Enabling the future grid: an analysis of operational and flexibility issues in the Indian power grid

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Abstract

The Indian power system is expected to integrate large amounts of renewable energy resources in the near future. However, the characteristics of renewable energy resources differ greatly from conventional energy resources. Integrating large quantities of renewable resources therefore warrants enhancements and modifications to current practices as the current Indian power system lacks sufficient operational services that protect the grid against contingencies. This dissertation aims to analyze the operational and flexibility needs of the Indian grid to accommodate diverse and new energy sources.

The first part of the dissertation analyzes the operational issues in the current power system. The Indian power system is restricted to a few services to support grid operation, which is primarily balancing demand and supply, in real-time. The different enhancements to the current balancing mechanism have varying impacts on the demand and supply balance, and this is reflected in the grid frequency. Therefore, the grid frequency under different balancing mechanism is modeled to understand the impacts. The results indicate that improving primary frequency response from generators along with a revision of the current prices is the most effective strategy.

Next, given the current conditions that exist in the grid, a feasible load balancing mechanism is analyzed to understand the related benefits and costs. While the first part of the dissertation analyzes grid level impacts of different balancing mechanisms, the second part explores a service that should be implemented by the electric system operator to support grid balancing. The results indicate that the proposed mechanism is beneficial in reducing real-time emergency events by 55% at a power purchase cost increase of 3.5%.

In addition to services, the system operators and regulators must ensure that there are sufficient flexible resources that can support the variability and uncertainty in the grid. The third part of the dissertation analyzes the impact of different generation scenarios on power system operation and reliability. The section highlights the need for flexible resources to counter the uncertainty and variability of renewable energy resources. In essence, the dissertation aims to encourage a rigorous approach to planning and policy making with regards to renewable energy integration.

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Chapter 1

Introduction

The Indian power system is experiencing tremendous growth in electricity demand, and there is enormous pressure on supply side investments and operations to catch up with this growth. The installed power generation capacity in India as of April 2014 is close to 250 GW [11], the fourth largest in the world. Yet, the country is expected to experience an energy shortage of 5.1% and peak shortage of 2% [13] at current energy prices. Particularly the southern regions are expected to face more acute shortages. In the future, the problem will become even more pronounced as India's power demand is likely to grow substantially. High levels of growth will be difficult to manage without addressing some of the major challenges that exist in the system today.

Due to concerns of fossil fuel shortages, the Indian government plans to invest heavily in renewable energy resources (REs) and nuclear energy. Currently, renewable energy resources, unlike conventional generation resources, are not readily dispatchable. The uncertainty and variability in renewable energy output places increased stress on power system operation. In smaller quantities, the increased stress can be adequately handled by existing support services. But, large-scale penetration of renewables require either significant modifications to current system operation or new electricity market services. Further, power systems require flexible generation to counteract the variability and uncertainty in RE production. India has always suffered from lack of flexible generation resources. And, the government's interest in nuclear energy further exacerbates this issue. Nuclear generation is generally used for base load, and rarely used for balancing services.

In recent times, there have been several discussions among regulators and system operators regarding electricity market services and operation. There seems to be a wide range of differing opinions among stakeholders. While some state and regional entities are content with the current state of market operations, the Central Electricity Regulatory Commission (CERC) and a few other states have called for the introduction of services that ensure reliability and quality of power supply [17]. It is a common notion that introduction of additional reliability services would increase the cost to consumers, and are hence viewed with caution. Historically, India has favored lower cost over power quality and reliability. The impact on various stakeholders due to poor reliability are often ignored. Therefore, progress in improving system operation has been painstakingly slow. The introduction of large quantities of renewable energy would test these convictions.

From a generation planning perspective, India faces several additional issues. India has always been an energy deficient nation. Coal is the main energy source for electricity production. But, coal production has fell short of targets in recent years, and imports are required to satisfy local demand [24]. Similarly, natural gas is imported to meet local demand due to production shortages. Given this environment, the Indian government has chosen to invest in renewable energy resources. The output characteristics of renewable energy resource are very different from conventional generators. Therefore, analysis of potential impacts of large-scale renewable resource investment is imperative for policy making.

In order to facilitate high penetration of renewables, the planners must ensure that there are enough flexible resources in addition to base load power plants. Further, the operators must ensure that there are sufficient mechanisms and services to utilize the flexibility resources efficiently and economically. The goal of this dissertation is to analyze the operational and flexibility needs of the system, and propose recommendations for future policy decisions. It also aims to encourage incentives for flexibility related resources and future technologies.

This dissertation aims to address some of the current and future issues that would be experienced in the Indian grid as it transitions to a more diverse set of generation resources. First, the main concerns of the current operational mechanism is analyzed. Next, the costs and system impacts of introducing alternative operational mechanisms is estimated. Finally, the impacts of large-scale penetration of renewable generation on power system operation and reliability with respect to different generation scenarios is modeled.

The structure of the thesis is as follows:

In Chapter 2, an overview of the different electricity markets in operation is presented. The chapter presents a comparison of the different market structures along with important services that are relevant to the thesis. Further, background information on the Indian electricity market structure and relevant schemes is discussed.

In Chapter 3, the main concerns in the operational mechanism of the Indian grid is explored. Grid operation is mainly concerned with maintaining demand and supply balance. Due to economic and technical constraints, the Indian power system is restricted to only a few services for demand-supply balancing that are often inadequate. Balancing services and related mechanisms have remained largely unchanged for nearly a decade and improvements are needed to accommodate demand growth and new energy resources. However, the impacts of the different balancing mechanism improvements are not fully understood. The goal of this section is to compare different proposed improvements to the balancing mechanism and analyze the impacts on system frequency and stakeholders (generators). For this comparison, a power system model that uses software agents to simulate market entities is used. The results indicate that adequate primary frequency control is necessary for improving the frequency profile, and providing compensation would help in ensuring adequate provision of the service. This, coupled with a revision of the current pricing mechanism, would be effective in improving the system frequency. These actions also constitute a good transitional platform for more advanced services and market designs in the Indian grid.

In Chapter 4, a feasible mechanism that can support grid balancing and operation is developed and estimated. While Chapter 3 analyzes grid level impacts of different balancing mechanisms, this chapter explores a service that should be implemented by the electric system operator to support grid balancing. The Central Electricity Regulatory Commission (CERC) in India has proposed the introduction of ancillary services. Among the services, frequency support ancillary service is expected to have a significant impact on the grid operation. This ancillary service would ensure that the demand and supply are balanced at all times. However, the service proposed by CERC is designed as a contingency service and not a balancing service. In this section, an alternative load balancing mechanism that serves the balancing needs of the Indian grid is proposed and analyzed. The main contribution of this study is the estimation of the costs and impacts of this mechanism using simulations based on data from the Indian state of Karnataka thereby fostering the design of effective ancillary services policies in India. The results show that the mechanism would reduce the number of real-time emergency events, which are used to avoid grid collapse, by around 55% at an energy purchase cost increase of 3.5%. This work illustrates the availability of cost-effective mechanisms for load balancing in the Indian power system, and also highlights the need for alignment of system stakeholder incentives.

In Chapter 5, the impacts of renewable energy resource penetration on the Indian grid operation is studied. As the penetration of renewable energy resources is expected to grow, the operation and planning of the grid needs to be upgraded to accommodate the changing generation mix. Though all systems have similar issues with regards to integration of large scale renewable energy resources, India faces unique challenges as it aims to utilize renewable energy resources to cover energy deficits.

In this section, a production simulation model is used to analyze a year of operation of the grid with different levels of renewable and flexible generation resources. Further, Monte Carlo simulations are used to study a typical day of electric grid operation in different seasons. The results indicate that renewable energy resources cannot satisfy demand in all hours by itself. There is a need for supplemental generation resource that act as a backup and is readily available during time of need. Results from the production cost simulation of the year 2013 show that the percentage of hours of unserved energy would be greater than 5% even with high penetration of renewable resources. At least moderate levels of flexible generation is required to avoid load curtailments in the system.

Chapter 2

Background

2.1 Overview of different electricity markets

2.1.1 US electricity markets

Restructured electricity markets in the US (MISO, PJM, CAISO, etc.) [45][74], follow a multi-settlement system consisting of a forward market and a spot market. The forward market (day-ahead or hour-ahead) determines generator and demand schedules for a future period. The spot market or load balancing that is operated close to real-time is used to handle the differences between the actual load and forward schedule. Both these services are essential for successful operation of the power grid. These markets are used to procure energy and ancillary services [56] simultaneously. Further, all these markets employ nodal pricing that accounts for transmission limitations that might create different prices at the nodes of supply and drawal during congestion. To hedge against price differences, financial transmission rights (FTRs) [61] [87] [90] are used. These mechanism have been employed by the markets for years, and undergo improvements consistently. Among the several improvements, most markets are currently in the process of improving the real-time markets to accommodate high penetrations of renewable energy [1][70][107].

2.1.2 Electricity markets in EU

In contrast to the pool-based electricity markets [1] in the US where the independent system operators (ISOs) handle trading and the transmission network operation, most countries in the EU trade electricity through voluntary energy exchanges [2] [6][108]. In this setup, the transmission system operator (TSO) of each country is responsible for scheduling and dispatch of generators within its boundaries. Each TSO has developed its own system and procedures for managing the grid. The TSO serves the demand using generators procured through bilateral contracts and day-ahead market [3]. In addition, the TSO also procures reserves (standby generation capacity (MW)) through balancing markets for managing real-time mismatch in demand and supply (load-following). In essence, there exists a day-ahead market for energy and balancing market for reserves. Further, many systems use intra-day markets to adjust their energy schedules close to real-time. An important aspect of the market mechanism is the disconnect between balancing markets and energy markets (day-ahead and intra-day). Though the products supplied in both the markets are interlinked, the balancing market and day-ahead market are operated independently a day before actual operation. This results in inefficient utilization of generators participating in both markets. For instance, partly loaded generators are generally used for real-time balancing. But, the quantity to be bid in the different markets is decided by the generator. This is less efficient than the system operator optimizing the quantity to be used for both services [58][100].

The EU has set a target of raising the share of energy production from renewables to 20% by 2020 [31]. As a result, TSOs in the EU are in the process of redesigning their electricity markets. In particular, the balancing mechanism and congestion management are being enhanced to facilitate renewable energy penetration [25][26][28][69]. This effort is being facilitated by the European Network of Transmission System Operators for Electricity (ENTSO-E), an association formed to promote co-operation and trading between EU countries. ENTSO-E currently specifies guidelines [27] for good practice in balancing mechanism and frequency management. In the future, it plans to align the trading and balancing mechanism of different countries to enable cross-border resource sharing [32], which is essential for facilitating high levels of renewable energy penetration. There are several exciting changes and enhancements proposed to create a pan-european electricity market.

[1] Power pool is an electricity market design in which all market participants are required to schedule their transaction through the system operator. The system operator manages the transmission network and scheduling as well as electricity trading. Market participants with bilateral contracts enter as price takers. For more information, please refer to [100].

[2] Energy exchanges [100] are another form of electricity market in which participation is optional. It is a platform for only trading energy; the scheduling and dispatch is managed by the transmission system operator (TSO).

[3] The term 'spot market' is often used to refer to day-ahead as there is no real-time market. To avoid confusion, use of the term spot markets is avoided.

Table 2.1: Comparison of different electricity markets

	Restructured Markets in the US	**Restructured Markets in EU**	**Indian Electricity Market**
Market type	Pool	Exchange	Exchange
Market Operator	ISO	National or multi-national energy exchanges	Multi-state (regional) energy exchanges
Grid Operator	ISO	Single or multiple TSOs for each country	SLDC (TSO) for each state
Energy Trading Markets	Day-ahead, intra-day, real-time	Day-ahead, intra-day	Day-ahead, intra-day
Congestion Management	Nodal Pricing	TSOs redispatch generators during congestion	TSOs redispatch generators during congestion
Cross-border transaction	ISO	Multinational energy exchanges and TSO-TSO contracts	RLDC/NLDC

2.2 Ancillary services for frequency support

As discussed earlier, maintaining balance between demand and supply, and thereby system frequency, is very important for the health and reliability of the power system. Ancillary services that are used by system operators for maintaining demand-supply balance is discussed in this section. The ancillary service design and compensation depends on the system operator's policies and reliability requirements (Table 2.2). The different ancillary services used for maintaining demand-supply balance are as follows [110][29][71]:

2.2.1 Primary Frequency Control (PFC)

Primary frequency control, which is compulsory in every system, provides immediate support to any changes in system frequency. Primary frequency control is provided through the generator governor control which uses a simple feedback loop. The generator governor monitors system frequency and reacts within seconds of any imbalance in the system. All capable generators in the system are expected to contribute to this service. Since a large number of generators are involved, contribution from a single generator would be low. For this reason, some of the system operators do not provide compensation for this service. On the other hand, some system operators, especially systems with generous frequency deviation limits, tend to compensate primary frequency control to ensure quality and sustained provision of the service [85]. Due to the nature and significance of the service, PFC is either mandated or procured through bilateral contracts and tendering processes [86].

2.2.2 Secondary Frequency Control (SFC)

Once the primary frequency control (PFC) acts to stabilize the grid, the system operator should take measures to relieve the generators that provide PFC. Secondary frequency control (SFC) is a fast responding service that acts to replace generators providing PFC. However, unlike PFC, secondary frequency control is not a compulsory service. It is used only in systems which require tight control of frequency. Island systems and systems with a single transmission system operator do not employ tight frequency control. Hence, SFC is not used in such systems.

SFC is established primarily through automatic generation control (AGC), also known as load frequency control (LFC), that uses advanced control systems to co-ordinate the output of generators. The dispatch of generators under AGC is performed through a dedicated frequency and interchange monitoring system that acts in parallel to the system operator dispatch system. Further, the reliability and performance requirement of AGC systems is subjected to inter-system co-ordination policies. For example, the North American Electric Reliability Corporation (NERC) employs measures known as control performance standards (CPS) to evaluate the compliance and performance of each entity in the North American interconnections [72]. Further, SFC has been an area of significant interest in recent times due to the increase in renewable energy penetration. Recent developments have led to higher compensation for faster and better performing SFC providers [77].

Procurement of SFC is dependent on the system structure. System operators in North America procure SFC in the spot market that uses a uniform clearing price to compensate all participants. Countries in Europe follow a range of procurement mechanisms that include spot markets, bilateral contracts and long-term tenders. Of particular interest is the Great Britain Grid. Since the system uses mostly HVDC lines for interconnecting with neighbors, the grid tends to operate as a single TSO without the need for tight frequency control. Therefore, the system does not employ SFC. The Indian system, despite being a multi-TSO system, does not use SFC. However, there are proposals to introduce SFC in the near future.

2.2.3 Short-term Dispatch (Balancing Mechanism)

Primary and secondary frequency control place greater emphasis on reliability and speed of response. After these services act to stabilize the grid, the system operator should use the most economic and efficient resource to replace the expensive generators providing PFC and SFC. This process, which is known as load balancing or load following, is usually performed every 5-15 minutes and is used to identify and re-dispatch the most economic generators. In systems that do not use SFC, the balancing mechanism plays a major role in maintaining the balance between demand and supply.

The balancing mechanism is the main focus of this thesis. The different balancing mechanisms are discussed in subsequent sections. The categorization of balancing mechanisms vary from one study to another and between system operators. While some consider generator dispatch as a separate service, many systems consider them as part of tertiary frequency control. In order to avoid confusion, generator dispatch is considered as a separate service in this paper.

2.2.4 Tertiary Frequency Control (TFC)

Backup resources (reserves) that are used during contingencies are classified as tertiary frequency control in this thesis. The need for contingency reserves is tied to the inherent uncertainty in demand and grid entities. The system is designed to possess a certain amount of capacity margin over the peak demand in the system. The system operators use the capacity margins in the form of reserves to handle unexpected contingencies in the grid.

The procurement mechanisms for tertiary frequency control include spot markets, long-term tenders and bilateral contracts. Tertiary frequency control can be classified into spinning and non-spinning reserves. Spinning reserves are provided by generators that are already online and producing energy. These reserves are expected to provide their output within a time period that is typically longer than that of balancing reserve. Non-spinning reserves are provided by generators that are not online but are able to come online and produce output within a stipulated time period that is typically much longer. Due to the longer timescale of deployment, the compensation for the availability of these services is typically much lower than for other reserves. Nevertheless, these services play a vital role in maintaining the reliability of the grid and are an integral part of grid operations.

2.2.5 Comparison of frequency control in different countries

The implementation of frequency control mechanisms depend on country specific policies and regulations. An overview of the frequency control mechanisms used in different countries [85][86][84] is shown in Table 2.1. Power systems can be divided into two categories based on frequency control mechanisms: (a) systems with tight frequency control, and (b) systems with wider limits for frequency deviations.

Table 2.2: Frequency support ancillary services in different markets [85][86][84]

	US Eastern and Western Interconn.	**Continental Europe Interconn.**	**Great Britain Grid**	**Indian Grid**
Primary Frequency Control				
Procurement	Mandatory Provision	Bilateral Contracts/ Tendering Process	Tendering	Mandatory Provision
Compensation	None	Pay as bid	Pay as bid	None
Secondary Frequency Control (AGC)				
Procurement	Spot Markets	Spot Markets/ Bilateral/ Tendering	None	None
Compensation	Uniform Clearing Price	Uniform Clearing Price/Pay as bid	N/A	N/A
Balancing Mechanism (Short-term Dispatch)				
Mechanism	Real-time Market	Real-time Market/ Balancing Reserve*	Balancing Reserve	Inter-state: UI mechanism#; Intra-state: ad hoc
Compensation	Uniform Clearing Price	Uniform Clearing Price/Pay as bid	Pay as bid	Inter-state: Frequency based pricing; Intra-state: Pay as bid
Tertiary Frequency Control (Contingency)				
Procurement	Spot Markets	Spot Markets/ Bilateral/ Tendering	Bilateral/ Tendering	None
Compensation	Uniform Clearing Price	Uniform Clearing Price/ Pay as bid	Pay as bid	N/A

*Balancing Reserves refer to generation capacity that is procured ahead of real-time operation and used to balance the difference between demand and supply.
Unscheduled Mechanism is a frequency based real-time pricing mechanism that is used in India.The details will be discussed in the following section.

Large interconnections with several transmission system operators (TSOs) prefer to employ a tight control of frequency. Since change in frequency affects power flows, tight frequency control is necessary for managing and accounting for transactions between the constituent TSOs. Large interconnections such as the US Eastern Interconnection, the US Western Interconnection, and the Continental Europe Interconnection (formerly UCTE) employ such tight frequency control [71][27]. These systems employ all of the forms of frequency control discussed in the previous section.

Single TSO systems that have few interconnections with neighbors can opt for wider frequency limits. In such systems, the frequency limits are determined based on operational characteristics of the generators and system security. A good example of such a system is the grid of Great Britain. The British grid is not synchronized with the Continental Europe frequency, and it is operated by a single TSO known as National Grid plc. The system does not use secondary frequency control, but instead relies on short term dispatch of generators [85]. The system frequency tends to stay in a wider band around the target value. Though the grid code allows the frequency to be maintained within 49.5-50.2 Hz [40], the system operator maintains the frequency within 49.9 - 50.1 Hz for most hours (Figure 3.1).

2.3 Indian Electricity Market

India is comprised of 29[4] states, and it follows a federal form of government with Central and State governments. The state-government owned utility companies are responsible for serving the electricity needs of the customers in their state (i.e., distribution). The transactions between state utilities and generators are handled by the state load dispatch center (SLDC), assuming the role of a transmission system operator (TSO). Besides state-owned generators and independent power producers, the SLDCs have access to central generation stations (CGSs) that are owned by the central government. Each TSO is allocated a percentage share from the output of CGSs based on the state demand. The SLDCs procure power from the CGSs through the regional load dispatch center (RLDC), which also handles transactions between SLDCs.

The structure of the Indian electricity market is illustrated in Figure 2.1. The operations and scheduling are carried out in multiple stages [79]: (a) state-level operations which are handled by the State Load Dispatch Center (SLDC), (b) regional grid operations which are handled by the Regional Load Dispatch Center (RLDC), and (c) any exchanges within RLDCs are handled by the National Load Dispatch Center (NLDC).

[4]Most of the states have unbundled their power system (albeit under government control), leading to dozens of power utilities, with many states having multiple distribution companies (DISCOMS) each with distinct geographic coverage.

2.3.1 State-level operations

The SLDC uses electrical energy from state-owned generators, Independent Power Producers (IPPs) and Central Generating Stations (CGS) to serve the electricity demand requested by state load serving entities. While the SLDC can schedule the in-state generators and IPPs directly, it has to participate in the region wide operation scheduling to procure power from CGSs. In addition, the SLDC can trade electrical energy in the energy exchanges. The SLDCs in India do not have an established procedure for conducting the first-stage of operations. States mostly follow heuristic approaches for intra-state operations.

Energy Exchanges are independent private entities that facilitate voluntary electricity trading in India. These exchanges provide a platform for IPPs and SLDCs to buy or sell power that is not under contract. Based on the proposals of CERC, the energy exchanges are expected to play a prominent role in the implementation of ancillary services.

2.3.2 Regional Grid Operation

The current regional level grid operation is conducted in two time scales: day-ahead and real-time. CGSs and IPPs (through energy exchanges) are required to submit their power production, while SLDCs submit their power demand. The energy exchanges are also required to submit the cleared transactions between states. The schedules are submitted in 15-min time blocks ahead of time, typically, a day ahead. Once scheduled, these entities are expected to adhere to the day-ahead schedules.

In real-time, any deviation from the day-ahead schedule will be subjected to a penalty or compensation where the level of penalty or compensation is dependent on the frequency in the system. Generators are penalized if its output is less than the day-ahead schedule, and the generators are compensated if its output is more than the day-ahead schedule. Similarly, load serving entities would be compensated or penalized based on its deviation. This mechanism is known as the Unscheduled Interchange (UI) mechanism [4], and is the core of the Availability Based Tariff (ABT) mechanism.

The Indian electricity market architecture is very similar to that of European countries (Table 2.1). The states, each with their own TSOs, are similar in structure to countries in Europe. The difference lies in that the states also have shared resources (CGSs), which are transacted through the RLDCs and NLDCs. The most crippling deficiency in the Indian system is the lack of a proper

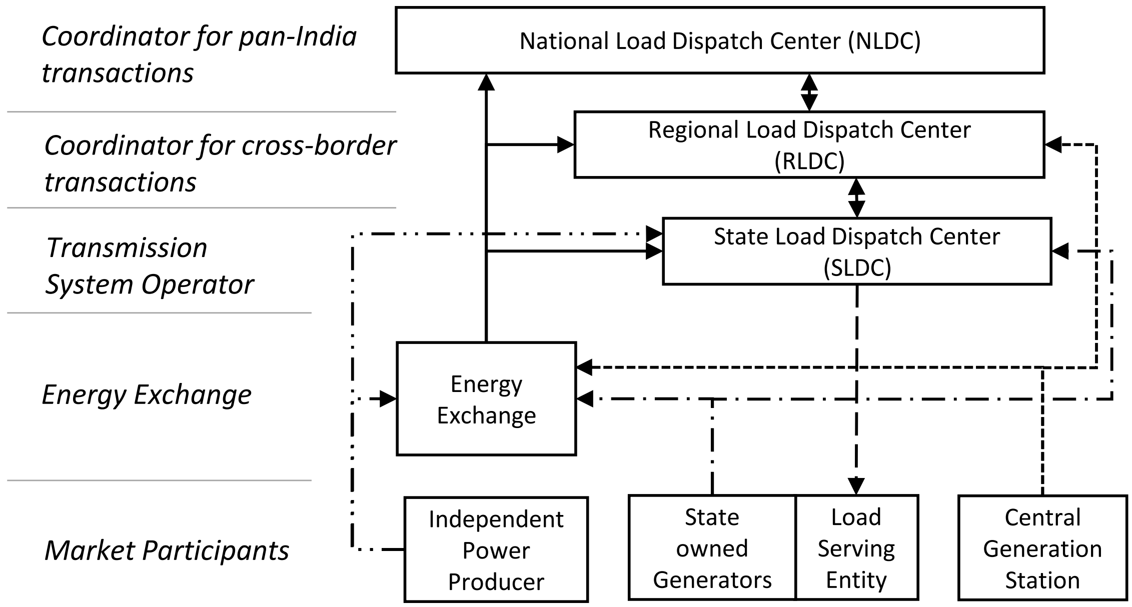

Figure 2.1: Structure of the Indian power system.The SLDC manages the in-state demand, state-owned generators and IPPs. It further participates in the upper stage arbitrated by the RLDC to procure energy from other states and CGS (Central Generating Stations). The upper stage is operated based on the ABT mechanism. In parallel to RLDC operation, power exchanges facilitate voluntary trade between the different entities. Finally, all transactions between regions (RLDCs) and power exchanges are facilitated by the NLDC.

balancing mechanism. This leads to the over usage of the mandatory primary frequency response. Since these services are not compensated, most generators do not provide these services. Further, there are no ancillary services in the system. The Central Electricity Regulatory Commission (CERC) of India, which regulates inter-state transactions, has put forward a proposal for ancillary services [17]. Among which, frequency support ancillary service (FSAS) is directly linked to load balancing and frequency control. These issues are further discussed in the subsequent sections.

2.3.3 Indian Grid Services

In contrast to the general structures discussed in the previous section, the Indian system follows a distinct set of services and methods. First, primary frequency control, known locally as free governor mode of operation (FGMO), is mandated by the regulating authorities but not compensated. Second, though the Indian grid is a large interconnection composed of several transmission system operators (TSOs), secondary frequency control is not employed in India. The frequency limits (49.7 to 50.2 Hz [18]) are quite generous compared to other large interconnections. Third, short term dispatch performed by TSOs is entirely dependent on the unscheduled interchange (UI) mechanism. The efficiency of the mechanism is crucial for the functioning of the grid. Finally, due to generation shortages in the grid, contingency reserves are not employed in the system.

The UI mechanism

Unscheduled interchange (UI), a frequency based deviation pricing mechanism, was developed with an intention to maintain the power system frequency within a prescribed frequency band, currently at 49.7 Hz to 50.05 Hz [18][4][95]. The mechanism aims to penalize/compensate deviations from the day-ahead schedule based on system frequency. Entities whose actions contribute to the demand-supply mismatch are penalized, and conversely entities that reduce demand-supply mismatch are compensated. The penalty/compensation increases at lower frequencies.

The UI price is expected to reflect the average cost of generators thereby encouraging generators to contribute to grid stability (see Figure 2.2). Base-load (cheaper) generators are expected to balance the grid when the frequency deviation is not significant. The need for expensive peaking power plants occur only when the frequency falls below the prescribed limit (below 49.7 Hz). Therefore, the maximum compensation is provided at the lower limit of the allowed frequency band. If not enough generation is available, the TSOs have to reduce their schedule deviations or face hefty fines. Consequently, the TSOs resort to feeder level load curtailment, dubbed ”load-shedding” in local parlance, when there is no additional generation available to avoid penalties.

The UI mechanism does not provide compensation or penalize the market participants when the frequency is at or above 50.05 Hz. The price at 50 Hz is based on the median value of the average energy charge of coal/lignite based generation stations, and the price below 49.7 Hz is based on the energy charges of expensive LNG (liquefied natural gas) based generation stations. The price at any frequency in between 49.7 Hz and 50 Hz is obtained through linear interpolation between the two points. Similarly, the price between 50 Hz to 50.05 Hz is also obtained using linear interpolation between the two points.

It is important to note that the UI mechanism is applied mainly in the regional level (inter-state). At this level, the state load serving entities procure energy from the central generation stations (CGS) that are shared between different states. The central generation stations are used to serve around 25-30% of the in-state demand. The rest of the demand is served using in-state and private

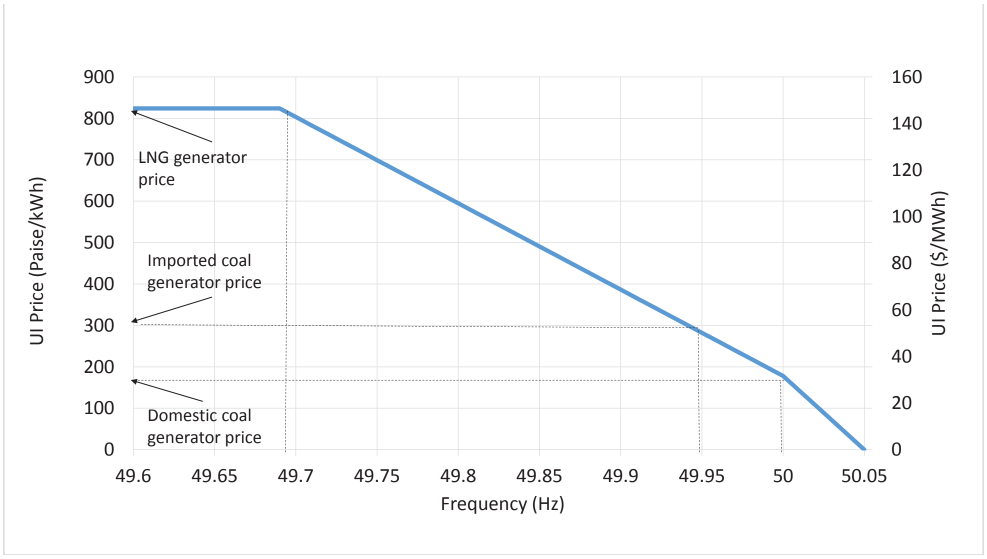

Figure 2.2: Frequency based pricing, aka Unscheduled Interchange (UI) mechanism, in the Indian System. The compensation/penalty for unscheduled production or withdrawal is based on the average system frequency in 15 minute time blocks. The price at 49.95 Hz is intended to promote coal generators to increase their production. And, the price below 49.7 HZ denotes the cost of producing power from the most expensive generators. Hence, when the frequency falls below 49.7 Hz, all generators can be expected to provide their maximum output [18]. An exchange rate of 1 USD = 60 Rs. is used.

generators. Due to multiple layers in procuring generation, there are additional mechanisms within the state that operate in parallel to the UI mechanism. However, these in-state mechanisms are similar to and heavily dependent on the UI mechanism. Therefore, an improvement to the UI mechanism will have a significant impact in all layers of grid operation.

Deviation Settlement Mechanism

The Deviation Settlement Mechanism (DSM) was introduced in 2014 as an additional penalty structure to supplement the UI mechanism [18]. The mechanism was introduced to discourage deviations from day-ahead schedule. Under DSM, grid entities face a higher penalty for greater deviation in schedule. As per the mechanism, the entities are penalized or compensated based on the UI mechanism for deviations within 12% or 150 MW (whichever is lower). Any deviations greater than this threshold is penalized at a rate higher than the UI. The additional penalty is based on the UI mechanism and adheres to the following structure:

- When system frequency is greater than 49.7 Hz:

- 12% of schedule is lesser than 150 MW:
  - Deviations that are greater than 12% and lesser than 15% of the day-ahead schedule face a penalty of 20% of UI in addition to the UI charges.
  - Similarly, deviations that are greater than 15% and lesser than 20% of the schedule face a penalty of 40% of UI in addition to the UI charges.
  - And, deviations that are greater than 20% of the schedule face a penalty of 100% of UI in addition to the UI charges.
- 12% of schedule is greater than 150 MW:
  - Deviations that are greater than 150 MW and lesser than 200 MW from the schedule face a penalty of 20% of UI in addition to the UI charges.
  - Similarly, deviations that are greater than 200 MW and lesser than 250 MW from the schedule face a penalty of 40% of UI in addition to the UI charges.
  - And, deviations that are greater than 250 MW from the schedule face a penalty of 100% of UI in addition to the UI charges.

- When system frequency is less than 49.7 Hz, the penalty is 100% of the UI. Therefore, the deviating entity is subjected to twice the maximum UI when deviating at frequencies below 49.7 Hz.

Chapter 3

Analysis of the current balancing mechanism

3.1 Introduction

A fundamental responsibility of power system operators is to balance demand and supply at all times. System frequency provides an indication of the mismatch between real-time demand and scheduled generation. Power system operators use a range of services to balance this mismatch. In general, the services used to balance demand and supply are categorized as primary, secondary or tertiary frequency control [85][71]. While primary frequency control and some form of tertiary frequency control are used in all systems, secondary frequency control is used in systems that need a tight control of frequency. The need for tight frequency control is dictated by the power system structure and reliability requirements.

Historically, Indian power system regulators have allowed generous frequency deviations eliminating the need for secondary frequency control. Ostensibly, this was a coping strategy for a system with supply shortfalls. Hence, the demand-supply balance is heavily dependent on the following two services: primary frequency control and the unscheduled interchange (UI) mechanism. All qualified generators are mandated to provide primary frequency control, but exclusive compensation is not provided for the service. The UI mechanism, which is considered as a form of tertiary frequency control, is the most important balancing mechanism in India [4][95]. Though applied mainly at the regional level (inter-state), state entities use the same mechanism or have mechanisms that are heavily dependent on the UI mechanism. The UI mechanism is a frequency based pricing mechanism that aims to minimize deviations in schedule and promote demand-supply balance. The real-time system price is based on the system frequency that is observable everywhere in the system. It eliminates the need for expensive communication systems, which appealed to the economically conscious Indian regulators. But the workings of the mechanism remained largely unchanged over the past decade. The changing energy landscape, including greater renewable energy, and advancement in technology raise doubts on the utility of the mechanism in the future grid.

Though the UI mechanism has brought some form of discipline to the grid, the frequency still fluctuates within a wide band. The Central Electricity Regulatory Commission (CERC) [1] has proposed to introduce ancillary services to the Indian grid [17]. Among the different services, frequency support ancillary services are aimed at improving system frequency. Proposals for the introduction of such services are the most needed and anticipated initiatives in the grid. But, the details of these services and timeline of implementation are yet to be discussed. Looking at the issue from a practical standpoint, it would be very difficult to establish all the advanced services present in other advanced systems in a short period of time. Therefore, it is also important to focus on the incremental changes proposed for the system.

The goal of this research is to analyze the current and proposed incremental changes to the balancing mechanism in India and study the impact on power system frequency and stakeholders (generators). Among the proposed incremental changes, there are two that seem to be more realistic as well as effective. First is the more common and popular method of revising the system price in the UI mechanism. This has been practiced in the past and is expected to continue in the future. Second is the less common and potentially contentious option of introducing compensation for primary frequency control. This has been practiced in several advanced markets that have less tight frequency limits than the US such as the UK National Grid [86]. The option has also been discussed in the Indian context earlier [79]. In this paper, these options are analyzed using a market model simulation composed of software agents. Such agent based simulation is a widely used approach to analyze power systems and electricity markets [109][104]. The main contributions of this paper therefore are: (a) a qualitative analysis of the balancing mechanism issues in the Indian grid, and (b) an estimation of the impacts of different balancing mechanisms on the Indian grid.

The chapter is organized as follows: rest of this section provides background information on issues in the current grid operation. Section 3.2 provides information on the research methods and the options being studied. Section 3.3 describes the simulation model, parameters and assumptions. Section 3.4 presents a discussion on the results and the related policy implications. Finally,

[1] CERC has regulatory jurisdiction over all power crossing state borders, which is approximately 30% of the electricity in India.

conclusions are discussed in section 3.5.

3.1.1 Issues with the current Indian Grid operation

As discussed in the previous sections, Indian grid operations are mainly based on primary frequency control and the UI mechanism. As a result, the frequency in the system is not tightly controlled resulting in the frequency deviating from the target value for a significant amount of time. There are widely differing opinions about the importance of tightly controlling the frequency. Many regulators and market players support the UI mechanism for its simplicity, and believe that maintaining the frequency in a wide band (49.7 Hz - 50.05 Hz) is acceptable. But, this stance overlooks several underlying issues in the UI mechanism and the grid [57]:

- **Unaccounted power flows between control areas:** The Indian grid is a large interconnection composed of several transmission system operators. The area under each TSO can be considered as a control area. Each state in India manages the in-state transmission system within its boundaries. As discussed in section 2.2.5, interconnections with multiple TSOs have a strong incentive to exercise tight control of frequency to manage and account for power flows between neighboring control areas. A floating frequency causes unpredictable and undesired power flows between the control areas [71][29]. Hence, a poorly managed control area that causes frequency deviations affects all other entities negatively.
- **Complexities with estimating power flows:** Ahead of time generator scheduling involves estimating power flows in the system to ensure system security. It helps in ensuring that no component of the grid is overloaded. All established methods for power flow estimation assume that system frequency is held constant at the target value [110]. A system with a wide frequency band makes any estimation of power flows extremely complex if not impossible. This reduces the effectiveness of the grid management and scheduling process leaving the grid at a higher risk for overloads and outages.
- **Lack of payment for primary frequency control:** Primary frequency control is the most important component of grid frequency control. Though it is mandated in all systems, compensation for this service is only provided in some systems (Table 2.1). Systems that employ secondary frequency control (AGC) relieve primary frequency control immediately resulting in minimal usage. In this case, compensation for primary frequency control is not necessary. In contrast, systems that do not employ secondary frequency should compensate primary frequency control because it is used substantially for prolonged amounts of time. The Indian

system mandates all capable generator to provide primary frequency control, and the service is substantially used due to lack of secondary frequency control. Yet, there is no exclusive compensation for primary frequency control. The lack of exclusive compensation and the wide frequency band have caused unfair usage of primary frequency control. This unfair treatment has resulted in many generators abstaining from providing primary frequency control resulting in worsening of grid frequency [80].

- **High frequency deviations with UI pricing:** The UI pricing mechanism is an atypical mechanism where the system price depends on the system frequency. The expensive generators are deployed only when the frequency is low. Therefore, during peak periods, when all the base load generators are fully utilized, the deviation in frequency would inadvertently be high. Frequency deviations is the norm rather than an anomaly with UI pricing. A comparison of the system frequency in the Indian southern regional grid and the Great Britain grid, which is the most comparable to the Indian grid in terms of frequency limits, is shown in Figure 3.1. It is observed that the system frequency stays below 49.9 Hz (-0.1 Hz below target) for 30-35% of the time in the Indian Grid, and only less than 3% of the time in the United Kingdom grid. The official report on the July 2012 Indian blackout stated that one of the main reasons for the blackout was due to overloading of a transmission line [16]. The report also stated that better grid management practices including better frequency management could have avoided the blackout.

- **Effects of frequency deviations on system security and reliability:** Operating close to frequency limits increases the probability of a large event causing grid failures and blackouts. Though most steam and combustion turbines are able to operate satisfactorily at the specified frequency limits, frequent grid failures and low frequency events increase the rapid aging of the mechanical components [48]. The impact of operating at various frequencies is shown in Figure 3.2. Further, prolonged operation at off-nominal frequencies reduces the efficiency and life of consumer's electrical equipment.

3.2 Research Methods

The main goal of this paper is to analyze the impact of current and proposed balancing mechanisms on the Indian power grid and its stakeholders. An electricity market model is developed to examine the impacts of the different balancing mechanisms. Most issues discussed in the previous section are directly or indirectly related to the power system frequency. Therefore, the analysis focuses on the impact of balancing mechanisms on system frequency and primary frequency control usage.

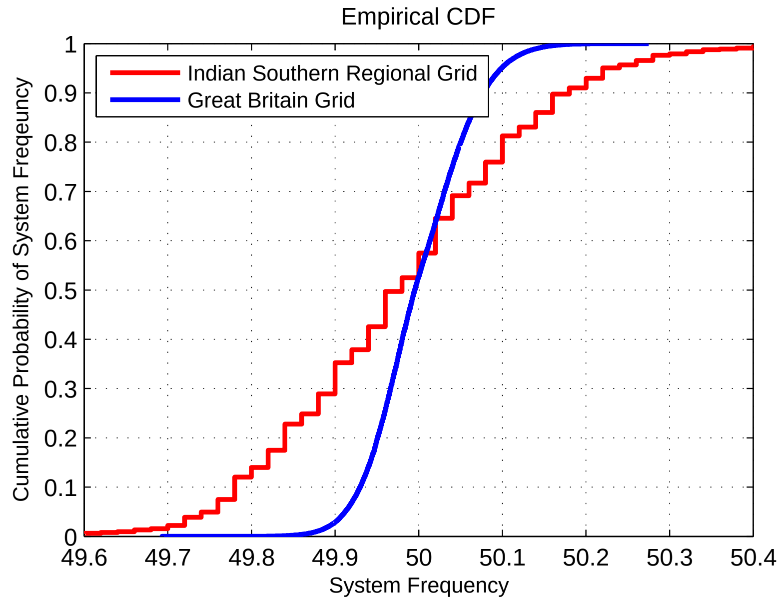

Figure 3.1: The cumulative probability of the frequency observed in the Indian southern grid and British grid is shown. The southern grid comprises of the four southern states of India. The southern grid was synchronized with the rest of the country in 2014. The southern Indian grid frequency data [99] comprises 15 minute average frequency observed in the period starting from April 1, 2013 to April 6, 2014. And, the British grid data contain 5 minute instantaneous frequency observed during the same period [41]. Though average frequency smoothens extreme values, it still presents a reasonable comparison of the instantaneous frequency in this context.

3.2.1 Multi-agent Systems for electricity market modeling

Electricity markets are extremely complex systems with numerous interacting components. Various electricity market models have been used to study different market issues [104]. The market models can be classified into three main categories: optimization models, market equilibrium models and simulation models. Optimization and market equilibrium models are mathematical programming and economics based models that are used to study problems that can be represented in a formal mathematical framework. But, electricity markets contain several complex systems that are very difficult to express mathematically. In such situations, simulation models are very useful in representing the system. A special class of simulation models known as multi-agent models are widely used for electricity market analysis [109][66][67]. A simulation model using agents can be used to represent the different entities of a complex system elegantly. The simple interactions among entities that lead to emerging complex behaviors can be modeled effectively. It represents a natural framework for representing electricity markets and constituent entities.

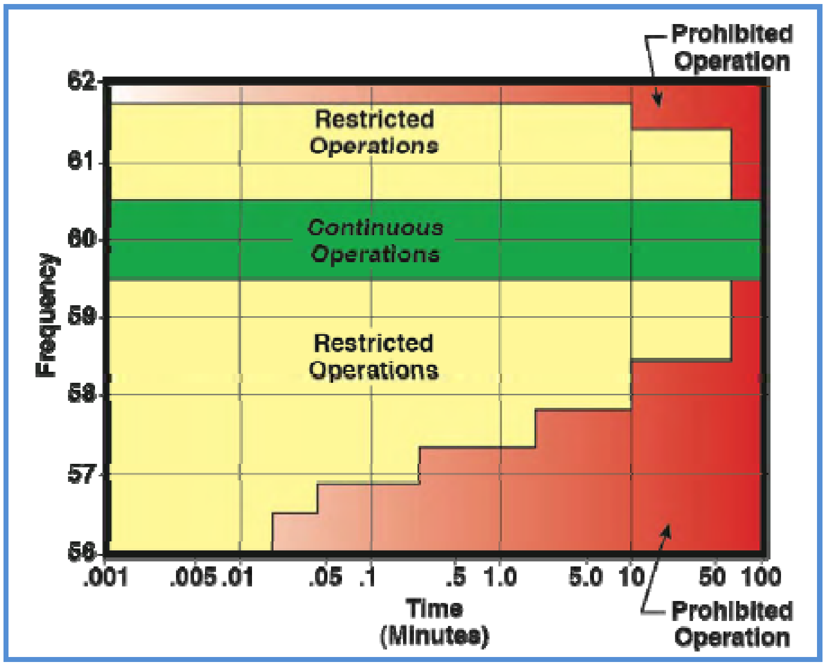

Figure 3.2: The operational frequency of a steam turbine is shown. The steam turbine was designed to operate in the range on +/- 0.5 Hz of the nominal frequency. Operating the generators in frequencies beyond that range has a negative impact on the life of the generator. The figure was obtained EPRI handbook on power system dynamics [29].

The notion of agents has been widely used in several fields of study; as a result, there exists several definitions. In the simplest form, as defined by Wooldridge [111], an agent could be any software or hardware entity that resides in an environment and has the ability to act or react autonomously to stimuli or other agents in the environment. But, this definition of agents is deemed very broad. Therefore, Wooldridge extended the concept of agents to intelligent agents. An intelligent agent exhibits three characteristics: reactivity, pro-activity, and social ability. Reactivity refers to an action that is taken in response to a stimuli or change in the environment as opposed to a timed repetitive action. Pro-activity refers to goal-directed behavior. Each agent must have a set of goals that it tries to achieve through its interaction with the environment. Social ability refers to the ability to interact with other agents in the environment to co-operate or negotiate in order to achieve individual or mutual goals. These rules and descriptions are applicable to a wide range of study areas. Though the niceties of the rules pertain to specific fields more than others, the underlying principles apply to all agent based models including electricity market models.

Multi-Agent Systems (MAS) and Agent-based Modeling (ABM) are two popular forms of modeling methodologies that are based on agents. Though both of these methods appear to have considerable overlap, there exist subtle differences between the two. While MAS has been used in the field of engineering and technology to analyze and address practical issues, ABM has been used in social sciences to model complex emergent phenomena that arise from simple interactions in natural systems. A refinement of ABM known as agent-based computational economics (ACE) deals exclusively with economics related to interacting complex systems. There are several electricity market modeling studies and platforms in both domains [66][109][59][22]. In general, market models with an emphasis on engineering studies are termed as MAS, and models with an emphasis on economics and participant behavior (learning) are termed as agent-based computational economics. Though the focus of this thesis is on both the technical and economic aspects of balancing services, special emphasis is placed on system frequency. Hence, the modeling method is deemed to be closer to Multi-Agent Systems.

3.2.2 Balancing Mechanism Scenarios

The current structure and design of the Indian grid is the result of several constraints and complications. India faces several distinct techno-economic and socio-political challenges that are not present in advanced power markets. Some of the pressing challenges faced by India include energy shortages, capacity shortages, lack of adequate monitoring and control, and lack of control area rules. Therefore, the Indian system is not able to simply adopt all the services and products present in advanced systems. Though the ultimate goal should be to address all the stated issues, it is not practical to solve all of them at once. The progress has to happen in incremental steps with priority for most pressing issues.

Over the years, there has been a few modifications and enhancements to the existing UI mechanism. For example, the prices in the UI mechanism have been revised in recent times. And, the lower frequency limit of the UI mechanism has been improved from 49.5 Hz to 49.7 Hz. Due to the familiarity with the UI mechanism, most future improvements discussed in India hinge on frequency based pricing. Given these circumstances, some of the expected future scenarios that will be examined are as follows:

- **Base Case:** The base case represents a scenario in which no changes are made to the current UI mechanism. In this scenario, the generators are not compensated for providing primary frequency control; hence, the performance of primary frequency control, though mandated, is insufficient.
- **Tightening frequency limits:** The UI mechanism remains largely unchanged and the sole

institutionalized mechanism. The UI prices have been revised in the past and the trend is expected to continue. The most probable scenario of revising the prices to further shrink the frequency limits is represented in this scenario. In the revised pricing mechanism, the maximum charges, which was previously applied when the frequency is below 49.7 Hz, is now applied when the frequency is below 49.9 Hz, and the charges for any frequency in between 49.9 Hz and 50 Hz is obtained through linear interpolation similar to the current mechanism 2.3.3. The charges when the frequency is above 50 Hz remains unchanged.

- **Payment for primary frequency control:** Primary frequency control plays a major role in the Indian system due to the large acceptable frequency band. But, lack of compensation has eroded the provision of this service. Many generators do not comply with the Central Electricity Regulatory Commission (CERC) mandated provision requirement [80]. This is in turn has worsened the frequency profile of the system. As practiced in some advanced markets, payment for primary frequency control would ensure sufficient response and ultimately improve the frequency profile. This option has been proposed by academics [79] and industry players, and it is explored in this scenario.

- **Hybrid Scenario:** The combination of tightening frequency limits through adjusted UI pricing and payment for primary frequency control is a potent option which will be explored in this scenario.

- **Ideal Scenario:** The biggest flaw in frequency based pricing is the failure to represent system conditions. The marginal generator, which is the most economical generator that is able to respond as per technical requirements, depends on the demand and system conditions. Ideally, the prices should encourage this generator to respond. Therefore, the real-time price should be based on the cost of the marginal generator. This concept is used in real-time markets in restructured electricity markets [110][62]. This scenario is used in the study as a benchmark to compare the performance of the other scenarios with the ideal situation.

3.3 Modeling and Simulation

As previously mentioned, multi-agent models are powerful tools to simulate and study electricity markets. In these models, agents are used to model the actions and states of different market players. Any simulation using agent-based models is meant to answer specific questions, and all models have simplifications and assumptions that should be justifiable for the considered application.

There are multiple already existing platforms for modeling electricity markets [59][22]. The impact of different frequency control mechanisms on the power system frequency that was simulated for WECC (Western Electricity Coordinating Council) in a previous study [88] is particularly relevant to this research. However, the operation and market structure of the Indian market is unique and requires ad-hoc modeling. Therefore, a multi-agent model that represents the Indian system is developed for this research. The details of the multi-agent model, data used in the simulation, and the related assumptions are discussed in this section.

3.3.1 Multi-agent model components

The System Operator, Generators and Consumers are the main agents that interact with each other in the power system environment. The system operator and generators are modeled as active intelligent agents. Consumer actions are split into demand (power consumption) and demand response. While demand is modeled as an inactive component that is part of the environment, demand response is modeled as a generation source via a generator agent. All these agents interact with each other through the power system environment. The power system environment comprises of all the components that contribute to the operation of the grid. The components include the electrical network, communication equipment, and monitoring devices. The outline of the model is shown in Figure 3.3. The details of the model are discussed in the following sections.

System Operator Agent

The system operator is responsible for managing the real-time operation of the grid. In real-time markets, the system operator sets the real-time price to promote demand-supply balance in the system. In the UI mechanism practiced in India, the system operator plays a less active role in setting the system price. The system price is based on the UI mechanism that uses a fixed frequency dependent price as discussed in Section 2.3.3. Therefore, the generators monitor the system frequency and react accordingly without much intervention from the system operator.

In the ideal scenario, the system operator sets the real-time market price based on system conditions. The real-time market price should reflect the marginal cost of the most economical resource that is available and meets technical requirements. Such a price would promote sufficient power output to satisfy the demand. However, the most economical resource that is available is dependent on system conditions. An optimization program equivalent to an economic dispatch is used to identify the most economical resource that can satisfy the requirement while adhering to system constraints and conditions. The economic dispatch program [110] used by the system operator agent is given

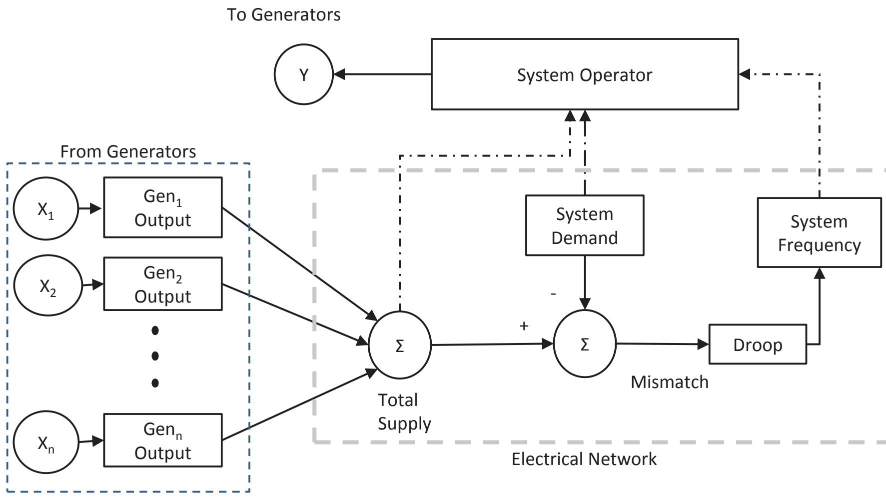

Figure 3.3: Schematic of the simulation model: The system operator, generators and consumers are the main agents in the system that interact in the electrical network environment. The aggregate droop characteristic of generators in the electrical system is an important factor that is used to convert the demand-supply mismatch to system frequency.

as follows:

$$\min_{z} \quad z = \sum_{i \in I} C_i * p_{i,t}^{RT} \tag{3.3.1.1}$$

subject to:

$$\sum_{i,t} p_{i,t}^{RT} = D_t \tag{3.3.1.2}$$

$$\underline{P}_{i,t} * x_{i,t} \leq p_{i,t}^{RT} \leq \overline{P}_{i,t} * x_{i,t}, \quad \forall i \in I \tag{3.3.1.3}$$

$$-(10 * RR_i^{min}) \leq p_{i,t}^{RT} - p_{i,t-1}^{RT} \leq (10 * RR_i^{min}), \quad \forall i \in I \tag{3.3.1.4}$$

where:

D_t = real-time demand observed in the system

$\overline{P_i}$ and $\underline{P_i}$ = upper and lower permitted limit of unit i at period t

$p_{i,t}^{RT}$ = power output of unit i in real-time.

$x_{i,t}$ = availability status of unit i.

RR_i^{min} = maximum rate at which the generator can change its output unit i (MW/minute).

The objective of the optimization program is to minimize the real-time energy costs. This is represented by the objection function (3.3.1.1) which is the sum of the products of incidental energy cost C_i and real-time power output $p_{i,t}^{RT}$ of all generators in the system at any time interval t. The energy cost C_i is based on the generator's average costs that is determined by the regulating authority. Constraint (3.3.1.2) ensures that the real-time demand is balanced by the real-time outputs of all generators in the system. Constraint (3.3.1.3) ensures that the outputs of the generator remain within the permitted limits. The ramp-rate RR_i^{min}restrictions of the generators are represented using constraint (3.3.1.4). The constraint ensures that the generators are capable of responding to real-time power requirements within 10 minutes. The real-time system marginal price is obtained from the Lagrange Multiplier λ associated with the demand balance constraint (3.3.1.2). The system marginal price will be set as the real-time system price by the system operator. The economic dispatch is a flexible mechanism that can include any constraint or requirement of the system.

The system operator agent satisfies the requirements of intelligent agents as discussed in Section 3.2.1. The system operator fulfils the reactivity condition of intelligent agents as it is modeled to respond to the system conditions and frequency by setting the system price. The price setting behavior of the system operator is in line with its goal of maintaining demand-supply balance. This goal-oriented behavior exhibits pro-activity. And, the social ability is fulfilled by the system operator's interactions with the environment and other agents through monitoring system conditions, obtaining generator states, and communicating the system price.

Generator Agent

The generator agent is the most important component in the analysis. The schematic of the generator agent is shown in Figure 3.4. The description of each of the components is as follows:

a Inputs: The generators perceive the system conditions through the system frequency and communication from the system operator. The communication from the system operator, which includes the system price and information on maximum allowable deviation, is used to instruct or negotiate with the generators.

b System State: The current state and characteristics of the generator is represented in this component. The current state reflects the generator set-point [2] and cost of the generator output. And, the characteristics reflect the operational limits of the generator.

[2] Set-point refers to the MW output of the generator at nominal frequency.

c Output Logic: The generator's response to the input (stimulus) is defined through the output logic. The system price, which acts as the stimulus to the generators, is compared to the marginal cost of the generator. Based on the difference, the generators respond by increasing or decreasing their output. In addition, business commitments, which include limits on deviations and must-run requirements imposed on the generators, are considered in the output decision. Given the business commitments are satisfied, a response from the generator will be activated if either of the following conditions are met:

   i Condition 1: If the system price is greater than the marginal cost by a small tolerance limit ϵ [3] and the frequency is less than the target value, the generator increases power output by increasing the set-point as long as it is within the operational limits.

   ii Condition 2: If the system price is equal to the generator marginal cost (difference is within $-\epsilon$ and $+\epsilon$) and frequency is less than the target value, the generator increases power output within its limit.

   iii Condition 3: If the system price is equal to the generator marginal cost (difference is within $-\epsilon$ and $+\epsilon$) and frequency is greater than the target value, the generator decreases power output within its limit.

   iv Condition 4: If the system price is lesser than the marginal cost by at least a tolerance limit ϵ and the frequency is greater than the target value, the generator decreases its power output as long as it is within the operational limits.

The generator agent satisfies the requirements of an intelligent agent as well. The generator agent satisfies the reactivity condition as it is modeled to respond to the system price by altering its output. The generators act in a way to avoid economic losses and adhere to business commitments. This goal oriented behavior satisfies the pro-activity requirement. Finally, the social ability is exhibited in the generator's ability to communicate and co-operate with the system operator.

Electricity Consumer

Unlike the system operator and generators, consumer demand is modeled as a passive component that is part of the power system environment. But, demand-response as a generation resource is modeled as a generator agent.

[3] In floating point calculations, computers use a large number of significant figures. A tolerance limit helps in simplifying logical operations and comparisons.

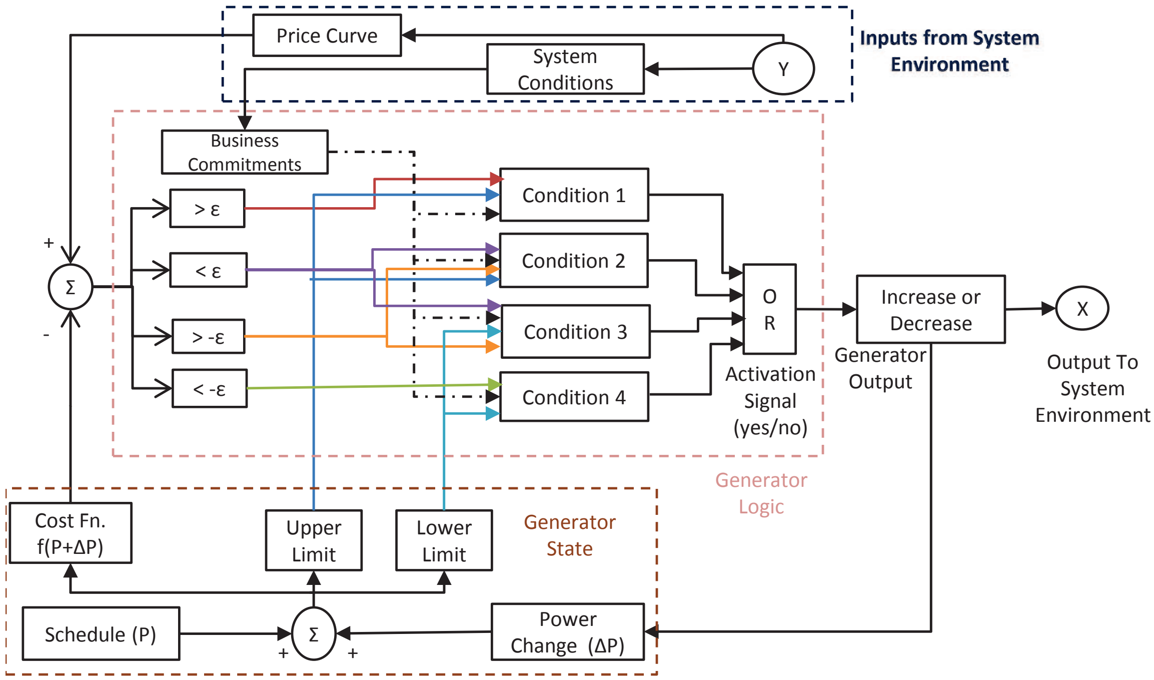

Figure 3.4: Generator Decision Model

Power System Environment

The power system environment covers all the components of the model. The consumer demand must be satisfied by the generators in the system. The system operator sets the system price to ensure that the demand and supply balance is maintained at target frequency. When there is a mismatch between the demand and the total scheduled generation (generator set-points), the frequency deviates and the generators respond by changing their output. The point at which the frequency settles depends on the droop of the generators. The resulting steady-state frequency deviation is estimated using the simplified equation [110]:

$$\Delta f_{ss} = \frac{-P_{D-S}}{(1/R_{eq}) + D}$$

where:

$$P_{D-S} = P_D - \sum_{i \in I} P_{G_i} \tag{3.3.1.5}$$

$$R_{eq} = \frac{1}{1/R_1 + 1/R_2 \ldots 1/R_n}$$

P_{D-S} is the demand-supply mismatch in MW, P_D is the total system demand in MW, P_{G_i} is the generator output set-point (manual dispatch setting) of generator i in MW, $R_1, R_2 \dots R_n$ are the droops of generators in Hz/MW of the generators, D is the sensitivity of load to a change in frequency expressed in MW/Hz, and I is the set of all generators in the system. The sensitivity is usually assumed to be 1% change in load for a 1% change in frequency.

3.3.2 Data

The main data required for the simulation are the electricity demand and generator characteristics. Since the main focus of the study is on real-time operation, generator availability and schedules are also required. The day-ahead generator schedule helps in placing the emphasis on real-time operation by eliminating the need for a scheduling procedure. Therefore, data from a real system are more useful than a test system.

A subset of the southern regional grid of India which uses the UI mechanism is used in the model. The main participants at the regional level are the central generation stations and state load dispatch centers. In addition to representing the in-state load serving entities, state load dispatch centers procure generation through in-state generators and co-ordinate demand response events during an emergency (maximum UI price). Further, at the time of this study, the southern regional grid was not synchronized with the central grid and relied primarily on HVDC lines for interconnection. Therefore, the system is treated as stand-alone and the energy transactions from neighboring regions are considered as firm transactions and not modeled explicitly.

Details of the data used in the simulation are as follows:

a Generator Characteristics: The list of generators used in the system along with the operational characteristics and cost is given in Table 3.1 [12][99]. The total installed capacity of the shared generators is about 11 GW.

b Generator Schedule: The day-ahead generator schedules and availability for each 15-minute time block was obtained from the Southern Regional Load Dispatch Center (Table 3.2)[99][98]. The schedules provide the expected generator outputs (set-points) for each time period. In real-time, the generator operator manually changes the output based on system price.

c State Demand: The real-time demand was also obtained from SRLDC [99][98]. The data contain real-time electricity demand of each state in 15-min intervals. Linear interpolation is used to smoothen the transition from one time interval to the next. The real-time power input from the neighboring regions is subtracted from the real-time state demand to obtain the net demand that was served by the generators within the considered region. This net demand is used in the simulation model.

Table 3.1: Generator data used in the simulations. Central generation stations that are subjected to the UI mechanism are used in the simulations. All central generation stations are thermal generation stations. The model assumes that demand-response and in-state generators will be used only during emergency situations when the system price is at the maximum.

Generation Stations	**No. of units**	**Unit Cap. (MW)**	**Total Cap. (MW)**	**Cost (Paise/ kWh)**	**Fuel**	**Ramp-rate (MW/min)**
Ramagundam T.P.S (NTPC) - 1	4	500	2000	215	Coal	10
Ramagundam T.P.S (NTPC) - 2	3	200	600	215	Coal	4
Neyveli - I (NLC)	3	210	630	242	Lignite	4
Neyveli - II (NLC)	4	210	840	242	Lignite	4
Neyveli TPS-I (Exp) (NLC)	2	210	420	310	Lignite	4
Talcher Stage - II (NTPC)	4	500	2000	241	Coal	10
Simhadri (NTPC)	2	500	1000	269	Coal	10
M.A.P.S Kalpakam (NPC)	2	220	440	196	Nuclear	11
Kaiga A.P.S (NPC)	4	220	880	304	Nuclear	11
Kudandulam Nuclear (NPC)	1	1000	1000	265	Nuclear	50
Vallur T.P.S (NTPC)	2	500	1000	483	Coal	10
In-state Gen./Demand-Resp.			5000	823	-	100

Table 3.2: Descriptive statistics of generator availability. The simulation uses day-ahead generator schedules and availability in 15-min intervals. The table presents an overview of the range of values observed for the availability of different generators in the system.

			Percentile				
	Mean	**Median**	**5th**	**25th**	**75th**	**95th**	**Maximum**
RSTPS-1	1704	1830	1200	1460	1980	2000	2000
RSTPS-2	441	480	330	400	484	486	486
NLC 1 - 1	453	502	315	355	525	544	572
NLC 1 - 2	619	695	344	524	714	733	755
NLC 2	341	386	189	320	388	392	394
Talcher	1573	1600	920	1325	1920	1950	1960
Simhadri	782	850	366	658	980	980	980
MAPS	203	140	130	135	290	304	390
KAIGA IPP	340	350	185	320	390	395	400
Kudandulam	72	0	0	0	0	610	680
Vallur	412	400	0	270	600	840	950

3.3.3 Simulation parameters and assumptions

The objectives of the study and the assumptions used in the model are discussed in this section:

- The goal of the simulation is to estimate the effect of different balancing mechanisms on system frequency. The simulated frequency is not meant to reflect the actual frequency in the system.

- Only a subset of the Indian grid is modeled to understand the impacts of the different balancing mechanisms.

- The generators are assumed to monitor the frequency constantly and respond based on system prices.

- The simulations were run for the period starting April 1, 2013 to April 6, 2014.

- The prices are set by the system operator every 5 minutes. In the case of UI mechanism, the generators monitor the frequency and deduce the prices every 5 minutes and react based on the output logic.

- A maximum ramp-rate of 2-5% of capacity per minute is used in the system. This is similar to values used in similar studies [5].

- Maximum output of the generators is equal to the installed capacity. The minimum output is taken to be 20% of the installed capacity.

- The generators are contracted to produce a certain quantity of energy in real-time. Though the generator can increase revenue by reducing their output when the frequency is favorable, it is assumed that the generators would not do this in order to avoid violating business commitments.

- In order to avoid market manipulation, the generators are not allowed to deviate by more than 12% or 150 MW, whichever is lower, from the schedule to be eligible for compensation [18]. This rule is included as part of the business commitments and represents the deviation settlement mechanism.

- The droop settings of the generators affect the primary frequency response. Due to lack of compensation, the generators in India fail to provide primary frequency control at the mandated droop of 5%. Therefore, the gene rators are assumed to provide primary frequency control at a droop of 10% when compensation is not provided. This is applicable to the first two scenarios considered in the study. In the scenarios in which compensation is provided, the generators provide response at 5% droop.

- Many nuclear generators are used for load-following in European countries [73]. In the model, the nuclear power plants are assumed to be capable of load-following.

- In-state generator and demand-response are very important components of the system. Model ing all in-state generators would be a daunting endeavor as the in-state generators are not subjected to the UI mechanism and the output is under the discretion of the state dispatch centers who in turn are constrained by several additional factors. Due to the complexity in including in-state generators, it is assumed that the state dispatch centers aim to adhere to their demand schedules in real-time and not produce above their schedules for financial gains. The state generators and/or demand-response is used only in adverse situations to prevent grid collapse. Therefore, these resources are expected to be used only when the system price is at the highest value of 823 Paise/kWh.

3.4 Results

The simulation model described in the previous section is run for a year. From the simulations, the frequency, real-time charges, and generator usage are used to study the impacts of the different balancing mechanisms on system operation. Each of these metrics provides interesting insights into the effectiveness of the different balancing mechanisms.

3.4.1 Frequency Simulation

The simulated frequency for the different scenarios is shown in Figure 3.5. It is observed that increasing UI prices alone (Scenario 2) does not improve the system frequency considerably. Particularly, there is no improvement in the extent of frequency drop. This is because primary frequency control, the most important service for frequency management, is not being provided adequately [4]. But, increased UI prices cause a better response from the generators in moderate deviation scenarios. Considering 49.9 Hz to be the acceptable lower frequency limit, the current UI mechanism violates the limit 40% of the time whereas increasing the UI price alone reduces the violation to around 30% of the time.

On the other hand, offering compensation for primary frequency control would ensure that the generators provide the service at 5% droop leading to an improvement in system frequency as seen in Scenario 3. The response can be further improved by combining payment for primary frequency control with increased UI (Scenario 4). This causes improvement in both primary frequency response and balancing response from generators. The frequency falls below 49.9Hz for only 20% of

[4]The aggregate effect of some generators not responding is assumed to result in an overall 10% droop.

the time when compensation is provided for primary frequency control and the UI price is adjusted. In spite of the improvements, given that all of these scenarios rely on the UI mechanism, there are still significant deviations in frequency. A tight frequency profile as demonstrated by Scenario 5 can only be achieved by considering system conditions in real-time pricing by using a procedure like economic dispatch. The economic dispatch procedure helps in procuring the least cost resource while adhering to technical limitations.

Over-frequency in the grid occurs primarily due to technical constraints or market constraints. Technical constraints occur commonly in systems with large amounts of renewable energy resources. Over frequency occurs, for example, when there is over production from renewable resources and conventional generators are not able to reduce the output below minimum operational limits or shut-down the generator. Since the system considered in the model does not possess large amounts of renewable generation, there are no technical constraints that cause over-frequency. Market constraints occur due to inactivity from generators or insufficient incentive to respond. Though there are often sufficient incentives to reduce output during over frequency, generators face external constraints that might cause lack of response. The external constraints might include commercial commitments and minimum capacity factor targets. The model does not capture the range of external market constraints resulting in only minor over frequency events in the results.

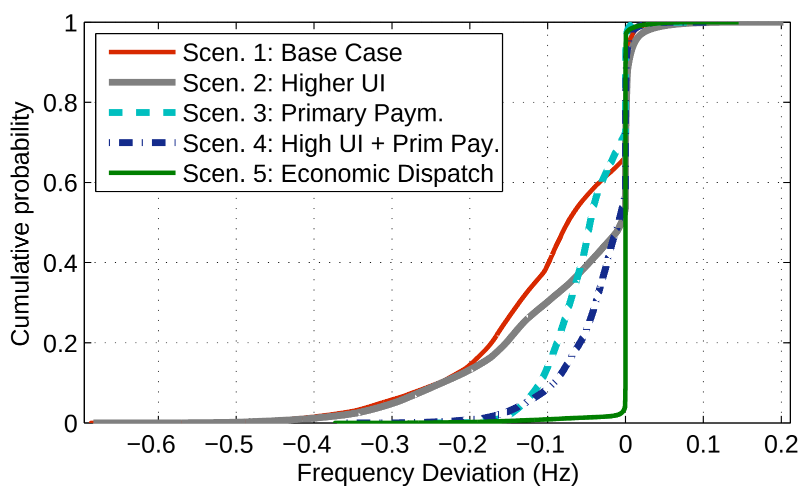

Figure 3.5: Cumulative probability of the simulated frequency

3.4.2 Real-time energy charges and product contributions

The main goal of the system operator is to maintain the demand-supply balance. The operator penalizes the entities that deviate from their schedule, and compensates the entities that balance the deviations. In the simulated model, the generators are dispatched to balance the deviations from the demand schedule. Figure 3.6 shows the total real-time payments received by generators for balancing demand deviations for different scenarios in the simulated year. The compensation provided is not the same in all scenarios. The black bars indicate total compensation (generator dispatch and primary frequency control payments) received by the generators. Whereas, the gray bars are for scenarios in which primary frequency control payments are external to the simulation. Figure 3.7 shows the contribution from primary frequency control and generator dispatch.

In scenario 1, primary frequency control is not compensated explicitly. The compensation received by the generators through the UI mechanism is expected to cover both primary frequency response and manual balancing response (generator dispatch). The total compensation available to generators is lower than in most other scenarios. But, the most important issue is the high usage of primary frequency control at almost 50%. Unlike generator dispatch, primary frequency response is not voluntary. High usage of an involuntary resource without proper compensation results in lack of response from the resource.

In Scenario 2, the system frequency deviates to a great extent from the target value due to lack of primary frequency control similar to the previous scenario. Due to higher UI prices, the situation causes high prices in the system prompting the generators to provide manual balancing response. Consequently, the demand faces high charges and the generators receive higher payments. The mechanism increases the charges faced by demand without sufficient improvement in system frequency.

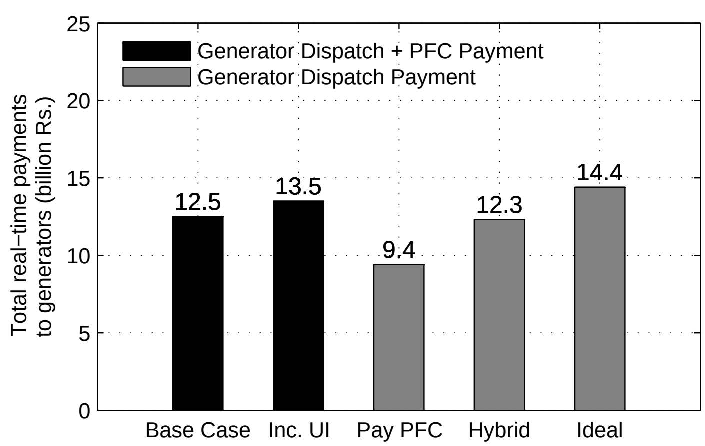

Figure 3.6: Annual generator payments due to real-time deviations in demand.

In scenario 3, primary frequency response is paid explicitly. This causes a better frequency profile in the system. Consequently, the system prices are low, and the generator compensation for

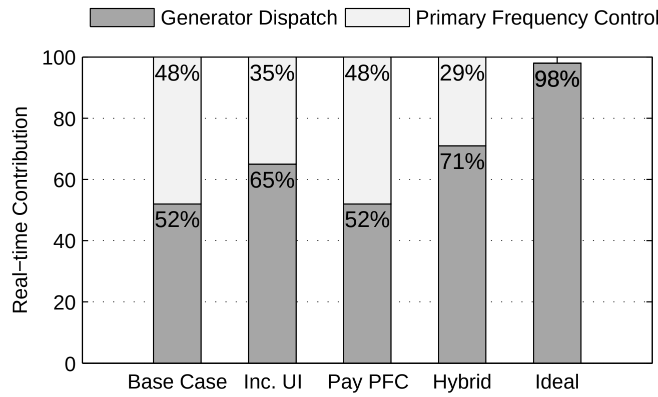

Figure 3.7: Contribution of balancing mechanism and primary frequency control to demand deviations

generator dispatch is also low. However, the cost efficiency of this mechanism depends entirely on the ability to procure primary frequency response economically.

The hybrid scenario (scenario 4) performs better than the previous scenarios in terms of generator compensation and lower utilization of primary frequency control. But, as with scenario 3, sufficient compensation must be provided for primary frequency control. The only scenario that does not depend significantly on primary frequency control is the economic dispatch (ideal) scenario. As generators respond to prices immediately, primary frequency provision is immediately relieved and the frequency is maintained close to nominal values.

3.4.3 Discussion and policy implications

Each of the scenarios analyzed in this work has its advantages and disadvantages:

- The current UI mechanism has been widely acknowledged for its simplicity and easy implementation. But, the mechanism causes the system frequency to be in a wider frequency band. And, as discussed earlier, there are significant issues related to maintaining generous frequency limits in a multi-TSO interconnection. Further, lack of sufficient compensation for primary frequency response leads to further deterioration of the frequency profile.
- Increasing UI prices with the goal of tightening frequency limits has been practiced in the past, and the practice is expected to continue in the future. Among the different upgrades, increasing UI prices would require the least amount of effort and procedural changes. Increased prices would force the power market participants to better adhere to their schedules.

This places pressure on load serving entities to ensure that the demand fluctuations are managed adequately. The power market risk is transferred to the load serving entities. While the well-managed entities would be able to handle the pressure, the resource constrained entities will be at a great disadvantage. The struggling load serving entities will have to resort to load curtailment due to lack of options and economic constraints. As the grid is heavily interconnected, the under performance of a few entities would negatively impact all others. Therefore, improvements to the surface level UI mechanism without addressing the roots of the issues would be less effective.

- Primary frequency control plays the most important role in managing the system frequency. Though mandated in every system the compensation depends on the frequency limits of the system. For instance, restructured pool-based electricity markets in the US do not provide compensation for primary frequency control due to the extremely tight frequency control. Primary frequency control in these markets are sparingly used and immediately relieved. On the other hand, systems that have more relaxed frequency limits such as Great Britain provide compensation to primary frequency control to ensure sufficient provision. Given the generous frequency limits in India, a compensation mechanism for primary frequency control would be very beneficial for the Indian grid. It would ensure sufficient provision of the much needed primary frequency response. But, creating a payment mechanism is a non-trivial task that needs deliberate effort.

- Compensation for primary frequency control would improve the frequency profile of the system. Improved frequency would cause lower prices in the system resulting in sluggish manual balancing response from generators. In order to improve the response, the UI prices should be increased as well. Combining both payment for primary frequency response and increased UI prices would be a potent option. Similar to the previous scenario, sufficient compensation for primary frequency response would play an important role in the viability of this option.

- The UI mechanism has helped in bringing some form of discipline in to the Indian grid. Its simplicity and low cost nature has appeased the cost conscious regulators. In the near future, an enhanced UI mechanism with or without an additional service would be the most probable choice. But the disadvantages of the mechanism outweigh the advantages in a future with abundant renewable energy resources. Though the current techno-economic and socio-political issues in India may not allow for the adoption of advanced services, these services are very crucial for operating a secure and reliable grid. The Indian regulators should make way for extensive upgrades in grid communication technology, training and education, and market operation.

Table 3.3: Comparison of different balancing mechanism scenarios

Scenario	**Prim. Freq. Resp**	**Generator Dispatch**	**Advantages**	**Disadvantages**
Base Case	48%	52%	• Simple to implement	• High frequency deviation • Insufficient compensation for PFC
Increase UI	35%	65%	• Least effort upgrade	• No considerable improvement in frequency • Increased pressure on demand side
Primary Frequency Payment	48%	52%	• Considerable improvement in frequency • Payment for PFC	• Requires good payment structure for primary frequency response
Inc. UI + Prim. Freq. Payment	29%	71%	• Good frequency response • Lesser utilization of PFC	• Requires good payment structure for primary frequency response
Ideal Case	2%	98%	• Tight control of frequency	• Extensive upgrades required in communication technology, training and market process

3.4.4 Limitations

The frequency simulation is intended to compare different balancing mechanisms. The simulation is not aimed at reflecting any specific actual system frequency. Simulating the actual frequency would require modeling all generators and entities in the interconnection accurately. In addition, the links between neighboring interconnections would need to be modeled as well. This would be an intensive exercise that is beyond the scope of this work.

The transmission network is not included in the model. Inclusion of the transmission network would increase the complexity of the model without causing significant difference in the results. In the case of the UI mechanism based models, transmission network congestion in the system does not impact system prices as the UI mechanism does not account for the transmission network. In the ideal scenario, including the transmission network in the economic dispatch procedure could be used to generate location dependent prices known as locational marginal pricing (LMP). But, inclusion of LMP would not add distinct value to this particular study.

The structure of primary frequency compensation is not discussed in the work. Regulators are expected to develop a feasible and effective payment structure for primary frequency response. The payments to generators should be both fair and sufficient for adequate provision of the service. The regulators should also ensure that the primary frequency response is provided by both in-state and central generation stations.

3.5 Conclusions

Balancing mechanisms form the core of power system operation. They ensure that the demand and supply are balanced at all times and that the power system frequency is kept within reasonable bounds. The UI mechanism, which is the major balancing mechanism in the Indian grid, is designed to allow frequency to fluctuate in a relatively wide range. However, large frequency deviations have significant impact on the operation of multi-TSO interconnections in India. But, enabling tight control of frequency requires a range of services along with significant changes to power system operation and investment in grid technology. Though the Indian grid would not be able to accommodate all the advanced services due to the techno-economic and socio-political issues, the grid should aim to progress steadily towards advanced services.

Among the balancing mechanism options discussed in the thesis, good primary frequency response led to the most significant improvement in system frequency. Though the Indian government mandates the provision of primary frequency response, it is not provided adequately due to lack of compensation. Compensation for primary frequency response is required in power systems with wide frequency limits to prevent unfair over usage. However, once the frequency is improved, the UI prices may not be high enough to trigger sufficient balancing response from generators. Therefore, the UI prices need to be revised as well. These actions would provide a good transitional platform for more advanced services and market designs in the future Indian grid.

Chapter 4

Design of a feasible load balancing mechanism

4.1 Introduction

One of the major challenges facing the Indian electricity system is the design of advancements in operational practices and services that allow for efficient use of the available generation resources. Due to the complex nature of power systems, additional services known as ancillary services are necessary for reliable and efficient operation of the power grid. Ancillary services are classified into three types [85][84][56]: (a) normal operation (continuous) services, (b) contingency (emergency) services, and (c) voltage and black start services. Normal operation services are continuous services that are always in action whereas contingency services, as the name suggests, are employed only during emergency. Voltage and black start services ensure power quality and resilience of the grid respectively. The main focus of this study are the normal operation services, which would have the most impact on grid operation.

The most important normal operation service is known as load balancing that is a part of frequency support services. The primary goal of this service is to maintain short term demand and supply balance thereby keeping the power system frequency close to nominal values (50 Hz or 60 Hz depending on the system). Failure to do so would result in frequency deviations and even grid failures in extreme cases. Further, an ineffective load balancing mechanism causes the power system frequency to be at off-nominal frequency constantly. Maintaining off-nominal frequencies for a prolonged time has several negative impacts. First, deviations in frequency diminish the life of generators. Steam turbine blades are very sensitive to frequency deviations. Operating steam turbines at frequency deviations greater than 0.5Hz for more than 50 minutes over the lifetime of a generator has an adverse effect [48]. Second, frequency deviations reduce the power system equipment's efficiency and lifetime. Motors, transformers, healthcare equipment, and many electronic devices are frequency dependent, and are impacted negatively. Third, off-nominal frequency affects overall operation of the grid. Frequency deviations reflect the fact that the scheduled generation is not equal to the system demand. And, it results in unplanned power flows as multiple entities in the system act to stabilize the frequency. This problem is more pronounced in systems with little real-time visibility of operational parameters such as transmission line, transformers and generator loading. For instance, the recent blackout in Northern India in July 2012 was due to overloading of a transmission line. The report on the findings [16] stated that better grid management practices including better frequency management could have avoided the blackout.

Realizing the need for good operational practice, the Central Electricity Regulatory Commission (CERC) is in the process of introducing ancillary services in the Indian Electricity Market [17]. Though ancillary services are new to India, they have been in use for several years in restructured electricity markets and vertically integrated utilities around the world. Established electricity markets have designed products with varying technical requirements and monetary compensation to provide ancillary services [84][85]. One of the most important services is the load balancing ancillary service. Restructured electricity markets in the US use real-time markets, while most countries in the EU use load following reserves for balancing the demand-supply mismatch. While these established markets provide guidance for designing ancillary services in India, a direct application is not possible due to differences in the power system structure and characteristics. For instance, none of the advanced electricity markets face severe energy and capacity shortages like India. Hence, scrutiny of the current system and proposed requirements is needed for a successful implementation of the services in India.

The issue of insufficient frequency control mechanisms has been raised in previous works [78] [80]. Though mandated, primary frequency support, which is a very elemental and crucial service required to maintain power system frequency, is not provided by generators due to insufficient compensation. This deficiency results in large unattenuated frequency variations that cause significant wear and tear losses. A recent paper [79] proposes to address the issue of poor compensation by procuring and paying for primary frequency support through a competitive market mechanism. While the mechanism aims to improve the primary frequency control, the secondary and tertiary frequency control mechanisms are based on existing operational practices (Unscheduled interchange (UI) mechanism[1]). Another work [89] has proposed an improvement to the UI mechanism by adding

[1]Unscheduled Interchange (UI) mechanism is used in real-time to manage deviations from day-ahead schedule. It is

location bias to the existing mechanism. [19] has developed a method for implementing automatic generation control (AGC/secondary frequency control) using signals from the UI mechanism. All these works have proposed improvements to the UI mechanism, which uses frequency based pricing. But, frequency based pricing doesn't reflect system conditions, and this causes expensive generators to be used only when the frequency is very low. For instance, though 49.8 Hz reflects a very high mismatch in scheduled generation and actual demand, the related frequency based price may not be sufficient for expensive generators to increase output. Thus, the system tends to stay at 49.8 Hz. The mechanism inherently causes the system frequency to stay at off-nominal values, which is unhealthy for the system. Thus, there is a strong impetus to introduce a full fledged frequency support ancillary service.

Given the absence of adequate mechanisms, the main goal of this study is to help the Indian system operators, regulators, and policy makers assess the costs and potential benefits of having a reserve based balancing mechanism in the system. In line with this goal, the thesis presents an analysis of a balancing mechanism by simulating a model of the Indian system based on actual data from the grid. The main contribution of the study lies in the estimate of the costs and impacts of the proposed balancing mechanism. The results are intended to foster effective ancillary services policies in the Indian grid. The main features of the study are:

- *Proposing a balancing mechanism suitable for the Indian electricity market*: Since India has additional constraints such as capacity and energy shortage, load curtailment is used as a resource in the proposed balancing mechanism that uses load following reserves.
- *Developing an optimization model consisting of a unit commitment and economic dispatch to study the impacts of the proposed service*: Though well established, unit commitment and economic dispatch are seldom used in Indian power markets. These methods are used in the case study for optimal procurement and dispatch of reserves.
- *Estimating the wholesale cost and other impacts of having a balancing mechanism*: The impact of market design changes on wholesale costs is a good indicator for preliminary evaluation before proceeding into in-depth studies [100]. A model of the Indian system with actual data are simulated to study the costs and impacts.

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a frequency based pricing mechanism; the penalty/compensation is based on the power system frequency.

4.1.1 Lack of adequate balancing mechanism in the state-level (TSO)

In India, state transmission corporations manage the bulk of transmission and distribution [2] and act as load dispatch centers. Further, the states are responsible for maintaining energy balance within their area and can be considered as a control area [94]. Based on the preceding descriptions, state load dispatch centers (SLDCs) are expected to perform the operations of a transmission system operator. But, most states and their SLDCs inherently do not have an organized mechanism for scheduling, dispatch or load balancing. While there are five regional load dispatch centers (RLDCs), they do not have control over state supply, let alone demand.

The UI mechanism, as mentioned in previous sections, is the only mechanism employed by regional load dispatch centers (RLDCs), not State LDCs (SLDCs), to improve load balancing within the states. In recent times, CERC has increased the UI prices in an attempt to narrow the frequency band. This in turn increases the stress on the states to comply with their day-ahead schedules. Some well managed states [37][93] have started using intra-state UI to manage the generators and frequency within the state, indicating that there is a need for a state-level (TSO-level) mechanism for load balancing. The need for an intra-state mechanism is strengthened due to the existence of multiple utilities within the state, and their overdrawals and underdrawals need to be regulated.

4.1.2 Frequency Support Ancillary Service (FSAS) proposed by CERC

Frequency support ancillary service (FSAS) is aimed to improve the system frequency by introducing load balancing. More recently, CERC has announced the plans for a reserve based service known as Regulation Reserve Ancillary service (RRAS). The salient features of the service are as follows:

- The primary focus is to maintain the power system frequency within specified limits. It aims to utilize surplus unused generation for improving the frequency. The importance of such a service increases once the amount of non-dispatchable renewable generation reaches significant levels.
- The service is to be designed as a separate product and handled by the nodal agency. The bids for the service will be collected from the surplus capacity not scheduled. The nodal agencies handle the bids and also send dispatch instructions in real-time.
- The frequency support ancillary service will be activated when a system contingency prevails for a set amount of time. For instance, a contingency event would be triggered if the frequency

remains 0.05 Hz below the lower operating range (currently 49.7 Hz) for two consecutive time periods of 15 minutes each. The real-time dispatch of the frequency service is expected to be handled by nodal dispatch agencies, and the paper recommends the National Load Dispatch Centre (NLDC), which oversees all of the regions in India, for the function.

- The proposal highlights the need for better balancing mechanism in India. Given the current power system structure and quality requirements, this initiative needs to be taken even further to achieve the objective of significantly improving the reliability of the Indian electric power system.

Concerns in the proposed Frequency Support Ancillary Service (FSAS)

Some of the concerns regarding the proposal are elaborated in [92]. This section supports and adds to the stated concerns. The proposed FSAS/RSAS increases the role of energy exchanges and the national load dispatch center (NLDC) in the electricity market. The regulators expect the NLDC to assume the role of an Independent System Operator (ISO) over the long term. At present, these two entities are only loosely coupled, so it will require extensive co-ordination to achieve success in implementing the proposed service. Further, some of the proposed methods are considered less efficient in established markets. For instance, procurement of energy and ancillary services which is done sequentially is considered less optimal and most system operators co-optimize the procurement [58] [100].

In addition, frequency support ancillary service is proposed to be deployed only during contingencies. An example of a contingency is a low frequency event when the frequency drops 0.05 Hz below the already generous lower operating point in the Indian grid for 30 minutes. In other systems, this would be considered an emergency or contingency service and not a frequency support ancillary services. Frequency support services in their definitions are usually continuous services and not such an event based service.

Lastly, an underlying assumption in the proposed FSAS is the use of surplus unused generation capacity. India today has very limited capacity with fast ramp up/down capabilities, except hydropower. The latter is attractive but limited for the following reasons: (1) Hydropower is mostly dual use - power and irrigation control, and control isn't always independent for power needs; (2) Water input is very seasonal and often limited, especially for parts of the year - such plants cannot be run 24/7; (3) Adding new hydropower capacity is socially and environmentally challenging given land-use and geographic constraints.

4.2 Description of the proposed balancing mechanism

The previous sections on the shortfalls of the CERC proposed ancillary service highlight the need for a more effective continuously operating load-balancing mechanism. This section presents the rationale and description of such a balancing service. The proposed balancing service is presented by first discussing the current balancing practices in other markets. The existing mechanisms are modified to include India specific constraints to create a feasible system. The system is enhanced using best practices from the considered systems.

Load balancing in developed electricity markets is usually provided through two services: (a) real-time fast energy markets and (b) load following [56]. Both methods are used to dispatch generators in short intervals to match real-time demand. Real-time fast energy markets rely on incidental response from online generators that have supplemental capacity available, whereas load following is a capacity service that uses stand-by generation held as reserves for the particular purpose. Since India is expected to continue facing power shortages in the future, real-time fast energy market will be ineffective due to lack of supplemental capacity at many time periods.

Energy and capacity shortage have been an important issue in the past years and will continue to be an issue in some regions[2]. Load curtailment is widely used to manage these shortages to a level where it has become an accepted practice. Due to frequently occurring load curtailment, the Indian power system is much more resilient than that of other countries since most critical functions often have back-up generation. However, unscheduled load curtailment has far greater negative effects than scheduled load curtailment as the consumers can better prepare for the outage. Therefore, load curtailment is included as an inevitable resource in our approach with greater preference for day-ahead planned load curtailment than unscheduled load curtailment.

Load following (balancing mechanism using reserves) is widely used in European countries. Each country has its own implementation of the process. But the common attribute is the presence of a day-ahead balancing market to procure balancing reserves. The procured balancing reserves are dispatched by the TSO in real-time. This mechanism is adapted to the Indian system by including additional constraints. Further, instead of a two-market mechanism for energy and balancing reserve, a single market mechanism that co-optimizes [58][100] the procurement of energy and reserve is used. This mechanism is widely used in US electricity markets for procurement of energy and ancillary service.

[2]The official shortfall is rather low, due to a quirk in the estimation method. The actual shortfall is likely several times higher. Reference: ”Re-thinking Access and Electrification in India: From Wire to Service”, Rahul Tongia, Brookings India Discussion Note 01-2014.

The features of the proposed service are as follows:

(a) reserves for load-following are procured in the day-ahead market along with energy, and dispatched in real-time,

(b) the procurement of energy and reserve is co-optimized,

(c) the energy shortage issue is addressed by using load curtailment as a resource.

The proposed load following service presents an alternative to the FSAS proposed by CERC. It is a separate service procured day-ahead and dispatched in real-time. More importantly, the service aims to improve the load balance in the power system that subsequently leads to an improved frequency profile. But, unlike the proposed contingency service, load-following is a continuous service that is always activated. This feature makes the service better suited for serving the needs of the system.

4.2.1 Mathematical Formulation of the Optimization Model

Based on the above discussion, a two-stage market design is proposed. In the first stage, a day-ahead unit commitment procedure is used to produce energy output schedules for generators based on forecasted demand. In addition, the procedure procures load-following reserves that would be used for balancing in real-time. In the second stage, the load-following reserves along with other available generation are dispatched based on an economic dispatch procedure to balance the mismatch between the day-ahead supply schedule and real-time demand. If neither load following reserve nor unused generation is available, the system uses emergency measures such as unscheduled load curtailment to maintain the demand-supply balance. The procedure is repeated several times within the hour in real-time.

First Stage: Co-optimized procurement of energy and ancillary service

Similar to established electricity markets, a unit-commitment procedure [63] is proposed to schedule the generators and procure load following reserves in an optimal way. The load following reserve quantity is defined as a percentage of the net demand[3], and it depends on the variability of net demand.

[3]Net demand is defined as dispatch linked net demand, which is the actual demand (demand served + load curtailment) after removing non-dispatchable supply such as wind power. Appendix 4.3.1 has more details.

The proposed procedure differs from previous methods in two ways: First, given the energy shortage in India, the optimization procedure explicitly includes load curtailment, with an associated (chosen) cost; no longer is load-curtailment treated as 'free' in the Indian grid, which often leads to its over-use. Second, some electric power generators like hydropower face fuel/prime mover shortages in addition to capacity limitations. Therefore, the optimization includes energy (fuel) constraints in addition to the capacity limitations.

The objective of the procedure is to serve the demand in the most cost effective way while adhering to operational constraints and procuring a pre-specified amount of load following reserves. The generation scheduling problem is modeled as a mixed-integer programming problem as it involves binary variables for shut-down and start-up of generators. The formulation applied in this work is an extension of the UC optimization found in [10] [112]. The description of the problem is as follows:

1. Objective Function:
   The objective function of the unit commitment corresponds to minimizing the overall cost, i.e., the sum of day-ahead energy cost, load-following reserve cost and load curtailment:

$$\min_{z} \quad z = \sum_{i \in I} \sum_{t \in T} (C_i * p_{i,t}^{DA} + RC_i * r_{i,t}^{up} + RC_i * r_{i,t}^{down}) + \sum_{t \in T} ls_t^{DA} * LS_t^{DA} \quad (4.2.1.1)$$

   where:
   C_i = energy cost of unit i($/MWh),
   $p_{i,t}^{DA}$ = day ahead power schedule of unit i at period t (MW),
   RC_i = load-following reserve cost of unit i ($/MW),
   $r_{i,t}$ = up or down load-following reserve provided by unit i (MW),
   ls_t = is the amount of load curtailed at period t (MW),
   LS_t = cost of load-curtailment ($/MWh) at period t,
   I = total number of generating units,
   T = number of time periods in the optimization horizon.

   Note that this allows the cost-of load-curtailment to vary over time, e.g., if one chooses to value an evening load-curtailment (when lighting demand is present) as worse than other periods. In our implementation of the day-ahead market, the time horizon is 48 hours and each period is one hour. A longer time horizon was chosen to accommodate long start-up and shut-down times. However, only the results of the first 24 hours is transferred to the second stage.

2. Constraints: Power system operation is subjected to several functional requirements, market restrictions, and equipment limitations. These constraints are modeled using mathematical equations as described in this section.

   (a) Power Balance Constraint: The elemental objective of an electric power system is to serve the electric power demands of the customers. The sum of power output $(\sum_i p_{i,t}^{DA})$ from each of the I generators in the system must be equal to the net demand (D_t) at hour t, inclusive of technical losses on the wires. If there is not enough generation in the system, load curtailment (ls_t^{DA}) will be used. This requirement is fulfilled by the following equation:

   $$\sum_i p_{i,t}^{DA} + ls_t^{DA} = D_t^{DA} \quad \forall t \in T \tag{4.2.1.2}$$

   where variables are as described earlier and,
   D_t^{DA}=day-ahead forecasted net demand at period t.

   (b) Generation-limit constraints: The generation limit constraints are used to model the upper and lower limit of the output capacity of generators. The following inequalitites are used to represent the constraints:

   $$\begin{aligned} 0 \leq \overline{p}_{i,t}^{DA} &\leq \overline{P_i} * x_{i,t}, \quad \forall t \in T \quad \forall i \in I \\ p_{i,t}^{DA} + r_{i,t}^{up} &\leq \overline{p}_{i,t}^{DA}, \quad \forall t \in T \quad \forall i \in I \\ p_{i,t}^{DA} - r_{i,t}^{down} &\geq \underline{P_i} * x_{i,t}, \quad \forall t \in T \quad \forall i \in I \end{aligned} \tag{4.2.1.3}$$

   where:
   $\overline{P_i}$ and $\underline{P_i}$ = upper and lower capacity limits of unit i,
   $\overline{p}_{i,t}^{DA}$ = a non-negative variable that represents the schedulable upper limit of generator i,
   $x_{i,t}$ = binary variable indicating on/off status of unit i at period t.

   The constraints link the status variable $x_{i,t}$ to the power output decision variable $p_{i,t}^{DA}$ efficiently and help in linearizing the constraints.

   (c) Energy Constraint: In addition to limitations on output capacity (MW), generators face restrictions due to shortage of fuel. This limits the quantity of energy (MWh) that could be produced per unit time. This MWh restriction is most relevant to hydro power plants that are subjected to seasonal impacts of water availability, which in turn depends on annual rainfall. In addition, temporary shortage of coal impacts some of the thermal power plants. These fuel/input-energy limitations are modeled using the energy constraint. For each generator i, the sum of power output ($\sum_t p_{i,t}^{DA}$) and the sum of reserve procurement ($\sum_t r_{i,t}^{up}$) over the optimization horizon (T) must be less than or equal to the energy available for that period (E_i). The corresponding mathematical equation is represented by:

$$\left(\sum_t p_{i,t}^{DA} + \sum_t r_{i,t}^{up} \right) * T/n \leq E_i, \quad \forall i \in I \tag{4.2.1.4}$$

where T/n is used to convert power in MW to energy in MWh, T is the number of time periods in the optimization horizon, and n is the number of time periods in an hour.

(d) Reserve Requirement: The proposed method requires a certain amount of generation capacity to be set aside as load-following reserve $(r_{i,t}^{up}, r_{i,t}^{down})$. The sum of reserve capacity from all generators is usually a percentage $(r_{\%})$ of the net demand (D_t^{DA}). These requirements are modeled using the following equation:

$$\begin{aligned} \sum_i r_{i,t}^{up} \geq r_{\%} * D_t^{DA}, \quad \forall t \in T \\ \sum_i r_{i,t}^{down} \geq r_{\%} * D_t^{DA}, \quad \forall t \in T \end{aligned} \tag{4.2.1.5}$$

(e) Day-ahead ramping constraints ensure that the increase in generator output is within permissible limits. This constraint in the day-ahead market is modeled using RR_i^{up}, RR_i^{down}, RR_i^{start}, and RR_i^{shut} for ramp-up, ramp-down, start-up ramp and shut-down ramp, respectively, and the binary status variables $x_{i,t}$. The corresponding equations are as follows:

$$\begin{aligned} \overline{p}_{i,t}^{DA} &\leq p_{i,t-1}^{DA} + RR_i^{up} x_{i,t-1} + RR_i^{start}(x_{i,t} - x_{i,t-1}) \dots \\ &\quad + \overline{P_i}(1 - x_{i,t}), \quad \forall t \in T, \forall i \in I \\ \overline{p}_{i,t}^{DA} &\leq RR_i^{shut}(x_{i,t} - x_{i,t+1}) + \overline{P_i} x_{i,t+1}, \quad \forall t \in T-1, \forall i \in I \\ \overline{p}_{i,t-1}^{DA} &\leq p_{i,t}^{DA} + RR_i^{down} x_{i,t} + RR_i^{shut}(x_{i,t-1} - x_{i,t}) \dots \\ &\quad + \overline{P_i}(1 - x_{i,t-1}), \quad \forall t \in T, \forall i \in I \end{aligned} \tag{4.2.1.6}$$

The formulation of these equations has been adopted from [10]. The appropriate ramp-rate becomes effective depending on the status variable. The final term $\overline{P_i}$ is added to ensure that the RHS is never negative, which would cause the optimization to be infeasible. $\overline{p}_{i,t}^{DA}$ is used for modeling convenience; it eliminates the need for using $p_{i,t}^{DA} + r_{i,t}^{up}$ repeatedly in the ramping constraints.

(f) Real-time/Reserve ramping constraints help in enforcing ramp-rate restrictions in real-time. It is expected that the reserve requirement needs to be fully deployable in 5 minutes to free the primary frequency provision, resulting in

$$\begin{aligned} \frac{r_{i,t}^{up}}{RR_i^{min}} &\leq 5, \quad \forall t \in T, \forall i \in I \\ \frac{r_{i,t}^{down}}{RR_i^{min}} &\leq 5, \quad \forall t \in T, \forall i \in I \end{aligned} \tag{4.2.1.7}$$

where RR_i^{min} is the unit ramp-rate in MW/min. The reserve ramping constraints are significantly simpler than the day ahead ramping constraints as all the status variables are handled by the day-ahead ramping constraints.

(g) Minimum up time constraints: For safe operation, generators are required to stay online for a certain amount of time before shutting down. The amount of time the generator needs to stay on is known as minimum up-time. The constraints in this category are adapted from [10] and ensure that the generators are on for the minimum-up time.

The period is split into three parts/constraints. The first equation fulfils the minimum up-time requirements of the previous day. In some cases, the generators might not have stayed on for the minimum amount of time during the previous optimization horizon. The system needs to ensure that those generators that were online in the previous day should fulfil their minimum up time requirements. The constraint representing this is given by:

$$\sum_{t=1}^{MU_i^0} (1 - x_{i,t}) = 0, \quad \forall i \in I \tag{4.2.1.8}$$

where, MU_i^0 is the remaining amount of time unit i needs to stay on at the start of the optimization. The parameter can take any value from zero to minimum up time MU_i depending on the up-time of the previous day.

The second constraint is applicable for most of the optimization period. It covers the period from after the initial up-time till $MU_i - 1$ periods towards the end. The constraints ensure that if a generator is switched on in this period, it stays on for the minimum-up time MU_i:

$$\begin{gathered} \sum_{n=t}^{t+MU_i-1} x_{i,n} \geq MU_i * (x_{i,t} - x_{i,t-1}), \quad \forall i \in I \\ \forall t \in MU_i^0 + 1 \dots T - MU_i + 1 \end{gathered} \tag{4.2.1.9}$$

The third constraint represents the $MU_i - 1$ periods towards the end of the optimization horizon. The previous equations are not applicable during this period as the optimization has no control over periods after the optimization horizon. If the generator is turned on during this period, the generator is requested to stay on until the end of the optimization period, i.e.

$$\sum_{n=t}^{T}[x_{i,n} - (x_{i,t} - x_{i,t-1})] \geq 0, \forall i \in I \qquad \forall t \in T - MU_i + 2 \ldots T \tag{4.2.1.10}$$

(h) Minimum down time constraints: The formulation of the minimum down time constraints is similar to the minimum up time constraints and are again adopted from [10]:

$$\begin{aligned} &\sum_{t=1}^{MD_i^0}(x_{i,t}) = 0, \quad \forall i \in I \\ &\sum_{n=t}^{t+MD_i-1}(1 - x_{i,n}) \geq MD_i * (x_{i,t-1} - x_{i,t}), \quad \forall i \in I \\ &\qquad \forall t \in MD_i^0 + 1 \ldots T - MD_i + 1 \\ &\sum_{n=t}^{T}[1 - x_{i,n} - (x_{i,t-1} - x_{i,t})] \geq 0, \quad \forall i \in I \\ &\qquad \forall t \in T - MD_i + 2 \ldots T \end{aligned} \tag{4.2.1.11}$$

where, MD_i^0 is the required down-time of unit i at the start of optimization and MD_i is the minimum down-time of the generator for the rest of the optimization horizon.

Second stage: Real-time Economic Dispatch

The output of the unit commitment provides generator schedules to supply the forecasted hourly net demand, and the generators are expected to adhere to these day-ahead schedules. But the real-time demand is continuously varying and will deviate from the forecast; even supply can deviate for various reasons. This deviation will be balanced using generators cleared for load-following reserve and unused generation. The real-time economic dispatch described in this section is used to handle this process.

The objective of the economic dispatch is to minimize incidental energy cost to supply the demand in real-time while determining the optimal set of generators from the available generation and load-following reserves. It should be performed in short-intervals, typically every 5-15 minutes. If the real-time demand is lower than the day-ahead forecast, the dispatch encourages relief of the most expensive generator. Conversely, the least expensive load following reserve will be deployed when real-time demand is greater than the day-ahead forecast. The optimization problem for each time interval t (5-min in the proposed design) is formulated as follows:

$$\min_{z} \quad z = \sum_{i \in I} C_i * p_{i,t}^{RT} + LS_t^{RT} * ls_t^{RT} \tag{4.2.1.12}$$

subject to:

$$\sum_{i} p_{i,t}^{RT} + ls_t^{RT} = EI_t \tag{4.2.1.13}$$

$$\underline{P}_{i,t} * x_{i,t} \leq p_{i,t}^{RT} \leq \overline{P}_{i,t} * x_{i,t}, \quad \forall i \in I \tag{4.2.1.14}$$

$$-(5 * RR_i^{min}) \leq p_{i,t}^{RT} - p_{i,t-1}^{RT} \leq (5 * RR_i^{min}), \quad \forall i \in I \tag{4.2.1.15}$$

where:
$EI_t =$ real-time demand observed in the system at time t
$\overline{P_{i,t}}$ and $\underline{P_{i,t}}$ = upper and lower capacity limit of unit i in period t
$RR_i^{min} =$ ramp-rate of unit i in MW/min
$p_{i,t}^{RT} =$ power output of unit i in real-time.

The objective function (4.2.1.12) is the sum of the products of the incidental energy cost and real-time power output for all generators in the system at time interval t. Constraint (4.2.1.13) ensures that the real-time demand is balanced by supply, load curtailment and emergency actions. The sum of real-time outputs of all generators in the system should be equal to the real-time demand. During shortages, load curtailment and emergency actions can be used to ensure that the demand-supply balance is maintained. Constraint (4.2.1.14) ensures that the generator outputs stay within their capacity limits. Finally, given the output level determined in the previous dispatch optimization $p_{i,t-1}^{RT}$, constraint (4.2.1.15) ensures that the generators respond to the real-time power requirements within 5 minutes to relieve the primary frequency control. RR_i^{min} represents the rate at which the generator can change its output. The Lagrange Multiplier λ associated with the demand balance constraint (4.2.1.13) reflects the real-time system marginal price. As such, the system marginal price is not currently used and is also not part of the proposed approach. Here, the dispatch instructions are sent to the generators providing load following from the system operator. But, the system marginal price may be useful for the establishment of a real-time market in which the generators can respond to the real-time prices as well.

4.2.2 Generator payments

The state system operators use pay-as-bid mechanism to compensate generators. The payments are based on the bid (contract) price and not the system marginal price, this continues the practice as followed in India where the state regulatory commission sets the price paid to each generator.

A two-part payment mechanism is used to compensate the generators for their service. In the day-ahead market, the generators receive payments for scheduled energy and load following capacity. In the real-time market, generators that provide load following and incidental energy will receive energy payments.

Day-ahead payments

First, generators that are cleared in the day-ahead market receive energy payments. The payments are based on the energy scheduled $(p_{i,t}^{DA})$ and the generator's government approved energy contract price (C_i):

$$\text{DA energy cost} = \sum_{i \in I} \sum_{t \in T} (C_i * p_{i,t}^{DA}) \tag{4.2.2.1}$$

Second, generators that are selected for load following reserves receive load following capacity payments. The capacity payments reflect the additional costs that is incurred by the generators for having the reserves on stand-by. Some of the factors that contribute to the additional costs are: fuel cost increase due to operation at non-economic output levels, heat rate increase due to operation at non-steady state, and increased variable operation and maintenance cost [82]. Hence, the capacity payment is given by

$$\text{DA reserve cost} = \sum_{i \in I} \sum_{t \in T} (RC_i * r_{i,t}^{up} + RC_i * r_{i,t}^{down}) \tag{4.2.2.2}$$

In addition, though load curtailment is not inherently valued and is not being compensated, there exists an intrinsic societal cost due to the inconvenience caused. Since load curtailment is used as a last resort measure after all the expensive generators are used, the cost of load curtailment should be higher than the most expensive generator used. The cost of load-curtailment will be the product of the quantity of load curtailed and the cost of load curtailment, i.e.

$$\text{DA load curtailment cost} = \sum_{t \in T} ls_t^{DA} * LS_t^{DA} \tag{4.2.2.3}$$

The sum over all of these costs corresponds to the objective function in the unit commitment process.

Real-time payments

The real-time economic dispatch uses the load following reserves and other available generation in real-time. The generators that produce more than the day-ahead schedule are compensated for aiding the load-balance in the system. The real-time payments are the product of incidental energy production and energy cost, i.e.

$$\text{RT energy cost} = \sum_{i \in I} \sum_{t \in T} C_i * max(0, p_{i,t}^{RT} - p_{i,t}^{DA}) \tag{4.2.2.4}$$

During contingency situations, when all generation resources are exhausted, the system can either search for emergency power or use load curtailment to maintain the frequency and prevent grid failures. These real-time measures often are very expensive and the following formula is used to calculate the cost of emergency measure in real-time.

$$\text{RT emergency cost} = \sum_{t \in T} ls_t^{RT} * LS_t^{RT} \tag{4.2.2.5}$$

where ls_t^{RT} is the load curtailed and emergency actions taken in real time and LS_t^{RT} is the price for such load curtailment. Generally, real-time load curtailment corresponds to unplanned load curtailment which means that LS_t^{RT} should be significantly greater than LS_t^{DA}.

4.3 Simulation Setup

As discussed earlier, the TSO (SLDC) is the most important entity in a balancing scheme, and the proposed mechanism is designed for a TSO. Therefore, the TSO in the state of Karnataka was chosen for testing and studying the proposed operational practices. Karnataka is also unique in India with the largest SCADA (Supervisory Control and Data Acquisition) system installed, and with sufficient availability of data. The detailed description of the data used in the simulation are provided in Appendix 4.3.1. The total installed capacity of the system excluding renewable energy resources is 11500 MW out of which 2250 MW cannot be used for load-following due to functional constraints.

In the first step of the simulation, the proposed unit-commitment procedure is simulated based on the state's generators and hourly net demand for each day. The unit-commitment is run with a time horizon of 48 hours to account for the long minimum-up and minimum down times, and only the results of the first 24 hours is retained. This procedure generates day-ahead schedules and load following reserves as outputs. In the next step, these outputs with the 5-minute net demand are used in the real-time economic dispatch. The economic dispatch is performed for every 5-minute of the simulation period. The schematic of the proposed procedure is shown in Figure 4.1. The simulation is carried out for an entire year, and for different levels of load-following reserve.

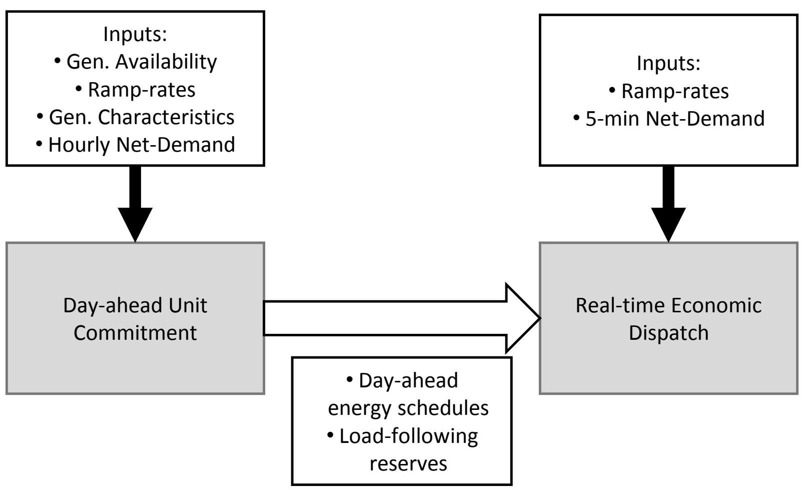

Figure 4.1: Proposed simulation setup that shows the required inputs and the linkage between day ahead unit commitment and real-time economic dispatch. The day-ahead unit commitment is performed ahead of time, typically a day-ahead of real-time operation. The results are transferred to the real-time economic dispatch, which is repeated for each time interval in real-time.

The analysis is based on data for the year 2013. Different scenarios were simulated to gain insights into the performance of the proposed operational practices:

- First, the simulation is carried out without any load following reserves. This scenario closely resembles a real-time market in a restructured electricity market that utilizes unused available generation. It is also similar to a scenario in which the TSO doesn't have any reserves and uses only unused available generation for load following, which is the situation in the present system. This scenario is considered as the status quo.

- Next, the simulation is carried out with 1%, 2% and 5% of the hourly forecasted net demand as load following reserve in each hour.

4.3.1 Simulation Data Details

The TSO in the state of Karnataka, which is part of the southern regional grid, is chosen for the analysis. The generation mix is listed in Table 4.1 and Table 4.2. The details of the entities are as follows.

Table 4.1: Installed Capacity of different generation sources (MW)

	2011	2012	2013
Thermal (coal)	3980	4880	5380
Non-conventional (wind & solar)	2550	3288	4073
Hydro	3657	3657	3657
Central Generation Station	1700	1836	1905
Captive Plants	350	350	350
Diesel	237	209	128
Total Installed	12474	14220	15493

Table 4.2: Generation sources as a percentage of total installed capacity

	2011	2012	2013
Thermal (coal)	32%	34%	35%
Non-conventional (wind & solar)	20%	23%	26%
Hydro	29%	26%	24%
Central Generation Stations	14%	13%	12%
Captive Plants	3%	2%	2%
Diesel	2%	1%	1%

Dispatchable Generators

i) Coal-based Generators

The state-owned generators sell electricity to state load serving entities (LSE) based on energy purchase contracts. Similarly, the independent power producers (IPP) have energy purchase contracts with the state-owned utilities for a portion of their output.

Due to the variability in power supplied to the state, the maximum generator output is modeled based on the daily peak output availability rather than the installed capacity for each simulated day. This also helps in incorporating outages faced by the generators. Figure 4.2 shows the maximum utilized capacity as opposed to installed capacity for days in year 2013. It is assumed that 90% of the daily peak output is available throughout the day.

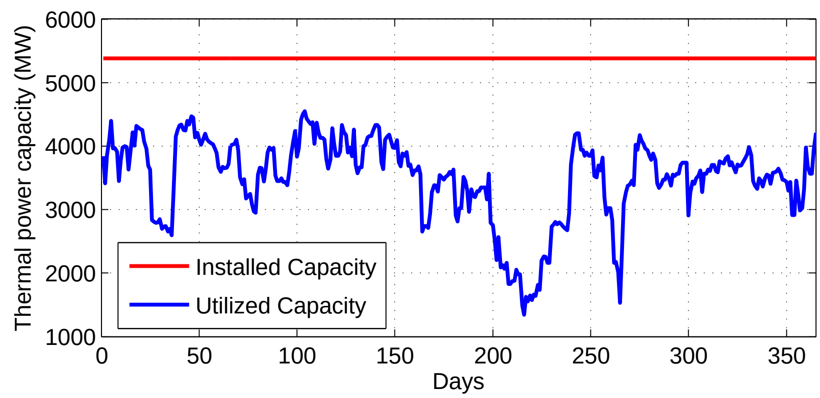

Figure 4.2: Thermal-power capacity utilized is lower than installed capacity due to constraints on availability. The data are shown for year 2013.

The average energy purchase cost per unit (kWh) of electricity will be used in our unit-commitment and economic dispatch optimizations to choose the economically optimal set of generators to serve the demand. The energy purchase cost is based on annual financial reports [3] and regulator approved energy purchase cost [52] for a state LSE. The energy purchase cost along with installed capacity for the thermal generators is shown in Table 4.3 & Table 4.4.

Traditionally, load-following was an inherent part of vertical integrated utilities and the costs were seldom calculated exclusively. After electricity market restructuring, load-following became a separate service and costs had to be estimated. Intertek Aptech [49] have estimated the lower bound of load-following costs by using data from generators in North America. These cost estimates are used by matching the thermal generators to the stated description as shown in Table 4.4 (conversion rate of 1 US$ = 60 Rs. is used).

In addition to costs, generator characteristics are included in the optimization. The ability of a generator to provide load-following service is dependent on its ramp-rates (maneuverability). The ramp-rates used in this study are obtained from [33][5]. The upper limit of the ramp-rates are used. Further, the other generator characteristics such as minimum output-level, minimum-off time and minimum-on time are obtained from IEEE RTS-96 [42].

ii) Hydro-power

Hydro-power generators have high ramp-rates and are capable of very flexible operation, and these have low marginal costs of generation. Nearly a quarter of the state's power generation capacity is composed of hydro-power but new capacity addition is limited due to geographic and social constraints. One major issue is that generator output is heavily dependent on water availability. The water availability in turn is dependent on various factors such as annual rainfall, irrigation schedules and seasonal demands. At present, the water available in dams after the rainfall season is almost equally partitioned for each day of the next year. Therefore, hydro-power is constrained by resource (water) availability in addition to capacity. Hence, constraints on daily available energy (GWh) in addition to capacity (MW) constraints are included. Figure 11 shows the daily energy used from hydro-power for the days of the year 2013. Though the allotment is equally partitioned, the usage is dependent on various operational factors and hence appears different for different days.

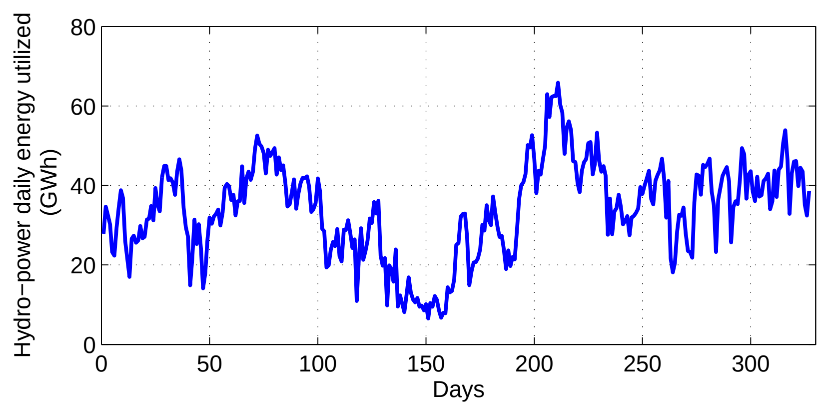

Figure 4.3: Daily energy output of hydro-power for the year 2013. The measureable decrease and increase corresponds to pre-monsoon and monsoon periods.

There are about 80 hydro-power generator units in the state. Modeling each generator individually would be computationally intense. Since hydro-power generators are extremely flexible, the results for an aggregated model and for a model with individual generator would not be significantly different if there are no transmission constraints. Therefore, hydro-power generators are modeled as a single aggregated resource with a power purchase cost of 0.78 Rs./kWh [3].

For this study, the ramp-capability of hydro-power generators is limited to that of diesel generators. The generator is estimated to ramp up to 15% of its capacity per minute. Further, the flexibility of the generator enables it to cycle (switch on/off) in less than an hour. Due to high flexibility, the load-following cost is assumed to be negligible.

iii) Diesel Generators

The state possesses about 210 MW of generation potential powered by diesel[4]. Diesel generators are comparatively small sized generators that are often used as backup power. Unit cost of electricity produced is expensive when compared to other generators. The installed capacity and power purchase cost of diesel generators in the state is shown in Table 4.3 and Table 4.4.

[4]This is the dispatchable diesel capacity, and excludes diesel owned by end-users for back-up power.

On the positive side, these generators have very high ramp-rates and are designed for handling varying output levels. Therefore, they would not incur any additional load-following costs from an operational perspective.

iv) Central Generation Stations

Central generations stations (CGSs) are generators that provide electricity to multiples states. Though the state can request up to its allocation and even more if available, the state will not have visibility of its overall operation as the generators serve multiple states. Therefore, these generators can be scheduled for energy but cannot be dispatched by the states for load following. The state's share of the central generation stations amount to about 1900 MW [60], and the power purchase cost is between 2 Rs./kWh to 3.1 Rs./kWh [3] [52].

v) Captive power plants

Captive power plants are usually part of a larger industrial operation with a primary objective other than producing electricity. Therefore, similar to CGS, captive power plants will be able to schedule energy but not provide load-following in order to avoid interference with the primary operation. The state has about 350 MW of captive power plant capacity with an average power purchase cost of 3.85 Rs./kWh to 5.34 Rs./kWh [3][52].

Table 4.3: Generator Description

Generation Station	Generation Type	Units Installed	Unit Cap. (MW)	Total Cap. (MW)
R.T.P.S. - 1	Thermal (Coal)	7	210	1470
R.T.P.S. - 2	Thermal (Coal)	1	250	250
B.T.P.S. - 1	Thermal (Coal)	1	500	500
B.T.P.S. - 2	Thermal (Coal)	1	500	500
UPCL*	Thermal (Coal)	2	600	1200
JINDAL 1*	Thermal (Coal/ waste-gas mix)	2	130	260
JINDAL 2*	Thermal (Coal)	2	300	600
JINDAL 3*	Thermal (Coal)	1	600	600
Aggregated	Hydro	1	N/A	3657
Y.D.G.S.	Diesel	6	22	129
Tata Power (IPP)	Diesel	5	18	81
Aggregated	Central Generation Station	1	N/A	1900
Aggregated	Captive Power Plant	1	N/A	350
Aggregated	Load Curtailment	1	N/A	4000

*Independent Power Producer (IPP)

Table 4.4: Generator Characteristic

Generation Station	Power Purchase Costs (Rs./kWh)	Load-following Costs (Rs./MW)		Ramp Rate (% of cap./minute) [33][5]	IEEE RTS-96 Ref.
		Best Estimate	Range		
R.T.P.S. - 1	3.9	200	115- 230	2%	U155
R.T.P.S. - 2	4.41	200	115 - 230	2%	U155
B.T.P.S. - 1	3.1	150	85 - 185	2%	U350
B.T.P.S. - 2	3.47	150	85 - 185	2%	U350
UPCL*	4.14	150	85 - 185	2%	U350
JINDAL 1 *	5.5	200	115 - 230	2%	U155
JINDAL 2 *	5.5	150	85 - 185	2%	U350
JINDAL 3 *	5.5	120	90 - 145	2%	U350
Hydro#	0.78	-	-	15%	U50
Y.D.G.S.	14.09	-	-	8.33%	U20
Tata Power*	12.87	-	-	8.33%	U20
CGS#	3.1	N/A	N/A	2%	U350
Captive Power Plant#	5.34	N/A	N/A	3%	U20
Load Curtailment#	18	N/A	N/A	15%	N/A

*Independent Power Producer (IPP)
#Aggregated Generation

vi) Load Curtailment

Energy shortage has been a chronic issue plaguing the Indian power system. This issue has resulted in significant amounts of load curtailment (aka load shedding) in the state. Though the installed capacity appears to be greater than the load served, there is high uncertainty in power availability due to fuel shortages and generator outages. Further, a significant portion of the generation is non-conventional energy resources with high uncertainty and variability. This worsens the generation availability and controllability. During energy shortages, as a last resort, power system operators use load curtailment to avoid severe grid outages. This is considered as a measure of last resort and, for the base calculation, valued higher than any generator available in the system at 18 Rs./kWh.

Non-dispatchable generation

Renewable energy resources such as wind and solar are considered non-dispatchable due to the uncertainty and variability in their power output, and are modeled as negative demand. Wind energy is the predominant source of renewable energy in the state. The state currently has a planned capacity of about 4000MW with energy purchase cost of 3.3 Rs./kWh to 3.85 Rs./kWh [3][52]. These costs are excluded from the calculations as they would be the same across all cases independent of the optimization procedure.

Demand data

The objective of the system operator is to serve the system demand at least cost while ensuring system stability and reliability. As several generation resources are non-dispatchable, net-demand is used in our optimization procedures.

$$NetDemand = DemandServed + LoadCurtailment - Windoutput$$

The demand served (5-minute interval) data are obtained from the Southern Regional Load Dispatch Center (SRLDC). And, load curtailment data, which represents the actual curtailment in the system, was obtained from the state load dispatch center (KPTCL). Finally, the non-dispatchable (wind) generation data was obtained from the state transmission system operator (KPTCL). The average hourly demand is used for the day-ahead market and the 5-minute data for the real-time market.

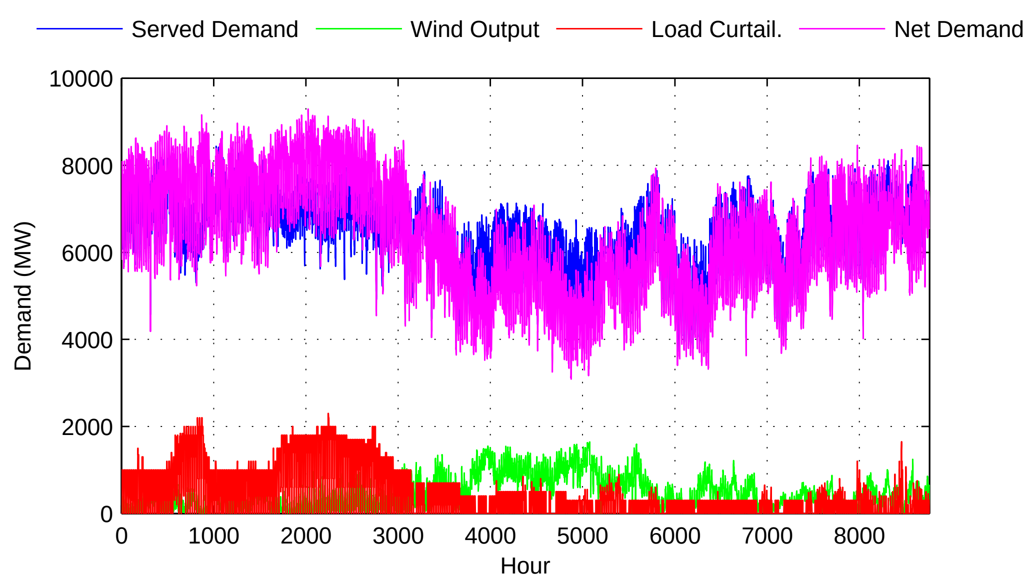

Figure 4.4: Net Demand Data for year 2013. Net Demand is obtained by subtracting wind output from actual demand (demand served + load curtailment) in the system.

4.4 Results and Discussion

4.4.1 The role of reserves in the Indian electricity market

Power systems planners and operators ensure that the system possesses adequate generation resources to satisfy the peak demand comfortably. Regulated utilities use integrated resource planning (IRP) to ensure that adequate generation resources are built. On the other hand, most restructured electricity markets in the US have developed some form of capacity market in addition to energy markets to ensure resource adequacy [97]. In addition to building new generation capacity, there have been several initiatives to utilize demand side management as a viable alternative to manage peak demand and shortages [96][106][103]. However, the technology has several challenges especially with regards to active load management and participation as a fast responding resource in real-time [101][55][9]. Demand-side management is a rapidly developing field and is expected to play a significant part in future power systems.

Unlike developed countries, capacity and energy shortages are an inevitable part of the Indian grid and the only way to improve the situation is to build more capacity or develop effective demand side management. Consequently, all the current efforts in the Indian grid are focused on building more capacity. And, demand-side management through load curtailment has become a necessity rather than an option. However, the important issue of operating the current power system and handling shortages is rarely discussed. At present, the lack of a formalized system operation procedure has resulted in a high number of emergency actions such as *unscheduled* load curtailment. This issue is extremely important as the Indian grid is expected to face shortages for a significant number of years in the near future.

The proposed load balancing mechanism aims to address the power system operation issue by using reserves. In the proposed method, load curtailment is treated as a resource and scheduled in the day-ahead along with the procurement of reserves. Having reserves in the system would benefit real-time operation by reducing the need for emergency action (unscheduled load curtailment). Figure 4.5 shows the simulation results of a typical day with mild shortages. Procuring reserves during energy shortages in the day-ahead procedure results in increased scheduled load curtailment. The procured reserves are then used in real-time to manage the variability of electricity demand. The reserves help in reducing emergency actions to a great extent.

The benefit lies in the fact that *scheduled* load curtailment is much more valuable than emergency actions (*unscheduled* load curtailment). At present, scheduled curtailment provides the customer ample time to prepare for the event which is very important to manage critical functions. In

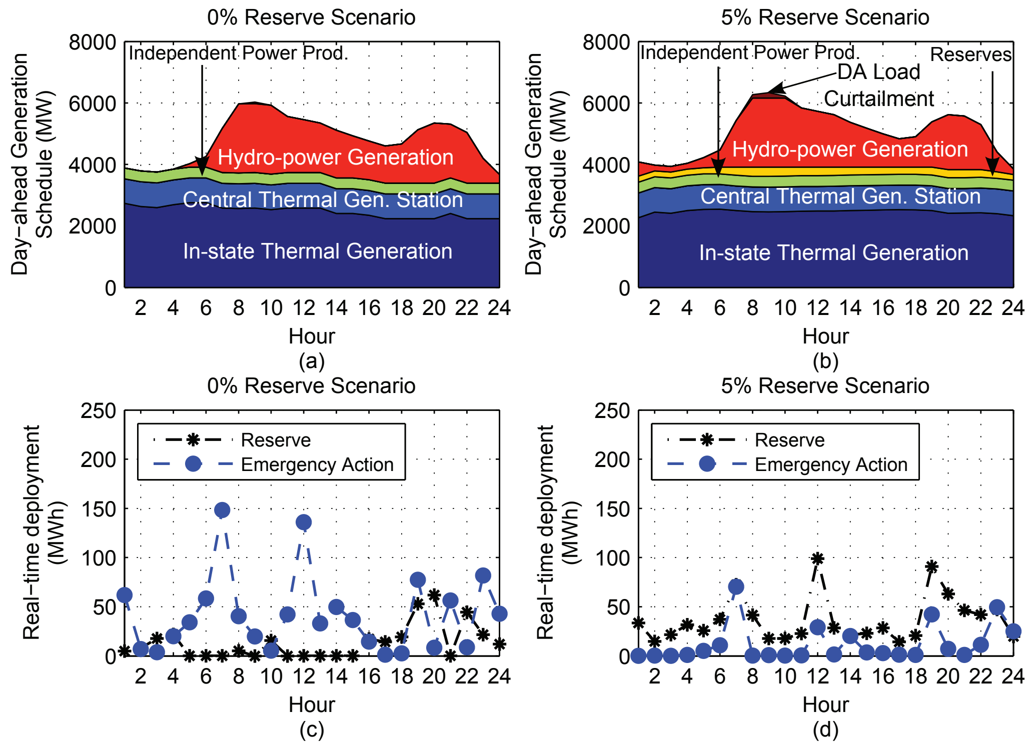

Figure 4.5: Simulation results for July 20, 2013: (a) day-ahead energy generation schedule with no reserve procurement, (b) day-ahead generation schedule with 5% reserves, (c) real-time deployment of resources in excess of day-ahead schedule with no reserves, and (d) real-time deployment of resources in excess of day-ahead schedule with 5% reserves. Procuring reserves result in increased scheduled load curtailment, but the reserves help in reducing emergency actions to a great extent.

the future, scheduled load curtailment will be replaced or improved by better demand side management practices. In any case, demand side management/load curtailment would benefit from providing energy or reserve service only with a better operational practice.

4.4.2 Cost Parameters

Based on the two-settlement system, the system incurs costs in the day-ahead and real-time markets. Figure 4.6 shows the monthly average of (a) the day ahead energy and reserve costs, (b) the day ahead load curtailment costs, (c) the real-time energy costs, and (d) the real-time emergency costs for each day and for each of the considered scenarios over an entire year.

Day-ahead energy and reserve costs

These costs are paid to the generator when they are scheduled in the day-ahead market. There is a significant difference in costs between the scenarios at the beginning of the year. The cost difference can be attributed to the high net demand (Figure 4.4 in the Appendix) during this period. When the net-demand is high, all generation resources are scheduled in the day-ahead market in the 0% scenario. If load-following reserves are procured during this period, the most expensive generation resources that should have been scheduled in day-ahead are now reserved for load-following. These generators receive only capacity payments. These payments are significantly lower than the firm day-ahead energy payments. Therefore, the day-ahead energy and reserve costs appear to be lower for scenarios with higher load-following reserves during higher net demand. During periods of lower net demand (middle of the year), there is enough capacity in the system resulting in the same generators being scheduled in the day-ahead for different scenarios. And, the unscheduled expensive generators are used as reserves. Since the DA reserve payments are comparatively low, the day-ahead energy and reserve costs appear to be similar for all scenarios.

Day-ahead load curtailment costs

Load-following reserves increase the total capacity requirement. Hence, during high demand periods, these reserves result in increased load curtailment. Therefore, load curtailment costs are higher when using load following reserves during periods of high net demand (scarcity periods). The day-ahead load curtailment costs are artificial costs that are not paid in reality. The costs reflect the amount of resultant load curtailment and not actual payments. The costs appear high as high value (nearly 3-4 times the average wholesale energy cost) is placed on load curtailment and it is minimized as much as possible.

Real-time energy costs

Large amounts of load following is beneficial to the system as all intra-hour variations are handled in the system without any need for emergency measures. This can be seen by the increase in the real-time energy costs for the cases with large amounts of reserves.

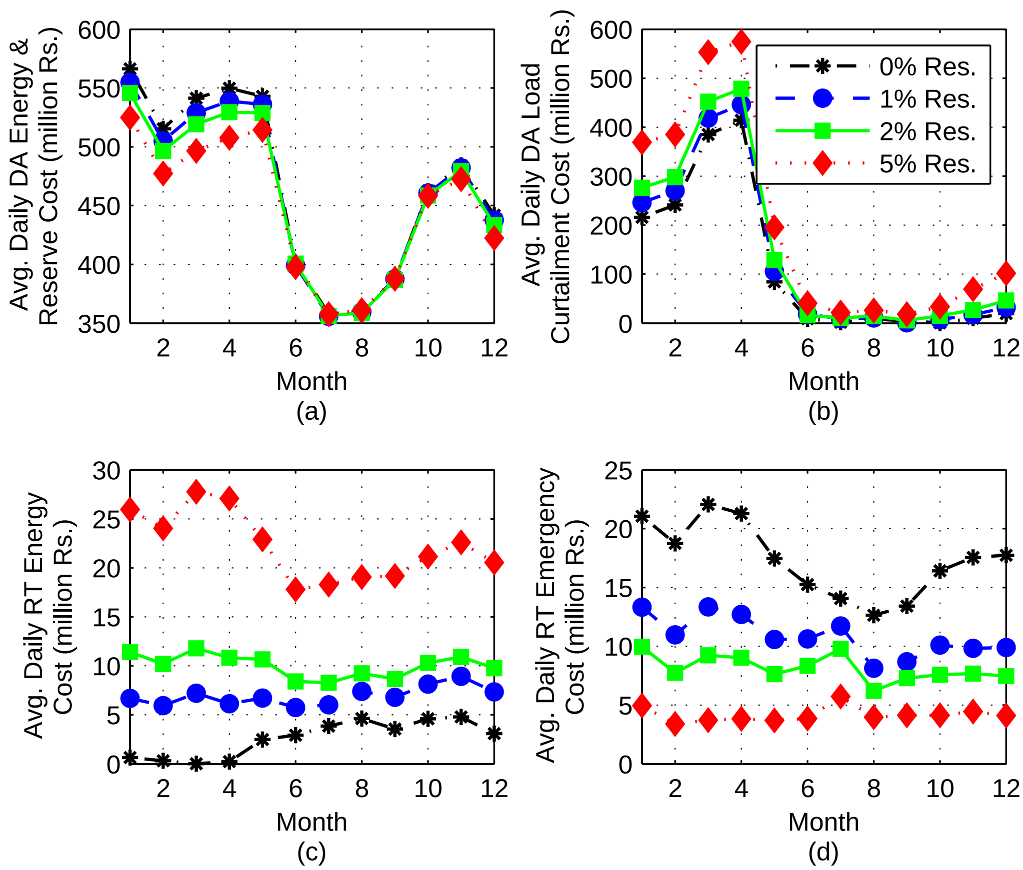

Figure 4.6: The four average daily costs for each simulated month of year 2013. (a) day-ahead energy and reserve costs. (b) day-ahead scheduled load curtailment cost, (c) real-time energy cost due to load-following reserve and incidental energy, (d) real-time costs due to emergency action. The day-ahead load curtailment costs are artificial costs that are not paid in reality. The costs reflect the amount of resultant load curtailment and not actual payments. The costs appear high as high value is placed on load curtailment and it is minimized as much as possible.

Real-time emergency costs

When there is insufficient load following reserves or unused online generation, the frequency of emergency measures increase drastically. Therefore, the cost of emergency measures such as unscheduled load curtailment in real-time increases as can be seen in the Figure 4.6(d). Hence, the cost is shifted from real-time energy to real-time emergency costs.

4.4.3 Average daily energy purchase costs for different levels of reserves

The average daily energy purchase costs for the simulated year is shown in Figure 4.7. These costs represent the average increase in costs that could be expected by the system operator when implementing the different systems.

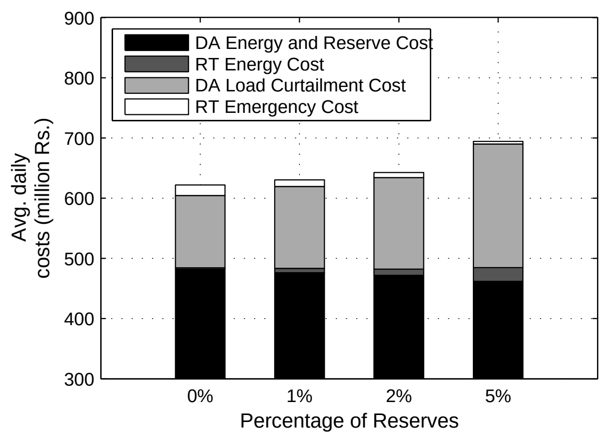

Figure 4.7: Average daily energy purchase costs for the different scenarios for year 2013.

The sum of day-ahead and real-time energy costs, which are firm (actual) payments to generators, are approximately the same in all scenarios. This is because all available generation is either scheduled in the day-ahead or dispatched in real-time due to energy shortages. Further, there is significant load curtailment costs due to energy shortages. Unlike current practice, significant value is placed on load curtailment in order to discourage extensive usage.

Load-following reserve in small quantities does not increase the daily costs substantially. The average daily power purchase cost is about Rs. 622 million for the no reserve scenario, and increases to Rs. 630 million and Rs. 643 million for 1% and 2% reserve respectively. But, having 5% load following reserves increases the amount of day-ahead load curtailment substantially and thereby increases power purchase costs to Rs. 695 million (Figure 4.7). The components of the power purchase cost and its ranges are shown in Figure 4.8.

Real-time emergency measures are quite frequent in systems with severe energy shortages. The real-time emergency measures occur when the system operator is unable to meet real-time demand due to system conditions or scarcity in a certain dispatch interval. Emergency measures are triggered by several factors such as energy shortages, ramping shortages, forecast error or equipment failure. In this study, real-time emergency support was needed for around 40% of the time. Such a energy deficient system benefits greatly from load-following reserve as shown in Section 4.4.1.

Load following reserves increase day-ahead load curtailment but decrease the need for real-time emergency measures. Figure 4.9 (a) shows the percentage of reduction in real-time emergency events due to load-following reserves. Since scheduled emergency measures such as unscheduled load curtailment are less desirable than scheduled load curtailment, having load following reserves is the better option. However, having load following reserves would increase overall costs during energy shortages.

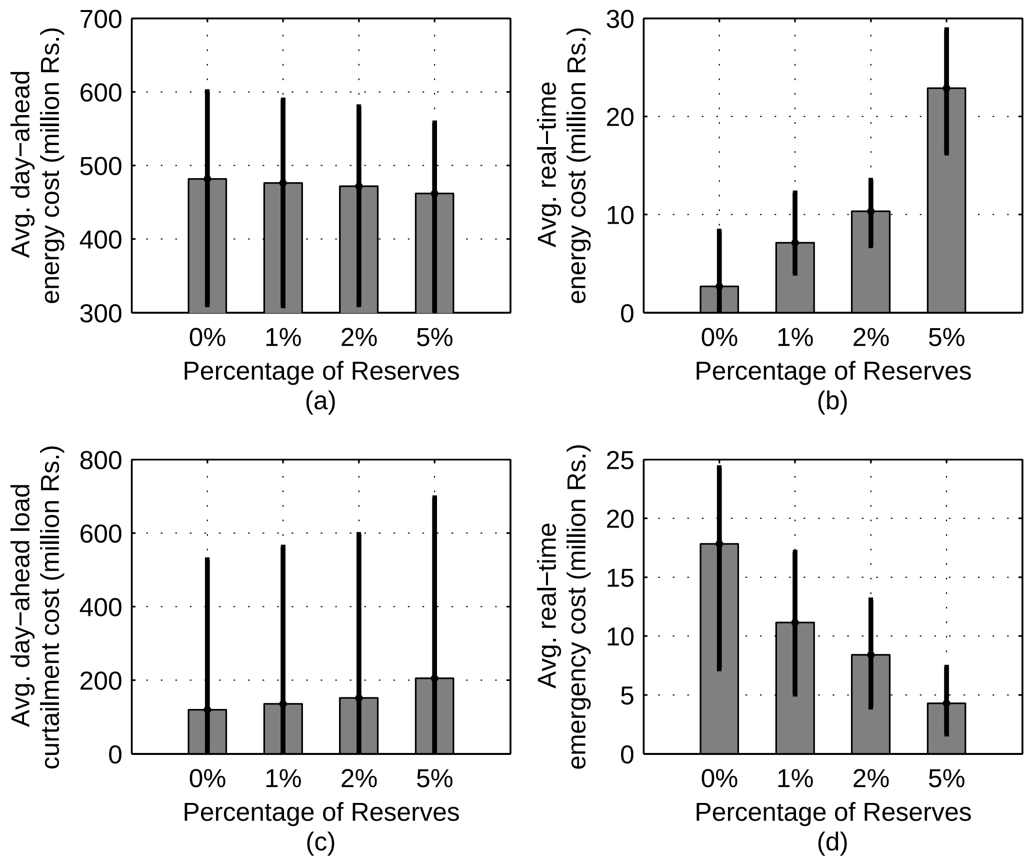

Figure 4.8: Components of the daily energy purchase cost.

The incremental generation (procurement) cost of having load following reserves with respect to 0% reserve (status quo) is shown in Figure 4.9 (b). From Figure 4.9 (a) and (b), it is observed that having 1% load following reserves increases power purchase costs by about 1.5% and reduces the emergency measure deployment events by around 40%. And, 2% load following reserves increase the costs by about 3.5% and reduce the emergency measure deployment events by 55%. Finally, though 5% load following reserves reduce the emergency measure deployments by 80%, the resulting incremental cost is very high at about 11.5%.

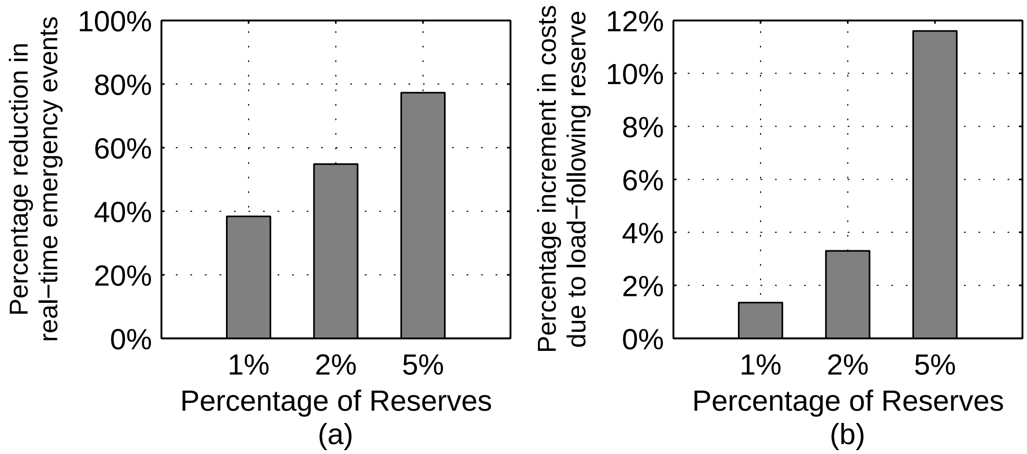

Figure 4.9: (a) Percentage of reduction in emergency measure deployment due to load-following reserves, (b) Average incremental procurement cost(energy purchase cost) of having load following reserves with respect to 0% reserves (status quo).

4.4.4 Sensitivity Analysis of Load curtailment cost

Load curtailment costs are not explicit in nature. It could be a representation of the customer's willingness to pay for electricity among others. These factors are extremely difficult to capture. The simulations are performed by assuming the value of load curtailment as 18 Rs./kWh. The sensitivity analysis of the impact of assuming various load curtailment costs is helpful in analyzing the uncertainty of this value.

Day-ahead load curtailment cost

The change in average daily costs for different values of day-ahead load curtailment costs is shown in Figure 4.10; the real-time emergency costs are held constant at 18 Rs./kWh. When load following costs are around 10 Rs./kWh, the incremental costs of having 1% or 2% load following reserve becomes negligible. Thereafter, the average daily energy purchase cost (a) increases linearly with daily load curtailment costs for each scenario, and (b) are very sensitive to the load curtailment cost assumption. Our assumption of load curtailment cost hinged on the belief that load curtailment occurs as an extreme measure. But, India is less sensitive to load curtailment due to chronic load curtailment. Therefore, the value of load curtailment can be lower than assumed. Further, introducing new generation resources, short-term purchases in the energy exchanges, or demand side management would result in energy that costs less than 10 Rs./kWh, and the new resources would be used instead of load curtailment. In such cases, having load following reserves in the system

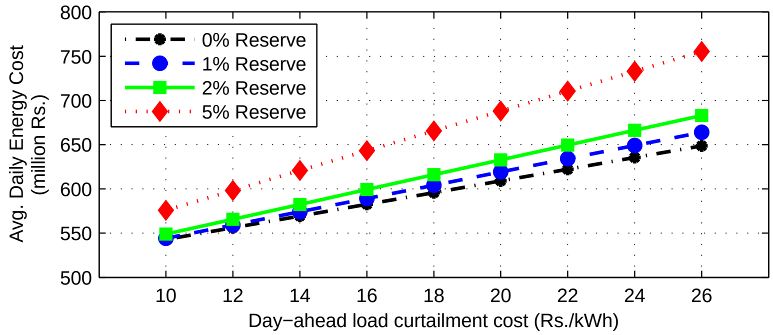

Figure 4.10: Sensitivity Analysis of day-ahead load curtailment cost.

would not be very expensive.

Real-time emergency cost

The change in average daily costs for different values of real-time emergency cost is shown in Figure 4.11. The average daily costs are less sensitive to variation in real-time emergency costs if the system has load-following reserves. This result holds true independent of day-ahead load curtailment costs. When there are no load following reserves, the average daily costs are affected by the volatility of the real-time market. The costs will be low if there are low cost emergency measures. But, often the emergency measures are very expensive from a social perspective if not from an accounting perspective. Considering the argument that day-ahead load curtailment costs will be comparatively low, attention is focused on scenarios with low day-ahead load curtailment costs (Figure 4.11 (a) and (b)). In these scenarios, there is little difference between 0% and 1% load following reserve when the real-time emergency costs are 18 Rs./kWh or higher. Since these are the scenarios with the highest likelihood, having at least small quantities of load following reserve is recommended.

4.4.5 Energy purchase cost and total cost of supplying electricity

From a state distribution utilities' perspective, the total cost of supplying electricity is comprised of several components. The major components of the total cost are energy purchase costs, operation and maintenance costs, establishment and administration costs, miscellaneous expenses, and fixed costs such as depreciation and interest payments. Among these, the energy purchase cost is the major component that makes up 70-80% of the total costs [38]. Therefore an increase in energy

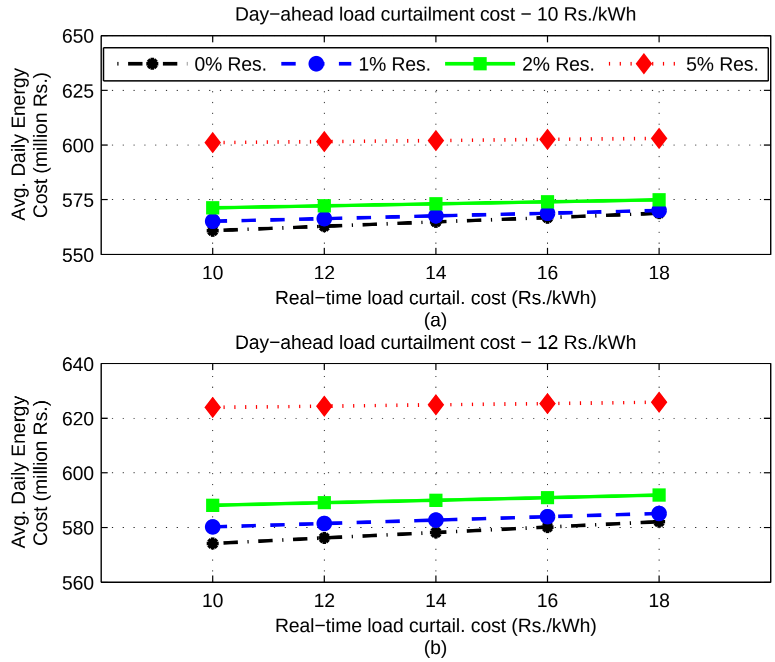

Figure 4.11: Sensitivity Analysis of real-time emergency cost.

purchase cost for the different load following scenarios would increase the total energy costs as shown in Table 4.5. While partly speculation, in the long term, power purchase costs as a share of total retail costs will decrease as utilities increase investments in operations, management, and even required profitability.

Table 4.5: Average increase in power purchase costs and total power costs for the different load following scenarios. Power purchase costs constitute 70-80% of the total power purchase costs. Therefore, a change in power purchase costs has a lesser impact on the total power purchase costs.

Percentage of Load following reserve	Average increase in energy purchase costs (%)	Average increase in total energy costs (%)
1%	1.5%	1-1.2%
2%	3.50%	2.45-2.80%
5%	11.5%	8-9%

4.4.6 Generator Lost Opportunity Cost

Energy prices in electricity markets do not reflect technical limitations and reliability requirements of the power grid comprehensively. This creates the need for out-of-market payments known as energy uplifts [34][7]. Energy uplifts have been a topic of significant discussion in electricity markets in the US [83][8]. The RTOs and ISOs aim to reduce energy uplifts and improve electricity market processes to account for all costs incurred by the service provider. Past research works [39] [114] have proposed improvements to the current electricity market pricing mechanism to help reduce out-of-market costs. Currently, these improvements are being tested and are expected to be incorporated in the future.

Among the different energy uplift payments, the lost opportunity cost (LOC) of generators that provide load following service is of significant importance to this study. Generators that are chosen to provide load-following reserve lose the opportunity to receive firm energy payments in the day-ahead market. In order to encourage participation in the service, the compensation provided through load following should be at least equal to the payments the generator would have received by providing energy in the day-ahead market. The generators that are chosen to provide load following reserves receive two payments: (a) day-ahead reserve capacity payment, and (b) real-time energy payments. The day-ahead reserve capacity payment covers the increased operational costs incurred due to load-following. In addition, the energy payment covers the cost of producing energy. The sum of these payments should be equal or greater than the possible day-ahead payments for the endeavor to be profitable.

A basic outline of lost opportunity (LOC) cost calculation in PJM markets is presented in [54]. Based on general principles, ex-post calculations of opportunity cost is performed in this study to understand the impact of reserves on opportunity costs. First, the generators that are at a disadvantage when providing reserves are identified for each hour. This is done by determining the generators with unit costs lesser than the shadow price[5](Figure 4.12) of the demand-balance constraint (4.2.1.2). These generators would have been selected in the energy market as their unit costs are lower than that of the marginal generator. Since these generators forgo firm compensation to provide reserves, opportunity costs are required to compensate the losses incurred while providing reserves. Next, the total compensation, which is the sum of day ahead reserve capacity payment and real-time energy payments, is estimated. If the total compensation is less than the possible day-ahead energy payment, the difference between the values is the lost opportunity cost of the generator. The estimated lost opportunity cost for the different reserve scenarios is shown in Figure 4.13. From a system perspective, it is observed that having 1%, 2% and 5% load following reserves result in an average lost opportunity cost that is about 1%, 2% and 4% of the total generator payments respectively.

[5]Shadow price represents the value of the Lagrange multiplier associated with a constraint in an optimization problem. In the context of this study, the shadow price represents the value of the next unit of electricity in the system.

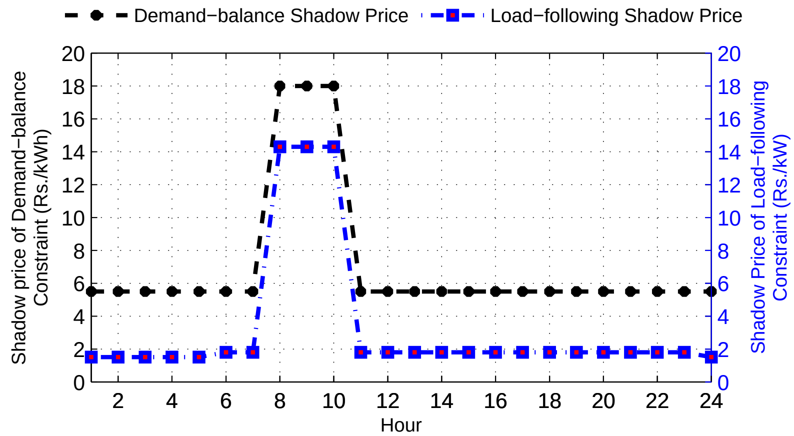

Figure 4.12: Shadow price of the demand-balance constraint and up-reserve constraint for July 20, 2013 in the 5% reserve scenario is shown. The shadow price represents the unit cost of the next available resource (marginal generator). As the same generators provide both energy and reserve, there exists a link between the demand-balance constraint and reserve requirement constraint. During the peak demand periods (7am - 11am), some amount of load curtailment is required. Therefore, the shadow price of the demand balance constraint reflects the unit cost of load curtailment (18 Rs./kWh). At the same time, the shadow price of the reserve requirement constraints also increases to reflect the fact that any increase in reserve procurement would result in an increase in load curtailment. The shadow prices are used as the market clearing price for energy and reserve in uniform price clearing markets. In pay-as-bid pricing markets, the shadow price can be used to identify generators that are eligible for lost opportunity cost compensation.

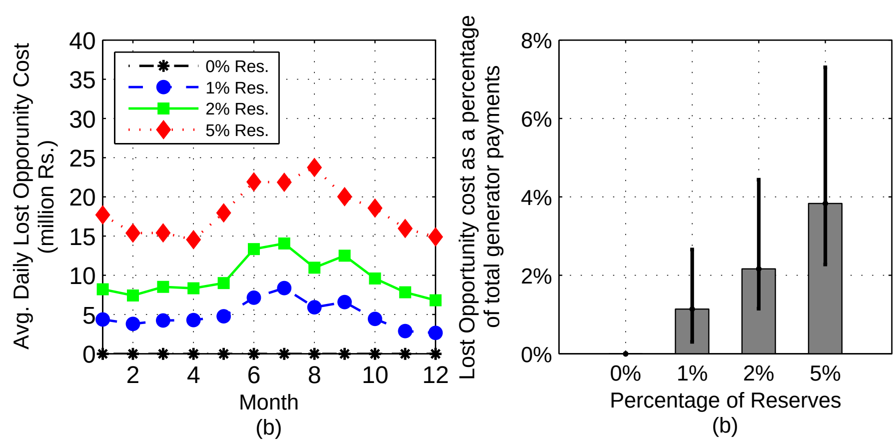

Figure 4.13: The lost opportunity cost estimates for the simulated year is shown: (a) The monthly average opportunity for different levels of reserves, and (b) the lost opportunity cost as a percentage of total generator payments.

It is observed that the opportunity costs tend to be higher during low demand periods and for higher percentage of reserves. If the system procures large quantities of reserves during low demand days, most generators may not be used in real-time, and may not receive sufficient compensation. It then becomes the responsibility of the TSO to cover the lost opportunity cost to ensure that the generators provide sufficient load following reserves. Therefore, the TSO should optimize the quantity of load following reserve procured to minimize lost opportunity cost and emergency action.

4.4.7 Handling deviations from dispatch schedule

The generators scheduled in the day-ahead procedure are expected to adhere to their schedules in real-time. There could be several instances in which the generators might deviate from their day-ahead schedules intentionally or out of necessity. The deviations might affect the system operation negatively at times. To protect against such adverse actions in the inter-state level, the Central Electricity Regulatory Commission (CERC) requires the participants to deviate not more than 12% from the day-ahead schedule to be eligible for compensation [18]. A similar mechanism needs to be extended to the state-level to deter generators from deviating from the schedule. Further, the response to reserve dispatch instructions should also be monitored continuously. Generators that fail to respond to dispatch instructions should be penalized as well.

4.4.8 Optimal reserve quantity

The study focuses on the introduction of reserves to a nascent Indian electricity market. Analyzing a range of reserve requirements helped in demonstrating the extent of potential costs and benefits. During practical implementation in the future, the system regulators and operators will be faced with the challenge of determining the optimal quantity of reserves required. Traditionally, most system operators use a deterministic and static approach to procuring reserves. In recent times, the system operators are moving towards probabilistic and dynamic approaches to determine reserve requirements [47]. In the simplest form, the reserve requirement would be based on the historical forecast errors. The demand and wind generation forecast errors are combined with generator failure rates to determine the optimal reserve requirement for each time period.

The increase in penetration of renewable energy resources has led to a wealth of research in optimal reserve procurement. Particularly, methods that optimize reserve requirement based on costs and benefits have gained prominence [76][65]. These methods employ a probabilistic estimation of the risk of loss of load. The method balances the cost of procuring reserves with the benefit of avoiding load curtailment. Further, there are other sophisticated approaches that employ stochastic optimization in determining reserve quantity [68][113]. Similar methods of sophisticated reserve requirement optimization is expected to be implemented in electricity markets in the future. In addition to the apparent benefits of these approaches, there could be challenges with regards to practical implementation of these methods. Most of these methods operate as a separate optimization procedure before scheduling; the compatibility and the computational requirements of these intensive procedures are yet to be examined.

4.4.9 Limitations

The calculations are based on a subset of the Indian power grid and so the results are representative of the generation mix and characteristics of the particular subset. Care must be taken when extrapolating the results for other systems.

In addition, the thesis does not discuss the interactions and transactions between different regional and state entities. The method is presented as a general mechanism independent of the territory of application. Further, the thesis discusses only the daily energy costs but not the implementation, transactional or fixed mechanism costs. Due to advancement in computing and communication technology, the implementation costs would not be prohibitively high.

4.4.10 Future work

Several additions to the work are expected to be added in the future:

- The proposed mechanism considers only one of several ancillary services. Inclusion of the other ancillary services might result in different generator utilizations and would provide useful insights.
- Further, the limit on hydro-power output, which is the most flexible and most economical resource, is modeled based on the system operator's actions in the simulated year. The system operators do not optimize the daily allocation. As the next step, in our future work, it would be beneficial to optimize hydro-power daily allocation based on annual rainfall, demand, renewable output pattern, and ancillary service requirements.
- Finally, the balancing mechanism is designed for a single TSO. It would be highly beneficial for neighboring TSOs to share their resources. A multi-TSO balancing service would be a complex but useful mechanism. The idea should be explored further to make way for a

pan-India system. This is in line with the current research in EU countries regarding a pan-European system.

4.5 Conclusions and Policy Implications

The CERC proposal for frequency support ancillary services is a much awaited and necessary addition to the Indian power grid. The implementation of the service as proposed by the regulators would be ineffective due to the existing conditions, such as energy shortages, in the grid. Further, the present and CERC-proposed mechanisms are not a full-fledged, continuous load balancing mechanism that is an essential characteristic of frequency support ancillary services. Therefore, there is a need for an effective load balancing service that is aware of the existing issues in the system.

The thesis analyzes a load-following service that serves as a reserve based balancing mechanism. The mechanism handles the issue of energy (fuel) and capacity shortages while ensuring demand-supply balance continuously. The results from the simulations indicate that the service is effective in reducing the emergency measure deployment events by 40% with only 1% reserves, and emergency events are reduced by 55% with 2% reserves. With 5% reserves, emergency events would be reduced by 80%.

As a developing country, costs play a crucial role in the adoption of the proposed methods. Assuming a high value for load-curtailment, adopting the proposed methodology would increase the daily power purchase cost in systems during periods of energy shortage. Given that there is a value placed on load curtailment, the costs would increase by 1.5-3.5% for having 1-2% load following reserves. On the other-hand, if load-curtailment or replacement power is valued at less than 12 Rs./kWh, the incremental costs are negligible for systems with 1-2% load following reserves. This is the more likely scenario as investment in generation and demand side management are expected to improve in the future. But the cost increase is a representation that includes societal costs when value is placed on load-curtailment. In reality, the physical monetary payments are not impacted (as shown in Figure 4.7).

As India aims to improve its system frequency and invest in renewable generation, frequency support ancillary services will be crucial for grid operation. System frequency is dependent on the ability of the system to maintain the balance between demand and supply at all times. Therefore, a good load balancing mechanism is crucial for frequency support. The proposed operational practice illustrates an efficient method for load balancing. The results indicate that the mechanism would be beneficial and cost effective for systems with sufficient generation capacity and high penetrations of intermittent generation. It is designed to provide a good transitional platform for more advanced electricity markets.

Chapter 5

Renewable resource integration in the Indian grid

5.1 Introduction

The Indian electricity grid has experienced tremendous growth and development in the past decade. This rapid growth in demand has led to various challenges, opportunities and regulations. It started with the Electricity Act of 2003 [15] which was a significant regulatory development that allowed for several significant improvements in the generation, transmission, and distribution sectors. The act allowed the delicensing of generators and encouraged participation of independent power producers. It paved the way for setting up regulatory agencies that would help co-ordinate the electricity exchange and trade between the states. It also had provisions for setting procurement levels from non-conventional generation sources. Since the Electricity act of 2003, several other notable improvements have further shaped the evolution of the Indian Electricity system. Notably the availability based tariff (ABT) mechanism and unscheduled interchange (UI) mechanism have helped in bringing operational discipline to the Indian grid. The other significant improvement was the Open Access Regulations of 2008 that laid the base for development of electricity trading platforms such as power exchanges. There are currently two power exchanges in India - the Indian Energy Exchange (IEX) and the Power Exchange India Limited (PXIL) - that operate zonal forward and spot markets. However, even though the regulatory agencies have put great emphasis on developing power exchanges, electricity trading in India is mostly done through Power Purchase Agreements (PPAs) that constitute 89% [14] of all electricity traded.

Despite the many advancements in the past decade, Indian power generation has chronically struggled to meet customer demand. The intention of several new regulations in the past decade was to foster investments in generation. Particularly, there has been tremendous interest in renewable energy sources. The government has a dedicated agency known as the Ministry of New and Renewable Energy to promote and support the growth of renewable energy in the country. As of 2015, the installed capacity of renewable energy resources is 33 GW [11], which is the third largest in the country after coal and hydropower. Wind power is the most prominent renewable energy resource at 22 GW, with over 7 GW from the southern state of Tamil Nadu. This trend is expected to continue in the future where wind and solar would be the major sources of energy in the electricity grid [102].

Increasing penetration of renewable energy resources however has increased the complexity of generation planning, integration and operation due to the uncertainty and variability of the output. The output of major renewable energy resources, such as wind and solar, are impacted by elements of nature that are difficult to predict. Therefore, the output of these resources are in most part not readily schedulable. This changes the conventional view of generation resources in the planning process. Most traditional generation planning processes accounted for the uncertainty of generation availability by including outage factors. With renewable energy resources, the output level is also uncertain and variable in addition to availability. This increased complexity has raised several challenges with regards to generation planning. Most developed countries plan to accommodate high penetration of renewables using the already existing surplus and/or flexible conventional generation. India, on the other hand, lacks surplus or flexible generation to supplement the uncertainty of renewable energy resources. Therefore, there is a need for a balanced approach that considers flexible generation or storage technologies along with renewable energy resource investment.

Renewable energy resources have grown to substantial levels only in recent times. Electricity system operators and planners are faced with the challenge of devising better methods to account for the increased complexity of operating the grid [30][64][81][51][20]. A review of renewable energy integration studies can be found in [23]. Each electricity system is unique with regards to the composition of energy sources. Therefore, the ability to accommodate high levels of renewable energy resources depends entirely on the electricity grid characteristics, geographical location and other factors.

Traditionally, generation planning procedures involve load duration curve based analyses. Though relatively rare, probabilistic methods have also been employed to account for outage factors in load duration curve analyses. More sophisticated methods that formulate the problem as an optimization model that covers multiple periods over the planning horizon have been developed [46][50][35].

These models are often used to find an optimal portfolio of resources that satisfies the reliability criteria (LOLE, LOLP) in a deterministic manner. Further, production simulation models can also be used to understand the impact of variable renewable energy resources on power operation. The deterministic models are capable of optimizing or studying different scenarios of load levels and renewable energy output. But, these deterministic models do not capture the impacts of the stochasticity of renewable energy output comprehensively. Modeling the variability of load and renewable energy sources via a Monte Carlo simulations is a potentially powerful method to assess the impacts comprehensively. Notably, the WILMAR [21] and REFLEX [43] models utilize renewable resource forecast errors and meteorological forecasts via Monte Carlo simulations. In recent times, these models have been used to assess the flexibility requirements in systems with high penetration of renewable energy resources.

The goal of this research is to build on the current body of work and adapt it to analyze a section of the Indian grid. Though all systems have similar issues with regards to integration of large scale renewable energy resources, India faces unique challenges as it aims to utilize renewable energy resources to cover energy deficits. In this study, a production simulation model is used to analyze a year of operation of the grid with different levels of renewable and flexible generation resources. Further, Monte Carlo simulations are used to study a typical day of electric grid operation in different seasons. The models utilize a mix of real-time grid and meteorological data. The results are used to understand the extent to which renewable energy resources can be used to reduce energy shortages in the grid. Further, the simulation helps in analyzing the different operational metrics that define the utilization and suitability of the resource.

The main contribution of this research is the estimation of the impact of different renewable generation scenarios on the Indian grid. The study is meant to support the policy analysis of power system planners and operators. It also presents a method that is better suited to plan and analyze renewable resource integration.

5.2 Research Method

The method proposed in this section is used to model the electric grid operation for the purpose of analyzing the impacts of different levels of renewable energy penetration. Hourly and sub-hourly dispatch modeling of the electric grid helps in understanding the dynamics that are often difficult to capture in load duration curve based analyses. The goal is to mimic the electricity grid operation in sufficient detail. The method uses actual system-wide historical grid data to model a year of operation. System data used in the study includes generator installed capacity, daily availability, maximum output, sub-hourly load data, and wind output. This was supplemented by solar output realizations that was modeled from meteorological data. Such a deterministic modelling of a year of operation in sub-hourly granularity helps in analyzing the impacts across a wide range of grid conditions that occur due to daily and seasonal patterns. The study focuses on understanding the reduction in energy deficits and operational issues that occur due to integration of renewable resources. In addition, the stochastic nature of the model inputs are better captured in a Monte-Carlo based hourly simulation of a typical day in two different extreme seasons.

5.2.1 Production simulation modeling

Production simulation modeling is a widely used modeling technique in the electric power sector [50][35]. The process is used to find the optimal solution to serve system demand with available generation subjected to system constraints. The models are helpful in estimating the expected amount of electricity produced by different generators in the system. This helps in analyzing the amount of generation that needs to be added to satisfy the expected demand in the system. Production cost models are made up of two main components: unit commitment and economic dispatch. Unit commitment, usually performed in an hourly scale, is used to commit resources (start-up, shut-down) that are needed in a particular time frame. Economic dispatch uses the committed resource schedule from the unit commitment procedure to decide the output levels of generators.

The objective of the unit-commitment procedure is to commit sufficient resources to serve the forecasted demand in the most cost effective way. Conventional generation resources require long start-up time and shut-down times. Therefore, the operators need to perform the unit commitment procedure well ahead of time to ensure that sufficient resources are available to serve the demand. The demand in this case is often a forecast of the mean hourly load of the period under consideration. In the proposed model, unit commitment is performed as a day-ahead procedure that commits resources for the next 24 hour period. The procedure uses generator characteristics, daily generator availability and daily maximum power output for fossil-fuel based generators. Hydropower often serves multiple purposes in the Indian system and the energy output depends on various factors. Therefore, hydropower is constrained by daily maximum energy output as well. Renewable energy resources are modeled as non-dispatchable resources and the output is not curtailed in any dispatch scenario.

After the unit commitment procedure commits generators for each hour of the day, the economic dispatch procedure uses the outputs of unit commitment to set output levels of the committed resources optimally. Generation availability, maximum output and generator constrains are transferred from the unit-commitment procedure to the economic dispatch procedure. The economic dispatch procedure is repeated for each 15-min interval of the simulated day. The sequential unit commitment and economic dispatch procedures are repeated for each day of the year as shown in Figure 5.1. Implementation of the production simulation model is performed using the commercial modeling software PLEXOS from Energy Exemplar[1].

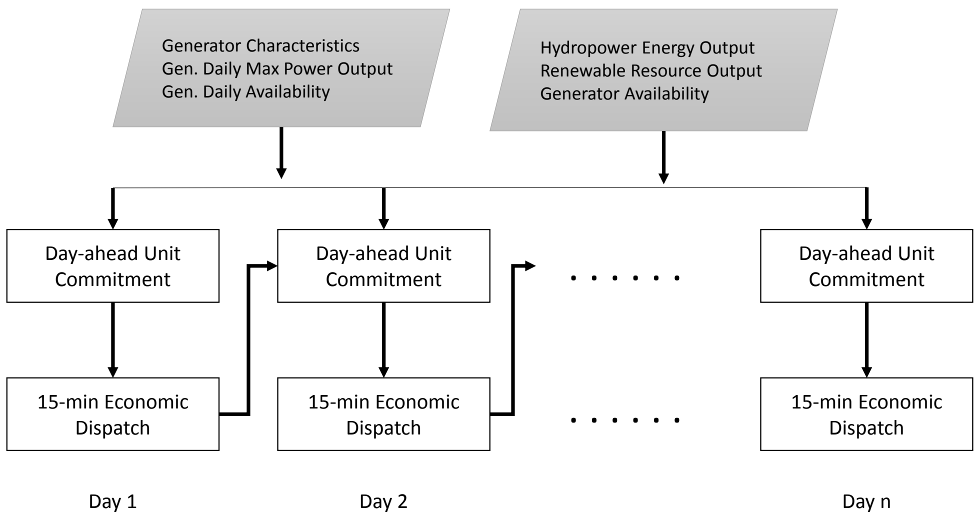

Figure 5.1: Schematic of production simulation model

5.2.2 Monte-Carlo Dispatch simulation

Production simulation models are powerful tools that model a system in a given time-period. Performing simulations over long periods of time has the benefit of studying all possible interaction in the grid. However, there is no guarantee that the models have represented all possible system conditions and states. It may not be able to model some extreme scenarios in the grid. Though the method is useful to study the system under normal conditions, the approach does not analyze several possible combinations of system conditions. It would be very beneficial to simulate a large number of days from historical data in order to better represent the full spectrum of system conditions that may be encountered. This probabilistic approach can be implemented using Monte-Carlo methods [44][58][105].

[1]PLEXOS for Power systems. ⟨http://www.energyexemplar.com⟩.

The term Monte-Carlo method is applied to simulations with stochastic inputs that are used to generate a large number of scenarios. The large number of scenarios is expected to model a wide range of possible scenarios in the grid including the extreme ones. It is an efficient and elegant method to analyze complex systems with several stochastic inputs. The method is straightforward and simple to apply. However, the biggest disadvantage is that a large number of realizations and computations are required to obtain a reasonable estimate. The schematic of the procedure is shown in Figure 5.2.

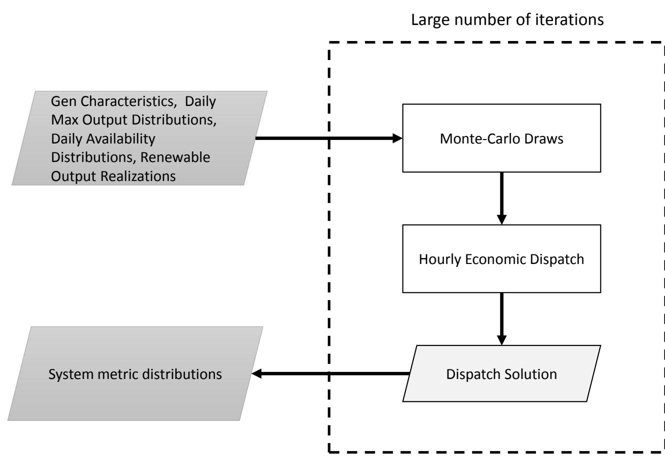

Figure 5.2: Schematic of the Monte-Carlo Simulation

5.2.3 Data

Geographical Scope of Analysis

India is a large country with diverse geographical characteristics. Due to the vast size, the different regional and state grids are of varying characteristics. The states are in different stages of progress with regards to renewable energy investment, generation and planning. Though India is rich in natural resources, the resources are concentrated in a few regions. For instance, the eastern region of India is blessed with abundant hydro power resources. Whereas, the western part of the country has great potential for solar power. Ideally, India should plan to utilize the wide range of resources in different parts of the country in an integrated fashion. However, the socio-political demarcations as well as technical and economic constraints of the country do not allow for an integrated approach. Often, the different states plan, to varying degrees, to invest in generation only with the state requirements in mind. Due to this practice, this research analyzes a single state and evaluates the ability to fulfil demand within the state with renewable resources.

The choice of state used in the analysis is dictated by data availability. The state of Karnataka in the southern region has invested in advanced grid monitoring and data acquisition systems. The state load dispatch center and transmission corporation have made many of the power system data public. Further, the state possesses a good amount of renewable resources that would be a fitting example for estimating the impacts of renewables.

Generator Data

Data on generator installed capacity is available through the state load dispatch center. The agency publishes detailed power plant operational data for each day of the year. The research utilizes daily generator availability, daily maximum power output (MW), and daily energy output (MWh) for each day of the year. Detailed description of generator data used in this study was presented in the previous sections. All conventional generation technologies used in the model have a limit on the maximum output that could be generated in a particular day. In addition, hydro-power resources are constrained by energy availability. The average energy purchase cost per unit (kWh) of electricity will be used in our unit-commitment and economic dispatch optimizations to choose the economically optimal set of generators to serve the demand. The energy purchase cost is based on annual financial reports and regulator approved energy purchase cost [52] for a state LSE. The installed capacity and power purchase cost of the generators in the state is shown in Table 4.3 and Table 4.4.

Demand Data

Demand data with 5-minute granularity was obtained from the state load dispatch center. The data represents total demand observed across the entire state in the modeled year. The demand for the simulated year is shown in Figure 5.3. From the figure, it is seen that the demand is higher during the first few months of the year, and subsequently lower during the middle of the year. Average demand for the hour is used in the unit commitment procedure, and a 15 minute average is used in the economic dispatch procedure.

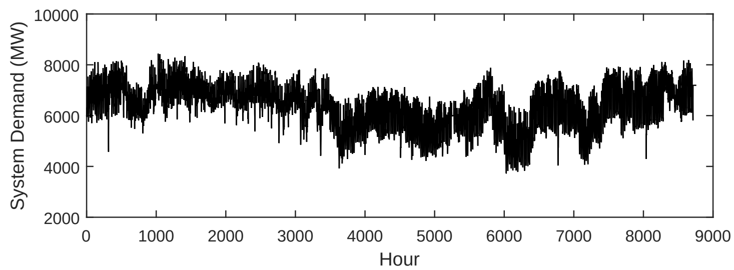

Figure 5.3: Hourly demand data for year 2013

Wind data

The wind power output data was obtained with 1-min granularity from the state load dispatch center. The data represents the power output of all wind power plants in the state for the simulation year. The installed capacity of wind during the year was around 2000-2200 MWs [13]. The hourly average output of wind power is shown in Figure 5.4. In contrast to demand, output from wind power plants tend to be lower at the beginning of the year, and tends to be high in the middle of the year.

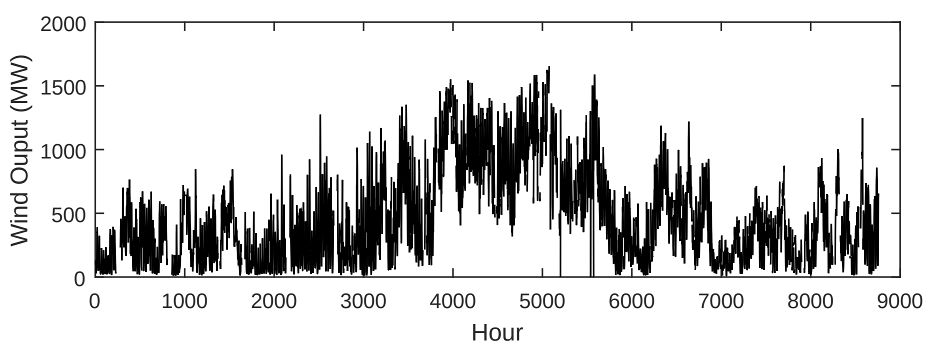

Figure 5.4: Hourly wind output data (installed capacity 2000 MW)

Demand and wind output data in the system under consideration tend to exhibit a negative correlation. An estimation of Pearson's correlation coefficient ρ of demand x and wind output y is obtained by using the formula:

$$\frac{\sum_{i=1}^{n} x_i y_i - n\bar{x}\bar{y}}{\sqrt{(\sum_{i=1}^{n} x_i^2 - n\bar{x}^2)(\sum_{i=1}^{n} y_i^2 - n\bar{y}^2)}}$$

where, x_i, y_i are the i^{th} observation of x, y, and $\bar{x}, \bar{y}$ are the mean values, and n is the number of observations. The resulting pearson coefficient of -0.38 indicates a weak to moderate negative correlation. Though the estimate is not statistically robust, it provides an indication that there is some impact due to seasonality that needs to be explored.

Solar Model

Solar power in the state is in a developing stage. Reliable data was not available from the state agency. Therefore, solar output was generated using models available from research labs (NREL SAM/PVWatts[2]). NREL PVWatts is used to estimate the electricity produced from photovoltaic systems based on inputs such as the installed capacity, the irradiance, the temperature, and the panel configurations. The electricity output estimate is based on several sub-models such as the module and inverter.

The state has several districts with varying number of planned projects. NREL PVWatts is used to generate PV output profiles for each of the districts. The annual hourly solar output generated from the application is shown in Figure 5.5. District share of total state installed capacity in the model is based on the values in table A.3. This value is used to obtain district-wise share of total future solar installs in the state.

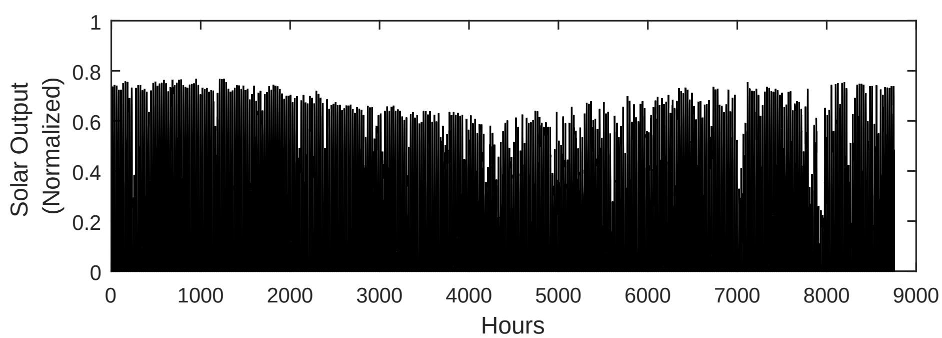

Figure 5.5: Annual hourly output of a 1MW solar PV system

5.2.4 Seasonal Impacts

As discussed in previous sections, the factors used in the production simulation model tend to have seasonal variations. The variations exhibited by these factors help in understanding and evaluat-

[2]System Advisor Model Version 2015.1.30 (SAM 2015.1.30). National Renewable Energy Laboratory. Golden, CO. Accessed March 12, 2015. https://sam.nrel.gov/content/downloads.

ing the impacts more accurately. The monthly output histogram for wind resources in the state is shown in Figure 5.6. The months can be broadly divided into two categories: low-wind months and high-wind months. During the low wind months (January, February, March), the output tends to be concentrated near zero with a few days of higher outputs. The average hourly output rarely exceeds 50% rated capacity during these months. In contrast, during the high wind months (June, July, August), the wind output tends to be near 50% rated capacity most of the time. The output throughout the season is significantly higher than the low-wind season. The output tends to follow more of a normal distribution during this period. Due to this variation in seasonal output, the monte-carlo dispatch is performed for a typical day in each of these two seasons.

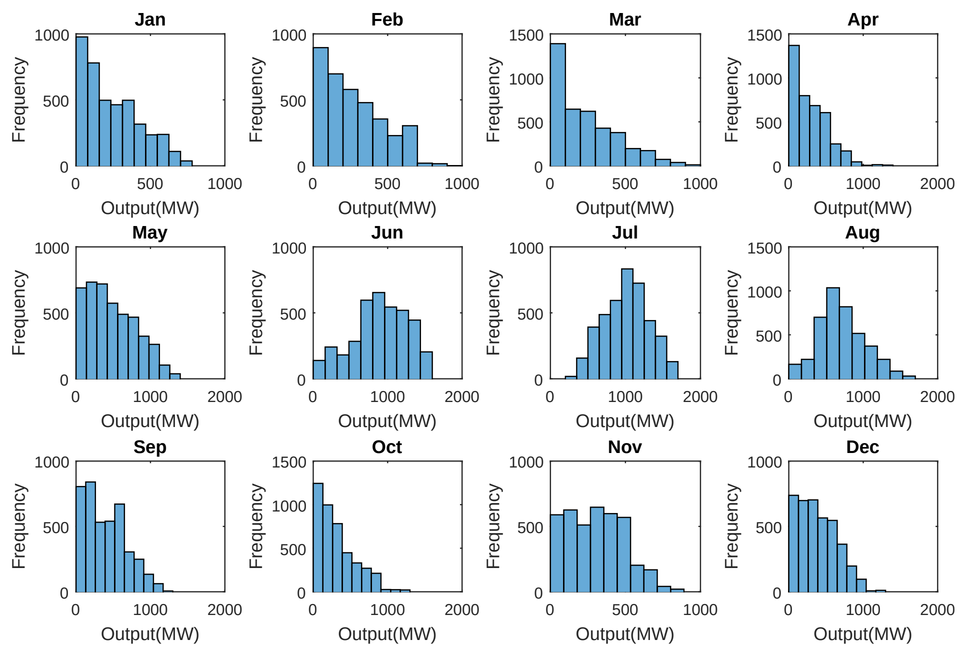

Figure 5.6: Monthly wind output distribution for the simulated year

5.2.5 Statistical models for Monte-Carlo dispatch

The Monte-Carlo dispatch simulation is based on the assumption that the variable factors in the model can be approximated using simple statistical models. There are several variable factors in day-to-day operation of the electric grid. The main variable factors used in the research include generator characteristics (availability, maximum power output, maximum energy output), hourly demand, hourly wind output, and hourly solar output. Each realization of a day is generated by utilizing randomly selected generator, load, wind and solar profiles from probability distributions that are based on historical data for the year. In order to reflect the seasonal and related meteorological correlations, the analysis is performed for two different seasons as discussed in the previous section.

Generator

The main variable factors of the generator model are:

1. Outage rates: The outage rates are used to model the availability of generators in a simulated day. It is based on the plant availability reported for the simulated year. The sampling is based on a binomial distribution; the available output (P_i) of a power plant is modeled by:

   $$P_i^{avail} = v_i N_i P_i^{max}$$

   where, $v_i \sim B(N_i, p_i)$, N_i is the number of units in the power plant, $p_i = 1 - q_i$ is the probability that the generator is available, q_i is the outage factor, and P_i^{max} is the daily max output of each unit in plant i.

2. Maximum output: The reported availability in the Indian grid tends to be much higher when compared to the actual output from the power plant. To account for the discrepancy, the daily maximum output from historical data are also included as an additional constraint in the system to account for factors beyond reported availability. The daily maximum output for each generator is modeled as a normal distribution:

   $$P_i^{max} = \bar{P_{i,d}} + x_i^p$$

   where, $\bar{P_{i,d}}$ is the mean daily output of unit i, and $x_i^p \sim N(0, \sigma_{i,p}^2)$ is the normally distributed random variable used to model the spread of possible maximum power output. The sampling in each iteration is independent of one another.

3. Maximum energy output: While conventional generators are subjected to a maximum power constraint, hydropower generators have constraints on maximum energy output. The constraints on maximum energy for hydro-resources is modeled as a normal distribution similar to the maximum power output.

Wind

Wind data used in the study are based on actual wind output observed in the system. The system-wide wind data encompasses all commissioned projects for the year. The data obtained are in 1-minute granularity and possesses good spatial and temporal coverage of all current projects. The average of the data points over the hour were used as the hourly output in the studies.

Unlike conventional generators, wind and solar generators are modeled as non-dispatchable resources whose output is not controlled by the operator. Therefore the output of the resources in itself is treated as a random variable in each hour. The wind power output exhibits two main patterns. First is the seasonal variation that is taken into account by performing the monte-carlo simulation based on two seasonal patterns. Second is the daily pattern that represents the difference in output in each hour of the day. Figure A.2 shows the hourly wind output distribution during high wind season. The output in each hour is approximated using a normal distribution. Modeling a random variable using a normal distribution might at times result in negative values. Therefore, limits are set such that negative values are truncated to zero. Further, the hourly samples are not independent of each other; the correlation between the output of a particular hour y_t and a future hour y_{t+k} is modeled using an autocorrelation function:

$$r_k = \frac{c_k}{c_0}$$

where,

$$c_k = \frac{1}{T-1} \sum_{t=1}^{T-k} (y_t - \overline{y})(y_{t+k} - \overline{y})$$

and c_0 is the sample variance of the time series, $\overline{y}$ is the sample mean, and T is sample size.

Solar Output

The hourly solar output generated from the model for each month for the geographical area under study is shown in Figure 5.7. The seasonal and daily pattern of solar output is depicted in the figure. It is observed that the seasonal variation of solar output is not as strong as wind but naturally it has a very strong daily pattern. This very phenomena makes utilizing and planning for solar power a challenge. Solar output is modeled similar to wind resources in the monte-carlo dispatch. Each hour of the simulated day is approximated using a normal distribution. In addition, auto-correlation function similar to wind modeling is used to create dependency between consecutive hours.

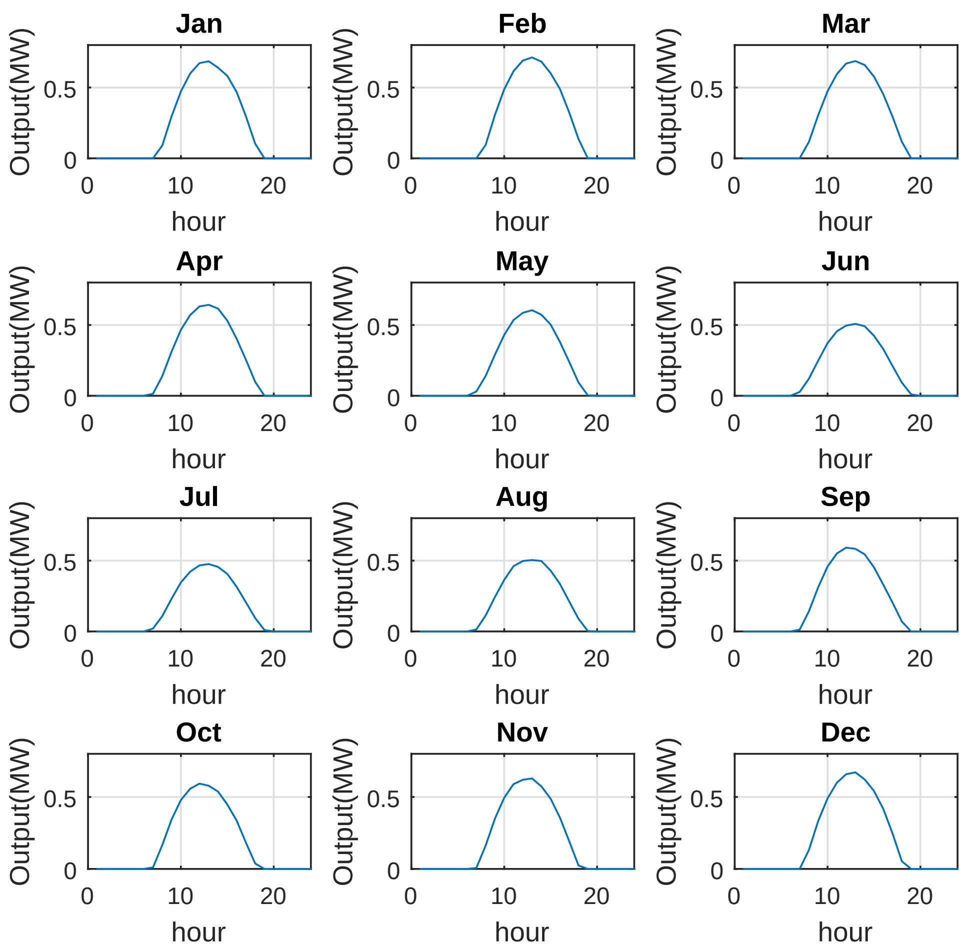

Figure 5.7: Average hourly solar output for each month of the simulated hour

Demand

The seasonal variations and daily patterns in system demand are significant. The Monte-Carlo dispatch is designed to represent the pattern by modeling demand as a random variable. Similar to the wind and solar model, hourly demand is approximated using a normal distribution. And, the correlation between the hours is established using the function discussed in the previous sections.

5.2.6 Scenarios

The Indian grid faces several challenges with regards to development and integration of renewable energy resources. In contrast to developed countries where the main drivers for renewable resources are environmental concerns and energy independence, the main driving factor in India is the need to build sufficient capacity to satisfy forecasted demand. Relying on renewable energy resources to meet demand raises several issues. Most renewable energy resources exhibit seasonal and daily variations in output capability. For instance, generation systems dependent on solar power cannot produce power in the night time unless supplemented with some storage technology. Similarly, wind power resources do not produce output at equal levels in all seasons. Therefore, there is a need to invest in either storage technologies or flexible generation to supplement renewable resources. Flexible generation, in the context of this study, is defined as any conventional generation technology with fast ramping and quick start-up/shut-down capability with variable costs typically greater than base-load generators. Flexible generation in the study is not rigidly defined and is used as a reference for future storage and flexible resources.

The research analyzes different combinations of renewable energy resources and flexible generation. The scenarios simulated in this study are:

- Base case: The base case represents the current state of the grid. During the year under consideration (2013), there were 80 MWs [13] of commissioned solar projects and greater than 2000 MW of commissioned wind power projects. The interest in wind resources had grown tremendously in the years prior to the study year resulting in a substantial amount of wind power in the system. Solar projects have not received the same amount of interest and therefore the region has not seen significant growth in solar generation in the past years.

- Solar growth scenarios (Scenarios 1 & 2): These scenarios are used to assess the impact of growth of solar resources. As per the state department of renewable energy resources, the aggregate capacity of all planned solar projects in the state is currently around 900 MW. The first scenario uses a value of 800 MW to represent a situation in which most of the planned projects are commissioned. In addition, a scenario in which interest in solar power grows to a great extent (2000 MW) is also simulated to understand the impact of very high amounts of solar in the system.

- Wind growth scenarios (Scenarios 3 & 4): During the study year, the system possessed about 2000 MW of wind resources. There is tremendous interest in additional wind power resources in the state; there are more than 10 000 GW [13] of planned wind power projects in the state. However, the number of projects that most likely will be commissioned is much lower. Considering this, the medium wind scenario represents a probable situation in which the amount of wind power resources in the grid is doubled to 4000 MW. In addition, a very high wind scenario with 6000 MW of wind resources is also modeled to simulate an extreme case of wind resource growth.

- Renewable energy (RE) growth scenarios (Scenarios 5 & 6): While the previous scenarios were used to study the impact of either solar or wind resources to varying degrees, RE growth scenarios are used to represent possible future combinations of solar and wind resources. Scenario 5 represents a medium growth scenario that has a high possibility of realization. Scenario 6 represents a very high renewable growth scenario that is possible only through significant regulatory support. These scenarios reflect situations in which emphasis is placed only on renewable energy growth.

- Flexible generation scenarios (Scenarios $7-11$): At present, the Indian grid planners and regulators have not focused on flexible generation resources as a supplement to renewable energy resources. The scenarios are designed to analyze the impact and benefit of adding flexible generation to the previous scenarios. Two levels of flexible generation growth is modeled. The first is a modest situation in which there is a moderate level of flexible generation in the order of 1000 MW. The second situation corresponds to a case with a high amount of flexible generation in the system. The scenarios with high levels of flexible generation serve as extreme cases as a point of comparison for other scenarios.

The scenario combinations formed from the above cases are listed in Table 5.1. The production simulation model and Monte-Carlo dispatch is performed for each of the listed scenarios.

Table 5.1: Scenarios considered in the simulation

Scenarios	**Solar (MW)**	**Wind (MW)**	**Flexible (MW) (MW)**	**Description**
Base	80	2000	0	Base Case
S1	800	2000	0	Med. Solar
S2	2000	2000	0	High Solar
S3	80	4000	0	Med. Wind
S4	80	6000	0	High Wind
S5	800	4000	0	Med. RE
S6	2000	6000	0	High RE
S7	80	2000	1000	Base + Med Flex
S8	800	4000	1000	Med RE + Med Flex
S9	800	4000	2000	Med RE + Hi Flex
S10	2000	6000	1000	Hi RE + Med Flex
S11	2000	6000	2000	Hi RE + Hi Flex

5.3 Results

5.3.1 Production simulation model

The production simulation model described in section 5.2.1 was simulated for each scenario for the year 2013. In the production simulation model, all other parameters except the installed capacity of renewable resources and flexible generation are held constant across the scenarios. The simulation is used to study the operational characteristics of the grid under different circumstances.

Since the main focus of this research is the estimation of the ability of renewable resources to reduce energy deficits, the amount of unserved energy is a useful measure in evaluating the impact of the additional resources. Further, the capacity factor provides an indication of the usage of the resources in the grid, and total energy output allows analyzing the contribution of the resource to total system needs. In addition, the number of hours in which there is unmet demand is studied.

Unlike developed countries, the Indian power system is much more resilient to power failures. Most critical applications are supported by backup power. In such a system, it is useful to evaluate the quantity of unserved energy as well as the cost of additional resources. Given that there is higher tolerance for load curtailment, there is a lesser need for excess investment in expensive generation to achieve high standards of reliability. The higher tolerance for unmet energy could be a deciding factor when moving towards higher levels of renewable generation penetration. Therefore, an analysis of the benefit derived from reduced unserved energy and related costs is important to evaluate the net benefits of increased renewable resources in the grid.

Unserved Energy

The amount of unserved energy is obtained from the 15-min economic dispatch procedure. The economic dispatch procedure schedules generators to meet the forecasted demand in short intervals. Ideally, the economic dispatch should be performed every 5-15 minute in order to re-position the generators for reliable operation. The 15-min dispatch procedure provides a good level of granularity to assess the impact of renewable resources on grid performance. It strikes a balance between rigor and computational effort. Further, the 15-min dispatch helps in capturing the variability of wind output in short intervals and allows measuring the amount of unmet demand with better granularity.

The unserved energy in the simulated scenarios is shown in Figure 5.8. In the base case that represents the current system configuration, 4.7% of energy demand is unserved. Increasing the amount of energy resources in the system leads to reduction in the amount of energy unserved. The amount of reduction depends greatly on the availability of renewable energy resources during periods of shortage.

Increasing the amount of solar resources from 80 MW to 800 MW and 2000 MW results in a reduction in the percentage of energy unserved from 4.7% to 3.7% and 2.5% respectively. Further, increasing wind resources from 2000 MW to 4000 MW and 6000 MW reduces the percentage of energy unserved to 3.2% and 2.3% respectively. Similarly, the scenarios with combined increase in renewable resources reduce the percentage of energy unserved to less than 2.5%. Specifically, the high renewable energy scenario reduces the percentage of energy unserved significantly to around 1%.

Though having renewable resources in the system reduces the amount of unserved energy, high amounts of renewables are required to achieve a considerable impact. The installed capacity of solar and wind resources required is quite high at 2000 MW and 6000 MW respectively. In comparison, adding just 1000 MW of flexible generation resources reduces the percentage of demand unserved to less than 1%. Further, there are several periods in which the renewable resource output is not sufficient to fulfil system demand even with high amounts of renewables. Therefore, supplementing renewable resource with flexible generation is better suited to achieve significant reduction in unserved energy.

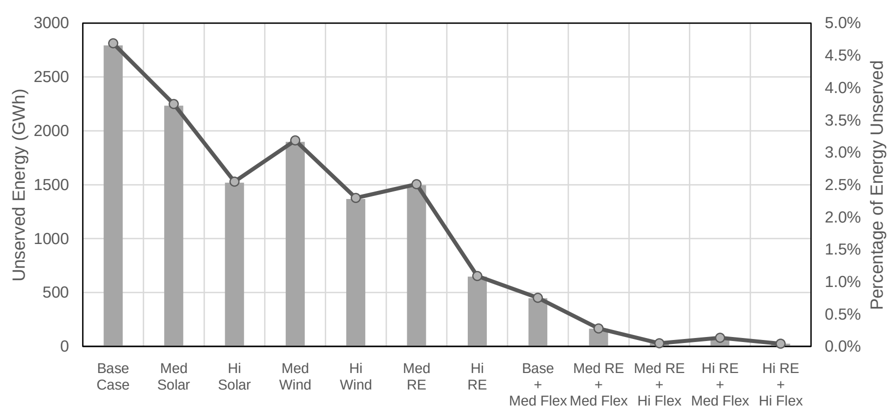

Figure 5.8: The amount of unserved energy in the simulated year for all scenarios.

Hourly impact of renewable resources on unserved energy

Unlike conventional generation resources, the output of renewable resources is dependent on seasonal and hourly factors. Therefore, the reduction in unserved energy due to renewable resources are non-uniform across different seasons and hours of the day.

The hourly impact of solar resources on unserved energy is shown Figure 5.9. Solar output follows a daily pattern and the output is highest during sunlight hours. The reduction in unserved energy is greatest during the middle of the day. During hours with no sunlight, there is no reduction in unserved energy in the medium solar penetration scenario. However, with a high amount of solar resources, the system capacity is greater than demand during sunlight hours. The excess capacity helps in shifting the utilization of energy resources such as hydro power to non-sunlight hours. This causes a reduction in unserved energy even during non-sunlight hours in the high solar scenario.

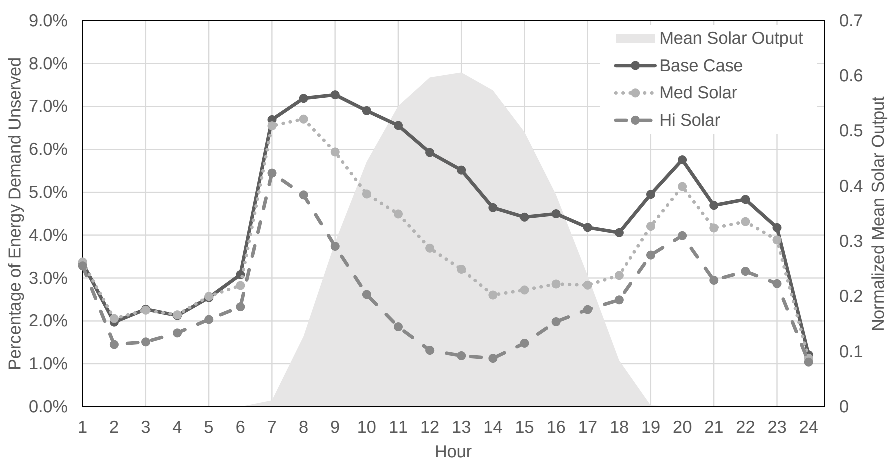

Figure 5.9: Hourly impact of solar resource on unserved demand. The reduction in unserved energy is greatest during the middle of the day. During hours with no sunlight, there is no reduction in unserved energy in the medium solar case. With high amount of solar resources, reduction in unserved energy is observed even during non-sunlight hours as excess solar power causes shifting of hydro power utilization.

In contrast to solar resources, wind energy resources exhibit a strong seasonal pattern rather than a daily pattern. The mean annual normalized wind output of each hour along with the reduction in unserved energy is shown in Figure 5.10. The difference between the wind output during on-peak and off-peak is not significant. Due to this, reduction in unserved demand occurs in all hours of the day. Increasing the amount of wind resources increases reduction in unserved demand in all hours.

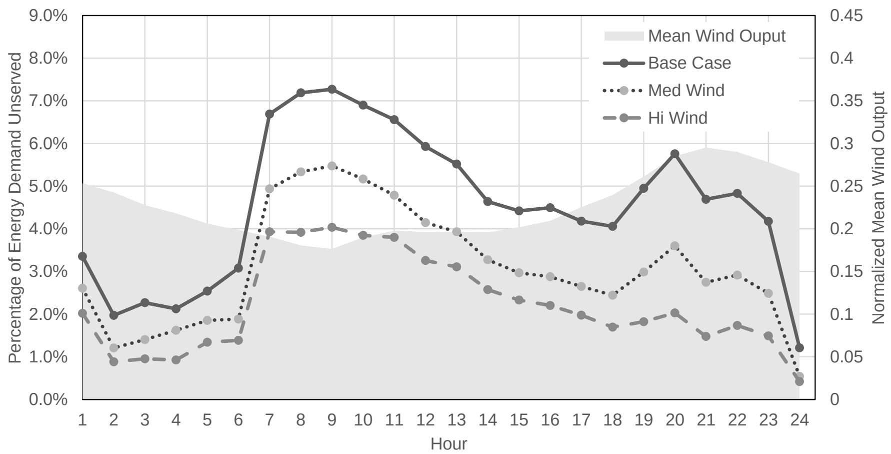

Figure 5.10: Hourly impact of wind resource on unserved demand. Wind resources exhibit a less pronounced daily pattern. Reduction in unserved demand occurs in all hours of the day. Reduction in unserved demand in greater during the later part of the day when wind output is high.

Due to the difference in output patterns of solar and wind resources, the impact of these resources on unserved energy varies. The impact of a 2000 MW increase in solar and wind resource is shown in Figure 5.11. As discussed earlier, solar resources have a greater impact during the middle of the day whereas the impact of wind resources is greater during the later hours. Overall, solar resources tend to have a greater impact on reducing unserved demand. This is because solar output is higher during sunlight hours and coincides with higher demand. Further, seasonal variation in wind output is negatively correlated with demand. That is, wind output is higher during low demand. In general, low demand periods have lower unserved energy thereby reducing the need for extra generation.

Due to the variability and uncertainty in solar and wind output, even high amounts of these resources cannot satisfy demand at all times. Therefore, there is a need for some amount of flexible generation resource. The impact of flexible generation on unserved energy is shown in Figure 5.12. The amount of unserved energy is significantly reduced with high amounts of renewable resources in the system. However, there still exists some unserved energy during peak periods. Flexible generation resources are needed to eliminate unserved energy at all hours.

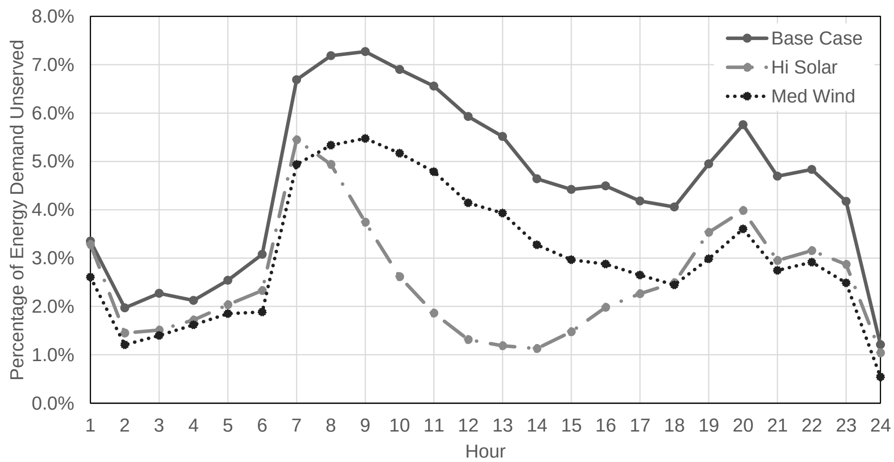

Figure 5.11: Comparison of the impact of a 2000 MW increase in solar and wind resource. Solar resources have a significant impact in reducing the amount of unserved energy during the middle of the day. Whereas, wind resources reduce unserved energy in all hours of the day to varying degrees.

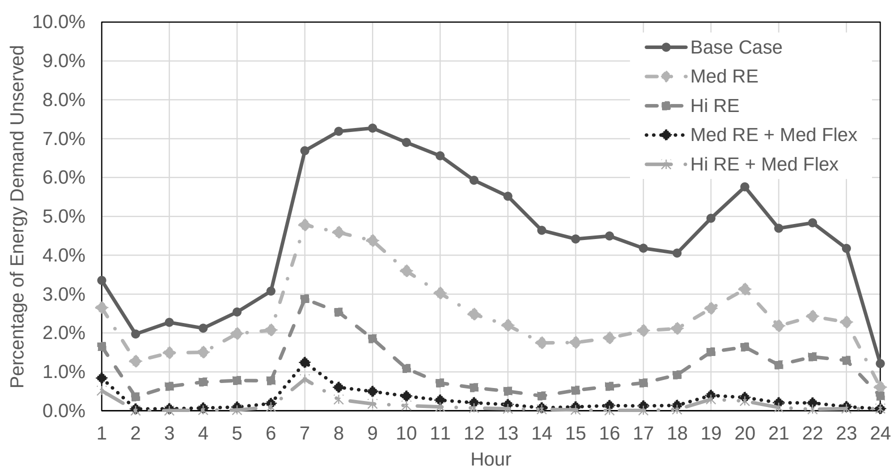

Figure 5.12: Comparison of the impact of flexible generation on unserved demand. Though renewable resources reduce the amount of unserved demand to a great extent, there remains some amount of unserved energy during peak hours. Flexible generation resources are needed to eliminate unserved energy at all hours.

Capacity Factor

Capacity factor represents the utilization of a generation resource, and it is an important measure of the impact of renewable generation on conventional generation resources in the system. Typically, cheaper resources have higher capacity factors, and expensive resources have low capacity factors. Expensive resources have low capacity factors because expensive resources are called only for a few hours a day during high demand periods. However, expensive resources that have very low capacity factors provide an indication that they are redundant resources and may not be needed in the grid.

The capacity factor is obtained by utilizing the output data from all simulated hours and determining the ratio of the actual output to the maximum potential output. Table 5.2 shows the capacity factors for the different scenarios and resources. Cheap conventional resources, such as coal power plants, will usually have very high utilization and capacity factor. In the simulation, coal power plants, which constitute the largest resource in the system, have a capacity factor of about 58% in the base case. This is because coal power plants faced fuel shortages in the simulated year which results in comparatively lower capacity factors. Across the different scenarios, the capacity factor of coal generators drop only in scenarios with high wind energy penetration. The capacity factor drops to 47% during high renewable scenarios. In these scenarios, coal generators are backed down to accommodate renewable resources.

Hydropower is the second largest resource in the system in terms of installed capacity. However, hydropower resources cannot be used at maximum capacity constantly. The resource is constrained by energy availability and auxiliary functions. There is also a seasonal component to the usability of hydro resources. Due to these factors, the capacity factor of hydro power stays at about 31%. Since hydro power is the cheapest and most flexible resource in the system, it is always employed to full capacity in all scenarios.

The renewable resources and flexible generation resources are used along with conventional resources to satisfy demand. Renewable resources are considered non-dispatchable in the model and their output is accommodated by adjusting other resources in the system. Since solar and wind resource have different capacity factors, the net capacity factor varies across the different scenarios and is dependent on the renewable generation penetration levels. Further, the capacity factor of flexible generation is much lower than other resources as it is used only during very high demand periods. Flexible generation, being the most expensive resource, is called upon only when all other resource are unavailable or exhausted. Despite the low utilization, flexible generation plays a very important role in ensuring reliability.

Table 5.2: Capacity factor of different generator types in the simulated year

	Coal	Hydro	Solar	Wind	Flexible Gen
Base Case	58%	31%	18%	22%	
Med. Solar	57%	31%	18%	22%	
High Solar	56%	31%	18%	22%	
Med. Wind	55%	31%	18%	22%	
High Wind	50%	31%	18%	22%	
Med. RE	54%	31%	18%	22%	
High RE	47%	31%	18%	22%	
Base + Med Flex	58%	31%	18%	22%	47%
Med RE + Med Flex	54%	31%	18%	22%	31%
Med RE + Hi Flex	54%	31%	18%	22%	21%
Hi RE + Med Flex	47%	31%	18%	22%	18%
Hi RE + Hi Flex	47%	31%	18%	22%	13%

Generator Output

Another metric of interest in this study is the total annual energy output of the generators. The total energy output helps in comparing the contribution from the different generation resources (Figure 5.13). In the system under consideration, coal generators are the largest resource in terms of installed capacity followed by hydropower. Renewable resources are currently the third largest and are expected to exceed hydropower in terms of installed capacity in the near future. Increasing renewable resource penetration has the advantage of reducing dependency on fossil fuels. However, the level of contribution from renewable generation is affected by the availability of the primary energy resource and how the resource is utilized.

Measured in terms of energy output, coal based generators are the largest contributors in all scenarios. Hydropower is the second largest producer in all scenarios except for the high remewable scenarios. In high wind scenarios, renewable energy resources (solar + wind) form the second largest electricity producer in the system (Figure 5.14).

Hours of unserved energy

Renewable energy resources in the Indian grid are thought of as an option to fulfil demand and reduce deficits. However, the uncertainty and variability of the power output from renewable resources makes it difficult to reach the expected production levels at all times of the day. An assessment of the inability of renewable resources to serve system demand is an important metric to assess the suitability of renewables. The number of hours in which the different scenarios fail to satisfy system demand is presented in this section.

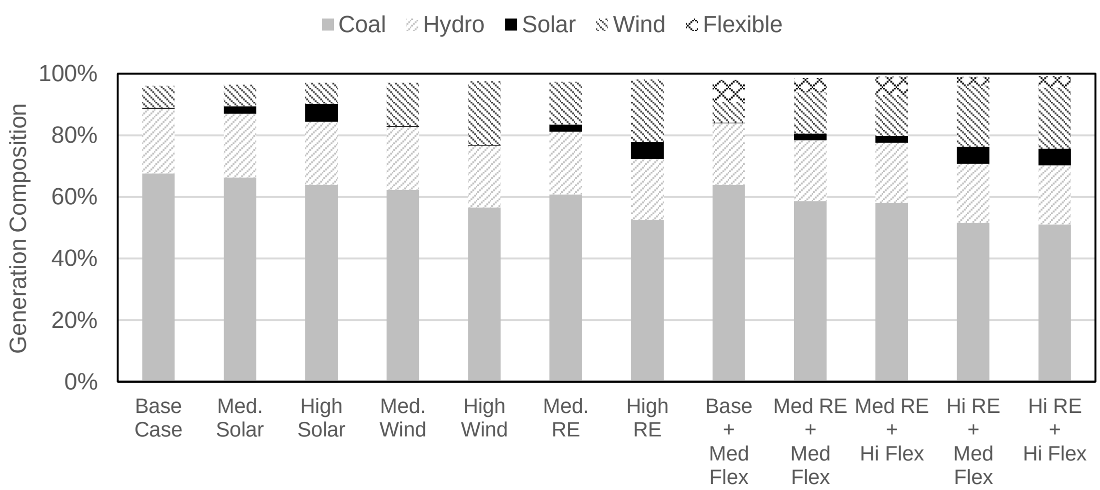

Figure 5.13: Energy composition of each simulated scenario.

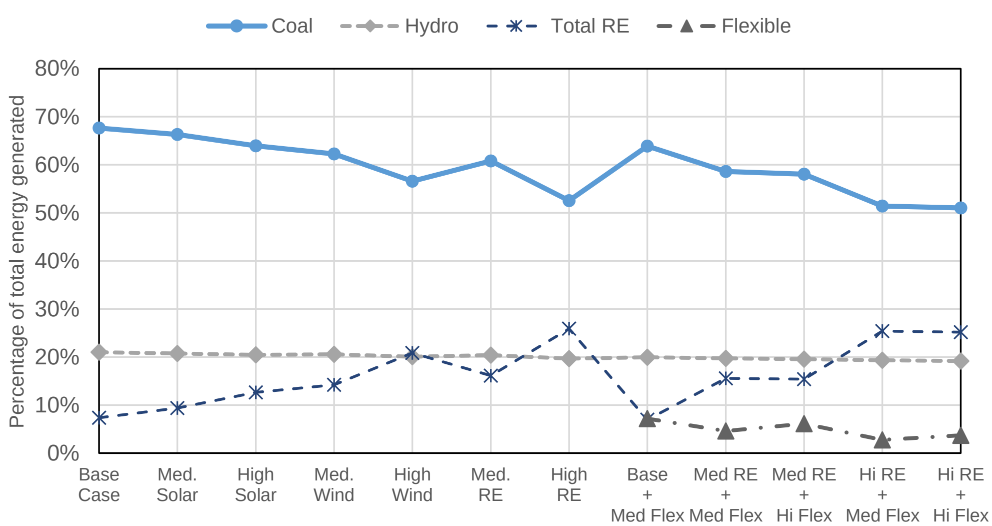

Figure 5.14: Percentage contribution of different resources to total energy generated. Coal is the largest contributor to energy production in all scenarios. Hydropower is the second largest producer in all scenarios except for the high wind scenarios.

The economic dispatch simulation is performed for each 15-minute interval of the year. The procedure utilizes the generators that are online to serve the demand in the interval. If the net demand (demand after subtracting renewable resource output) is greater than the available generation, there is a deficiency of supply in that particular interval. These intervals are counted towards the hours of unserved energy.

The number of hours of unserved energy as a percentage of total hours simulated is shown in Figure 5.15. The results exhibit a wide range of outcomes. The base case is used as a reference for the different scenarios. In this scenario, there is some amount of unmet demand in 45% of all hours. Scenarios 1 and 2 (Med Solar and Hi Solar) represent scenarios in which only the amount of solar resources in the grid are increased. Increasing solar resources in the grid does not have a significant impact on the number of hours of unserved energy. With 800 MWs of solar, the percentage of hours of unserved energy drops from 45% to 40%. With 2000 MW of solar power resources, the hours of unserved energy drops to 30%.

As discussed earlier, wind resources have very high seasonal variation. In addition, wind resources have a moderate negative correlation to system demand. Therefore, wind resources are not able to cater to the requirements of the grid during time of need as shown by medium and high wind scenarios. Though the amount of wind resources are doubled (medium wind scenario) in the grid, the percentage of hours of unserved energy still stays at 33%.

Flexible generation, though typically more expensive than conventional generation technologies, are capable of quick start and rapid change in output levels. This quality makes them well-suited to balance the variability of renewable power output as well as provide emergency response when needed. Having even 1000 MW of flexible generation brings the percentage of hours of unserved energy to about 5% in medium renewable scenario and to 2% in the high renewable scenario. Having high amounts of flexible generation (2000 MW) would drastically reduce the percentage of hours with unserved energy to less than 1%.

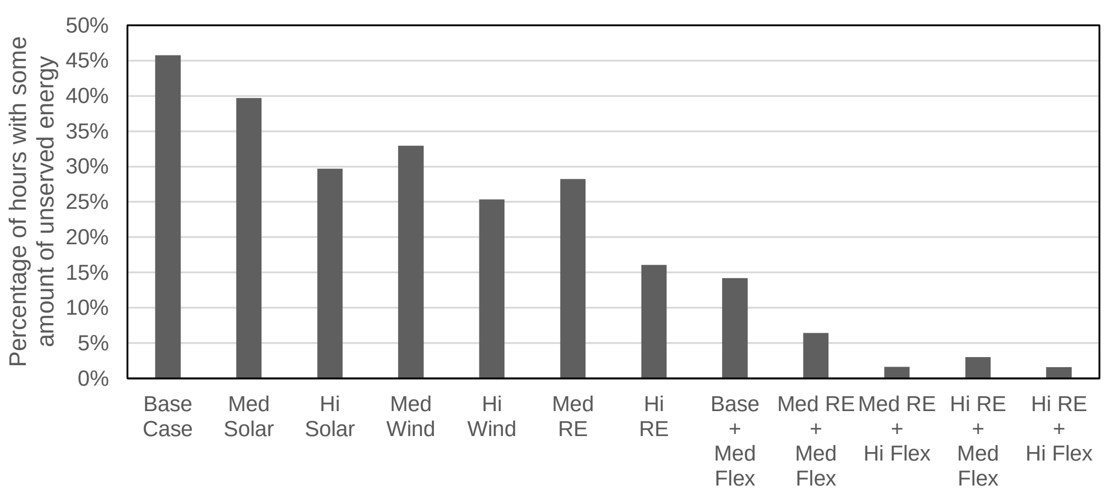

Figure 5.15: Percentage of hours of unserved energy in the simulated year

5.3.2 Cost Estimation

In addition to performance metrics, incremental costs of adding new resources is an important factor for planners and decision makers. An estimation of the cost of the additional resources in each scenario is presented in this section. The cost estimates are based on the levelized cost of energy (LCOE) for each technology.

The levelized cost of energy is the cost of generating electricity that encompasses all costs over the lifetime of the system. The levelized cost includes overnight capital costs, operation and maintenance costs, fuel costs and cost of capital. LCOE is the minimum price at which the resource must be compensated to break-even. It is influenced by the discount rate to a great extent. The discount rate must be carefully chosen based on the cost of capital and an assessment of the financial risk involved.

The assumptions used in the system is shown in Table 5.3. The capital recovery factor is used to convert the present value of overnight costs into annuity payments over a specified time at the stated discount rate. The capital recovery factor for a discount rate i and number of annuities n is:

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$$

The simple levelized cost of energy is calculated using the following formula:

$$sLCOE = \frac{(OCC * CRF) + OM_{fixed}}{8760 * CF} + \frac{FC * HR}{10^6} + OM_{var}$$

Where OCC is the overnight capital cost $(Rs./kW)$, OM_{fixed} is the fixed operation and maintenance cost $(Rs./kW - yr)$, OM_{var} is the variable operation and maintenance cost $(Rs./kWh)$, FC is fuel cost is $(Rs./MMBtu)$, and HR is the heat rate (Btu/kWh). Since solar and wind output are not curtailed, the capacity factor (CF) remains fixed in all scenarios. The capacity factor of flexible generation depends on the utilization and differs for each scenario. It is obtained from the production simulation model.

The average cost of additional resources C_{res} is obtained from the LCOE and energy output of the resources in each scenario. It is obtained by dividing the total cost for each scenario by total energy output from the additional resources. It is estimated using the following formula:

Table 5.3: Cost data used in the estimation

	Wind		**Solar**		**Flexible**		
	Low	**High**	**Low**	**High**	**Low**	**High**	**Reference**
Number of years of useful life			25				
Cost of Capital			15%				
Capital Recovery Factor			0.155				
Overnight Capital Cost (Rs./kW)	46,000	75,000	52,000	72,000	40,000	60,000	
Fixed O&M (Rs./kW-year)	600	3500	650	3250	325	1625	[75, 5, 53, 91]
Variable O&M (Rs./kWh)					0.13	0.585	
Fuel Cost (Rs./MMBTU)					300	500	[36]
Heat Rate (BTU/kWh)					8500	11500	[5]
Capacity Factor	22.2%		18.2%		30.0%	12.5%	
sLCOE (Rs./kWh)	4.0	7.8	5.5	9.0	5.2	16.3	

$$C_{res} = \frac{E_w * sLCOE_w + E_s * sLCOE_s + E_f * sLCOE_f}{E_w + E_s + E_f}$$

Where E_w, E_s, E_f are the incremental energy outputs (with respect to base case) from wind, solar and flexible resource respectively, and $sLCOE_w, sLCOE_s, sLCOE_f$ are the simple levelized cost of energy. Estimation of the costs in the different scenarios are shown in Table 5.4. The energy output of the individual resources are obtained from the production simulation model. The capacity factor and sLCOE for solar and wind resources remain constant for all scenarios. Whereas, the capacity factor and sLCOE for flexible generation changes depending on the installed capacity and resource utilization.

Renewable resources technology are expected to be the most prominent energy resource in the future. The increased interest has led to a wide range of cost estimates for renewable resources. In general, the average cost of additional energy is estimated to be around 4.5 to 10 Rs./kWh. The scenarios exhibit variations in cost depending on the capacity factor and generation composition.

In addition to costs, an important factor that dictates the choice of generation is the resulting reduction in unserved energy. This is considered as the benefit of procuring more resources. The optimal generation portfolio provides the most benefit to the system. An assessment of the net benefit of each scenario provides a good estimate of the overall impact of the scenario. Net benefit is the difference between the total benefit obtained and total costs incurred. The net benefit of the different scenarios is estimated using the following formula:

$$NB = (E_u * C_{lc}) - (E_w * sLCOE_w + E_s * sLCOE_s + E_f * sLCOE_f)$$

Table 5.4: Estimation of the cost of additional energy. Cost of additional energy is estimated using LCOE and energy output of individual technology types. The sLCOE used for wind and solar is shown in Table 5.3. The sLCOE of flexible generation varies based on the capacity factor. The capacity factor of flexible generation in the different scenarios is shown in Table 5.2.

	Wind Energy Output	Solar Energy Output	sLCOE Low	Flexible sLCOE High	Energy Output	Average Cost of Additional Energy Low	Average Cost of Additional Energy High	Perc. Of Energy Unserved
	GWh	GWh	Rs./kWh	Rs./kWh	GWh	Rs./kWh	Rs./kWh	
Base Case	3876	127						4.69%
Med. Solar	3874	1275				5.5	9.0	3.75%
High Solar	3873	3189				5.5	9.0	2.55%
Med. Wind	7760	127				4.0	8.0	3.19%
High Wind	11630	126				4.0	8.0	2.30%
Med. RE	7759	1274				4.3	8.2	2.51%
High RE	11620	3186				4.4	8.3	1.09%
Base + Med Flex	3855	126	4.3	9.0	4106	4.3	9.0	0.75%
Med RE + Med Flex	7738	1271	5.1	10.4	2677	4.6	9.0	0.28%
Med RE + Hi Flex	7740	1270	6.3	12.4	3564	5.2	10.0	0.05%
Hi RE + Med Flex	11607	3181	6.7	13.1	1602	4.7	8.9	0.13%
Hi RE + Hi Flex	11615	3174	8.6	16.3	2184	5.1	9.6	0.04%

Where, E_u is the incremental energy unserved (with respect to base case) in GWh, and C_{lc} is the cost of load curtailment. Energy unserved in the different scenarios is estimated using the production cost simulation. The cost of load curtailment is the value that the system operator places on the load. Given the frequent load curtailment in the Indian system, the load curtailment cost is expected to be much lower than developed countries. Nevertheless, the value of load curtailment plays a very important role in choice of generation investments.

The net benefit of the different scenarios with various load curtailment (load shed) cost is shown in Table 5.16. The sLCOE of wind, solar and flexible generation used in the estimation is 4 Rs./kWh, 6 Rs./kWh and 10 Rs./kWh respectively. The net benefit is highest in the cases with medium levels of renewable and flexible generation. However, the difference between the net benefits of medium and high levels of flexible generation is negligible when the load curtailment costs are high.

The result of the net benefit estimation with a wider range of load curtailment costs is shown in Figure 5.16. At low load curtailment cost (15 Rs./kWh), the system is more tolerant of load curtailment and the more expensive flexible generation resources do not provide incremental benefits. Therefore, scenarios without flexible generation provide higher net benefits. At higher load curtailment costs, the system operator chooses to reduce the amount of load curtailment in the system. The net benefits of having expensive flexible generation is greater. At very high load curtailment cost, scenarios with medium amount renewables with flexible generation are the optimal choice.

Table 5.5: Net benefits estimation of the different generation scenarios. sLCOE of wind, solar and flexible resources is 4 Rs/kWh, 6 Rs/kWh, and 10 Rs/kWh respectively. Net benefits are estimated for different values of load shed cost. The scenario with the highest net benefit in each of estimate is highlighted.

	Energy Output			Energy	Net Benefit		
	Wind	Solar	Flex	Unserved	Load Shed 30 Rs./kWh	Load Shed 45 Rs./kWh	Load Shed 60 Rs./kWh
	GWh	GWh	GWh	GWh	Billion Rs.	Billion Rs.	Billion Rs.
Base Case	3876	127		2793			
Med. Solar	3874	1275		2233	9.9	18.3	26.7
High Solar	3873	3189		1519	19.8	38.9	58.0
Med. Wind	7760	127		1899	11.3	24.7	38.1
High Wind	11630	126		1368	11.7	33.1	54.5
Med. RE	7759	1274		1495	16.5	36.0	55.5
High RE	11620	3186		648	15.0	47.2	79.4
Base + Med Flex	3855	126	4106	447	29.3	64.5	99.7
Med RE + Med Flex	7738	1271	2677	165	**29.8**	**69.2**	**108.6**
Med RE + Hi Flex	7740	1270	3564	30	24.9	66.4	107.8
Hi RE + Med Flex	11607	3181	1602	79	16.1	56.8	97.5
Hi RE + Hi Flex	11615	3174	2184	25	12.0	53.5	95.0

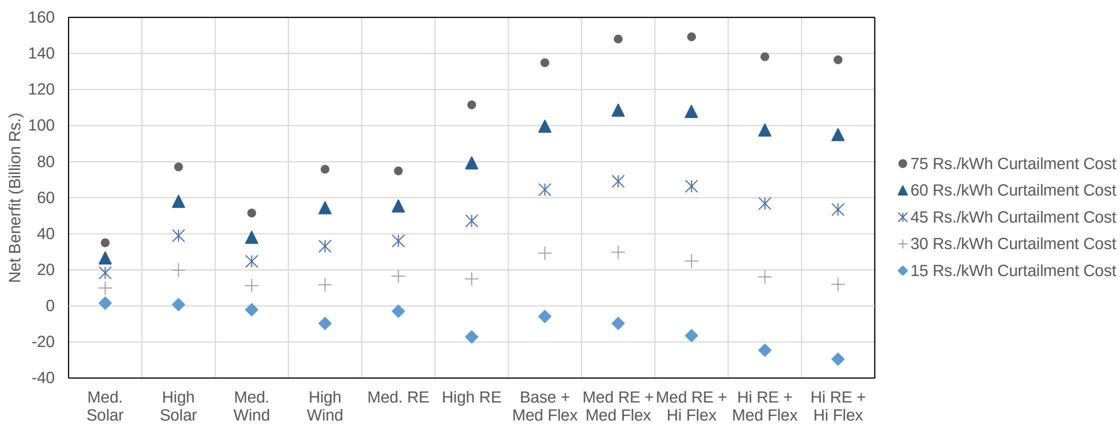

Figure 5.16: Net benefit of the simulated scenarios for different assumptions of load curtailment cost. sLCOE of wind, solar and flexible resources is 4 Rs/kWh, 6 Rs/kWh, and 10 Rs/kWh respectively. At low load curtailment costs (15 Rs./kWh), the system is more tolerant of load curtailment and the more expensive flexible generation resources do not provide incremental benefits. At higher load curtailment costs, the benefit of reducing load curtailment is greater. Therefore, scenarios with flexible generation resources have greater net benefits.

The optimal generation scenario, that has the highest net benefit, depends on the cost of the generation resources and load curtailment. A sensitivity analysis is performed to estimate the impact of varying cost. The results of the sensitivity analysis is shown in Figures 5.17 to 5.18. When the cost of flexible generation is low, the net benefit of scenarios with only flexible generation is higher. Similarly, when the cost of renewable resources is low, scenarios with renewable resources have greater net benefits.

In general, renewable resources are less effective in reducing unserved energy when compared to flexible generation. Therefore, cost of renewable resources must be sufficiently low to realize benefits. Further, the incremental reduction in unserved energy due to renewable resources can be justified only when the load curtailment costs are high.

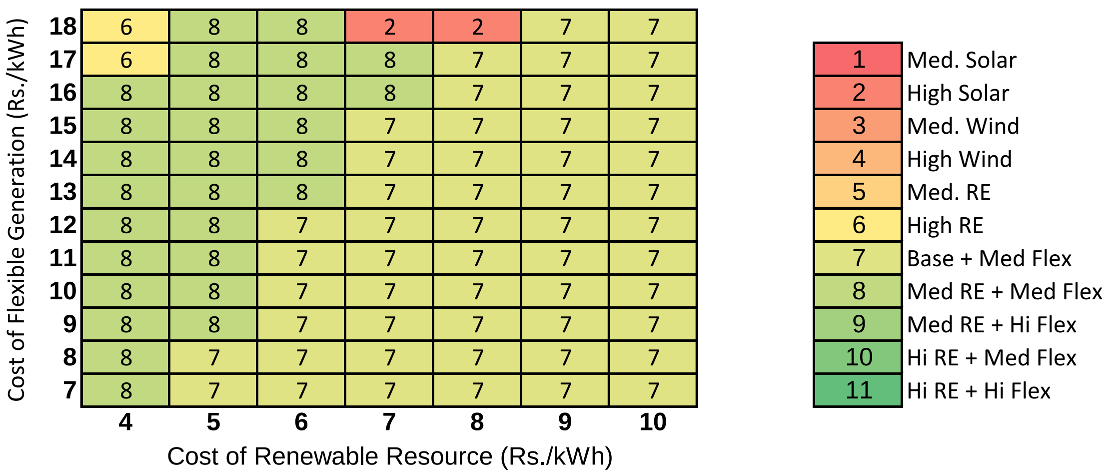

Figure 5.17: Sensitivity analysis of the optimal scenario (highest net benefit) to variation in cost of renewable resources and flexible generation. The load curtailment cost is fixed at 45 Rs./kWh. The optimal scenario depends on the cost of the resources. At lower renewable costs, scenarios with renewable resources are chosen.

5.3.3 Sensitivity of the results to change in capacity of hydropower resources

Hydropower is a cheap, efficient, and fast responding resource. The system simulated in this study possesses significant amounts of hydropower resources. Several regions in India do not possess the same level of hydropower resources. Therefore, additional scenarios with varying levels of hydropower is simulated to estimate the sensitivity of the results to changing levels of hydropower.

Hydropower resources are subjected to energy constraints in addition to capacity constraints. Replacing hydropower with thermal generation impacts both energy output and capacity output. Multiple scenarios are generated to capture both of these impacts. In the first scenario, 50% of

Cost of Flexible Generation (Rs./kWh) \ Cost of Renewable Resource (Rs./kWh)	4	5	6	7	8	9	10
18	10	8	8	8	8	7	7
17	10	8	8	8	8	7	7
16	8	8	8	8	7	7	7
15	8	8	8	8	7	7	7
14	8	8	8	8	7	7	7
13	8	8	8	8	7	7	7
12	8	8	8	7	7	7	7
11	8	8	8	7	7	7	7
10	8	8	8	7	7	7	7
9	9	9	7	7	7	7	7
8	9	9	7	7	7	7	7
7	9	9	7	7	7	7	7

1	Med. Solar
2	High Solar
3	Med. Wind
4	High Wind
5	Med. RE
6	High RE
7	Base + Med Flex
8	Med RE + Med Flex
9	Med RE + Hi Flex
10	Hi RE + Med Flex
11	Hi RE + Hi Flex

Figure 5.18: Sensitivity analysis of the optimal scenario (highest net benefit) to variation in cost of renewable resources and flexible generation. The load curtailment cost is fixed at 60 Rs./kWh. The optimal scenario depends on the cost of the resources.

hydropower in the system is replaced with equal amounts of an energy resource. The capacity factor for individual hydropower plants range from 15% to 55%. Based on a 50% capacity factor, a 2000 MW reduction in hydropower is replaced with 960 MW of thermal capacity (coal) with 95% availability factor (a small difference exists because existing generator plants are duplicated; a combination of existing generation units do not sum up exactly). In the second scenario, about 50% of hydropower in the system is replaced with similar capacity of thermal (coal) generation.

The results of the production cost simulation is shown in Table 5.6. The results indicate that substituting hydropower with equal amounts of thermal energy increases the amount of unserved energy in the system. This can be attributed to two factors. First, the additional thermal capacity is insufficient to cover deficits during peak periods. That is, the system experiences capacity shortages during peak periods. Second, the additional thermal capacity is not flexible enough to start-up and/or ramp quickly to support renewable resources. This factor increases the amount of unserved energy in the system.

Substituting hydropower with equal thermal capacity reduces the amount of unserved energy in the system. This is attributed to the higher maximum capacity of the system which reduces unserved energy during peak hours. Further, the higher availability factor of thermal resources helps in reducing unserved energy during off-peaks hours. An increase in capacity in a constrained system leads to lower unserved energy. The analysis indicates that the results are more sensitive to installed capacity than generation configuration.

Table 5.6: Impact of varying hydro-power resources in the system.

Scenario	Hydropower Capacity (MW)	Additional Thermal Capacity (MW)	% Energy Unserved		
			Base Case	Hi Solar	Med Wind
Current System	3800		4.7%	2.5%	3.2%
50% Hydro Energy Replaced	1830	950	7.5%	4.5%	5.5%
50% Hydro Capacity Replaced	1830	1950	3.2%	1.7%	2.2%

5.3.4 Monte-Carlo Dispatch model

Production cost modeling is helpful in simulating the operation of the grid based on observed data. The simulations model a range of grid conditions that occurred in a particular year. However, these simulations do not capture a wide range of possible extreme scenarios that could possibly occur and could lead to large impacts on the grid. In order to expand the analysis, a Monte-Carlo based model is used to simulate a large number of possible combinations of grid conditions.

Based on data obtained from the grid, the year is split into two periods: low wind season and high wind season. During low wind season occurring at the beginning and the end of the year, system demand and solar output are relatively higher than in other periods. Conversely, during high wind season, system demand and solar power output are relatively lower. The Monte-Carlo simulation procedure is used to perform hourly economic dispatch for a large number of days for each season. The procedure involves 1000 iterations of representative days.

Low-wind season

In the system under consideration, wind and demand have a moderate negative correlation. Therefore, system demand is high during low wind season. Due to the low availability of wind resources during this period, the system demand relies heavily on conventional generation plants. But, the conventional generation technologies often have constraints on fuel availability in addition to outages. These factors reduce the capability of conventional generators to satisfy demand. This leads to severe shortages in the grid.

Results of the monte-carlo simulation for all scenarios are shown in Figure 5.19. The figure shows the cumulative distribution of the number of hours of unserved energy in a simulated day. From the results, it is observed that only less than 12% of the simulated days experience no unserved energy in the base case. That is, nearly 88% of the days experience some amount unserved energy during the low-wind season. Increasing solar or wind resources in the grid improves the percentage of days with no unserved energy to about 20% simply because more energy is available. Adding high amounts of solar and wind resources individually improves the percentage of days with no unserved energy to about 30-40%. Further, combining high amounts of solar and wind resource could improve the percentage of unserved energy to greater than 60%. However, at least moderate levels of flexible generation resources are required to improve the percentage of days of no unserved energy to greater than 80%. And, having high levels of flexible generation results in a grid in which all demand is satisfied even during the low-wind season.

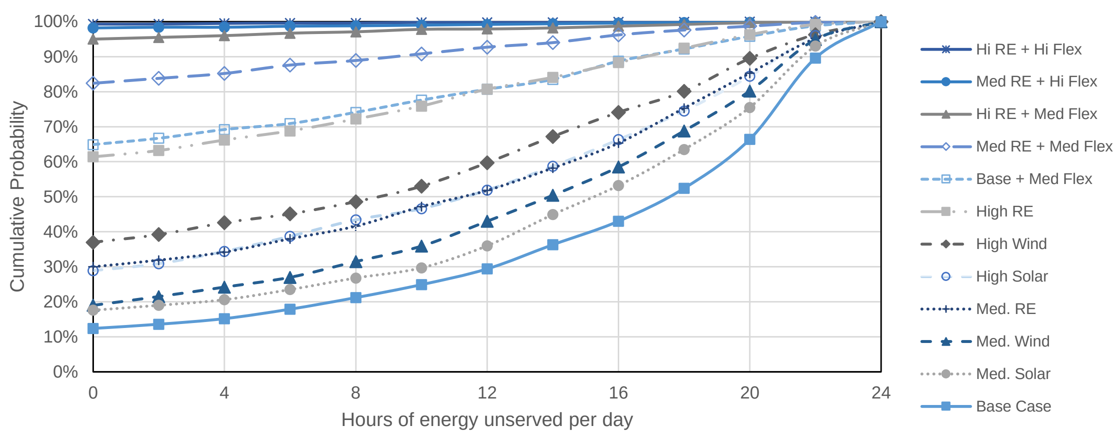

Figure 5.19: Cumulative probability distribution of the hours of unserved energy per day during low-wind season

High-wind season

During high wind season, the system demand is relatively low. The conventional generators are able to fulfil the system demand without the need for extra generation. Results of the simulation of all scenarios during high wind season are shown in Figure 5.20. From the results, it is observed that the grid can easily handle the demand during high wind season with moderate levels of renewables in the system. Due to sufficient resources in the grid and relatively low demand, the percentage of days with unserved energy is extremely low. Even in the base case, the percentage of days with unserved energy is less than 6%. With moderate levels of renewables in the grid, the percentage of days with unserved energy drop to nearly 1%. Having flexible generation in the grid results in a system in which all demand is fulfilled. However, the utilization of the flexible generation resources needs to be assessed to gauge its usefulness and provide a complete picture of the situation.

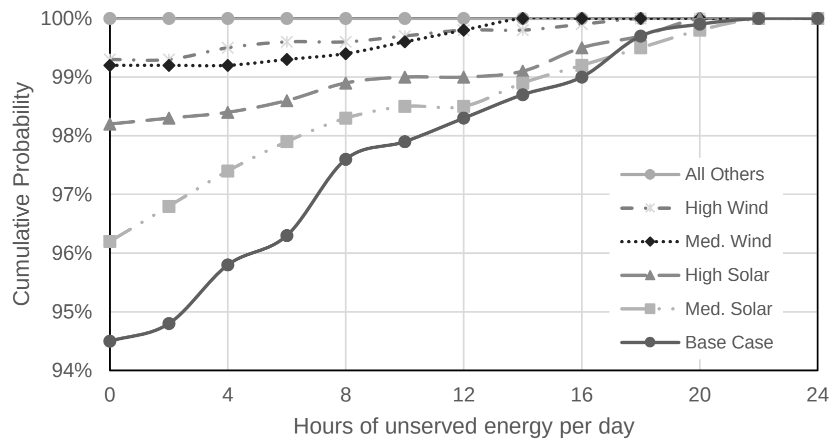

Figure 5.20: Cumulative probability distribution of the hours of unserved energy per day during high-wind season

Capacity factor of flexible generation

Based on the discussion in preceding sections, it can be concluded that the need for flexible generation depends on the season. During high wind season, there is enough output from wind power plants to satisfy demand without the need for flexible generators. Conversely, there is a significant need for flexible generation during low-wind season. The capacity factor of flexible generators during the different seasons provides information on the change in usage patterns. During low wind season, the mean capacity factor for moderate levels of penetration of flexible generation is about 40 - 60%. With a high level of flexible generation in the system, the mean capacity factor drops to about 20 - 40%. This level of utilization is considered high for fast responding expensive resources. On the other hand, the mean capacity factor during high wind season drops to less than 5%. This variation in mean capacity factor during different seasons is an important factor in power purchase agreement and investment decisions. It affects the choice of flexible generation as well.

5.4 Limitations and Future Work

There are numerous issues related to large-scale integration of renewable energy resources. This analysis considers only the operational and flexibility concerns. Other important concerns such as transmission planning and financial analysis require consideration as well.

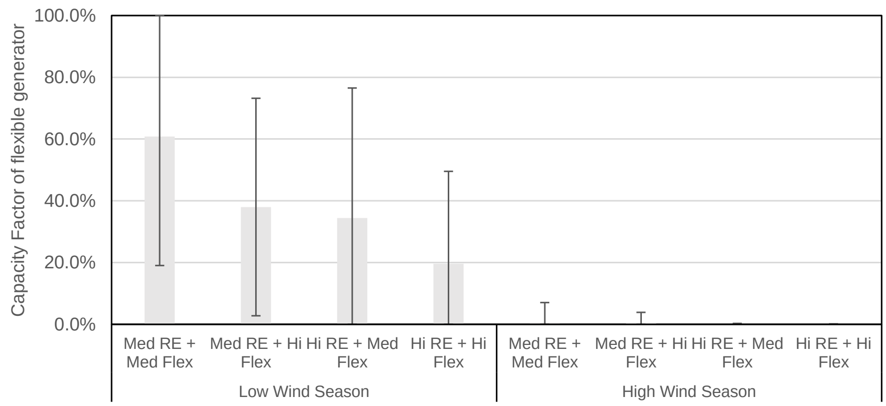

Figure 5.21: Capacity factor of flexible generation across the different scenarios

The analysis presented in the system requires large amount of system data. As the Indian power system lacks sufficient infrastructure, data availability for all regions is limited. Therefore, the analysis was performed for the state of Karnataka which had good amount of data. Care must be taken when extrapolating the results to other regions, and the validity of the assumptions must be verified. In general, the impact of renewables are dependent on the season and time of day. The results would vary for regions with different seasonal patterns.

Renewable resources increase the variability in power system operation. Dispatchable generators are required to change output more rapidly with increased penetration of renewables. The ramp-rate of the generators is an important factor that determines the ability of the system to handle the variability of renewable resources. The study does not estimate the ramping requirement of the system exclusively. It is an important analysis that could be explored in the future.

The main goal of the research was to analyze different generation scenarios that would be best suited to reduce unserved demand in the current system. The analysis is based on one year of operation. The power system was simulated for each 15-minute of the simulated year. The analysis does not look at future demand growth and generation retirements. In the future, the analysis should be expanded to multiple years.

5.5 Conclusions and policy implications

Renewable energy resources are experiencing tremendous growth around the world. Power system planners and operators are developing enhanced planning and operating methods to accommodate high levels of renewables. The Indian power grid is no exception to this growing trend. The Indian power system is expected to integrate a significant amount of renewables in the near future. In addition to environmental benefits and energy independence, renewables are considered to be a solution to India's energy shortages. This outlook is complicated due to the uncertainty and variability in renewable energy output. Renewable resources have to be supplemented by other resources to be able to satisfy system demand reliably. This complex relation cannot be captured by traditional load duration curve based power system planning methodologies. Therefore, better methodologies that capture the complex interactions have been developed in recent times. Production cost simulation is one such advanced procedure that simulates grid operation. The method is able to capture the different combinations of demand and renewable energy availability in the grid. Modeling of the different availability scenarios helps in estimating the actual impacts in a more detailed fashion. The production simulation is further enhanced by employing monte-carlo based simulations. The approach enables the analysis of a wide spectrum of possible combinations of renewable production and demand scenarios.

The analyses indicate that the renewable energy resources exhibit significant seasonal and daily variations. Due to the low capacity factor and low flexibility, very high penetration of renewable energy resources is required to achieve significant reduction in unserved demand. Further, renewable resources are less effective in reducing unserved energy when compared to flexible generation. However, the cost of flexible generation is high compared to renewable resources. Therefore, a mix of renewable resources and flexible generation is required to achieve a cost-effective reduction in unserved energy. The performance and cost analysis from the study was used to estimate the net benefits of different generation scenarios. The results indicate that moderate levels of renewable resources paired with flexible generation have the greatest system benefits.

The complex relation between renewable resources and seasonality is further analyzed using monte-carlo simulations. The results indicate that the need for flexible generation occurs only during the low wind season. Conversely, the flexible generation resources are rarely used during high wind season. Therefore, the flexible resources experience highly varying utilizations in different seasons. These factors play an important role in planning, investing and procuring of these flexible resources.

The characteristics of renewable energy resources increase the complexity of power system planning. The Indian power system planners and operators must consider the uncertainty and variability of renewable resources in their planning procedures. Further, renewable resources need some amount of flexible resources in the grid to operate reliably. Therefore, a balanced approach that includes flexible generation or other means to compensate the variability and intermittency such as storage or demand response is necessary for large scale integration of renewable energy resources.

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Appendix A

Detailed Data and Additional Results

A.1 Data of generators used in the study

Table A.1 shows details of all generators used in the simulation.

Table A.1: Detailed list of generators used in the simulation

Generators	Fuel	Capacity	Location	IEEE Ref	Power Purchase Cost (Rs/kWh)
RAYALSEEMA	Diesel	30	IPP	U20	6.62
DG PLANT	Others	350	IPP		6.413
TATA	Diesel	80	IPP	U100	5.52
Jindal-1	Diesel	260	IPP	U100	5.52
YDG plant 1	Diesel	20	In-state	U20	5.52
YDG plant 2	Diesel	20	In-state	U20	5.52
YDG plant 3	Diesel	20	In-state	U20	5.52
YDG plant 4	Diesel	20	In-state	U20	5.52
YDG plant 5	Diesel	20	In-state	U20	5.52
YDG plant 6	Diesel	30	In-state	U20	5.52
Jindal-2	Coal	600	IPP	U350	3.0333
UPCL	Coal	1200	IPP	U350	3.0333
RTPS1	Coal	215	In-state	U155	3.0333
RTPS2	Coal	215	In-state	U155	3.0333
RTPS3	Coal	215	In-state	U155	3.0333
RTPS4	Coal	215	In-state	U155	3.0333
RTPS5	Coal	215	In-state	U155	3.0333
RTPS6	Coal	215	In-state	U155	3.0333
RTPS7	Coal	215	In-state	U155	3.0333
RTPS8	Coal	215	In-state	U155	3.0333
BTPS	Coal	500	In-state	U350	2.487
GERUSOPPA1	Hydro	60	In-state	U50	2.73
GERUSOPPA2	Hydro	60	In-state	U50	2.73
GERUSOPPA3	Hydro	60	In-state	U50	2.73
GERUSOPPA4	Hydro	60	In-state	U50	2.73
ALMATTI 1	Hydro	50	In-state	U50	2.33
ALMATTI 2	Hydro	50	In-state	U50	2.33
ALMATTI 3	Hydro	50	In-state	U50	2.33
ALMATTI 4	Hydro	50	In-state	U50	2.33
ALMATTI 5	Hydro	50	In-state	U50	2.33
ALMATTI 6	Hydro	40	In-state	U50	2.33
TB	Hydro	14.4	In-state	U50	1.54
KADRA 1	Hydro	50	In-state	U50	1.5
KADRA 2	Hydro	50	In-state	U50	1.5
KADRA 3	Hydro	50	In-state	U50	1.5
KODASALLI 1	Hydro	40	In-state	U50	1.23
KODASALLI 2	Hydro	40	In-state	U50	1.23
KODASALLI 3	Hydro	40	In-state	U50	1.23
MGHE JOG 1	Hydro	40	In-state	U50	1.012
MGHE JOG 2	Hydro	40	In-state	U50	1.012
MGHE JOG 3	Hydro	40	In-state	U50	1.012
MGHE JOG 4	Hydro	20	In-state	U50	1.012
SHIVASAMUDRA 1	Hydro	4	In-state	U50	0.9
SHIVASAMUDRA 2	Hydro	4	In-state	U50	0.9

Table A.2: Detailed list of generators used in the simulation (contd.)

Generators	Fuel	Capacity	Location	IEEE Ref	Power Purchase Cost (Rs/kWh)
SHIVASAMUDRA 3	Hydro	4	In-state	U50	0.9
SHIVASAMUDRA 4	Hydro	4	In-state	U50	0.9
SHIVASAMUDRA 5	Hydro	4	In-state	U50	0.9
SHIVASAMUDRA 6	Hydro	4	In-state	U50	0.9
SHIVASAMUDRA 7	Hydro	4	In-state	U50	0.9
SHIVASAMUDRA 8	Hydro	4	In-state	U50	0.9
SHIVASAMUDRA 9	Hydro	4	In-state	U50	0.9
SHIVASAMUDRA 10	Hydro	6	In-state	U50	0.9
GHATAPRABHA 1	Hydro	16	In-state	U50	0.68
GHATAPRABHA 2	Hydro	16	In-state	U50	0.68
MUNIRABAD 1	Hydro	10	In-state	U50	0.64
MUNIRABAD 2	Hydro	10	In-state	U50	0.64
MUNIRABAD 3	Hydro	10	In-state	U50	0.64
VARAHI 1	Hydro	115	In-state	U50	0.56
VARAHI 2	Hydro	115	In-state	U50	0.56
VARAHI 3	Hydro	115	In-state	U50	0.56
VARAHI 4	Hydro	115	In-state	U50	0.56
MANI DAM (MDPH) 1	Hydro	4	In-state	U50	0.52
MANI DAM (MDPH) 2	Hydro	5	In-state	U50	0.52
SHIMSHA 1	Hydro	8	In-state	U50	0.405
SHIMSHA 2	Hydro	9.2	In-state	U50	0.405
NAGJARI (NPH) 1	Hydro	150	In-state	U50	0.356
NAGJARI (NPH) 2	Hydro	150	In-state	U50	0.356
NAGJARI (NPH) 3	Hydro	150	In-state	U50	0.356
NAGJARI (NPH) 4	Hydro	150	In-state	U50	0.356
NAGJARI (NPH) 5	Hydro	150	In-state	U50	0.356
NAGJARI (NPH) 6	Hydro	120	In-state	U50	0.356
SUPA 1	Hydro	50	In-state	U50	0.356
SUPA 2	Hydro	50	In-state	U50	0.356
LINGANMAKI (LDPH) 1	Hydro	30	In-state	U50	0.2118
LINGANMAKI (LDPH) 2	Hydro	25	In-state	U50	0.2118
SHARAVATHY 1	Hydro	108	In-state	U50	0.126
SHARAVATHY 2	Hydro	103	In-state	U50	0.126
SHARAVATHY 3	Hydro	103	In-state	U50	0.126
SHARAVATHY 4	Hydro	103	In-state	U50	0.126
SHARAVATHY 5	Hydro	103	In-state	U50	0.126
SHARAVATHY 6	Hydro	103	In-state	U50	0.126
SHARAVATHY 7	Hydro	103	In-state	U50	0.126
SHARAVATHY 8	Hydro	103	In-state	U50	0.126
SHARAVATHY 9	Hydro	103	In-state	U50	0.126
SHARAVATHY 10	Hydro	103	In-state	U50	0.126
BHADRA 1	Hydro	8	In-state	U50	0.126
BHADRA 2	Hydro	8	In-state	U50	0.126
BHADRA 3	Hydro	8	In-state	U50	0.126
BHADRA 4	Hydro	8	In-state	U50	0.126
BHADRA 5	Hydro	7.2	In-state	U50	0.126
CSG 1 - 3	Coal	400	Out-of-state		2.05
CSG4	Nuclear	320	Out-of-state		2.05

A.2 Solar Model Parameters

Table A.3: Solar power plants projects in the state of Karnataka

Districts	Capacity Requested	Capacity Allocated	Capacity Commissioned
Bagalkot	110	0	0
Bagepalli	10	5	0
Bangalore	4	0	0
Belgaum	3	3	3
Bidar	128	6	0
Bijapur	293	10	10
Chamarajanagar	5	0	0
Chikkabalapur	26	3	0
Chikmangalore	10	0	0
Chitradurga	936	375	37
Davanagaree	10	10	10
Gadag	10	0	0
Gulbarga	284	60	10
Haveri	21	15	0
Kolar	21	6	6
Koppal	128	108	0
Mandya	5	5	5
Raichur	3	3	3
Tumkur	135	110	0
Yadgir	60	10	0
Grand Total	**2202**	**729**	**84**

Table A.4: Solar power projects dispersion percentage and geographical location

District	Dispersion %	Latitude (N)	Longitude (E)
Bagalkot	5.0%	16.12	75.65
Bagepalli	0.5%	13.75	77.75
Bangalore	0.2%	12.75	77.75
Belgaum	0.1%	15.85	74.55
Bidar	5.8%	17.95	77.55
Bijapur	13.3%	16.85	75.75
Chamarajanagar	0.2%	12.05	77.35
Chikkabalapur	1.0%	13.45	77.75
Chikmangalore	0.5%	13.35	75.75
Chitradurga	42.5%	14.25	76.45
Davanagaree	0.5%	14.55	75.85
Gadag	0.5%	15.45	75.65
Gulbarga	12.9%	17.35	76.85
Haveri	1.0%	14.85	75.45
Kolar	1.0%	13.15	78.15
Koppal	5.8%	15.35	76.15
Mandya	0.2%	12.55	76.95
Raichur	0.1%	16.25	77.35
Tumkur	6.1%	13.35	77.15
Yadgir	2.7%	16.75	77.15

A.3 Monte-carlo simulation parameters

A.3.1 Generator Parameters

Table A.5: Maximum Output and outage factors of generators in the simulated year

	Max Capacity (MW)		
Generator	**Mean**	**Std. Dev**	**Outage Rate**
ALMATTI	17	16	0.05
BHADRA	2	3	0.05
BTPS	371	126	0.15
CGS	1100	350	0.12
GERUSOPPA	51	16	0.01
GHATAPRABA	6	10	0.05
Jindal	898	259	0.06
KADRA	43	16	0.008
KODASALLY	34	13	0.03
LDPH	19	9	0.05
MDPH	3	2	0.05
MGHE	12	4	0.23
MUNIRABAD	5	4	0.05
NPH	123	39	0.13
RTPS	160	41	0.18
SHARAVATHY	87	24	0.08
SHIMSHAPURA	5	3	0.05
SIVASAMUDRA	3	2	0.05
SUPA	35	21	0.05
TATA	0	0	0.05
TB	7	54	0.05
UPCL	748	381	0.075
VARAHI	81	34	0.01
YDGS	5	5	0.05

Table A.6: Maximum daily energy output of hydropower generators

	Max Energy per day (GWh)	
Hydropower Generator	**Mean**	**Std.dev**
Alamatti	1.22	1.87
Bhadra	0.13	0.14
Gerusoppa	1.50	0.93
Ghataprabha	0.23	0.29
Kadra	0.90	0.88
Kodasalli	0.81	0.66
Lingamakki	0.66	0.41
MDPH	0.08	0.08
MGHE	0.56	0.31
Munirabad	0.24	0.26
NPH	6.38	4.10
Sharavathy	13.65	5.24
Shimsha	0.17	0.19
Shivashamudra	0.54	0.46
SUPA	1.15	0.88
TB	0.09	0.08
Varahi	3.38	2.20

A.3.2 Demand Parameters

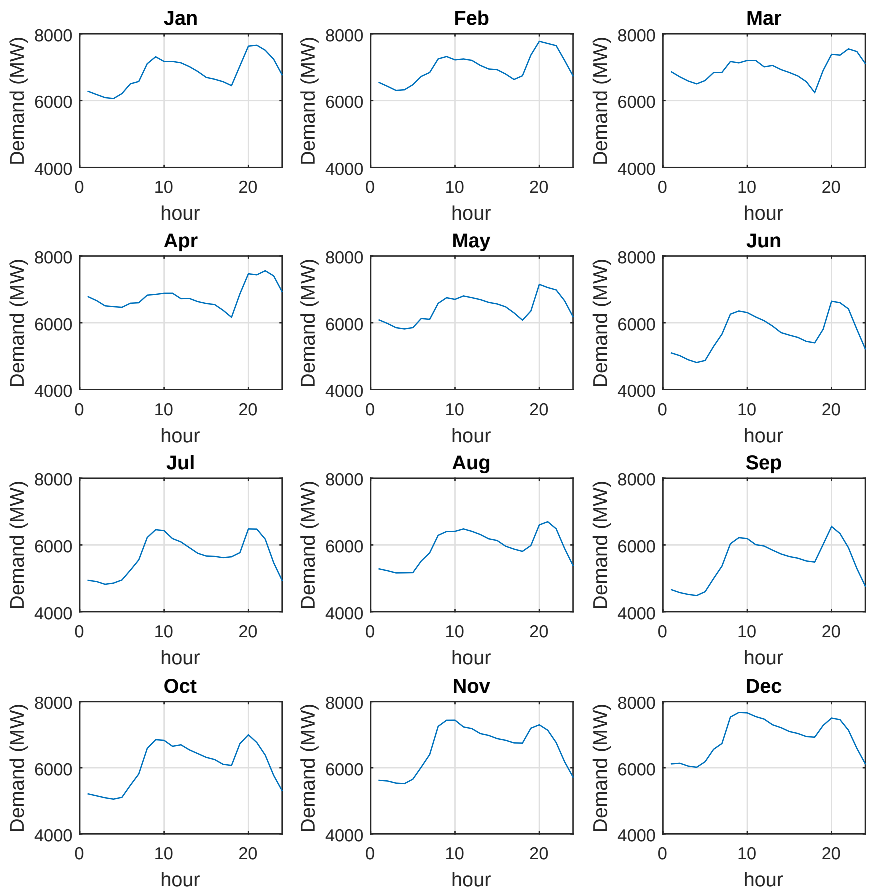

Figure A.1: Average hourly demand for each month of the simulated hour

Table A.7: Hourly demand characteristics during low and high wind seasons

Demand (MW)				
	Low Wind Season		High Wind Season	
Hour	Mean	Std. dev	Mean	Std. dev
1	6561	437	4940	513
2	6441	439	4899	544
3	6328	450	4821	538
4	6295	411	4822	542
5	6428	382	4882	657
6	6687	363	5200	749
7	6751	362	5503	755
8	7173	437	6128	815
9	7252	469	6326	797
10	7197	420	6327	787
11	7206	432	6217	544
12	7114	450	6150	547
13	7041	432	6020	554
14	6915	419	5887	553
15	6817	427	5806	570
16	6723	402	5733	792
17	6588	396	5661	796
18	6469	693	5637	753
19	7093	430	5832	724
20	7592	480	6507	765
21	7573	425	6508	481
22	7565	381	6227	517
23	7308	423	5604	527
24	6879	407	5057	508

A.3.3 Wind and Solar parameters

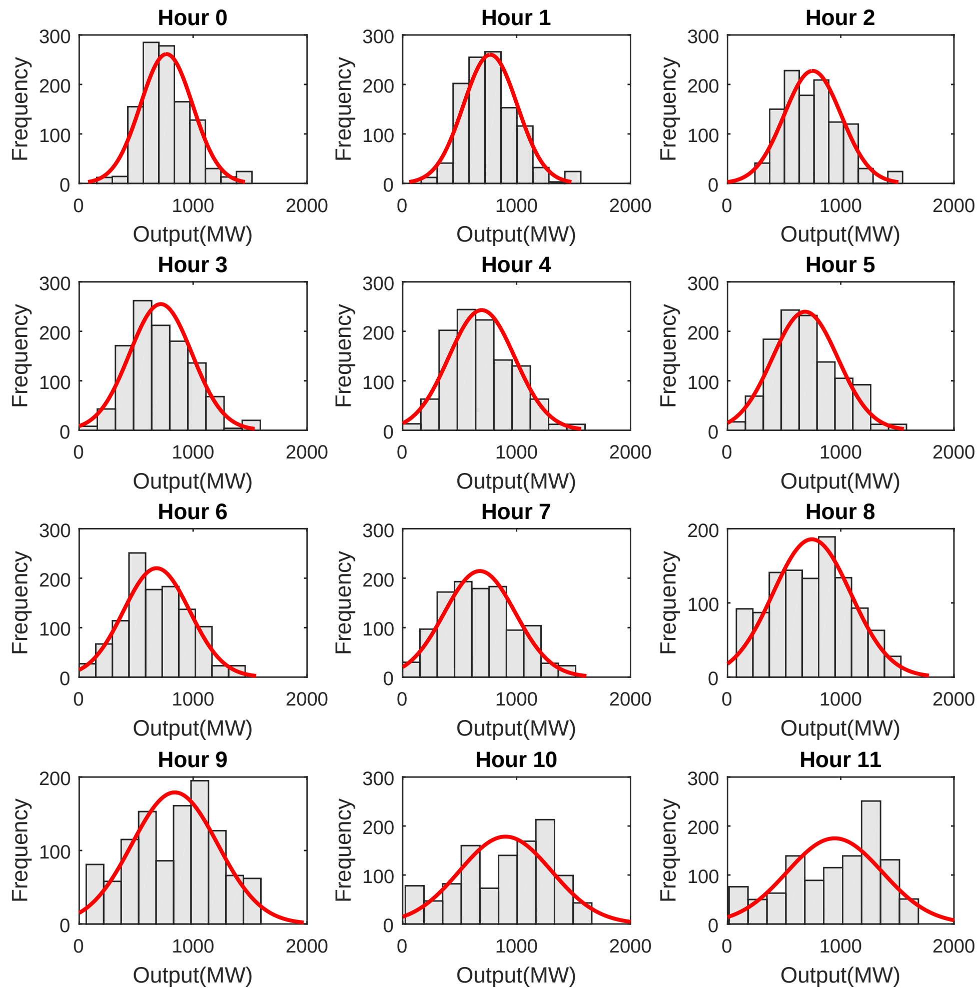

Figure A.2: Hourly output pattern during high wind season (hours 0 - 11)

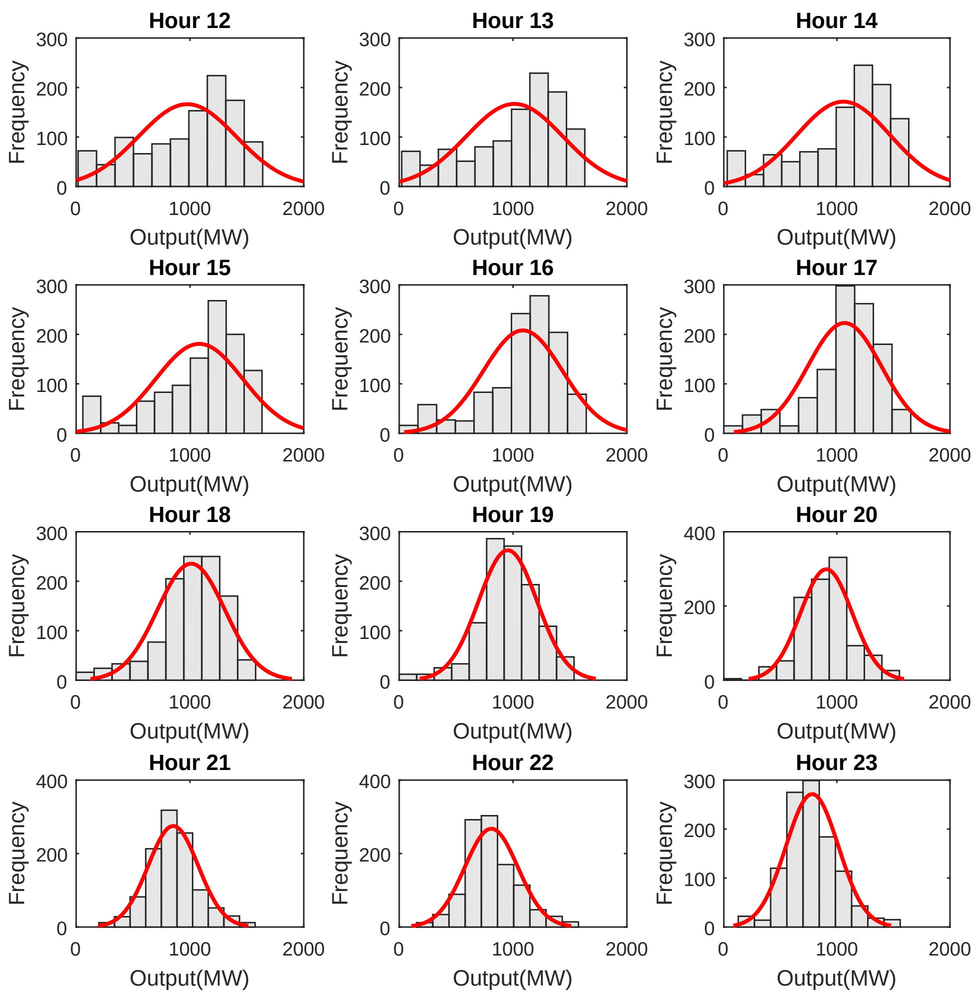

Figure A.3: Hourly output pattern during high wind season (hours 12 - 23)

Table A.8: Hourly wind output characteristics during low and high wind seasons

Wind Output (Normalized)				
	Low Wind Season		High Wind Season	
Hour	Mean	Std. dev	Mean	Std. dev
1	0.2	0.11	0.38	0.15
2	0.18	0.11	0.37	0.16
3	0.17	0.11	0.37	0.17
4	0.16	0.11	0.35	0.17
5	0.15	0.1	0.33	0.18
6	0.14	0.09	0.33	0.19
7	0.14	0.09	0.33	0.19
8	0.12	0.08	0.33	0.20
9	0.09	0.08	0.34	0.22
10	0.1	0.09	0.38	0.24
11	0.1	0.1	0.42	0.26
12	0.1	0.11	0.44	0.27
13	0.09	0.1	0.46	0.28
14	0.09	0.1	0.47	0.29
15	0.08	0.09	0.50	0.29
16	0.08	0.09	0.52	0.27
17	0.09	0.1	0.53	0.26
18	0.11	0.1	0.52	0.24
19	0.16	0.1	0.50	0.21
20	0.2	0.1	0.48	0.19
21	0.24	0.1	0.47	0.17
22	0.25	0.1	0.44	0.16
23	0.24	0.1	0.42	0.16
24	0.23	0.11	0.40	0.16

Table A.9: Hourly solar characteristics during low and high wind seasons

Solar Output (Normalized)				
	Low Wind Season		High Wind Season	
Hour	Mean	Std. dev	Mean	Std. dev
1	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00
7	0.00	0.00	0.01	0.00
8	0.05	0.01	0.09	0.01
9	0.15	0.03	0.23	0.04
10	0.21	0.04	0.34	0.07
11	0.23	0.05	0.43	0.09
12	0.25	0.06	0.48	0.09
13	0.27	0.08	0.51	0.09
14	0.29	0.10	0.50	0.08
15	0.29	0.10	0.47	0.08
16	0.26	0.09	0.42	0.07
17	0.22	0.07	0.34	0.06
18	0.16	0.04	0.21	0.05
19	0.06	0.01	0.08	0.03
20	0.00	0.00	0.01	0.01
21	0.00	0.00	0.00	0.00
22	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00

A.4 Sensitivity analysis of the optimal scenario at low load curtailment costs

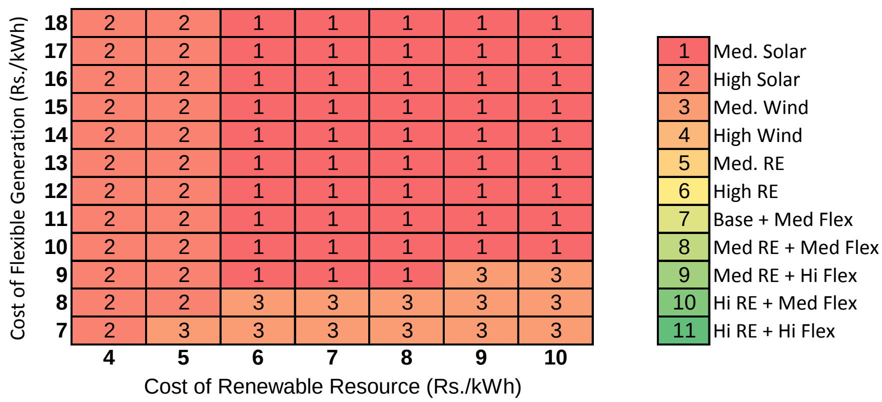

Figure A.4: Sensitivity analysis of the optimal scenario (highest net benefit) to variation in cost of renewable resources and flexible generation. The load curtailment cost is fixed at 15 Rs./kWh.

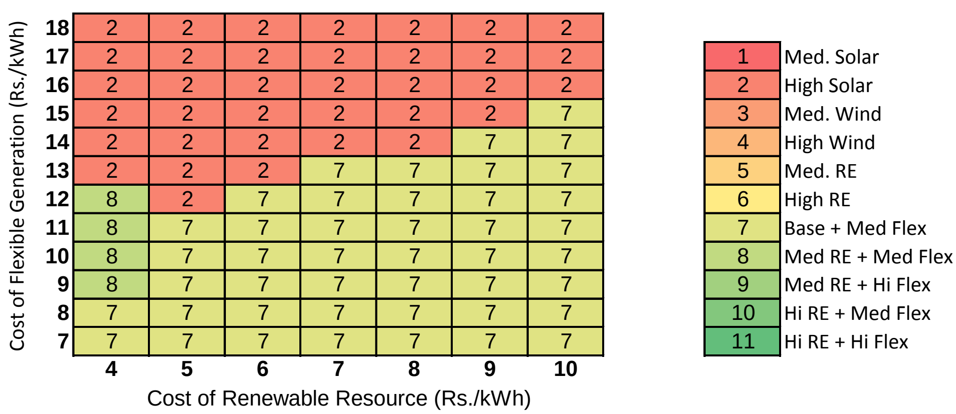

Figure A.5: Sensitivity analysis of the optimal scenario (highest net benefit) to variation in cost of renewable resources and flexible generation. The load curtailment cost is fixed at 30 Rs./kWh.