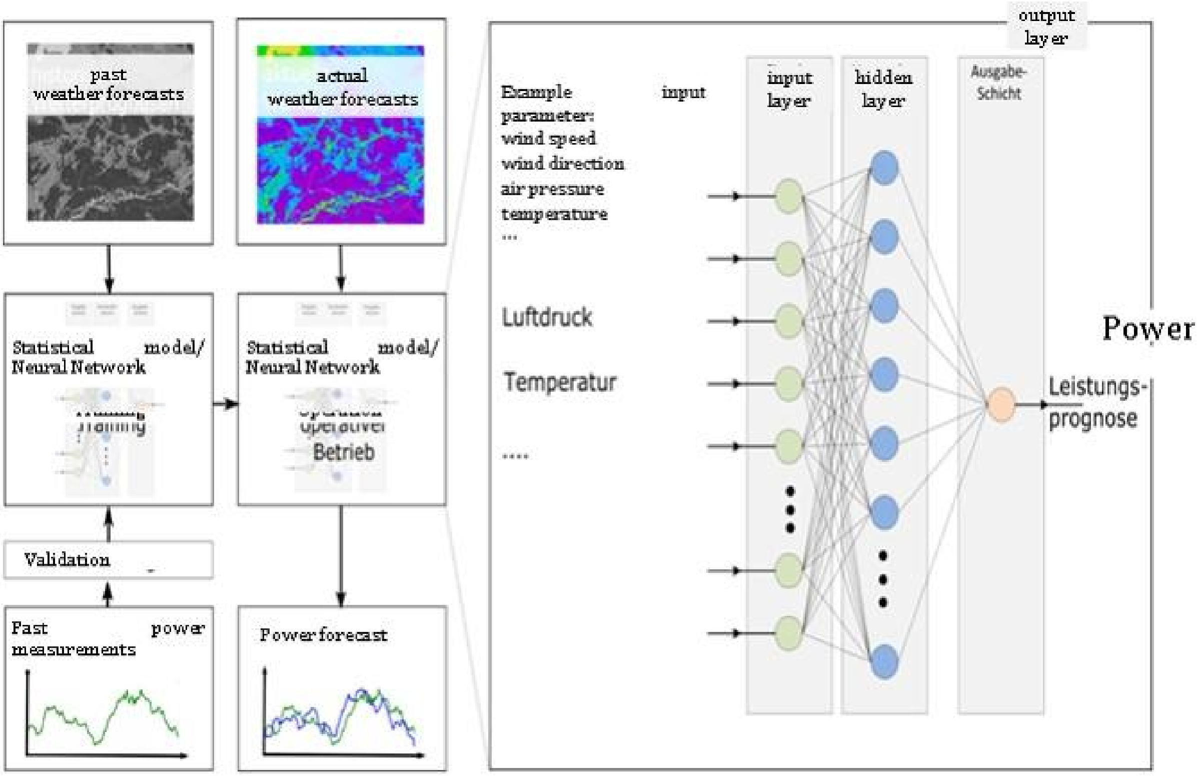
Figure 1: Physical wind power forecast model



1.1.2 Statistical wind power forecasting

Statistical wind power forecast models describe the relationship between various model parameter of the weather model and the measured power output.

Figure 2: Statistical wind power forecast model



1.2 Solar Power Forecasting

Depending on the application and its corresponding time scale, different forecasting approaches have been introduced. Time series models using on-site measurements are adequate for the very short term time scale from minutes up to a few hours. Intra-hour forecasts with a high spatial and temporal resolution may be obtained from ground-based sky imagers. Forecasts based on cloud motion vectors from satellite images show a good performance for a temporal range of 30 minutes to 6 hours. Grid integration of Photovoltaic (PV) power mainly requires forecasts up to two days ahead or even beyond. These forecasts are based on numerical weather prediction (NWP) models. Methods used for solar power forecasting depend on the application of interest and the relevant time scale associated with this application. This overview concentrates on bulk solar power generation and its integration into power grids and consequently covers mainly NWP-based forecasting with time scales of one day and more. Also, only photovoltaic solar power generation is considered. However, the introduction of concentrated solar thermal power technologies (CSP) is similarly in need of high-quality forecasting information. As much of the methodology described here is applicable as well, the need of direct normal solar irradiance (DNI) in these devices involves an additional step in the generation of solar power forecasts with an additional source for uncertainties.

TS – Time series modelling

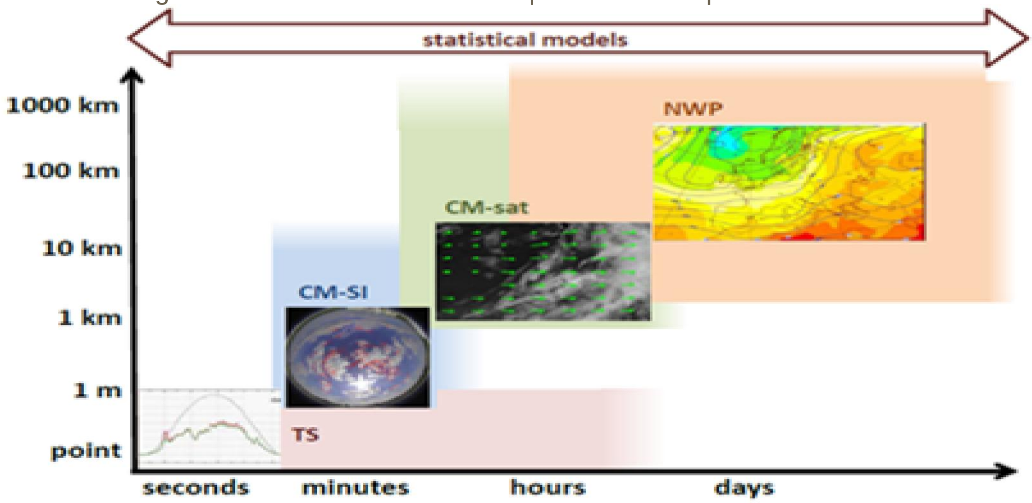
CM-SI - cloud motion forecast based on sky-imagers

CM-sat - cloud motion forecast based on satellite images

NWP - numerical weather prediction

TS: time series modelling CM-SI:Cloud motion forecast based on sky-imagers CM-sat:cloud motion forecast based on satellite images NWP: :numerical weather prediction

Fig 3: Forecasting methods used for different spatial and temporal scales



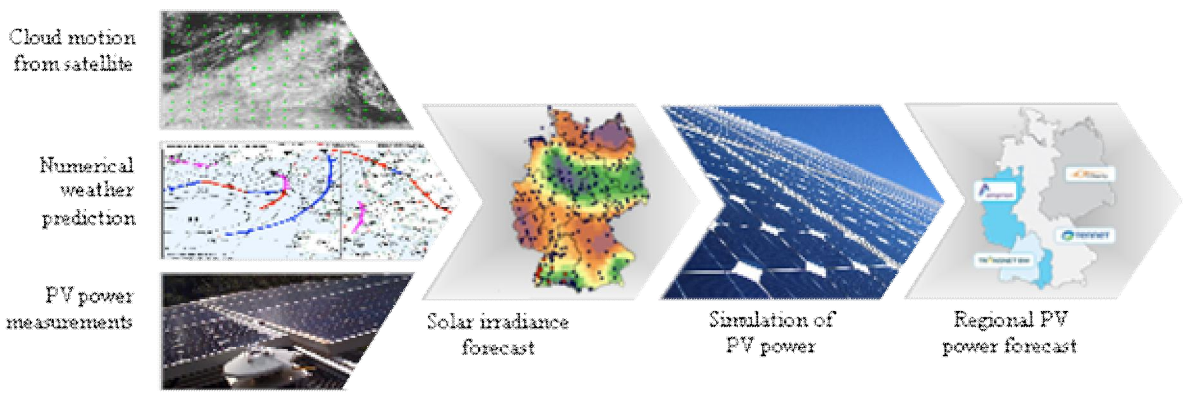
TS: time series modelling CM-SI:Cloud motion forecast based on sky-imagers CM: sat:cloud motion forecast based on satellite images NWP: :numerical weather prediction

1.2.1 Design of a PV Power Prediction System

Power prediction of PV systems usually involves several modelling steps in order to obtain the required forecast information from different kinds of input data. A typical model chain of a PV power forecasting system comprises the following basic steps:

- Forecast of site-specific global horizontal irradiance
- Forecast of solar irradiance on the module plane
- Forecast of PV power.
- Regional forecasts need an additional step for up-scaling.
- Forecast of regional power production.

Figure 3: Overview of a regional PV power production scheme



These steps may involve physical or statistical models or a combination of both. Not all approaches for PV power prediction necessarily include all modelling steps explicitly. Several steps may be combined within statistical models, for example, relating power output directly to input variables like measured power of previous time steps or forecast variables of NWP systems.

Forecasting of global horizontal irradiance is the first and the most essential step in almost any PV power prediction system. Depending on the forecast horizon, different input data and models may be used.

In the very short-term time scale from minutes to a few hours, on-site measured irradiance data in combination with time series models are appropriate. In short-term irradiance forecasting, information on the motion of clouds which largely determine solar surface irradiance may be used. Forecasts based on satellite images show a good performance for up to 6 hours ahead. From subsequent images information on cloud motion can be extracted and extrapolated to the next few hours. For the sub-hourly time scale, cloud information from ground-based sky imagers may be used to derive irradiance forecasts with much higher spatial and temporal resolution compared with satellite data. Forecast horizons are limited here through the spatial extension of the monitored cloud scenes and corresponding cloud velocities.

From about 4–6 hours onward, forecasts based on NWP models typically outperform the satellite-based forecasts. Some weather services, for example, the European Centre for Medium-Range Weather Forecasts (ECMWF), directly provide surface solar irradiance as model output. This allows for site-specific irradiance forecasts with the required temporal resolution produced by downscaling and interpolation techniques. Statistical models may be applied to derive surface solar irradiance from available NWP output variables and to adjust irradiance forecasts to ground-measured or satellite-derived irradiance data.

From horizontal irradiance, the irradiance on the plane of the PV modules has to be calculated next. Different installation types have to be considered. Systems with a fixed orientation require a conversion of the forecasts of global horizontal irradiance to the specific orientation of the modules based on information on tilt and azimuth of the PV system. For one- and two-axis tracking systems, these models have to be combined with respective information on the tracking algorithm. Concentrating PV systems require forecasts on direct normal irradiance. The procedure is then the same as with any concentrating system, e.g., solar thermal power plants.

The PV power forecast then is obtained by feeding the irradiance forecast into a PV simulation model. Generally, two models are used in this step:

- One for the calculation of the direct current (DC) power output and
- Another for modelling the inverter characteristics.

Both models are widely available in the PV sector with various degrees of complexity. For PV power prediction, rather simple models show a sufficient accuracy. Additional input data are module temperature, which can be inferred from available temperature forecasts, and the characteristics of the PV module (nominal power etc.), usually taken from the module data sheets.

In the final stage towards an optimized power forecast for a single PV system, the power forecast may be adapted to measured power data by statistical post-processing techniques. Self-calibrating recursive models are most beneficial if measured data are available online. Off-line data is successfully used as well for model calibration.

Prediction of bulk PV power usually addresses the cumulative PV power generation for a larger area rather than for a single site. This is achieved by up-scaling from a representative set of single PV systems to the regional PV power production. This approach leads to almost no loss in accuracy when compared to the addition of the complete set of site-specific forecasts if the representative set properly represents the regional distribution of installed power and installation type of the systems. In addition to the power prediction, a specification of the expected uncertainty of the predicted value is important for an optimized application. As the correlation of forecast errors rapidly decreases with increasing distance between the systems, the uncertainty associated with regional power prediction is generally much smaller than for single PV systems.

1.3 Evaluation of Different Approaches to Irradiance Forecasting

In the framework of the International Energy Agency's SHC Task 36 'Solar Resource Knowledge Management' a common benchmarking procedure for solar irradiance forecasting has been developed and applied to seven different solar irradiance forecasting procedures. The algorithms used in the different forecasting methods can be grouped into three categories: (i) combination of a global NWP model with a post-processing technique involving historical surface observations or satellite-derived irradiance data, (ii) combination of a meso-scale NWP model and a post-processing technique based on historical surface observations, and (iii) forecasts of the meso-scale model WRF without any integration of observation data. A common one-year data set of measurements of hourly irradiance data from four different European climatic region was chosen. The different forecasting approaches are all based on global NWP model predictions, either ECMWF global model or GFS data.

A strong dependence of the forecast accuracy on the climatic conditions was found. For Central European stations the relative RMSE of the NWP based methods ranges from 40% to 60%, for Spanish stations relative RMSE values are in the range of 20% to 35%. Irradiance forecasts based on global model numerical weather prediction models in combination with post-processing showed best results. All proposed methods perform significantly better than persistence. For short term horizons up to about six hours the satellite based approach leads to best results. Selected results are shown in Figure 4 and Figure 5.

Figure 4: RMSE of five forecasting approaches and persistence for three German stations for the first three forecast days. (1)–(3): different global models plus post-processing, (4)–(5):

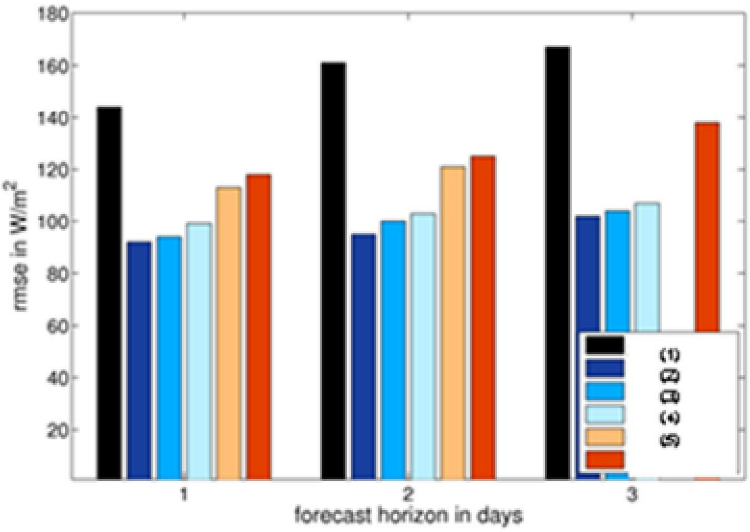
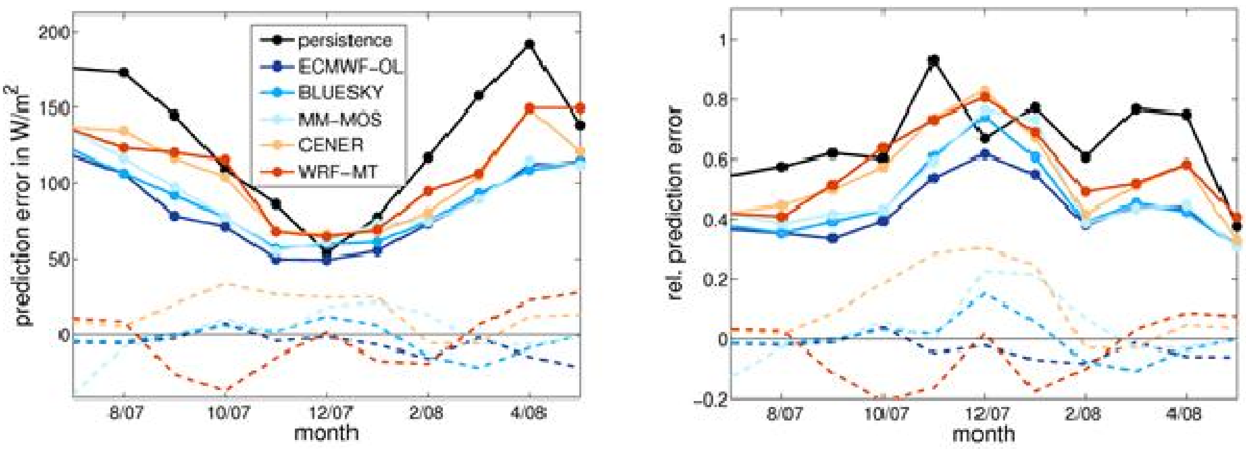


Figure 5: Absolute (left) and relative (right) forecast errors



RMSE (solid lines with circles) and bias (dashed lines) of five different forecasting approaches and persistence in dependence on the month for the first forecast day.

1.4 Wind and Solar Power Forecasting Practice in Germany

In the German power sector currently more than 75 GW of wind and solar power are subject to operational RE forecasting. These renewable power generators are must-run-plants according to the Renewable Energy Act (Erneuerbare-Energien-Gesetz, EEG) which was established in 2000 with guaranteed feed-in tariffs. Transmission System Operators (TSOs) are required to preferentially feed-in this electricity into the grid over electricity from conventional sources. The system has only recently been modified to also include a market premium system.

The German power transmission system is subdivided into four areas, each of them run by one of the TSOs Tennet, Amprion, 50Hertz, and TransnetBW. As they are responsible for grid operation within their respective control area they also are demanding for high-quality RE forecasts for these given areas. Due to the EEG system, single power producers are not in need of having high-quality forecasts, to be precise, of no forecasts at all. The only exception is if they decide not to supply power according to the EEG rules but to act in the direct marketing domain. However, this need for forecasting then is purely due to economic constraints.

This need for regional forecasting for the areas of the four TSOs resulted in the establishment of several different providers of forecasting services on the German market. In the beginning, no meteorological expertise was found at the level of the TSOs and they used the power forecasts provided by the services without further treatment. In the meantime, the TSOs – as well as several of the larger DSOs – have built up their own forecasting expertise (mainly through educated meteorologists) and now are able to perform extensive evaluations of forecast performance and to give valuable feedback to the forecast providers. Furthermore, this capacity lets them deploy own post-processing schemes based on a set of different power forecasts delivered by different providers. This can be seen as an additional post-processing at the TSO level combining these different power forecasts. Purchasing several RE power forecasts from different providers has become common practice as it increases knowledge about forecast uncertainty at relatively low costs[1]. In this respect,

[1] As a consequence of the market situation with several suppliers of RE forecasts the market price for wind and solar power forecasts came down during the recent years by a large amount. Purchasing RE forecasts thus is generally a minor item compared to e.g. infrastructure (of REMC), personnel

forecast service providers and TSOs more and more interact and in future the integration of full forecasting services into special divisions within the TSO structure could be possible.

The following list includes typical characteristics and functionalities of a state-of-the-art forecasting system operated for German TSOs

- Wind and solar power forecasts for the four control areas of the TSOs,
- Forecast horizons of typically up to three days (although RE forecasting can be easily extended up to 7 days),
- Temporal resolution of the forecasts 15 minutes to one hour,
- Capability of additional very-short term forecasts of up to six hours,
- Updates on an intra-day time scale,
- Forecasts for ramps (time of occurrence, duration, magnitude, ramp rate),
- Detailed information on forecast uncertainty (mostly resulting from probabilistic forecasts),
- Including available on-line measurement data in the forecasting workflow, and
- Continuous evaluation of the forecasts according to community-accepted accuracy measures

Although all the RE forecast systems are capable of delivering forecasts on any spatial scale down to single generation plants, the majority of todays' services – and all forecasts serving control zone operation – is providing regional forecast products. Single site forecasting – as has been outlined before – yields much poorer performance figures in terms of accuracy.

Within that scheme, any forecasting system includes a set of post-processing steps aiming at

- Reducing systematic forecast errors,
- Accounting for local effects (e.g., topography, surface),
- Accounting for wind farm effects (wakes) in wind power
- Accounting for the influence of selected variables in more detail (e.g., aerosols in solar power),
- Deriving parameters that are not provided as direct NWP model output (e.g., wind speed in hub height, direct solar irradiance)
- Combining the output of different models.

1.5 Recommendations for Wind & Solar Power and Load Forecasting in India

For the purpose of this report, it is assumed that the primary need for wind and solar forecasting is to ensure the stability of the electricity supply in general, and in particular, of the grid operation. The authors are aware of further needs and applications of RE forecasting, for example in the domain of market mechanisms or accounting. Within this document, the requirements for ensuring grid stability are considered to be of utmost priority.

A strong consensus among all stakeholders in the Indian electricity sector is witnessed, based on the fact that expected future deployment of RE strongly needs to be supported by state-of-the-art forecasting schemes for the fluctuating wind and solar power generation. This forecasting functionality should be a major component of the Renewable Energy Management Centres (REMCs) to be established in or attached to the existing regional and state despatch centres. This consensus was expressed also during the workshop ‘Enhanced RE Grid Integration with Emphasis on Forecasting, REMC and Balancing Capacity’, held April 22-23, 2015 in Delhi.

Below is presented the recommendations on how forecasting services can be implemented in the framework of the REMCs to be established.

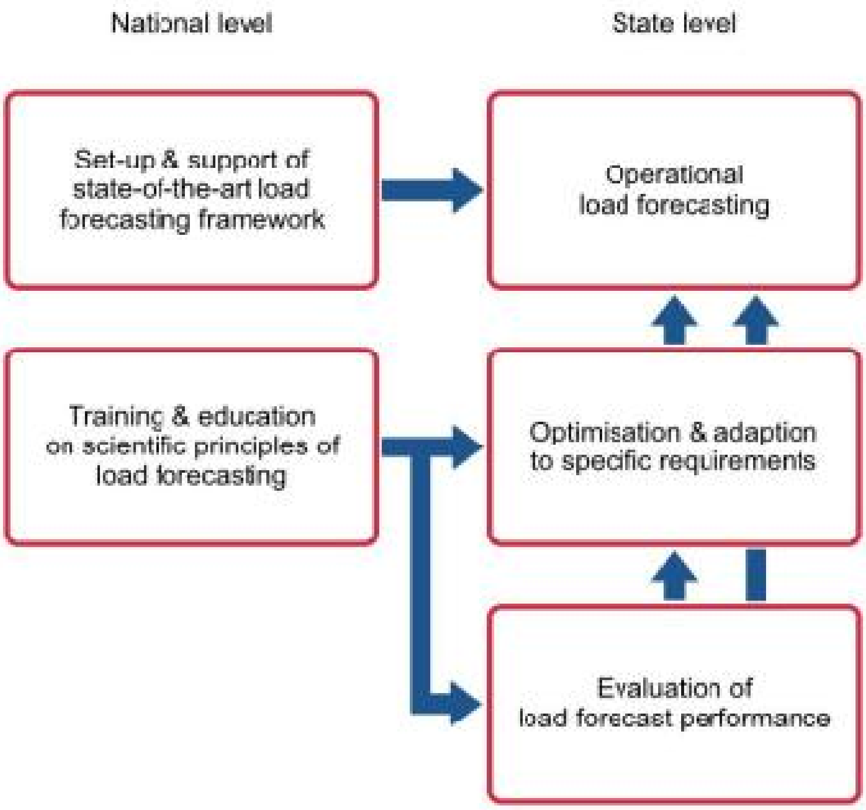
- Due to the large uncertainty of RE forecasts on a local level, i.e. for single sites, it is strongly suggested to not concentrate on this spatial scale. Larger areas considered in forecasting at SLDC level result in a smoothing due to the spatial averaging and therefore lead to lower uncertainties. This forecasting level also corresponds to the spatial scale on which decisions with respect to grid control, balancing, and scheduling are usually taken.
- The recently proposed ‘Framework for Forecasting, Scheduling & Imbalance Handling for Wind & Solar Generating Stations at Inter-State Level’ foresees that forecasting needs to be done by both the RE producer and the concerned RLDC. The RE power producer may choose to utilize its own forecast or the regional forecast given by the concerned RLDC (via its REMC).
- The RE forecast system should at least provide the following functionalities:
  - Wind and solar power forecasts on state (i.e., SLDC) level,
  - Forecast horizons of up to two days,
  - Temporal resolution of the forecasts 15 minutes,
  - Updates on an intra-day time scale ,
  - Option for forecasts in the time scale of up to six hours,
  - Ramp forecasting (time of occurrence, duration, magnitude, ramp rate),
  - Detailed information on forecast uncertainty (mostly resulting from probabilistic forecasts),
  - Capability to make use of on-line measurement data, and
  - Continuous evaluation of the forecasts according to community-accepted accuracy measures
- Forecasts in different states may be provided by different forecast service providers. This could be beneficial as this offers the opportunity of exchanging information on the performance of the various systems and to compare them with respect to their capability of targeting the Indian specific meteorological and technical conditions. At a later stage, this may be expanded to a central organisation of forecasting making use of several RE forecasts to yield an optimised forecasting scheme for each state.
- A high-quality forecast system for wind and solar power needs to be supplemented by a load forecasting scheme of at least the same accuracy. Available information from the Indian power sector indicates that this is yet to be achieved and load forecasting is primarily done on a manual and intuitive basis and not using science-based software support. It is therefore highly recommended to put efforts on the establishment of state-of-the-art load forecasting techniques. It is likely that different solutions have to be applied for different states. A joint effort for setting up a common framework for load forecasting – best to be organised by a national authority – is needed for all states. Within that framework, support could be given to the individual states to establish state specific operational load forecasting approach. Also, training on load forecasting techniques should be provided on the national level.
- Successful implementation of RE forecasting is not only based on high quality forecasting models but also on the availability of well-trained staff that are familiar with the RE forecasting. It is recommended to start an educational program including
  (i) Basic meteorological concepts
  (ii) Post-processing techniques
  (iii) Probabilistic methods

(iv) Statistical evaluation of forecast performance.

Training activities by external forecast providers to be offered regularly to staff personnel should be mandatory.

- Any forecast system includes statistical components (mainly in its post-processing part) which need some time to adjust to the specific configuration of the application. To optimise this process, RE forecasts need to be continuously evaluated. At the REMCs, a standardised evaluation process should be implemented and the results should be communicated to the forecast providers regularly. A complete evaluation process not only helps to improve forecasting but also enables the forecast user to monitor forecast quality. A possible option to develop a standardised process could be a centrally organised Evaluation Handbook which is continuously updated.
- It is recommended to include IMD's expertise in future solar and wind power forecasting activities. As this is a new field of activity for IMD, appropriate resources should be provided. The link between IMD and the electricity sector needs to be strengthened by bilateral consultations and training on the specific needs of the sector. IMD may contribute significantly in training staff people in the REMCs on meteorological forecasting.

Figure 6 - Proposal of a load forecasting framework



1.6 Establishment of Renewable Energy Management Centres (REMC)

In view of the expected increase in RE penetration, there is a need to equip the power system operators with state-of-the-art tools along with real time data of RE generation. The establishment of Renewable Energy Management Centres (REMC) equipped with advanced forecasting tools, smart despatching solutions, and real time monitoring of RE generation, closely coordinating with SLDCs/ RLDCs has been envisaged as a primary requirement for grid integration of large scale RE. Renewable Energy Management Centres (REMCs) at State, Regional and National level should be co-located with respective Load despatch centres (LDC) and integrated with real time measurement and information flow. There should be a hierarchical connection between the State Load Despatch Centre, Regional Load Despatch Centre and National Load Despatch Centre.

Analysis of the existing systems and processes in place, has led to development of the following recommendations regarding REMC establishment in the state.

- Establish new independent and standardized SCADA Systems for the REMCs, which are specifically designed for their needs. For the necessary exchange of information with the existing SCADA/EMS systems international standard interfaces and communication protocols should be used. This approach enables for competitive tendering of a standardized control system for all REMCs,
- REMC system should have standard functionalities realised through modules that can be introduced seamlessly into the system at any time as per need,
- Partner with RE developers to obtain online RE generation data from Pooling Substations as well their Machine control Station, if feasible,
- Enforce regulation of mandatory RE Developer SCADA interface capability before allowing integration of RE power into the grid, including single wind/solar farm production and availability data (available at pooling station) for future farms as per state regulation,
- Dedicated Forecasting, scheduling, SCADA and Communications teams required at the SLDC,
- Redefine Roles and responsibilities of stakeholders namely; Power Procurement Committees, Renewable Energy Development Authorities, RE Developers and other new actors at policy and regulatory levels,
- Define a blueprint for Capacity Building in the area of large scale RE integration into the grid, and
- REMC should be part of the SLDC as a specialist group for renewables generation management.

Establishment of Dedicated Renewable Energy Management Centres, to facilitate large scale integration of renewables into the grid, is a global best practice. Renewable Energy Management Centre (REMC), equipped with advanced Forecasting Tools, Smart Despatching solutions, & Real Time Monitoring of RE generation, can closely coordinate with the Grid Operations team for safe, secure and optimal operations of the overall grid.

REMC should have a dedicated team for managing forecasted RE generation, its despatch and real-time monitoring to ensure safe, secure and optimal operation of the grid. REMC acts as the RE Single Point of Contact for the main Grid Operations team. In order to facilitate better coordination between REMC and the main xLDC teams, it is essential that REMC team should be collocated with the main LDC team.

The overall expected functionality of REMCs is listed as below:

- Real time RE generation Data Acquisition and Monitoring,

- Provide RE data to its partner xLDC, forecasting and scheduling applications,
- Forecasting of RE generation ,
- Data Archiving and Retrieval,
- Providing RE information to its concerned xLDC for despatching and balancing RE power,
- Central Repository for RE generation data that will be used by the concerned xLDC for MIS and commercial settlement purposes,
- Coordination agency on behalf of xLDC for interacting with RE Developers,
- Training and Skill building for RE integration into the grid,
- Developing future readiness for advanced functions such as Virtual Power Plants, Storage etc., and
- All the RE related data generated and stored at the REMC at the SLDC level (except the real time RE generation) shall be sent to the RLDC and NLDC.

Figure 7: Scheme of logical interconnectivity between various Software modules at REMC

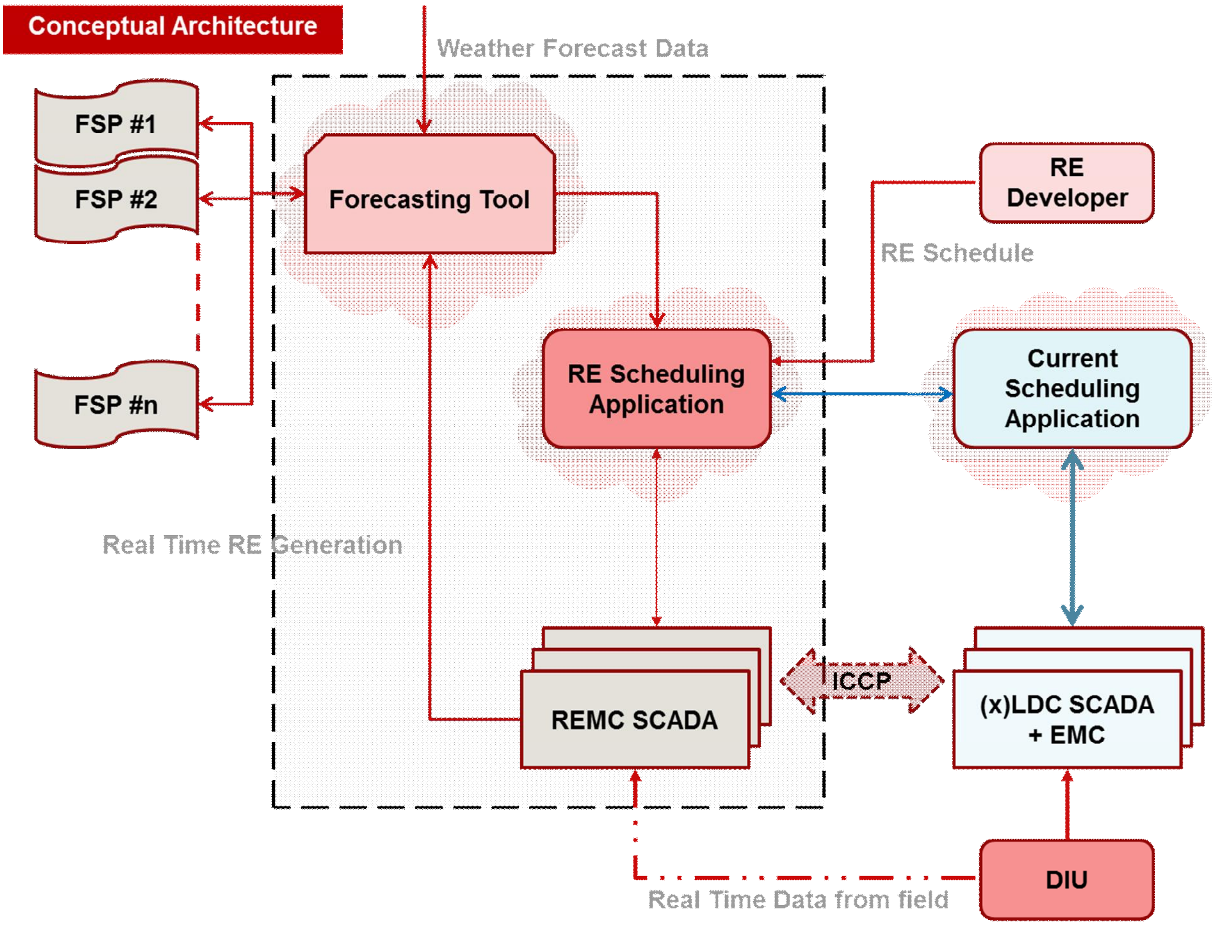


Figure 7 shows Conceptual Architecture of recommended REMC. REMC at control centre comprises of following modules:

1. REMC SCADA,
2. Forecasting tool, and
3. RE Scheduling Tool

1.6.1 Forecasting Tool

The REMC Forecasting tool will have an in house RE generation forecast module and will also interface with 3rd party forecasting service provider systems. Real-time actual RE generation at various STU pooling stations in the area of responsibility should be provided to the forecasting tool from the REMC SCADA tool. Weather forecast data (for day ahead and intraday updates) shall also be obtained at this tool level and sent to the individual FSPs with the discretion of the concerned xLDC. Static data from RE generators will also be provided to the tool for accurate generation forecast.

The tool will help to provide an aggregated RE generation at the state level which will aid the SLDC in the grid operation and managing conventional generation. This tool shall be configured to accept potential forecast in the area of responsibility from these external FSP systems in a standard data interface format. The tool will combine the multiple forecasts as per predefined algorithms into a single potential forecast generation for larger control area and the overall area of responsibility.

The aggregated and STU pooling station wise forecast can be made available on the public domain as per the SLDC's discretion. The RE developers in the area of responsibility can subscribe and use this information. Primary objective of this tool is to support REMC in assessing the day ahead generation forecast of RE in its control area. This information will be used by SLDC to arrive at day ahead balancing needs, load flow calculations, and plan its grid operations and for any other future applications. Forecasting can be done for day-ahead or for intraday. Forecasted data will be sent to a RE scheduling tool.

1.6.2 RE Scheduling Tool

The tool enables individual RE developers to upload their schedules in the REMC's RE scheduling tool and with this information retrieved from RE developers, RE schedule for day ahead and intra-day operations is developed. Aggregated forecasted RE generation data for the state level will be received in the RE Scheduling tool. Each FSP will also provide the forecasted RE generation data for all STU pooling stations with RE injection. The difference between aggregated RE forecast generation at the control area level and the final day ahead RE schedule in 96 time blocks will be calculated and passed on to the xLDC to help them optimally manage conventional generation and operation. The scheduling tool also will provide the facility to reschedule of the RE generation in case of system contingencies as and when intimated by xLDCs.

1.6.3 REMC SCADA

The assessment of the existing SCADA systems across different states has shown that the control systems installed are based on the mainline standard products of the different vendors, they have different software releases and different project specific software packages installed. Further, different states have different levels of readiness for implementation of REMC. Hence, to keep the complexity of the overall system as low as possible, it is recommended that each REMC should have a stand-alone SCADA system.

REMC SCADA should be able to acquire real time RE generation data from existing/future RTUs either through standard protocols such as IEC 101, IEC 104, etc. or through the main xLDC over standard ICCP protocol. In absence of RTU efforts should be made to install new RTUs at pooling station level. Data Engineering in REMC SCADA System is recommended to be done independently as not all xLDCs are CIM compliant. However, REMC SCADA must be CIM compliant.

Chapter 2: Balancing Capability Enhancement

2.1 Introduction

The focus being on demand for balancing power, RE and conventional generation, the overall objective is to avoid frequency deviations arising out of RE integration. Accuracy of the schedule and despatch process in tandem with grid discipline is imperative for optimal performance of the national grid. The balancing capacity of states using hydro and conventional plants has been evaluated, and measures to improve these capacities with respect to their technical and economic considerations have been suggested.

The assessment on balancing was carried out through four major steps, such as stakeholder consultations held in India, assessment of existing balancing capacity, enhancing of balancing capacities and qualitative cost analysis of suggesting balancing options.

In the stakeholders' consultation, there were a lot of mixed views garnered from the state and central perspective. However, there were certain issues, such as lack of available capacity of hydro and gas for balancing due to technical and economic considerations were repeatedly pointed out by the stakeholders at both the levels. India has a limited ability to back down conventional generation due to a variety of technical and economic considerations. Hydro power available for balancing is low in capacity and also not completely at the disposal of grid operators. Gas availability is a key issue for thermal plants which can used for secondary as well as tertiary balancing. Concern of managing variability of RE sources was highlighted as one of the key concerns due to several considerations. It was pointed out that lack of regional balancing plays a very important role in maintaining the grid stability in control areas of the grid.

The central grid operator POSOCO highlighted the need for control reserves. The lack of control reserves puts the onus of frequency regulation on the level of grid discipline. There is a regulation which provides for 5% control reserve to be maintained by all generators above specific capacity, however compliance and enforcement of this regulation is low.

With an emphasis upon the variation of RE sources as one of the key concern, it was imperative to assess the existing balancing capacity prevalent in the states. The second section of this chapter focuses on the balancing potential that could be theoretically available to the grid operator. A plethora of issues were identified while conducting the assessment, such as the flexibility of the conventional plants, ramping potential of plants, availability of storage facilities of power and many more.. Indian conventional generation plant portfolio has plants of a variety of make and age. Their flexibility of operations varies significantly. It was identified that in the public domain there is no data defining the actual operating limits of the plants available. Thus estimating the balancing potential available is difficult and only indicative of the actual potential. The available data indicated that Indian power plants have a low turn down capability when compared to international standards. This is attributed to a variety of factors ranging from age to technical configurations of the plants.

Ramping potentials of plants vary significantly and may need retrofitting to achieve the desired performance levels. Hydro balancing potential of the states has been evaluated. It was found that on a state to state basis it varies significantly from sufficient to highly insufficient. Hydro balancing potential was found to be further restricted by the control and use of plants by the irrigation department. It was also observed that most hydro power plants in the country are not reservoir based hence cannot be used for balancing.

Upon conducting the assessment of balancing potential, it has driven an inquisitiveness to study about the methods of enhancing the balancing capacities. This section of chapter outlines strategies in three phases such as short term, medium term and long term, which can be implemented to achieve enhanced balancing capacities.

In the Short Term Solutions it is suggested that improvement in load forecasting would give the grid operator an improved perspective of the scheduling requirements. RE generation forecasting is critical to improvement of schedule and despatch correlation. System operations and plant flexibility need to be enhanced significantly. The use of central thermal plants for balancing needs to be explored. Revision of mandatory generation flexibility for new plants is needed. Retrofitting of existing power plants is required to improve flexibility. Allocation of gas to RE rich states will be helpful to ensure the balancing needs.

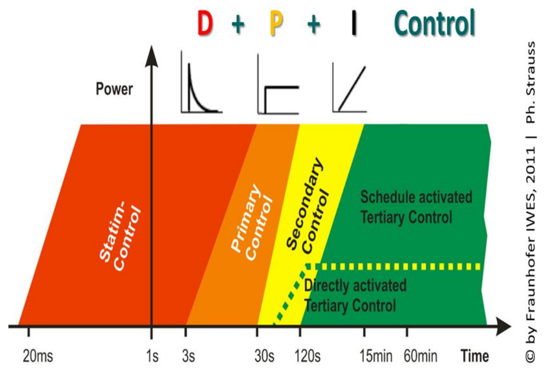
In the Medium Term Solutions it is suggested that use of hydro power plants with storage reservoirs for intraday balancing needs to be explored and developed. The control areas where balancing is done need to be increased in geographical size. This would reduce the balancing requirement for the said control area. There needs to be a regulatory framework to promote regional balancing between the individual control regions. There is a requirement for development of large scale pumped storage type hydro-electric plants. Demand side management needs to be regularized and streamlined in the country.

In the Long Term Solutions it is suggested that the wind generation is to be dispersed over a large geographical area. Geographical dispersion of WEGs is known to reduce the overall balancing requirement of the system. It is suggested that power storage options need to be explored and a significant push towards the R&D of these technologies is required.

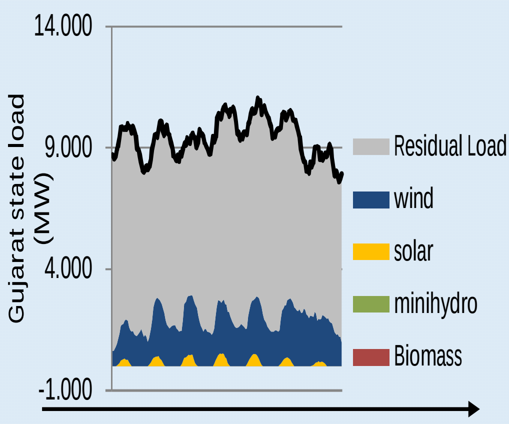
These approaches and solutions will help to salvage the immediate concerns of balancing RE sources and also enables the country to plan for its future outlook. It is suggested that the options of regional balancing and retrofitting need to be explored to their complete potential before storage projects are undertaken. This helps the reader to decide upon the priorities of actions with qualitative comparison of various parameters.
The challenges of balancing RE generation of RE-rich states in India have also been discussed in this document. The focus of this section of the study is on hour(s)-or day(s)-ahead balancing of demand, RE and conventional generation. Optimal load and generation balancing is done in order to avoid frequency deviation. Balancing in terms of limiting frequency deviation in the short-term (seconds to minutes) will be dealt with later on.

When physical delivery of power is concerned, better scheduling process and grid discipline is required to ensure fewer mismatches. Therefore, proper balancing hours- and day(s)-ahead is a necessity for proper integration of RE and for system operation in general. Balancing hour(s) and day(s)-ahead is indirectly linked to frequency deviation. The distinction between the types of balancing is depicted in Figure 8 (balancing hour(s) - and day(s)-ahead and in short-term blend into each other in real system operation.)

Figure 8: Focus of study and distinction between short-term (frequency control) and long-term balancing (scheduling)



„Balancing (frequency control) seconds and minutes ahead"

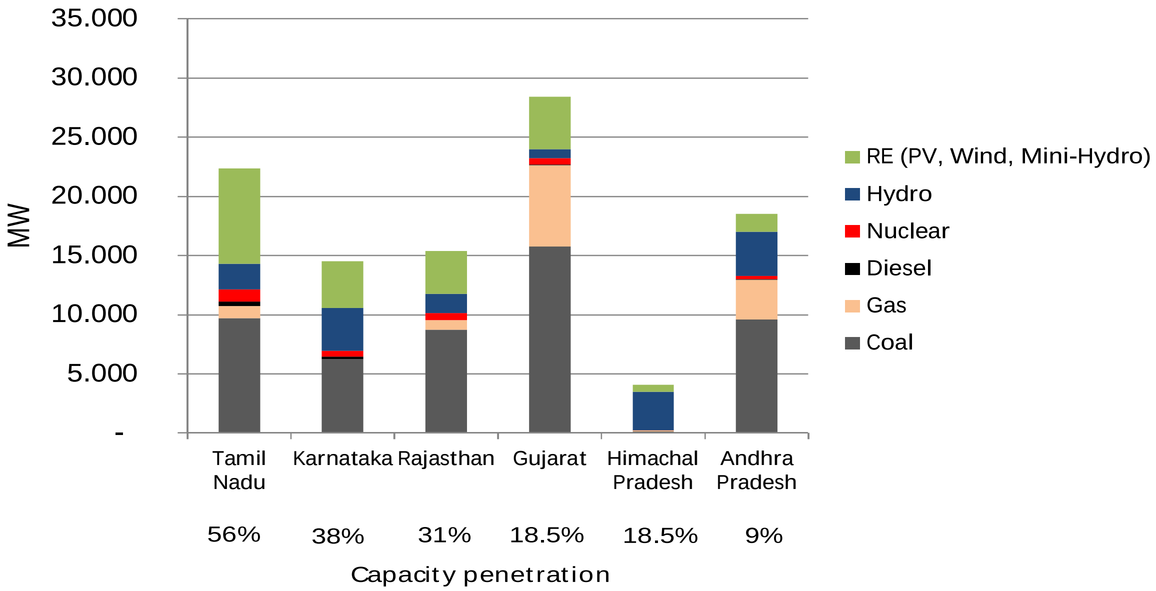


„Balancing (scheduling) hours- and day(s)-ahead"

This study assesses the hours- and day(s)-ahead balancing capability in India and recommends measures for improvement. The general assessment of available balancing capacity, actual practice and enhancement options for the six states (Himachal Pradesh, Gujarat, Rajasthan, Andhra Pradesh, Karnataka and Tamil Nadu) is presented in subsequent sections of this document. This assessment is based on experience of on-site investigations in India during which different stakeholders have been interviewed and information has been collected. The SLDCs of the six states, the SRLDC in Bangalore, Power Grid, the Ministry of New and Renewable Energy, the Ministry of Power, POSOCO and the NLDC were visited. The information presented in this study also includes observations from the first series of workshops conducted under the IGEN-GEC project.

Balancing the variable generation from RE is becoming challenging as new capacities are added. Installed RE capacity in Indian states ranges between 639 – 8,075 MW including wind energy, PV, biomass and mini-hydro. Except for biomass power plants, all of these RES are intermittent power sources. The variable generation has to be integrated by the system operator by balancing the existing flexibility in the system. Today capacity penetration of the states under analysis (Tamil Nadu, Andhra Pradesh, Karnataka, Gujarat, Rajasthan and Himachal Pradesh) ranges between 18% – 56% compared to 12% on national level. As most of the balancing is to be done by the state, the integration challenges vary among the states according to their level of RE deployment which is depicted in Figure 9. The balancing capacity of fossil fuels and hydro power plants in relation to installed capacity of RE is very different within the states. The challenges in balancing from a state and the central perspective are described here.

Figure 9: Installed capacity and capacity penetration of RE in the analysed states in India in 2014



2.2 State perspective on challenges for balancing

There are numerous challenges that the states have with respect to integration of RE. The major integration challenges have been identified and tabulated below:

Table 1: Challenges for balancing and integrating RE in India – state perspective

Problems identified by states level stakeholder interviews	Contributing factors
1. Limited ability to back-down generation	▪ technical limits of thermal units stated to be only 70% (additional fuel oil needed below) ▪ retro-fitting to increase limit needs one year during which the plant is not available for normal power production ▪ shut-down and start-up (i.e. hot-start) of power plants is often not being practiced ▪ central power plants are often not used for balancing ▪ conventional generation is less expensive than RE generation ▪ threat to PLF targets of conventional units
2. Low availability of hydro power for balancing	▪ correlation of hydro and wind power availability ▪ multi-purpose of hydro plants restricts flexible despatch (i.e. irrigation) ▪ high share of run-of-river plants in many RE-rich States being not flexibly despatchable ▪ low pump-storage capacity, many units out of work or allocated in states with lower RE shares
3. Low availability of gas-fired thermal power	▪ shortages in fuel availability ▪ high costs for natural gas

Problems identified by states level stakeholder interviews	Contributing factors
4. Uncertainty of RE supply	▪ absence of forecasting for RE
5. Rate of change of power contribution from RE	▪ fast changes in irradiation or wind speed ▪ low availability of flexible balancing plants
6. Lack of regional balancing	▪ limited amount of market mechanism to export power ▪ high transmission fees for wind energy (solar energy is exempted) ▪ no involvement of states with low shares of RE regarding balancing and lacking balancing cooperation between all states

Source: stakeholder interviews

2.3 Central perspective on challenges for balancing

The central perspective on balancing issues is very important. The national grid operator (POSOCO) is responsible for maintaining load and generation balance in the national grid. However, due to the lack of system reserves, frequency deviation depends mainly on the level of grid discipline of the states. The occurrence of their load and generation imbalance is very frequent. The unscheduled interchange and the variation of frequency deviation have therefore largely been reduced in the past years due to the implementation of the Availability Based Tariff (now: Deviation Settlement Mechanism). This mechanism incentivizes that the load and generation imbalance of a state does not exceed 12% or 150 MW of the state's schedule for inter-state transmission.[2]

The next aim of the national grid operator is to bring the grid frequency even closer to 50 Hz and introduce primary and secondary frequency control reserves on state level. Today a regulation of CERC is in place which requires the States to preserve 5% of their power plant capacity on bar as a reserve. However, compliance and enforcement of this regulation is low.[3]

POSOCO and stakeholder from NLDCs stated that the main reasons for imbalances between load and generation occurring on state level are due to:

- Deviation of actual load from scheduled load (over-, under-drawal, line tripping)
- Deviation of actual generation from scheduled generation (outages, line tripping)

Table 2: Problems in respect to grid operation and challenges of RE integration – central perspective

Problems identified by central level stakeholder interviews	Contributing factors
1. Poor generation schedule accuracy of states	▶ Uncompensated outages of generation, line tripping ▶ Schedule inaccuracy of generators

[2] In the recent amendment slightly more deviation by bigger states allowed
[3] Discussion during the Stakeholder workshop, 22./23.04.2015, Delhi; especially referred to by POSOCO personnel.

Problems identified by central level stakeholder interviews	Contributing factors
2. Poor load schedule accuracy of states	▶ Absence of high quality load forecast ▶ Line tripping, outage of (sub-)transmission equipment ▶ Difficulties of unmetered and unexpected load
3. Lack of forecasting for RE	▶ Lack of high quality forecasting of RE power generation ▶ The current regulation requires RE operators for commercial purposes to schedule their power production on pooling station level; however schedules are often not delivered or inaccurate and cannot be used for system operation ▶ So far, there is no centralized forecast by either SLDCs, RLDCs or the NLDC which can be used for system operation
4. Lack of control reserve (secondary and primary)	▶ Lack of available power capacity for provision of positive control reserve ▶ Lack or no practice of regulation to apply control reserve and lack of related market mechanisms; CERC regulation says that states have to hold 5% of capacity on bar as reserve is in place but not being enforced

Source: stakeholder interviews

2.4 Conclusion and recommendations

In all states except in Tamil Nadu, theoretical balancing capacity is sufficient to integrate the current amount of RE. Residual load followed by conventional generation should currently be feasible due to the ramping capabilities of conventional generation and hydro power. However, different shortfalls and practical problems limit the efficient use of the existing balancing capacity. These are:

- Fuel supply shortage,
- Not using conventional power plants for balancing,
- Low technical standards in terms of plant parameters, and especially
- Lack of forecasting of RE and uncertainty in system operation.

However, given increasing penetration level of RE, integration is envisaged to become more difficult. The Indian government is planning for 45 GW of wind power and 37 GW of solar power within Himachal Pradesh, Rajasthan, Gujarat, Andhra Pradesh, Karnataka and Tamil Nadu until 2022. Referring to the plans of installing 100 GW of solar and 60 GW of wind power in India, these six states will be responsible to provide 75% of total wind power and 37% of total solar power. Even if the conventional capacity increases, balancing capability will decrease in relative terms within the single states.

Accordingly, measures have to be taken to foster integration of RE. Some of the possible actions identified are explained in the next section and are categorized under short-term, medium-term and long-term actions.

For six Indian states where high penetration of renewables is expected or even already present the capacity for balancing fluctuations of RE is assessed. The assessment includes existing and planned renewable energies (RE) and balancing capacities from conventional power plants and hydro power plants. An outlook on the use of storage technologies for balancing is provided.

The electricity systems of all Indian states are interconnected to one single power grid. The grid size is comparable to the European interconnected system – interconnections between different states are better established than many grid connections between European countries. This offers a great potential to integrate a high share of RE in the power system. Balancing in the sense of day- or hours-ahead scheduling has a vital role within this integration task.

- All over India the balancing potential is sufficient to handle todays and even higher shares of RE generation. The crucial question is how to utilize the regional or national potential of balancing and how to distribute the effort for RE integration within all states.
- Organizing a burden sharing for the balancing task will become more and more urgent in order to support a cost effective way of RE integration: This is valid not only for balancing of electricity demand and supply, but also for RE electricity production. Burden sharing in terms of costs will be a component of a successful strategy which realizes the ambitious capacity addition targets set-up by the Indian government. Efficient market mechanisms (i.e. for exporting power and selling power between states) need to be found and existing regulation needs to be adjusted. A proper refinancing scheme for RE will support these developments. The spatial enlargement of the balancing area and the enhancement of inter-state power exchange of RE is most important to harmonize balancing potential in non-RE rich states with the variable generation from RE in different regions in India.
- Increasing the balancing capabilities of the Indian states from a technical perspective is of high priority. In order to prepare the Indian power system for additional RE generation a variety of measures are proposed which have been outlined summarized and evaluated on a qualitative basis.
- For an efficient balancing the implementation of high quality forecasting of RE as well as load is vital. Both will significantly reduce the uncertainty in system operation and is prerequisite for an optimized scheduling and despatch of conventional power plants.
- The setup of new flexible power plants is of high importance from the technical infrastructure point of view. Flexible power plant solutions add costs on future capacity addition. However, in relation to the overall investment in new generation capacity these expenditures are rather small. In this context, a set of very high flexibilities standards should be obligatory for new capacity addition. It should be enforced that the flexibility can be effectively used in real operation.
- Retrofitting of plants regarding technical flexibility is important also. Especially to handle situations of high feed-in from RE which today contribute to over-frequencies in the grid or lead to curtailment of RE. In addition, retrofitting would be beneficial for fast and flexible residual load following. The increase of gas fuel availability would also enhance the balancing capabilities as already existing generation capacity can be made fully operational if sufficient fuel is available.
- Flexible hydro capacity with storage capability has to be further developed. The high seasonal correlation of hydro power availability and power from RE is both chance and challenge. It is recommended to study the use of hydro power plants for intra-day balancing of load and supply in each state and assess its potential taking into account restrictions from multi-purpose use (i.e. irrigation).
- A special focus should also be put on developing further pumped hydro storage plants. There is a tremendous potential for pumped hydro storage plants in India that should be utilized in large scale.

- A large spatial distribution of RE supply is recommended. This will minimize the balancing effort, because geographical distribution of RE in combination with the large Indian power grid offers the potential to smooth RE fluctuations significantly. In combination with the large Indian power grid it offers the potential to minimize RE fluctuations in the first place.
- Smoothing effects of Wind and Solar Energy Supply in India. For PV generation, the correlation of power supply in different regions in India is much higher than for wind energy. This is due to the relatively stable and homogenous solar irradiation conditions in India (mainly clear sky conditions). The generation from wind energy is less correlated. The combined simultaneity factor shows a larger band width between 55% and 75% for different Indian states, compared to separate simultaneity factors for wind and PV. Therefore, in terms of system integration a combination of wind and PV is beneficial for most states.

Table 3: Measures to increase balancing capability in RE-rich states in India and qualitative evaluation of priorities, costs and impact

Measures	*Priority (1 = highest, 3 = lowest)*	*Costs*	*Potential Impact on Balancing*
Short-term solutions			
Improve load forecasting	*1*	*very low*	High
Implement RE forecasting	*1*	*low*	Very High
Improve balancing possibilities with central power plants	*1*	*no costs*	Medium
Retro-fit existing power plants	*2*	*high*	High
Increase gas availability by import of LNG and higher domestic production	*2*	*high*	High
Increase of gas allocation to RE-rich states	*1*	*very low*	Medium
Setup of new flexible conventional generation	*1*	*high*	High
Definition of minimum flexibility requirements for new conventional power plants	*1*	*very low*	High
Medium-term solutions			
Usage of hydro power stations with storage for intra-day balancing	*1*	*low*	Medium
Increase the balancing area	*1*	*negative costs*	Very High
Enhance inter-state power exchange	*1*	*low*	Very High
Setup of additional pumped hydro storage power plants	*1*	*high*	High
Demand Side Management	*3*	*low*	Medium
Increase transmission capacity of regions and to other countries	*2*	*high*	High
(very) Long-term solutions			
Regional diversification of supply from	*3*	*high*	Medium

wind energy			
Battery storage	*3*	*very high*	Low
Use of electric vehicle for balancing	*3*	*high*	Low
Sector-Coupling (heat/electricity)	*3*	*high*	Low
Power-to-gas	*3*	*Very high*	Low

Source: Fraunhofer IWES

Chapter 3: Market Design for Renewable Energy Grid Integration in India

3.1 Introduction

The variable and intermittent nature of RE; could affect the safe, secure and reliable operation of the Indian power system. This is a matter of concern as the Government of India is targeting a cumulative RE generation capacity of 175 GW by 2022. The mitigation of RE variability and intermittency can be achieved through forecasting, balancing and ancillary services. While RE generation forecasting is rapidly evolving, there is no methodology for estimating RE generation with 100% accuracy. The following are the barriers to large scale integration of RE into the Indian grid.

- RE power (solar and wind) is non-despatchable, which means the plants can generate power only when solar and wind resources are available. Therefore, power system requires despatchable plants during the period when RE generation is not available.
- Grid support services are required to manage RE grid integration. There is need for flexible generation and load which can respond rapidly and maintain a balance between generation (RE & conventional) and load.
- Presently, flexible frequency band and deviation settlement mechanism along with a few storage reserves are playing a crucial role in balancing minute-to-minute variation in load and supply. These mechanisms also take care of unscheduled outages of a generator. Adequacy of this mechanism is challenged with an increasing integration of RE and an increasing variability of net load (load minus renewable generation).
- Offtake of RE power is still a challenge due to its price competitiveness with conventional sources of power. RPOs, Feed in tariff, competitive bidding, tax policy and many other policy, fiscal and regulatory interventions are providing impetus to facilitate off take of RE. However, in future would such intervention still facilitate off take of additional large shares of RE generation such solar and wind into the grid. Hence, it is imperative to develop a market driven mechanism in addition to regulatory interventions in order to foster higher shares of renewables into the grid.
- Sufficient, low cost financing mechanism and adequate financial instruments are needed to foster increased share of renewables into the grid.

To enable the large scale integration of RE into the grid, evolution to regulations, policy and market mechanisms will be required. In India, these are currently designed for a predominantly conventional generation power system.

A future roadmap is needed to chalk out the changes in regulatory, policy, institutional, capacity building and market measures required to support the power system in achieving the following.

1) Must Run status for RE power is honoured via market mechanisms
2) 100% off take of RE power
3) 100% power to be traded over the Power Exchanges (PXs) in long term
4) Ancillary and balancing reserve products to be traded on the PXs
5) Introduction of reserve products derived from flexible loads
6) Incentivizing of grid discipline by introduction of generator and/or consumer Balancing Groups (BGs)
7) Incentivizing flexible generation and load
8) Capacity building of central as well as state agencies

In order to accomplish above, the current power system operations and market operations should go through phase transformation without subjecting the system to any sudden changes in regulations, policy or market mechanisms. This document describes the measures required over a 15 year period for such a transition. This timeline is only representative and may be modified as seen appropriate at the time of implementation. The transition is proposed in 3 major phases as below:

1 Phase 1: Initiation of transition: The most crucial phase to initiate transformation in the system and prepare readiness for large scale RE capacity addition and grid integration. This phase will witness many policy, regulatory, capacity building and new market/financial instruments that will ensure the capacity addition. Introduction of new grid support services and products through market mechanism would ensure grid stability and RE off take. It can be expected that volume of power transactions through power exchange will gradually increase in this phase.

2 Phase 2: Mid transition Measures: This phase will witness the gradual maturity of critical actions undertaken in Phase 1 and also enable tremendous capacity addition of RE. This phase of the market transition will feature two major milestones viz. involvement of consumers in supporting grid stability and trade of more than 50% power on the PXs post completion of phase 2. The phase will enable the introduction of demand side management and incentivize consumers to forecast loads and also provide demand response products.

3 Phase 3: Completion of transition: This is the final phase of the transformation. This phase would not involve extensive regulatory measures. On completion of phase 3 all power would trade via the PXs, all reserve products and ancillary services would also be provisioned via the PXs.

Each phase of the transition is 5 years long. It is assumed that the transition starts in 2016-17. A delay in the year of initiation would lead to a subsequent delay in all phases. If the prerequisites are met during any phase, capacity markets can be introduced in the Indian power market. After the completion of Phase 3, the introduced capacity market can be reviewed depending on existing market conditions.

3.2 Achieving market transformation phase 1 - Initiation of Transition

The objective of the proposed market design is to transform India's current market structure into a 100% market based electricity system. Products like power, generation capacity and regulation reserves would be offered by a large number of players to a large number of buyers. This is aimed at increasing the cost efficiency of the power system. This transition is designed for a 15 year period starting 2016. The time period for transition or its phases as mentioned may be altered as required, however key issues to be addressed would remain the same.

The following key issues need to be addressed for a smooth transition into the proposed market design.

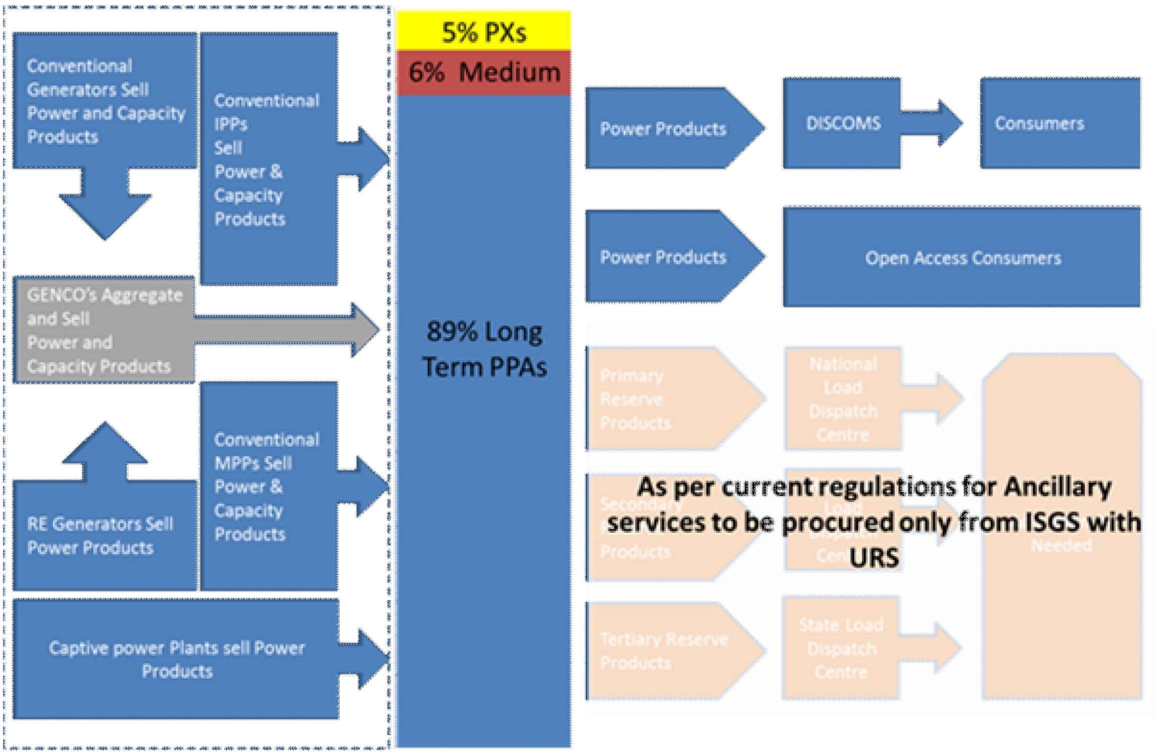
a) PPAs which have remaining validity between 1 month and 25 years will continue. However new PPAs for conventional generation can be restricted through a regulated procedure. During the initial phase long term (20 years) PPAs should only be offered to projects based on RE.

b) The restriction on signing of new PPAs would create the need of a reliable source of revenue for the businesses investing in any component of the power system. Without the assurance of revenue that a PPA offers, lending institutions will find it risky to invest in generation projects.

c) To address the issues of investment risk futures products will need to be introduced on the power exchanges. These products would enable developers to trade in power to be despatched up to 15 years into the future, however there will need for restrictions on % capacity a generator can bid for the futures products.
d) Once the market has stabilised and 10 year price trends on the market are available or earlier, futures products should be restricted to 5 years and a maximum of 1 month of continuous generation. Players may be allowed to buy/sell consecutive products involving 2 or more months of continuous operation. These restrictions are required to maintain liquidity in the market.
e) Defaulting on contract would lead to imbalances and a threat to system security; these would be mitigated by the formation of balancing groups and introduction of ancillary services.
f) Ancillary service products are currently procured only from ISGS with URS. This prevents more optimally located and possibly more economic generators from providing reserves. In the future it is recommended that ancillary services and associated reserves also be procured on the PXs from a pool of eligible and certified players.
g) Introduction of new products in the market

The following figure depicts the current Indian power market design.

Figure 10 - Current Power Market Design in India



This first phase of the transition is most crucial as it lays the regulatory, policy and market foundation for the current and future integration of large scale RE onto the grid. At the completion of this phase of transition, it can be foreseen that the current 6% medium term market power transactions will happen at the exchange thereby increasing the volume of the power traded at the exchange from 5% to 11% or more. It cannot be foreseen that the OTC transactions will be completely shelved off;

instead it is recommended that medium term transactions should be carried out through the power exchange in addition to short term market transactions, to have transparency in pricing.

3.2.1 Introduction of new products on PXs

To enable sale of all power on the PXs and the returns of new generators the products on the exchanges would need to be introduced as below. The long duration products would be phased out in later phases of the transition.

Table 4: Proposed Products on the Power Exchange

Product	Time to Despatch (Days)	Capacity Step (MW)	Price Step (INR/ MW)	Min no of Continuous time Blocks in a day	Max No of Continuous time blocks in a day	Duration (Days)
Electricity Futures short	12- 30	.25	.01	4	96	1-7
Electricity Futures Medium	30-90	.5	.1	8	96	8-30
Electricity Futures year	91-365	.5	.1	8	96	8-30
Electricity Futures Long	366-5475 (365*15)	2	1.0	16	96	31-90

3.2.2 Introduction of Generator Only Balancing Groups

This regulation would require generators interstate/intra-state to organize into balancing groups which are represented by a Balance Responsible Party (BRP). These BRPs would aggregate the schedule of all generators in their jurisdiction and provide it to the respective LDC as needed. The BRPs would be financially liable for their netted deviation from schedule. The formation of balancing groups would allow the members of a group to net their imbalances and support each other in ensuring adherence to schedule of the group.

The BRP would pay/receive imbalance energy charges are required based on their deviation from schedule and the status of the grid at the time of deviation.

Formation of balancing groups intra-state would allow the functioning of an intra-state Deviation Settlement Mechanism, where multiple BRPs in a state would be responsible for their aggregated schedules to the SLDC of the state.

Deviation & Settlement

Every BRP would be responsible for the deviations in their schedule. In case of imbalance due to under generation, the BRP will bear the cost for alternative energy sourced to net the imbalance. In case of imbalance due to over generation, BRP would receive reduced payment for the energy generated after adjusting for the penalties. The financial settlement for the imbalance would happen as below

a) Between BRP and SLDC

   Here the BRP will pay the responsible SLDC or vice versa based on the type (+/-) of deviation from schedule and the situation of the grid at the given time. All contracts between BRPs and SLDCs will be standardized across the complete system. The contracts will be regulated.

b) Between BRP and Group Member

   Here the penalties/incentives will be shared between the BRP and the members as agreed upon between the parties at the time of group formation. These contracts will not be regulated.

Deviation settlement would be done at both the intrastate and interstate levels; however the entities participating in DSM would be balancing groups at various hierarchical levels (National/State/Intrastate). Intrastate deviation settlement mechanism is currently operational in six states only.

Intra-State Deviation Settlement

The balancing groups which are formed within the jurisdiction of a single SLDC would enable the operation of a DSM like mechanism within the state, where generators and consumers provide a composite schedule for every 15 minutes of the next day and are financially liable for the deviations. The introduction of this mechanism is expected to improve grid discipline within a state and resulting in an overall improved frequency profile of the national grid. Participation of consumers in balancing groups via load forecasting and scheduling (flexible loads) is expected to improve frequency profiles of the national grid. This would prepare the stakeholders for the introduction of consumers in balancing groups in Phase 2.

The introduction of balancing groups within a state would also allow the BRPs of the various groups formed to leverage the effect of imbalance netting and reduce the overall penalty payable due to deviation from schedule.

Inter State Deviation Settlement

The proposed introduction of balancing groups allows generators or consumers to form balancing groups across a singular or multiple state boundaries. These balancing groups would benefit by leveraging the netting of imbalances and spatial smoothening of deviations due to RE (if RE generators are present in the group). It is expected that transmission constraints would play an inhibitory role in the formation of interstate balancing groups as they would restrict the flow of balancing energy. The regional restrictions on formation of groups is described below.

Regional Restrictions

Balancing group formation would need to be restricted to regions based on transmission constraints. The regional restrictions would be similar to the splitting of the PXs due to transmission constraints. Each region would have different imbalance energy prices based on its generation mix. The difference between imbalance energy prices between regions, would act as an indicator to the deficit in transmission capacity. This difference in prices would need to be factored into transmission planning. These regional restrictions would not be required once adequate transmission capacity is available; as a result the imbalance energy would have a standard Market Clearing Price (MCP) instead of multiple Area Clearing Prices (ACPs).

Mandatory Group Formation

It will be mandatory for all generators to form balancing groups within 6 months of notification of the regulation. Any generator defaulting would not be allowed to despatch power unless it can justify the delay under which circumstance it would be allowed a temporary extension on deadlines. These exemptions will be solely at the discretion of the regulatory commissions.

3.2.3 Congestion Management

Congestion Management and transmission planning will need to be modified to cater to the following:

a) Regional splitting of PXs and BGs due to transmission constraints
b) RE evacuation intrastate and interstate
c) Extra margin for open access consumers

3.2.4 Flexible Generation

Standards for all generators commissioned post notification will need to be upgraded to cater to the flexibility required by a grid with large proportions of RE generation. These standards would need to be at par with international best practices and will have to be revised periodically to ensure continuous adoption of flexible and efficient generation.

3.2.5 Introduction of Ancillary Services & Reserve Products

To ensure safe, secure and reliable operation of the power system with large scale RE integration ancillary and reserve products would need to be introduced. The products would be procured from prequalified providers on the PXs by the LDCs as below.

a) Primary Reserves (Contracted by NLDC)
b) Secondary Reserves (Contracted by RLDCs)
c) Tertiary Reserves (Contracted by SLDC)

This hierarchical placement of reserves will ensure that conflicting activation of reserves does not take place and to avoid operational inefficiencies. Over compensation to frequency correction would also destabilise the system.

Restriction on capacity contracted per provider

The contracting of reserves will have to be done keeping in mind that no single provider should be allowed to bid for more than a small fraction of the reserves required in the time block. This is to ensure that the failure of the provider affects only a small fraction of the available reserve and reduces the risk of the reserve failing altogether due to the failure of a large provider. This will also incentivise a larger number of players to upgrade and participate in the market for these reserves.

Distribution of reserves

To prevent inter regional power flows due to reserve activation, The NLDC, RLDC and SLDC would need to ensure that the contracted reserves are distributed all over the control regions and activation does not lead to large inter control region power flows, in a case of grid congestion the reserve might be rendered ineffective and further deteriorate the frequency condition. The estimation of the quantum of reserves required in every control region would need to be done based on the reserve dimensioning and the scheduled power flows.

The scheduling of availability of reserves will be done for each of the 96 time blocks; however despatch is function of need based on contingencies as they arise. The activation of reserves should be a seamless process. The activation of primary reserves is to arrest the change in frequency and is required to react immediately; secondary control is activated within 30 seconds and reaches full load within 5 minutes, and the tertiary reserve is activated in 5 minutes and reaches full load in 15 minutes, tertiary reserve sustains the secondary reserve till needed.

This ensures that primary reserves are freed up by the activation of secondary reserves and the activation of tertiary reserves frees up the secondary reserves.

Primary Reserves - Capacity as required and estimated by the NLDC for every time block would be contracted at latest in the day-ahead market, any corrections to this contracted capacity could be done in the intra-day contingency market. These reserves do not have a scheduled despatch; however they have a scheduled availability. They are implemented by the simultaneous action of FGMO in plants which have been contracted for the purpose in the time block. Primary reserves would be contracted and activated automatically by the NLDC. The NLDC would contract only capacity for the primary reserves. In India this cost should be recovered by socializing it among the balancing groups pro rata based on their portfolio size

Secondary Reserves - Capacity as estimated by the RLDCs for their respective control regions in every time block would be contracted through the term ahead, day ahead and Intraday contingency markets for each of the 96 time blocks. The despatch of this capacity is not planned and is triggered by a frequency excursion (+/-). These reserves are used to restore the frequency after its change has been arrested by the primary reserve activation.

Secondary reserves would be contracted by the RLDCs for their respective control areas. The activation (if not automatic) of the secondary reserve would be the responsibility of the RLDC. The Power provision will be tuned by the RLDC with intra-state exchange schedules to account for any congestion (described in section named "grid control cooperation"). For secondary control both, power and energy are contracted. This remuneration of energy costs have to be settled together with SLDCs. With reference to the provisions proposed for primary control above the component of cost that is paid for contracting the reserve would be socialized as above. The cost of actual energy used to handle the imbalance would be borne by the BRP responsible for the deviation after netting their imbalances

Tertiary Reserves - These are the only reserves whose despatch is a part of the schedule, the purpose of tertiary reserves is to continue the action of primary reserves. They are required to reach 100% output in 15 minutes from activation. These reserves are included as a part of the schedule for the time blocks they are activated for. Currently the Indian power system has only tertiary control available. Regulations for the introduction of primary and secondary reserves have not been notified yet.

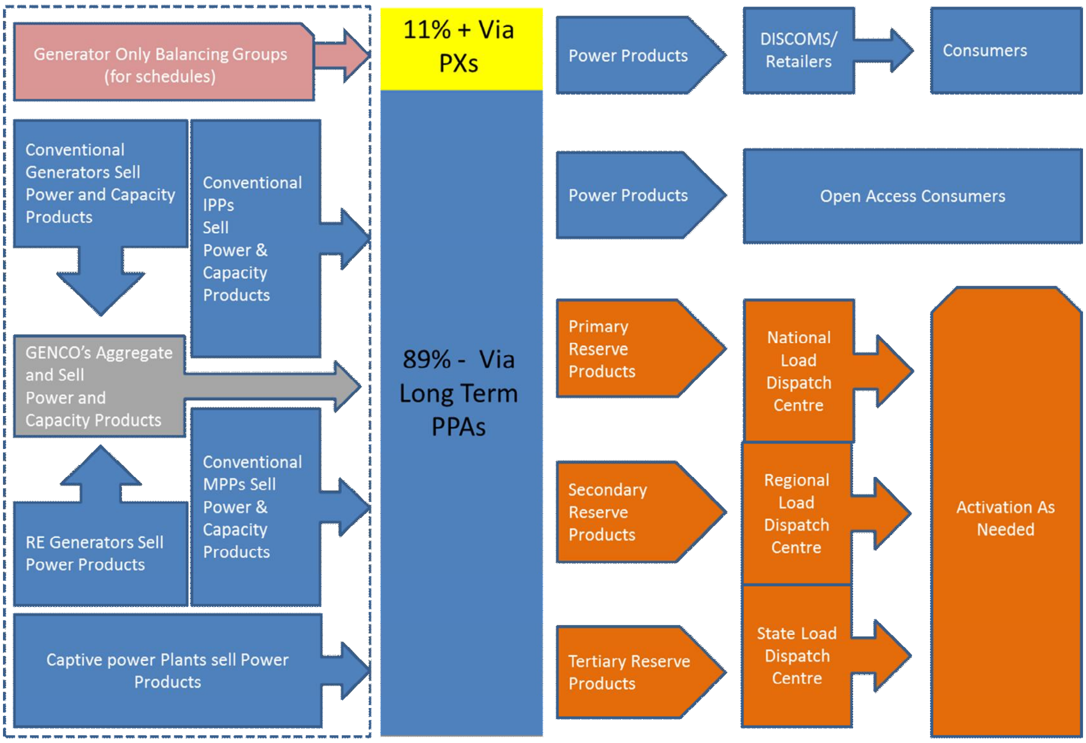
These reserves would be contracted by the SLDCs. The activation control and monitoring of these reserves would be under the jurisdiction of the SLDC. For tertiary reserves both capacity and energy is contracted. The capacity contracted is paid for by socialization of the costs as above. The cost for the actual energy required would be paid for by the balancing group responsible for the netted imbalance.

In case of insufficient reserves there should be a common reserve sharing platform that would allow RLDCs to also be able to contract tertiary reserves.

3.2.6 Market Post Completion of Phase 1

In the market post completion of Phase 1 of the transition, it is expected that 11% of the power will be traded at the exchange.

Figure 11: Market Post Completion of Phase 1



All the numbers are indicative and would be subject to change

3.3 Achieving market transformation phase 2 - Mid transition Measures

This phase of the market transition will feature 2 major milestones viz. Introduction of consumers in balancing groups and trade of more than 50% power on the PXs post completion of phase 2. The introduction of consumers in balancing groups would enable the introduction of demand side management. Consumers would be incentivized to forecast loads and also provide demand response products. The following regulatory, policy and capacity building measures are recommended for achieving this phase of transition:

3.3.1 Required Legislative and Regulatory Changes

The appropriate act / regulations may go through the required revisions over the 5 years period of phase 1 therefore this section refers to the amendments required in the most recent revision of the law and regulation during that time period.

3.3.2 Introduction of Consumers in Balancing Groups

The introduction of consumers in the balancing groups would create three types of balancing groups as below:

a) Generator only groups
b) Consumer only groups
c) Generator and consumer groups

BRPs would be responsible for the combined schedule of the group (planned generation and forecasted load).

3.3.3 Introduction of Demand Side Products

Loads which are flexible and/or interruptible would be allowed to trade in demand side measures to help support the grid. These loads will participate as part of balancing groups. These products would be procured from the PXs similar to other reserve products.

3.3.4 Load Forecasting

Load forecasting should be incentivized by the introduction of consumers into balancing groups. This would require the introduction of forecast service providers for loads. Accurate load forecasting and management would allow a balancing group to minimize its deviations and therefore the penalizations.

3.3.5 Review of Balancing Group Regional Restrictions

Based on the development of transmission capacity over the first phase of transition the regional restrictions on balancing groups would need to be reviewed and removed if found unnecessary.

3.3.6 Migration of PPAs

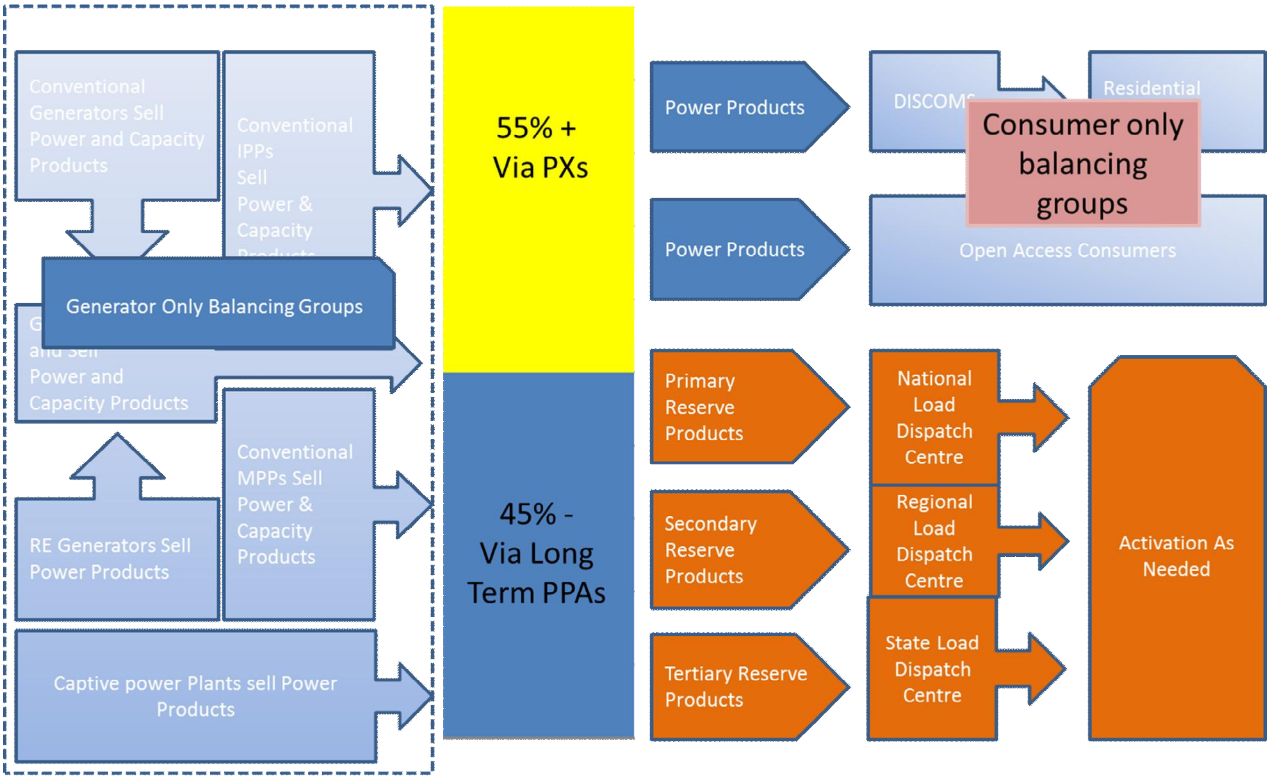
Generators with PPAs older than 10 years at the beginning of phase 1 would migrate to the PXs by the end of phase 2. Most generators would now have recovered their costs over 20 years as per their PPAs. For the remaining life of the project by regulation the plant would be required to trade all its power on the market.

The plants that were commissioned up to year 2000 would have completed a minimum of 20 years by the beginning of phase 2 and a minimum of 25 years by the end of phase 2. As a result all plants commissioned before 2000 (expired PPAs) and after 2015 up to 2020 would be trading all their power on the market as existing products or new products introduced in phase 1.

3.3.7 Market Post Completion of Phase 2

The illustration below in Figure 12 represents the market post completion of phase 2.

Figure 12: Market structure after complete implementation of Phase 2



All the numbers are indicative and would be subject to change

3.4 Achieving market transformation phase 3 - Completion of transition

This is the final phase of the market transition. This phase does not involve extensive regulatory measures. On completion of phase 3 all power would trade via the PXs, all reserve products and ancillary services would also be provisioned via the PXs; however the completion of the market will require the following:

3.4.1 Required Legislative and Regulatory Changes

3.4.1.1 Modification of Products on PXs

The long term products which were introduced in phase 1 to mitigate investor risk will now be modified to ensure that the longest time period between trade and despatch not to exceed five years (15 year products introduced in phase 1). This would be possible in phase 3 as the market would have operated for 10 years and in this time the price trends would have been well understood by the investors.

3.4.1.2 Migration of PPAs

As in phase 2, the generator whose PPAs have expired would be required to trade all their power in the PXs. The power markets would have operated with incrementally higher amounts of power being traded on it for 10 years. Understanding of price patterns and returns on market based products would have matured over this operating time. Based on this a two pronged approach may be followed to migrate the remaining generators onto the exchange.

Optional Migration

Based on the market trends, a generator whose PPA has completed 10 years at this point would be encouraged to dissolve these PPAs and migrate to the PXs. These generators would migrate expecting better returns from the market than the current PPAs would offer.

Mandatory Migration

At the end of phase 3 remaining PPAs would have a maximum remaining validity of 10 years. This is assuming it was a 25 year PPA signed 1 day before the notification of restriction on PPA regulations. The longest permitted gap between trade and despatch would be reduced to 5 years.

All remaining PPAs would be converted into 5 year products tradable on the exchange, if not traded would function similar to the PPA for these 5 years. Once a PPA has completed 20 years then it would be terminated and henceforth the parties involved would trade on the PXs only.

Exemptions

Exemptions could be made on a case to case basis up to a point where all investors have broken even. Beyond that point all power would trade in the market.

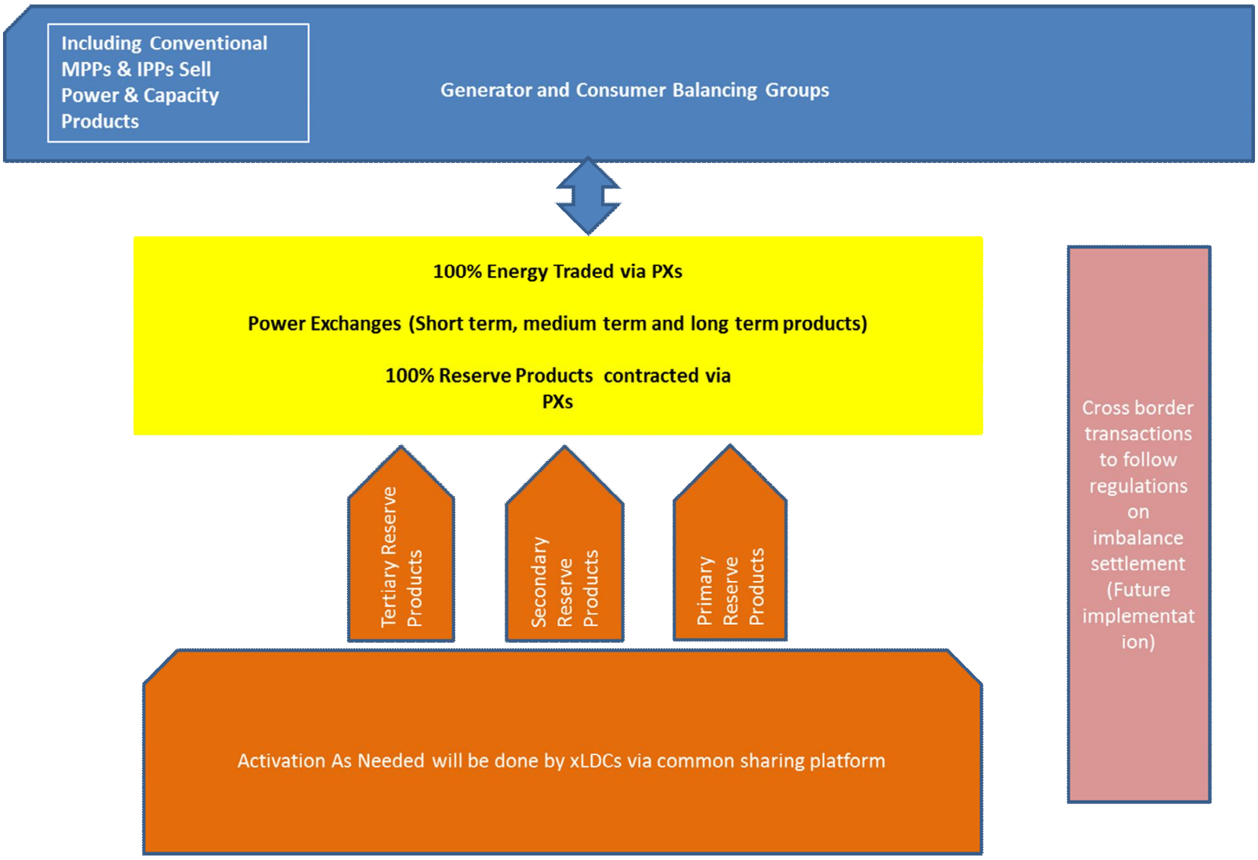
3.4.1.3 Review of RPO/REC

It is estimated that by the beginning of phase 3, RE power would have become cheaper than the MCP and RPOs/RECs may not be required. Based on the situation at the time they should be phased out.

3.4.1.4 Market Post Completion of Phase 3

The illustration below in Figure 13 below represents the market post completion of phase 3.

Figure 13: Market on Completion of Phase 3



3.5 Necessary conditions for a Capacity Market

Addressing both (a) adequacy of resources (access to enough power to be able to meet the highest expected level of demand) and (b) system quality (right mix of resource (consumers and generators) capabilities deployed to ensure that demand and supply are always balanced), is essential to maintaining reliability of power at least-cost while the power sector shifts from being dominated by conventional power to renewables. Rising shares of variable renewables is making resource flexibility, effective demand side management, generation forecasting and accurate load forecasting an investment consideration as well as an operational one. It is expected that the above mentioned phases will lead to the development of a power market where 100% of the power is sold at the exchange and has a well-established ancillary services market.

For the Indian context, the following steps are proposed before a viable capacity market can be created. These steps should be undertaken to make sure that the system has effective access to all of the cost-effective flexibility available from the existing generation portfolio and untapped existing demand-side management potential in the short term. In the long term, these steps should ensure that the market supports investment in a portfolio of new and existing supply- and demand-side resources capable of efficiently and cost-effectively meeting the projected need for flexible resource capabilities over a longer time.

i) Before introducing flexibility in the generation portfolio, operational challenges posed by growing shares of variable RE can be substantially mitigated through a number of relatively low-cost measures.

- Introduction of shorter scheduling intervals for increasing accuracy of schedule
- Creation of balancing groups balancing power flows at SLDC or Sub-SLDC level
- Investment in transmission to mitigate congestion and remove barriers to free flow of inter and intra state power
- Enable regional balancing of power
- More accurate forecasting of RE power and mandatory introduction of demand forecasting at DISCOM level
- Consumers (such as flexible industrial loads as well as large commercial buildings) to leverage their load as a reserve to be more responsive to uncontrollable changes in supply to manage unplanned imbalances to be included in balancing groups

ii) Ensure that existing power market is designed and operated to extract all cost-effective flexibility services available from all existing resources (consumers and generators).

- There should be sufficient capability to stop/start and ramp generation up and down (or in the case of consumption, down and up) fast enough
- A fully functional mechanism should be developed so that the above flexibility measures can be used in the according to the necessary quantity and frequency over multiple scheduling intervals in a least-cost manner to ensure system reliability

iii) Ensure that all qualifying demand-side management options are fully able to participate in the market, both directly and through aggregators.

iv) Historically there has been investment in resource adequacy however, system quality is ensured in operational timescales (imbalances managed by xLDCs at their own levels). Going forward, large shares of variable and intermittent RE requires that investment is done to ensure system quality.

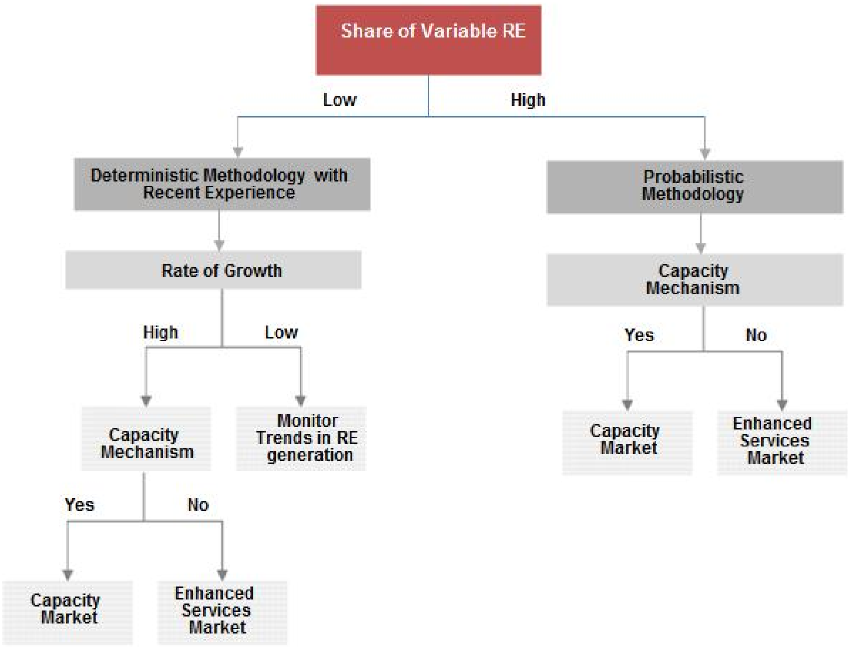
- The CERC regulation on Ancillary Services (Ancillary Services Operations Regulations, 2015) is a first step in this direction
- A fully functional control reserves market to ensure provision of ancillary and balancing service should be introduced

v) Establish a procedure for combining gross demand forecast with RE generation forecast to derive a net demand forecast. Use this net demand forecasts to assess on a periodic basis, the demand for critical flexibility services, taking into account the available despatchable resources (consumers and generators) to provide these services.

vi) Establish a methodology for setting the maximum value to the upcoming generation (both conventional and RE) depending on expected future peak load forecast and system reliability requirements.

Depending on the expected market condition, a simple deterministic approach based on recent experiences or a more complex probabilistic approach using production modelling can be used to set up capacity markets for the Indian scenario as depicted in the following figure. The desired resource capabilities can be procured through either enhanced services markets or apportioned forward capacity mechanisms, depending on the individual market circumstances.

Figure 14 - Decision Framework



3.5.1 Enhanced Services Market

This approach utilizes a long-term services market (essentially adoption of existing ancillary services mechanisms, with new services added as necessary) to procure the target mix of resource capabilities derived from the net demand forecast. Capabilities of interest would most likely include traditional system operator functions such as spinning and non-spinning reserves and operating reserves. Obligations to secure such services would remain with the system operator.

Required balancing services may include short-cycle stop-start and aggressive despatch or ramping options, parameters meant to reflect how fast and how frequently, across multiple scheduling intervals, a resource can be turned off and on, as well as the up-ramp and down-ramp rates and ranges. For both traditional ancillary services as well as these less traditional balancing services, their value could be set by periodic "forward" auctions and paid to all new and existing resources capable of providing them.

This approach would seek to realign the mix of system resources by providing those resources with the desired capabilities access to a stable, long-term revenue stream that is unavailable to less flexible resources. This would afford more flexible resources a competitive advantage in the energy markets. This approach has the benefit of decoupling the long-term procurement of system services from processes designed around firm production capacity, allowing greater flexibility in targeting specific services (e.g., energy storage). For this same reason it may take longer to see the desired impact on the pattern of supply-side investments. Until these services markets establish a track record investors may be slow to incorporate the relevant capabilities into long-term resource investment plans unless they have a more immediate motive to do so (such as the capacity mechanism described below). Therefore pursuing an enhanced services market may be more appropriate for markets where there is no perceived urgency to invest in a significant amount of new firm supply resources. Nonetheless, this approach represents a viable option for regions experiencing a growing share of variable renewables where creating a separate forward capacity payment mechanism may not be desirable.

3.5.2 Forward Capacity Market

An alternative approach, involves simply apportioning the capacity mechanism into products based on the target mix of resource capabilities derived from the net demand forecast. All resources, including qualifying demand-response and end-use energy efficiency resources, would bid into the highest-value product for which could qualify. The most flexible product is cleared first, followed by the next, and so on.

It is important to keep in mind that capacity mechanisms are not intended to provide additional revenues to system resources over and above what they would expect to earn in a properly functioning energy-only market. Rather they are designed to substitute a more stable, predictable stream of payments for capacity in place of a portion of the more variable, less predictable revenues that would otherwise have been earned through the sale of energy. With that in mind, the apportioned approach to capacity mechanisms described here allows market operators to differentiate the value of capacity payment streams available to system resources based on a set of critical operational capabilities. As a result more flexible resources can realize a higher proportion of their earnings from stable, long-term, predictable capacity (or “capability”) revenues, which should afford them an overall competitive advantage over less flexible resources in the energy, capacity and ancillary services markets. As shares of variable resources grow, experience is gained and institutional capacity is built, markets may want to evolve over time toward a reliability market structure that is able to incorporate cost/benefit trade-offs dynamically, but this level of complexity is unlikely to be necessary or feasible in most markets in the immediate future.

Chapter 4: Grid codes and regulatory aspects of grid management

4.1 Introduction

With more and more renewable generation installed at all levels of the electricity grid, the requirements for generators have to cover various aspects of system stability, operation and security. To meet the RE integration targets set in India, a focused strategy looking at the most relevant aspects is needed. One of the main differences between the situation in smaller countries (e.g. Germany) and India is that a large number of regulations and mechanisms in India are subject of state intervention rather than decision or regulations on a national level. Due to the federal structure of India incentives for RE capacity additions (i.e. feed-in tariffs) are for example developed on state level. Therefore harmonization of state and central level regulation and measures to integrate RE on a national level are important. With an RE penetration level rapidly increasing in single states, India could implement more aspects of nation-wide burden sharing elements in RE integration approaches in order not to slow down the development in RE-rich states which are only capable to efficiently integrate RE until a certain limit.

Beneficial for a joint integration process is the well-developed electricity network which offers a better interconnection between the Indian states than between the European countries if put in relation to the electrical system size. Thus, technical balancing of RE should become a regional or national task either by obliging non-RE rich states to import RE and take responsibility for integration (e.g. backing-down of other generation, taking responsibility for implications resulting from forecast errors) or by strengthening joint markets where short-term price signals result in balancing actions by all market participants across different states.

After a detailed study of the Indian power system, the associated grid codes and regulations, the following have been identified as the key drivers for developing the strategy for large scale RE integration in India.

Driver 1 - Funding & Refinancing of RE

Situation in India: Funding and refinancing is largely done on state level; RE production is in most of the cases sold to state utilities based on fixed state-wise Feed In Tariff (FiT); refinancing of costs for FiT is basically left to the utilities which finally need to increase electricity tariffs for consumers within the state in order to levy the necessary funding; as utilities are often in poor financial health, under the current regulation the future growth of RE is very much dependent on financial support or recovery of these utilities; although there is an alternative option for RE producers which is selling the electricity based on bilateral agreements or spot market transactions while selling RE-certificates on the market, the actual situation puts a thread to future capacity addition.

Key Considerations: state RE strategy and FiTs / central FiTs (for CTU connected plants), enforcement of RPO obligations, open access conditions and RE delivery to industrial consumers (electricity price development, other incentives).

Further options of possible development:

- Enforcement and redefining the methodology for determination of RPOs
- Socialization of costs for funding and refinancing RE all over India by alternative mechanism than (not enforced) RPOs
- Especially: participation of non-RE rich states in order to introduce better burden sharing and not to slow down implementation in RE-rich states

Driver 2 - Technical Balancing

Situation in India: Technical balancing in India is basically done within the state according to merit-order of conventional plants coordinated by the respective SLDC; difficulties in balancing are especially occurring due to non-availability of RE forecasting but also by lack of balancing capabilities (not sufficient conventional capacity or low flexibility, stranded capacity, restrictions from multi-purpose use of hydro power plants); the current power market structure does not necessarily lead to engagement of non-RE rich states in the balancing process; in contrary they are able to fulfil their RPO by simply buying RECs; there is no obligation for them to actively take part in balancing by changing the production patterns of their conventional units; apart from that RPO are not enforced and low demand on the REC-market does not allow for sale of all existing RECs.

Non-RE rich states should be involved automatically within the technical balancing process by fulfilling RPO. This is only possible if the purchase of green electricity is coupled with the time of production.

Further options of possible development:

- Strengthening of spot marketing (conventional and RE) via joint market places across state boundaries e.g. as the Indian Energy Exchange; this could lead to the despatch of conventional power plants according to market signals also in non-RE-rich states and technical balancing would be required i.e. in times of high / low market prices; clarification for cost effectiveness in PPA based environment as in India needed *(market based approach)*
- Combine RPOs with the responsibility to technically balance renewables; this could be an obligation to back down / increase generation for non RE producing states which fulfill RPOs by only buying RECs not reacting physically on variability of RE; incentive could be a quota based on 15 minute intervals redirected by RLDCs from RE producing to non RE producing states (regulation based approach)
- Increase of cooperation between state balancing areas; eventually step to regional balancing schemes

Driver 3 - Reserve Control

Situation in India: At the moment India does operate the electricity system without procured reserves. It is consensus that control reserves (Automated Generation Control) would enhance the ability to keep a stable frequency in the grid.

Further options of possible development: Introduce Automated Generation Control in terms of primary, secondary and tertiary reserves

Driver 4 – Forecasting

Situation in India: Up to today professional RE forecasting has not been integrated in the system operation in the Indian states and on the regional level (SLDC and RLDC level). Given the high capacity penetration in some states forecasting is an essential prerequisite for secure and efficient system operation. First experiences with forecasting have been made in Gujarat and activities have started in Tamil Nadu. Aggregated forecasts are necessary for system operation on the control zone level (SLDC/RLDC/NLDC) and for economic purposes which heavily depends on future regulations. For the economically motivated forecasts it is strongly recommended that regulation should allow forecasting and marketing of RE for RE generator pools instead of restricting forecast to generator based or pooling station based forecasts.

Further options of possible development:

- Immediate implementation of professional RE forecasting in all RE-rich states

- Tendering of forecasting activities on control zone level (jointly or separately); contracting of state-of-the-art forecast from established international forecast providers
- Implementation of necessary IT infrastructure at REMCs
- Capacity addition in the field of forecasting at SLDCs/RLDCs, IMD and at research institutes
- Establishment of cooperation and work at the IMD and NCMRWF
- Encouragement of establishment of domestic forecast service providers

<u>Driver 5 - Pilot projects for measures to enhance RE integration</u>

Situation in India: Pilot projects at utilities, SLDCs, RLDCs, and other relevant institutions enhancing grid integration could be fostered. However, these projects should have a lower priority than the mentioned points above.

Further options of possible development: Start of pilots projects to introduce demand response schemes, time of the day tariffs.

For India the most urgent next steps to enhance grid integration are clearly to implement forecasting and control reserves on state and/or regional level. First actions for policies should be taken as soon as possible and with highest priority. The first step is to entail the support of remote-controlled network operation activities, such as feed-in management or power curtailment, as well of dynamic behaviour in the case of network faults. Accordingly, the scope of the interconnection requirements of renewable generators has to be broadened.

The following section describes the recommendations resulting from the analysis focusing on the interconnection requirements of renewable generators in the distribution and transmission grid in India.

4.2 Phase ZERO – Foundation Phase for interconnection requirement for RE

The individual grid codes of Andhra Pradesh, Gujarat, Himachal, Karnataka, Madhya Pradesh, Maharashtra, Rajasthan, and Tamil Nadu were reviewed along with the IEGC. In the grid codes of these states no special description of the interconnection requirements for RE generators were found going beyond the IEGC. Thus, the recommendations are valid also for the individual states.

The analysis showed that most of the issues are addressed in the Indian grid code and standards, but often a sufficient level of detail is missing. The general recommendation is to provide more detailed information about the functionalities to avoid misunderstandings.

4.2.1 Active power reduction

According to the Indian grid codes, wind farms shall have the ability to limit the active power output at grid connection point as per system operator's request. System operator may instruct wind generator to back down wind generation on consideration of grid security [CERC 2010].

This functionality is described in the Indian Grid Code and Guidelines in a general way. In order to avoid misunderstandings or different interpretations, it is recommended to provide more detailed information about this functionality in the grid code.

4.2.2 Ramp Up/Down capability

According to the Indian Grid Code, the grid connected wind farms shall have the ramp up/ramp down capability, but no further information about how to ramp up and down active power according to the frequency was found in [CERC 2010].

This functionality is described in the Indian Grid Code and Guidelines in a general way. In order to avoid misunderstandings or different interpretations, it is recommended to provide more detailed information about this functionality in the grid code.

4.2.3 Reactive power compensation

According to the Indian Grid Code, The reactive compensation system of wind farms shall be such that wind farms shall maintain power factor between 0.95 lagging and 0.95 leading at the connection point [CERC 2010], [MOP 2013].

This functionality is described in the Indian Grid Code and Guidelines in a general way. In order to avoid misunderstandings or different interpretations, it is recommended to provide more detailed information about this functionality in the grid code.

4.2.4 Fault-ride-through (FRT) capability

A FRT capability for wind turbines is given in the grid codes. This capability could be complemented with more detailed information. No requirements for PV plants were found in the Indian Grid Codes. This has to be added.

After this disconnection, the increase of the active power supplied to the network of the network operator concerned must not exceed a gradient of maximally 10 % of the network connection capacity per minute.

It is recommended to provide detailed information about this functionality in the grid code. High voltage ride through capabilities are gaining importance in the view of different network operators.

4.2.5 Dynamic behaviour during fault

According to the Indian Grid Codes, wind farm shall have the capability to meet the following requirements during fault:

- Minimize the reactive power drawl from the grid.
- Provide active power in proportion to retained grid voltage as soon as the fault is cleared.

According to [MOP 2013] “During voltage dip, the generating station shall maximize supply of reactive current till time voltage starts recovering or for 300 ms, which ever time is lower”. But no specification of how this reactive power injection has to be done was found.

No requirements for dynamic behaviour during fault for PV plants were found in the Indian Grid Codes.

This functionality is described in the Indian Grid Code and Guidelines in a general way, thus misunderstandings or different interpretations are likely to happen. PV plants should be included.

4.2.6 Protection systems

The minimum protection functions for distributed generators are provided by the Indian Grid Codes. This functionality is described in the Indian Grid Code and Guidelines in a general way. In order to avoid misunderstandings or different interpretations, it is recommended to provide more detailed information, such as recommended settings for each protection function.

4.2.7 Control reserves

Requirements for the capability of renewable energy sources regarding control reserves should be provided in the Indian Grid Codes. As an example, the German Grid Codes require each generating unit with a nominal capacity of more than or equal to 100 MW to be capable in participating in primary control. There are exceptions for generating units using renewable energy sources.

4.2.8 Remote control

Some of the above mentioned functionalities as for example limitation of active power production, provision of reactive power, among others could require remote control by the network operator.

According to [BDEW 2008],"for secure network operation, it is necessary to include the generating plant into the network operator's remote control scheme on request of the network operator, such as for example: control of the circuit breaker (in particular opening of the circuit breaker in case of critical network conditions – „remote switch-off"), limitation of active power production, provision of reactive power. On the basis of the network operator's applicable remote control concepts, the necessary data and information required for system operation management shall be made available by the connection owner for processing in the control and communication system in the transformer substation (in the case of connections to the network operator's bus-bar) or in the transfer station".

Related specifications were not found in the Indian grid codes and standards and should be included.

In order to make amendments to the IEGC as recommended, the following table comparing the Indian and the German electricity grid code can be used as a reference.

Required functionality	Indian Grid Code and Technical Guidelines	German Grid Code and Technical Guidelines
Active power reduction	Requirement: Wind farms shall have the ability to limit the active power output at grid connection point as per system operator's request. System operator may instruct wind generator to back down wind generation on consideration of grid security [CERC 2010] Remark: No further information about how to perform this active power reduction was found in security [CERC 2010] "Provided that as far as possible, reduction in active power shall be done without shutting down an operational	Requirement: Generating units using renewable energy sources must be controllable in terms of active power output according to the requirements of the Transmission System Operator [VDN 2007] Remark: The reduction of the power output to the signalized value must take place with at least 10% of the network connection capacity per minute without disconnection of the plant from the network

Required functionality	Indian Grid Code and Technical Guidelines	German Grid Code and Technical Guidelines
	generating unit and with reduction being shared by all the operational generating units pro rata of their capacity" [MOP2013]	
Ramp Up/Down capability	Requirement: The grid connected wind farms shall have the ramp up/ramp down capability Remark: No further information about how to ramp up and down the active power according to the frequency was found in security [CERC 2010]. Droop characteristics for frequency regulation are given for thermal (3% to 6%) and hydro power plants (0% to 10%) in [CEA 2007], [MOP2013]	Requirement: All adjustable power generation systems shall reduce or increase the generated active power according to the frequency Remark: All adjustable power generation systems shall reduce or increase the generated active power (Pm) instantaneously with a gradient of 40% of Pm per Hertz. The generation unit will continuously move up and down the frequency characteristic curve in the frequency range of 50.2 Hz to 51.5 Hz with regard to its active power feed-in. Non-variable power generation systems are permitted to disconnect from the network in the frequency range of 50.2 Hz to 51.5 Hz.
Reactive power compen-sation	Requirement: The reactive compensation system of wind farms shall be such that wind farms shall maintain power factor between 0.95 lagging and 0.95 leading at the connection point [CERC 2010], [MOP2013] Remark: No further information about characteristics for reactive power injection by inverter based generation was found in [CERC 2010]. Different operating power factors for conventional power plants, e.g. gas turbines are given in [CEA 2007]	Requirement: Generating units shall allow under normal stationary operating conditions the following power factors (cos phi) depending on their apparent power Remark: • S ≤ 3.68 kVA: cos phi = 0.95 (under-excited) to 0.95 (over-excited) • 3.68 kVA < S ≤ 13.8 kVA: characteristic curve provided by the network operator within cos phi = 0.95 (under-excited) to 0.95 (over-excited) • S > 13.8 kVA: characteristic curve provided by the network operator within cos phi = 0.90 (under-excited) to 0.90 (over-excited) • Different specifications and characteristic for reactive power feed in are provided according to the voltage

Required functionality	Indian Grid Code and Technical Guidelines	German Grid Code and Technical Guidelines
		level
Fault Ride Through (FRT) capability	Requirement: The wind generating machines shall be equipped with fault ride through capability [CERC 2010] Remark: A FRT capability curve is given with different parameters according to the voltage level	Requirement: The wind generating machines shall be equipped with fault ride through capability Remark: Two different curves are given in the FRT capability curve (border lines 1 and 2). Different requirements for operation above these two borderlines are given
Dynamic behaviour during fault	Requirement: During fault ride-through, the Wind turbine generators (WTGs) in the wind farm shall have the capability to meet the following requirements [CERC 2010]: • Shall minimize the reactive power drawl from the grid. • The wind turbine generators shall provide active power in proportion to retained grid voltage as soon as the fault is cleared. Remark: “During voltage dip, the generating station shall maximize supply of reactive current till time voltage starts recovering or for 300 ms, which ever time is lower” [MOP2013]. No specification of how this reactive power injection has to be done was found.	Requirement: For all generating facilities which are not disconnected from the network during the fault, active power supply must be continued immediately after fault clearance and increased to the original value with a gradient of at least 20% of the nominal capacity per second. The generating facilities must support the network voltage during a voltage drop by means of additional reactive current. Remark: Voltage support by means of reactive current injection during fault is required with a specific V/Iq charac-teristic depending on the inverter’s k-factor.
Critical fault clearing time	Requirement: Fault clearance time when all equipments operate correctly, for a three phase fault close to the bus-bars shall not be more than: • 100 ms for 765 kV & 400 kV • 160 ms for 220 kV & 132 kV	Requirement: Fault clearing times of up to 150 ms, three-phase short-circuits close to the generating unit must not lead to instability throughout the operating range of the generator
Protection systems	Requirement: Distributed generation resource operating in parallel with electricity system shall be equipped with the following protective functions [CEA 2012]: ► Over and under voltage trip functions if voltage reaches above 110% or below 80% respectively with a clearing time of 2 seconds ► Over and under frequency trip	Requirement: The following functions of the protective disconnection equipment shall be realized: ► Under-voltage protection. ► Rise-in-voltage protection. ► Under-frequency protection. ► Rise-in-frequency protection. ► Reactive power and under-voltage protection (Q & U<): disconnection from the network

Required functionality	Indian Grid Code and Technical Guidelines	German Grid Code and Technical Guidelines
	functions, if frequency reaches 50.5 Hz and below 47.5 Hz with a clearing time of 0.2 seconds ▶ The distributed generation resource shall cease to energize the circuit to which it is connected in case of any fault in this circuit. ▶ A voltage and frequency sensing and time-delay function to prevent the distributed generation resource from energizing a de-energized circuit and to prevent the distributed generation resource from reconnecting with electricity system unless voltage and frequency is within the prescribed limits and are stable for at least 60 seconds; and ▶ A function to prevent the distributed generation resource from contributing to the formation of an unintended island, and cease to energize the electricity system within two seconds of the formation of an unintended Island. Remark: A list of minimum protection schemes that shall be installed for wind farm protection is provided in [CERC 2010]. No recommended settings were found in [CERC 2010].	after 0.5 s, if the voltage is below 0.85 Uc (agreed service voltage) and the generating plant simultaneously extracts inductive reactive power from the network. Remark: Recommended settings for different connections schemes are provided in [VDN 2007]

4.3 Introduction of Automatic Generation Control

Necessary technical requirements for AGC should be included in the grid code based on the reserve design. A pre-qualification procedure for the reserve provision should be specified. This procedure should define the necessary dynamics (ramp rates etc.) and reliability of the reserve provision as well as necessary communication processes. In case of mandatory reserve provision the requirements can be introduced in the grid code. In case of market based reserve provision, the stakeholders can agree on the requirements for market participation.

Phase I – Initiation Phase

After the foundation steps of amending the grid code in line with future targets have been taken, following issues have to be addressed.

4.3.1 Amendments to RE Tariff System

Short Term Recommendations

The following are some recommendations to help DISCOMs purchase RE power without suffering financial losses in the short run.

- National Fund to Finance RE Tariff
    - Such a fund could be set up to cover the cost difference between power purchase costs of conventional plus income from REC and the costs incurred by DISCOMs to pay the RE generators. The fund could be financed by all states according to their RPO obligations by collecting a minimal surcharge from every final consumer above the BPL category/ subsidised agricultural consumers.
- A tax component could be levied by the federal government on luxury goods which could also be used to finance RE power purchase by DISCOMs if states are not willing to engage in a burden sharing approach.

Long Term Recommendation

In the long run, competitive bidding based on generators‘ bid is recommended to be used for price discovery for RE power for large scale RE projects. Further, GENCOs can act as aggregators of RE power by purchasing all RE power at the price discovered through competitive bidding and then sell the RE power on the exchange as proposed in the future market design.

4.3.2 Framing of Performance Standards of RE Generators

Once the interconnection requirements have been changed as described above, there is a need to introduce a testing and certification process.
The grid code compliance of distributed and renewable generation is crucial for the safe and secure operation of the energy system with significant shares of renewable generation. Because of the high numbers of small generators the testing cannot be done at each installation individually. Therefore a testing and certification process is used.
For this process, firstly, agreed and in depth specified grid code and testing requirements are needed. Secondly, certification bodies have to be established, independent from other stakeholders (manufacturers, project developers, grid operators …). Certification bodies can offer own testing services or make use of accredited testing laboratories. Thirdly, the interconnection of generators not certified for grid code compliance can be rejected by the grid operator.

4.4 Measures for enhancement of grid security and introduction of automatic generation control

Recommendation 1: Enforce compliance with grid code regarding provision of balancing power
The currently valid Indian Electricity Grid Code (IEGC) requires under regulation 5.2 that the thermal generating units above 200 MW and hydro units above 10 MW which are synchronized with the grid shall provide a reserve margin in the amount of 5% of their rated power.

However, it was reported that most of the units currently in operation do not comply with this requirement. Reference is made to document “Petition being filed by National Load Despatch Centre on 24 February 2015” and supporting documents.

It is therefore highly recommended that appropriate measures shall immediately be taken in order to ensure compliance of generation units with the requirement in nearest future.

Recommendation 2: Introduce and enforce compliance of effective deviation settlement mechanism

Proper compliance with schedules is required in order to minimize frequency deviation and limit the usage of expensive balancing reserves. With the DSM mechanism there is a regulation of settling deviations between different states and central units. For RE units connected to the central transmission utility (CTU) the framework of forecasting, scheduling and imbalance handling has been finalized after consultation phase on 7th of August, 2015. However, RE generators connected to the grid of state utilities and conventional generation and consumption does not fall under a similar regulation up to now. Only, 5 states introduced an intra-state regulation on deviation settlement.[4]

- Intra-State deviation settlement mechanism should be introduced. Generator-wise or stakeholder-wise (GENCOs, DISCOMs etc.) accounting for deviation from schedule is necessary to improve frequency fluctuations decreasing required amount of procured and despatched reserves in the future. Transparent stakeholder-wise accountability is important in order to enforce schedule discipline and to apply penalties to deviating parties.
- Enforcement of existing and future regulation is crucial. The payment for schedule deviations should be high enough to successfully incentive compliance.
- The balancing group concept used in Germany can be revised by the regulatory commissions and eventually adopted to Indian conditions. In the long-term when frequency control is established, related costs can be reimbursed by the penalty which is charged to deviating parties under this deviation settlement mechanism.

Recommendation 3: Monitoring of effects from regulation on Ancillary Services Operation

The outcome and impact of the regulation on Ancillary Services Operation should be monitored (handling, operating efficiency, frequency stabilisation) before designing more extensive reserve systems.

Recommendation 4: Decision on control reserve design

Based on the results of adequacy of the tertiary reserve and based on international practice a regulation should be drafted in the long-term regarding the primary, secondary and tertiary reserve structure in the future. The following features need to be clarified:

- Dimensioning of reserves
- Response time per reserve type
- Products (product length, time/hours of delivery, minimum bid size)

Recommendation 5: Establishment of balancing power market

To efficiently allocate reserves under a competitive mechanism a market based solution is recommended in the long-term. While the actual, already existing regulation (Ancillary Services Operation) is giving uniform price incentives for generators (25% of tariff for down-regulation and tariff + mark-up for upwards-regulation), it is recommended to procure the reserve capacity in the long-term via a market mechanism (i.e. auctions). This opens the opportunity that prices are below a regulatory predefined threshold. However, sufficient competition can be expected in order to achieve lower prices. If this is the case the recommendations is to:

[4] Discussion on the workshop of work package 1

- Design a primary, secondary and tertiary control reserve market. In case of an auction the auctioned time intervals need to correspond to the required products (product length, time of delivery, minimum size). The method and rules for auctioning need to be defined (auction and pricing mechanism for both procurement and despatch; i.e. uniform pricing, pay as bid).
- There should be one control reserve market per type of reserve as for each type of reserve different prerequisites needs to be fulfilled (i.e. response time).

Recommendation 6: Technical implementation of reserve controls (primary control & tertiary control)

The technical implementation can and should run in parallel to the other recommended measures wherever technical adjustments are required. Primary frequency control is completely decentralized solution based on frequency. Required technical changes are to be made at plant level to enable governor functioning and droop characteristics. The same holds true for secondary reserves, however a communication infrastructure is necessary between system operators and reserve provider for exchanging activating signals. Tertiary reserve can be activated manually or automatically; infrastructure and communication procedure is required both ways. The steps should include:

- Assessment and adoption of control reserve functionalities
- Necessary adaptation works at the generating plant
- Revision and improvement of telecommunication infrastructure
- Required operation details and specifications of software use at SLDC units
- Control concept & establishment of control cooperation between different balancing areas
- Initial operation and Trial

Recommendation 7: Introduce prequalification procedure

In order to make sure that power plants are capable of delivering power with an adequate and required quality (response time, reliability, ramp rates, duration of revision) a prequalification procedure should be introduced. The prequalification procedure should take into account the requirements for each type of reserve and should be processed by the respective transmission system operator.

- Generators acting on the balancing market need to ensure that they are able to adequately provide control reserve in conformity with the actual regulation and product requirements
- The prequalification procedure assured e.g. that participants are e.g. able to fulfil speed of reactions, required ramps and duration of provision

Phase II – Transition Phase

4.4.1 Implementation of AGC

The purpose of AGC is to regulate the frequency of the network and control exchanges of electricity with neighbouring networks. There are basically three types of control.

1) Primary Control
2) Secondary Control
3) Tertiary Control

Each control has its own importance. Primary control is a decentralized solution. Secondary control, which is also named Automatic Generation Control (AGC), is a centralized solution belonging to the functions of the Load Despatch Centre. The variations in frequency occur due to problems on both the generation as well as consumption side.

Recommendation 1: To ensure safe, secure and reliable operation of the power system with large scale RE integration ancillary and reserve products would need to be introduced. The products would be procured from prequalified providers on the PXs by the LDCs as below.

a) Primary Reserves (Contracted by NLDC)
b) Secondary Reserves (Contracted by RLDCs)
c) Tertiary Reserves (Contracted by SLDC)

Recommendation 2: Prior to the adoption of secondary control via AGC there are some major prerequisites that have to be fulfilled in the Indian environment:

- Introduction of adequate balancing energy capacity and implementation of a new grid code for the Indian power market that obliges all parties to comply with the agreed schedules must be the first step for realization of Automatic Generation Control.
- Automatic Generation Control is a technical means for realization of secondary load-frequency control but requires the availability of the needed control power at all times. One major precondition is the establishment of a balancing energy market. Sufficient capacity for provision of regulation energy must be made available.

Recommendation 3: Technical requirements for AGC

After establishing the regulations requirements and energy market requirements, next step is to lay the technical foundations for frequency control through AGC. However, this will require some changes in the following areas:

1) Generating plants: In addition to the adaptations in the primary control functionalities, further adaptations are needed in secondary control, i.e. AGC. These are:

- Installation of an AGC control module at the power plant control system
- Modification of the unit or block control by implementation of a logical switch which allows the AGC set point to drive the unit if AGC is “ON” or the local set point if the AGC mode is “OFF”
- Installation of an RTU (remote terminal unit) that connects the power plant control system to the SCADA system of the responsible load despatch centre in both monitoring and control centre.

2) Telecommunication infrastructure:

- Telecommunication infrastructure has to be established or upgraded. This will be best addressed by the application of fibre-optic communication technology.
- A standardized communication protocol like the IP-based IEC 60870-5-104 should be used for communications to the power plants in both monitoring and control directions.
- State-of-the-art security standards have to be met, like IEC 62351 and other relevant standards.

3) Control Centres:

Software package for AGC needs to be included in the software capabilities of the relevant Control Centre Systems and needs to be parameterized and customized to the specifics needs. Commissioning and point-to-point testing together with the individual equipment accommodated at the power plant will have to be performed.

Recommendations 3: Functional Requirements for Automatic Generation Control

1) AGC system requirements: The AGC program shall execute every in fast cycles, preferably 2 s and shall compute and process an ACE.

- AGC system shall support the multiple AGC operation modes such as
    - Economic
    - Fast ramp
    - Emergency
    - Suspend
    - Trip
- Unit Control Modes: As a minimum, the AGC program shall have provisions for different classes of despatch units. These classes shall be determined based on telemetry data.
- Unit Limits
- AGC control suspension
- Load following and time-error correction

2) Interface and communication requirements

- ICCP interfaces
- Forecast and scheduling system
- Alarm processing for AGC

Recommendation 4: AGC Control Concept for Indian Power Market

For Indian market, a very effective and innovative grid control cooperation, which is introduced in Germany, could be used as a reference. Grid Control Cooperation (GCC) is an innovative network control concept, by means of which the four German transmission system operators (TSOs) optimize their control energy use and the control reserve provision technically and economically through an intelligent communication between the load-frequency controllers of the TSOs.

The horizontal structure of the control areas in the European interconnected system offers the GCC the possibility to exploit synergies in terms of network control like in a single fictitious control area, without giving up the proven structure of control areas. It also enables a flexible response in case of network bottlenecks.

4.4.2 Incentivizing flexible generation

From our analysis, it can be concluded that the country currently does have sufficient balancing potential for managing variable generation provided the flexibility of thermal generation is optimally utilized. However, increased capacity addition of renewable challenges the need for more capacities of flexible generation. For the target for 2022, the capacity can be derived from flexible conventional plants, pumped storages and demand side management.

The following table summarizes the key recommendations of this section.

1	CEA should release technical flexibility standards and appropriate retrofits for conventional

	plants.
2	CEA can undertake technical audits of the power plant and clearly define flexible technical standards/characteristics for the conventional plants of different technologies and of different sizes.
3	Based on the above audits, a regulated benchmark flexibility capacity tariff has to be determined.
4	Reserve pricing mechanism to ensure so that generators have clear visibility of price signals between energy and reserve provision.
5	Upon the introduction of balancing groups in future, the long term bilateral contracts can be negotiated amongst generators within the group in order to net imbalances.

4.5 Phase III – High RE Penetration

This phase will witness high RE penetration the minimum exceeding 65% in the grid. With such high penetrations it is critical to have necessary equipment and mature processes that ensure dynamic system supports, voltage and reactive power management systems. All RES systems should be mandated to meet their reactive power management themselves. For instance, large off-shore wind farms connected by voltage source converters can meet the requirements better than large offshore wind farms using an AC connection. Since it has to be compensated for its reactive power (charging capacity) and also meet the requirements at the point of connection to the voltage system, in such scenarios, deployment of flexible AC transmission system devices (FACTS) will aid in grid security.

The selection and placement of control equipment required towards handing variable renewable energy sources ensuring the stability of the grid can be divided into different stability criteria of the grid. Despite various control equipment options, reasonable planning, utilization, and controlling of the equipment and interactive coordination between the different load despatch centres is essential. On the basis of our study, it is recommended that the following be introduced at this stage.

4.5.1 Appropriate Usage of FACTS devices

Usage of these devices is recommended to be begin from the transition phase, however it is suggested in this phase with the view of intending to have established mature operation procedure and appropriately system planning.

The deployment of FACTS needs to be evaluated and simulated in power system studies, to justify the need technically and economically towards the end of transition phase. For economic reasons, simpler FACTS (switchable) are preferred over more complex devices (e.g. thyristor- or IGBT-controlled).

For technical, especially dynamic behaviour reasons, complex and more expensive reactive power devices (e.g. synchronous condensers, STATCOMs) are preferred.

Highlight some practices observed in other countries such as Denmark and Germany. In Denmark, centralized synchronous condensers are used for controlling dynamics in case of RES and their deployment is coordinated with the conventional generation, transmission grid, and the HVDC interconnections. In Germany, the TSOs try to cope with the different challenges they face by the "Energiewende" (more renewable energy, no nuclear power plants, less coal) with FACTS as well. In the view of TSO, the transmission grid extension, which is behind schedule, can be alleviated by introducing FACTS at strategic locations, where conventional power is missing, and due to intermittent RES generation different transmission load flows will be achieved.

For example, the 380 kV lines will be heavily loaded with high RES transmission before re-despatch is activated. Voltage will go down at the end of such line and will be supported by MSCDN (mechanically switched capacitors with damping network). In case of low line loading, voltage will go up and might exceed limits, hence, the voltage has to be brought down to acceptable levels by using (switched) shunt reactors. Both options are cheaper than choosing e.g. synchronous condensers or STATCOMs because their additional features of dynamic and short circuit power support is not needed in such a case and the remaining network can take over such parts. However, if such features were needed, they also would be considered, bearing in mind that such devices will incur considerable losses (especially cooling and switching losses) that also need to be reviewed.

Operations of STATCOMS were investigated in combination with the installation of certain type of wind turbines (fixed-speed). STATCOMS were found to show better performance e.g. for flicker mitigation compared to SVCs at low voltage conditions in such a configuration. Additional devices that are recommended should be established.

MSCDN

Mechanically switched capacitors with damping network can provide reactive power and hence, support voltages. In addition, due to the damping network, operation losses are minimized. Another feature of such a device could be to tune the capacitor/shunt reactor configuration in such a device to a specific harmonic to be treated at the point of connection of the MSCDN (e.g. 3rd, 5th, or 7th harmonic).

Shunt Reactor

Shunt reactors are needed

1. When voltage levels in the respective RES area are reaching the upper limits, and
2. To compensate cable capacitances, e.g. by connecting offshore wind farms.

Usually the investment is high and depending on the grid situations, usage of a shunt reactor might not reach a lot of hours during the year. The grid voltage profile in usually weak grids needs to be supported, but not artificially lowered. I.e. installing shunt reactors for projects with RES seems to be unnecessary since RES usually are far off weak networks. Therefore shunt reactors will not be of use a lot of the time during the period of a year and also because voltage drops can be reached by other means like generation capping.

SVC

Static Var Compensators are thyristor switched or controlled capacitance and/or reactance, i.e. functions as a shunt-connected, controlled reactive admittance (Hingorani).

Classical have the good characteristic to also provide short term overload in mostly both reactive power directions (capacitive and inductive).

STATCOM

Static Synchronous Compensators are modern SVCs, which, with a converter-based var generator, functions as a shunt-connected synchronous voltage source (Hingorani).

This basic operational difference (voltage source versus reactive admittance) accounts for the STATCOM’s overall superior functional characteristics, better performance, and greater application flexibility than those attainable with the SVC.

An example of connecting a STATCOM to a wind farm in a simulation is given in AIM/CCPE 2012[5].

Synchronous Condensers

As mentioned before, synchronous condensers are seeing a revival and this has several reasons.

Synchronous condensers can provide reactive power in both directions in a reasonable time, i.e. not as fast as STATCOMs, but fast enough for most grid-related control power challenges.

Synchronous condensers can have significant overload and do provide additional short circuit power which is essential for weak power systems for fault clearing and stabilization.

In addition, modern synchronous condensers are fairly robust built and might have less operational expenses (losses) than STATCOMs (this depends on several factors).

Series compensation (e.g. TCSC)

Series compensations to be used for RES integration will be rare and is only used in wide spread networks with long power lines (There is no series compensation is installed in the German high voltage grid). The need to compensate reactive power arises at the point of generation and might only be relevant to certain special installations far from the point of common coupling.

Phase shifting transformers

Phase shifting transformers are used to control power flow in meshed networks and therefore only of limited use in terms of reactive power. For integrating RES in the grid, phase shifting transformers will only be relevant if the need to control the power flow in the grid arises by the RES integrations. For example, if certain power lines will be loaded too high while generation is high, power flow could be adjusted without curbing generation. However, phase shifting transformers only make sense when network upgrading is not planned (i.e. transmission infrastructure) for RES integration or, where congested areas in interconnected grids (for example cross border transmission lines) shall be avoided.

Phase shifting transformers are a consequence of missing infrastructure, but help only very limited in reactive power management for RES integration i.e. providing or absorbing reactive power of RES.

4.5.2 Strategic & cost efficient deployment of energy storage technology

Learnings from German RE market suggest that if the penetration of the power system with RES is very high (e.g. 80% or more) storage technologies of any kind become technically and foremost economically feasible. The efficiency of such systems, investment and operation expenses, and the full load hours must be taken into consideration. Existing plans for energy storage and already implemented measures, if such exist, must be revised and adapted accordingly to not create sunk cost.

In this scenario where RES penetration in the grid is more than 60% and large number of small scale distributed systems are connected in the grid, strategic and cost efficient methodology for deployment of energy storage technologies need to be adopted.

The implementation of energy storage can be done by evaluation conducted in the following steps:

[5] [AIM/CCPE 2012] STATCOM for Improvement of Active and Reactive Power at the Wind Based Renewable Energy Sources, S. Narisimha Rao, J. Sunil Kumar, G. Muni Reddy - Mobile Communication and Power Engineering - Second International Joint Conference, AIM/CCPE 2012, Bangalore, India, April 27-28, 2012, Revised Selected Papers (2013)

- Selection of energy storage technology
- Upstream residual load analysis
- Developing potential RE generation scenario
- Fluctuation analysis of RES generation scenarios
- Modelling of influence factors on storage demand
- Modelling and evaluation for the mid-term : In the mid-term, i.e. a scenario with a certain percentage of RES penetration in the network, the extension of the network as well as the development of generation units will be taken into account

Based on the above steps, it is imperative to decide on the sizing and placing aspects of the energy storage technologies. Below are certain aspects that help the determination.

- Transmission system planning (in terms of construction or future demand)
- Transmission system extension
- Transmission network and generation strategies (in terms of interconnections, power plant strategies)
- Renewable sources available (wind onshore/offshore, solar)
- Renewable energy generation mix (percentage of the concerned RES)
- Renewable generation share of power system (percentage of RES in a state/regional/interconnected market)
- Market regulations (e.g. CO_2 certificates, priority for RES generation, secondary and minute reserve, system services)
- Potential of storage technologies to participate in the market
- Market incentives (to build RES and/or storage facilities)
- Market flexibilities (changes of percentages of certain generation within a power system based on scenarios, i.e. the viability of a storage project over the projected life-time)
- Cost for storage technologies
- Efficiency of storage technologies
- Flexibilities of storage technologies
- Location for storage technologies (e.g. pumped hydro, next to gas pipeline network (to transport gas instead of electricity), close to RES)
- Profitability of the storage facility

For RES rich states, the power system needs to be evaluated.

- Is the transmission/distribution system eligible to transmit the calculated/installed RES in-feed?
- Where does the transmission capacity not meet the expected demand?
- What is the strategy to cope with it?
- Is there enough flexible generation to cope with forecasted RES in-feed?
- Are there potential installed storage/flexible RES generation facilities, e.g. pumped hydro, biomass, and CHP plants?
- Does the state power supply system provide enough reserve capacity?

Imprint

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Published by

Deutsche Gesellschaft für

Internationale Zusammenarbeit (GIZ) GmbH

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This project/programme' assisted by the German Government, is being carried out by Ernst and Young LLP on behalf of the Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ) GmbH.

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