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# Techno-Economic Assessment of Integrating 175GW of Renewable Energy into the Indian Grid by 2022

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# List of Abbreviations

| | |
|---|---|
| **bcm** | Billion Cubic Meters |
| **CEA** | Central Electricity Authority |
| **CERC** | Central Electricity Regulatory Commission |
| **Cr** | Crore ($10^7$) |
| **DOE** | Department of Energy |
| **EPS** | Electric Power Survey |
| **ER** | Eastern Region |
| **FOR** | Forum of Regulators (of India) |
| **FY** | Financial Year. India's financial year starts in March of the previous year and ends in March of next year. E.g. FY 2022 starts in April 2021 and ends in March 2022. All references to years in this report refer to financial years unless specified otherwise. |
| **KG** | Krishna Godavari (Basin of Natural Gas Production) |
| **LNG** | Liquefied Natural Gas |
| **LOLE** | Loss of Load Expectation |
| **mmscmd** | Metric Million Cubic Meters per Day |
| **MNRE** | Ministry of New and Renewable Energy |
| **MOP** | Ministry of Power |
| **MW** | Mega Watt |
| **MWh** | Mega Watt Hours |
| **NAPCC** | National Action Plan on Climate Change |
| **NER** | North-Eastern Region |
| **NR** | Northern Region |
| **PGCIL** | Power Grid Corporation of India Limited |
| **POSOCO** | Power System Operations Corporation |
| **RE** | Renewable Energy |
| **ROE** | Return on Equity |
| **RPO** | Renewable Purchase Obligation |
| **RPS** | Renewable Portfolio Standard |
| **Rs** | (Indian) Rupees. 1 USD = Rs 65 (approx.) |
| **SERC** | State Electricity Regulatory Commission |
| **SR** | Southern Region |
| **WR** | Western Region |

# Executive Summary

## 1. ***Introduction***

In 2015, India announced a target of increasing the renewable energy (RE) installed capacity from nearly 34 gigawatts (GW) in 2015 to 175GW by 2022; solar power capacity is targeted to increase from 3GW (2015) to 100GW (2022), wind power capacity would increase from 23GW to 60GW, and small hydro and biomass capacity would increase from 7GW to 15GW. Given such aggressive targets, there is significant discussion on the policy, regulatory and commercial strategies to integrate renewable energy in the Indian power system. Although large scale RE grid integration has been analyzed widely in the US and European context, there is very limited literature on this topic in the Indian context. The objectives of our analysis are to assess the technical feasibility of integrating the large renewables capacity in the Indian electricity grid, ascertain its impact on power sector investments and operations, and quantify the incremental cost of such large-scale RE grid integration.

## 2. ***Methodology and Data***

We conduct our analysis using PLEXOS, a power system capacity expansion and production cost model. For various levels of RE penetration targets, PLEXOS identifies the least cost investment and operations (power plant dispatch) strategies to integrate the specified level of RE subject to a range of operational constraints. We model the Indian electricity grid using 5 nodes – one node for every region viz. north, east, west, south, and north-east which allows us to broadly assess the transfer capacities across regions assuming each region as a balancing area. It is important to note that given the regional level resolution of the model, this analysis cannot answer questions on the intra-regional (across states within a region) and intra-state transmission and dispatch issues. Hence, the results can be interpreted as what is needed for RE integration once the intrastate and interstate transmission constraints are resolved and scheduling and dispatch is coordinated at the regional level.

We assess the following three scenarios for RE penetration for the financial year (FY) 2022 (April 2021 – March 2022):

(a) ***13th Plan***: This scenario serves as the baseline and uses the generation capacity addition for all technologies as projected in the Government of India's 12th Plan document that includes projections up to the 13$^{th}$ Plan period (2022).

(b) ***RE Missions***: This scenario models the Government of India's announcement in 2015 to increase the total installed capacity of solar projects to 100GW and wind projects to 60 GW by FY 2022. MNRE has also specified individual state level installed capacity targets for each technology.

(c) ***National Action Plan on Climate Change (NAPCC)***: This scenario models the target in India's NAPCC (2009). NAPCC targets RE to provide 15% electricity by energy by 2020 (PMO 2009). If the same trend between 2009 and 2020 is projected up to 2022, RE capacity would provide ~20% electricity by energy by FY2022. Keeping the installed capacity of small hydro and biomass the same as the 13th Plan, we split the rest of the NAPCC target into wind and solar PV using 75:25 ratio (by energy). Regional targets are estimated by applying the current ratio of the RE installed capacity.

The following table shows the total installed capacity of RE technologies by 2022 in GW.

| | 13th Plan | NAPCC | RE Missions |
|---|---|---|---|
| **Wind** | 41 | ~108 (13% by energy) | 60 |
| **Solar** | 22 | ~58 (4% by energy) | 100 |
| **Small Hydro** | 6.6 | 6.6 (1.5% by energy) | 6.6 |
| **Biomass** | 7.7 | 7.7 (1.5% by energy) | 7.7 |

Our key assumptions are summarized below:

*Demand*: We project the hourly of FY 2022 based on the historical hourly demand pattern between FY 2010 and 2013, projected urbanization, and the projected load growth in the Central Electricity Authority's (CEA) 18$^{th}$ Electric Power Survey (EPS). By 2022, the national peak demand is projected at 287GW and total energy consumption is projected at 1906 TWh/yr (both at bus-bar).

*RE Generation*: Hourly profiles of wind energy generation have been forecasted using the actual historical generation data for FY 2010 through 2013 from the states of Tamil Nadu, Karnataka, Maharashtra, and Gujarat. For estimating the hourly generation profile of solar PVs, we chose 100 sites spread over all 5 regions with best quality solar resource (measured in Global Horizontal Irradiance (GHI) kWh/m$^2$) using the national solar energy dataset for India developed by the National Renewable Energy Laboratory. Simulated hourly PV output profiles of the sites in each region were averaged to arrive at the regional solar PV generation profile.

*Generator characteristics:* Generator characteristics such as unit size, heat rates, ramp rates, and minimum stable level of the power plants have been estimated using the historical dispatch data, outage and other performance data, regulatory orders on heat rates and costs, other relevant literature.

*Generator costs:* Capital costs and fixed O&M costs for each technology have been taken from CERC's tariff norms for 2014-2015. Future trends in the capital cost of wind and solar have been taken from the literature. We assume that the solar prices continue to drop and reach Rs 3.4/kWh in 2022 from the current price of nearly Rs.5.1/kWh, resulting in average cost of solar for 100 GW of capacity addition to be Rs 4.0/kWh. Further, we assume that highest quality wind resource is used in future capacity additions leading to an average capacity factor of 30% (for new capacity) that leads to an average wind cost of Rs 3.3/kWh. Note that all costs numbers are expressed in terms of real 2015 values.

*Fuel prices and availability*: We take the current year fuel prices and use historical trends to project the fuel prices in 2022. Domestic coal availability for the power sector has been taken from the Ministry of Coal's projections in the 13th five-year plan up to 2017; the same trend has been projected up to 2022. We have assumed that the domestic gas availability for the power sector in the future remains the same as the current quantity. No quantity restrictions are assumed on imported fuels.

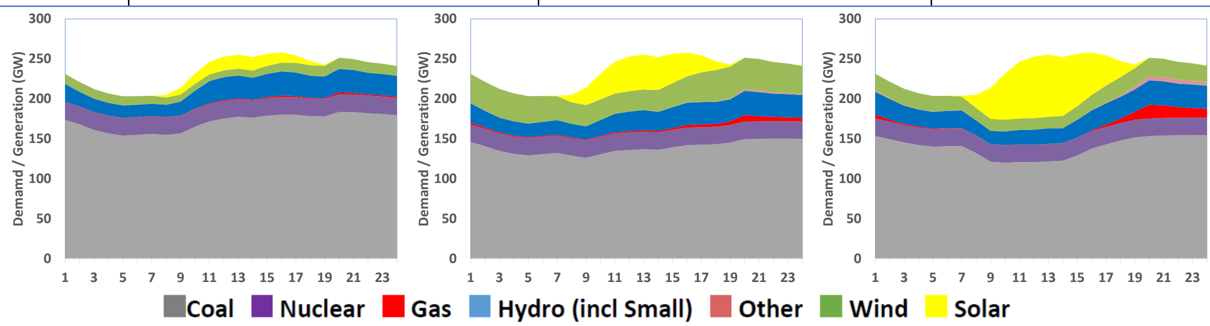
*Transmission*: We assume that there are no transmission constraints. Our model gives a high-level assessment of the power transfer capacity needed across regions in order to minimize the total generation costs. Note that we have not considered any international import of power in to India from the neighboring countries like Nepal, Bhutan, and Bangladesh.

## 3. Results

Table 1 shows the total (national) capacity additions, installed capacities, and capacity factors (i.e. Plant Load Factors) of each technology. In NAPCC and RE Missions scenarios, much lower coal capacity is needed compared to the 13th Plan scenario (baseline). Instead, moderate level of additional peaking and flexible capacity (e.g. gas) is needed for integrating RE. Figure 1-Figure 3 show the average hourly national dispatch in each season for all scenarios. In all scenarios and seasons, most of the available coal units are operated as base load units. RE can provide significant support during afternoon peak demand period during summer (mainly solar) as well as monsoon (mainly wind). In both seasons, gas based generation (or other flexible source) is needed for evening ramp-up support and meeting evening peak demand. In Winter, both solar and wind generation drop significantly; albeit demand is also much lower. Note that the gas based capacity is primarily required to generate during evening peak hours, especially during winter and early summer, leading to a low (7-9%) capacity factor. The total gas required is 3.6-6.2 bcm/yr, which is lower than the current domestic gas consumption (i.e. allocations) by the power sector (10 bcm/yr), and thus, no LNG imports would be necessary.

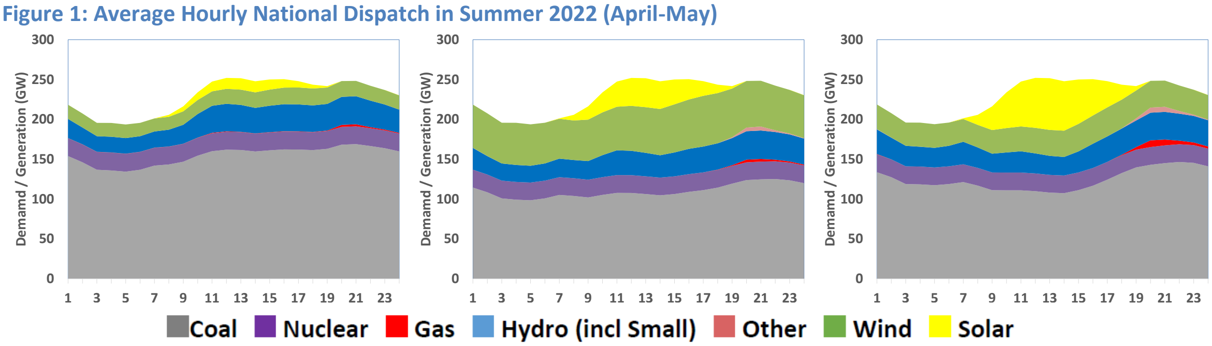
**Table 1: Capacity Built (GW), Installed Capacity (GW), and Capacity Factors (%) in Each Scenario by FY 2022**

| | 13th Plan | | | NAPCC | | | RE Missions | | |
|---|---|---|---|---|---|---|---|---|---|
| | Capacity Built (2015-2022) | Installed Capacity in 2022 (GW) | Capacity Factor (%) | Capacity Built (2015-2022) | Installed Capacity in 2022 (GW) | Capacity Factor (%) | Capacity Built (2015-2022) | Installed Capacity in 2022 (GW) | Capacity Factor (%) |
| **Coal** | 79 | 243 | 64% | 17 | 182 | 71% | 17 | 182 | 73% |
| **Gas** | 0 | 23 | 7% | 2 | 25 | 7% | 10 | 33 | 9% |
| **Diesel** | 0 | 1 | 0% | 0 | 1 | 0% | 0 | 1 | 0% |
| **Nuclear** | 19 | 25 | 89% | 19 | 25 | 89% | 19 | 25 | 89% |
| **Hydro** | 18 | 59 | 37% | 18 | 59 | 37% | 18 | 59 | 37% |
| **Small Hydro** | 2 | 6 | 37% | 2 | 6 | 37% | 2 | 6 | 37% |
| **Biomass** | 4 | 8 | 1% | 4 | 8 | 2% | 4 | 8 | 2% |
| **Solar** | 18 | 22 | 20% | 55 | 58 | 19% | 97 | 100 | 19% |
| **Wind** | 18 | 41 | 25% | 85 | 108 | 29% | 39 | 62 | 29% |
| **Total** | **159** | **428** | | **203** | **472** | | **207** | **476** | |



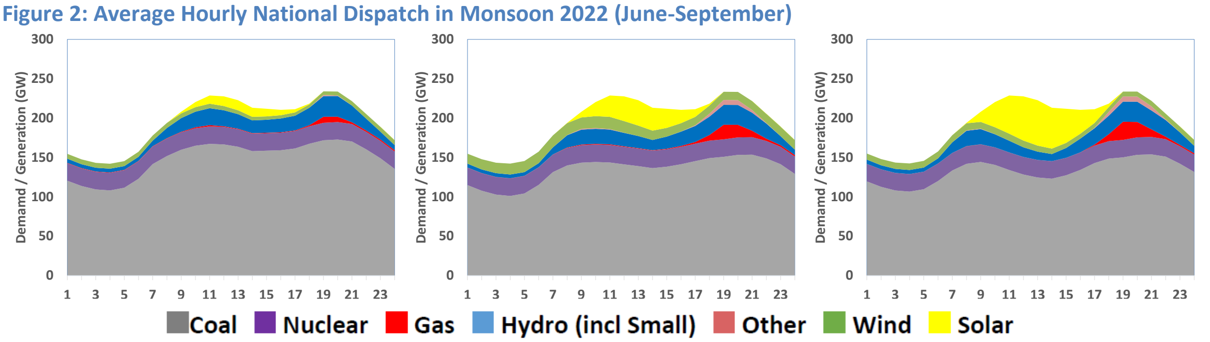
(a) 13th Plan (41GW Wind; 22GW Solar) (b) NAPCC (100GW Wind; 60GW Solar) (c) RE Missions (60GW Wind; 100GW Solar)

**Figure 1: Average Hourly National Dispatch in Summer 2022 (April-May)**



(a) 13th Plan (41GW Wind; 22GW Solar) (b) NAPCC (100GW Wind; 60GW Solar) (c) RE Missions (60GW Wind; 100GW Solar)

**Figure 2: Average Hourly National Dispatch in Monsoon 2022 (June-September)**



(a) 13th Plan (41GW Wind; 22GW Solar) (b) NAPCC (100GW Wind; 60GW Solar) (c) RE Missions (60GW Wind; 100GW Solar)

**Figure 3: Average Hourly National Dispatch in Winter 2022 (December – February)**

**Table 2: Inter-regional Power Transfer Capacities (MW) Required by FY 2022 in Each Scenario**

| | East-North | East-South | East-West | NorthEast-East | West-North | West-South |
|---|---|---|---|---|---|---|
| **13th Plan** | 15124 | 8656 | 9171 | 2914 | 23173 | 10896 |
| **NAPCC** | 11215 | 16563 | 8717 | 2907 | 17315 | 14731 |
| **RE Missions** | 12489 | 18354 | 6772 | 3195 | 15654 | 20285 |

One of the key enablers of the reliable grid integration is the transmission network. In order to integrate 175GW of RE capacity, the additional power transfer capacities (relative to the 13th Plan) are moderate as shown in Table 2; the only significant increases in the transfer capacities are West-South (increase by 3000 to 4000 MW relative to the 13th Plan) and East-South (increase of 6000 to 8000 MW relative to the 13th Plan). Also, West-North transmission corridor may need additional strengthening, especially relative to the 2015 levels. Note that these are power transfer capacities; actual transmission capacity investments may be significantly higher (about 2-3 times depending on the network) due to oscillations, stability etc concerns in the AC network. In NAPCC and RE Missions scenarios, some of the inter-regional transmission interfaces would have to be used in both directions because of the seasonal and diurnal RE generation patterns. For example, during summer and monsoon seasons, RE generation from the west and the south flows to the east and the north; during evening peak demand periods in all seasons, especially winter, the coal based power from north and the east would have to flow to the south and the west. This implies that an appropriate policy and regulatory framework for moving power across regions more freely (for example, national intra-day and ancillary services markets with wide participation) is crucial.

The incremental wholesale cost of electricity supply (at region boundary) in NAPCC and RE Missions scenarios is Rs. 10,000 Cr/yr and Rs 32,000 Cr/yr respectively over the 13$^{th}$ Plan (total cost of 13$^{th}$ Plan is Rs 774,000 Cr/yr). This is equivalent to an increase in the average wholesale supply cost by 3p/kWh (1%) and 14p/kWh (4%) respectively for NAPCC and RE Missions scenarios. The incremental RE generation over the 13$^{th}$ Plan is 245 TWh/yr in NAPCC scenario and 197 TWh/yr in RE Missions scenario. Note that our analysis does not consider the environmental and energy security benefits of RE generation.

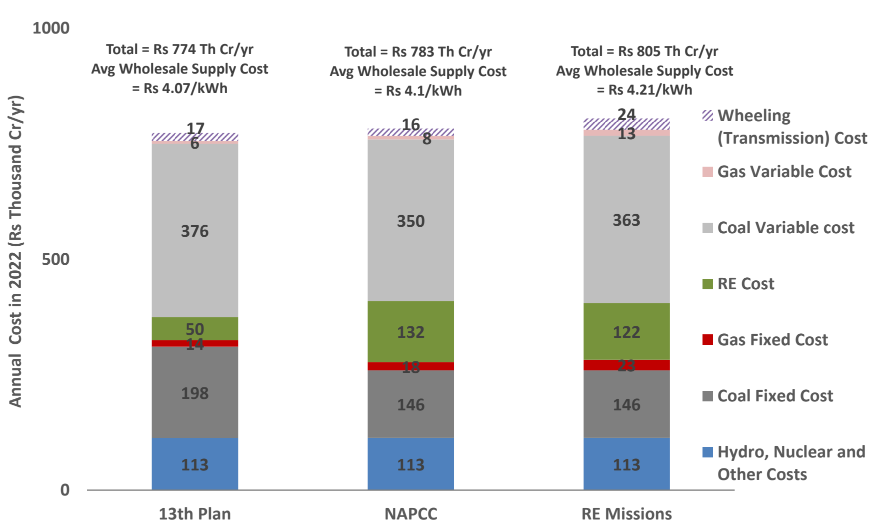



**Figure 4: Annual Total and Average Wholesale Electricity Supply Cost (at Region Boundary) in 2022**

The cost estimate includes majority of the RE integration cost such as additional investments in flexible capacity (such as gas turbines etc.) or operation of the expensive gas or diesel-based power plants, etc. What it does not include is the cost for procuring additional reserves (spinning, contingency, or otherwise) or other ancillary services. However, in US or European studies, such incremental ancillary services cost are found to be 5-10% of the RE generation cost. Also, coal investment costs in all scenarios have been estimated without considering the new norms for Particulate Matter, SOx, and NOx emissions (2015), which may increase their fixed costs by over 10% and reduce the cost-differential between the 13$^{th}$ Plan and RE Dominant scenarios further.

We conducted sensitivity analysis to assess the impact of key parameters such as renewable energy capital costs, slippages in the coal capacity addition etc. on generation investments and cost. If solar costs do not reduce further and if the highest resource quality wind is not accessed, RE costs will further increase by ~Rs 25,000 Cr/year by 2022 in case of RE Missions scenario (further increase in the wholesale electricity supply cost of generation by ~3.5%). If the generation capacity is optimally planned in the 13th Plan (or slippage in the capacity addition targets), the wholesale supply cost of the 13$^{th}$ Plan portfolio reduces by 2% thereby increasing the cost differential in the NAPCC and RE Missions scenarios to 3% and 6% respectively. To the contrary, if the coal capacity addition in the RE Missions scenario stays the same as originally planned in the 13$^{th}$ Plan (making a "high coal and high RE" scenario), the capacity factor of the coal capacity drops to 56% (national average) resulting in an increase in the average wholesale supply cost by 4% relative to the RE Missions scenario; however, despite such an inflexible system, RE curtailment is not found to be necessary. Wholesale electricity supply cost in both these RE dominant scenarios is significantly less sensitive to the fuel price and supply risks; if by 2022, imported fuel prices are 25% more expensive than their projected prices, average wholesale electricity cost for the 13th Plan increases by 3.0%. In the same situation, average wholesale electricity cost for the RE Missions and NAPCC scenarios increases by 0.4% and 0.1% respectively.

## ***4. Conclusion***

In both NAPCC and RE Missions scenarios, coal capacity requirement is much lower than the 13$^{th}$ Plan; moderate level of additional flexible and peaking capacity (e.g. gas) needs to be added. During summer and monsoon, renewable energy can provide significant support during afternoon peak demand periods; in winter, solar and wind generation both drop, albeit load also reduces. Flexible generation capacity (such as gas, biomass etc) is crucial for providing the evening ramp-up support as well as energy support during evening peak hours in all seasons. This implies that the flexible resource used for grid integration in India should be able to provide cross-seasonal support. Hydroelectric projects (reservoir type) would be able to offer such support – however, there are significant restrictions on their dispatch and barriers to their construction. Gas based projects also can provide such cross-seasonal support - however, reliable gas availability is a major concern in India. One solution to that could be building on-site gas storage facility so gas power plants do not have to always depend on the gas pipelines; importing LNG could help; however, that may involve significant price and supply risks. Demand response is another cost-effective option for providing the ramping and peaking support across seasons and needs further exploration.

The regional diversity in RE generation and its complementarity with demand and other RE resources help reduce the impact of extreme events such as sudden loss of RE generation or over-generation, etc. on the system. But RE forecasting is absolutely crucial for utilizing such complementarities. With newer state-of-the-art forecasting techniques, forecast errors have been reducing rapidly especially with the use of the real-time generation data. With installation of Renewable Energy Management Centers and the new forecasting regulations for the interstate RE generators, India has already started creating a robust framework for RE forecasting.

One of the key enablers of the reliable grid integration is the transmission network. While the additional power transfer capacities are found to be moderate, some of the inter-regional transmission interfaces would have to be used in both directions because of the seasonal and diurnal RE generation patterns. This implies that appropriate policy and regulatory framework for moving power across regions more freely is crucial. This could be achieved by creating robust markets and other measures such as intra-day and ancillary services market, imbalance markets or balancing area coordination etc. in addition to the transmission investments.

The incremental wholesale cost of electricity supply (at region boundary) in NAPCC and RE Missions scenarios is Rs. 10,000 Cr/yr and Rs 32,000 Cr/yr respectively over the 13$^{th}$ Plan (total cost of 13$^{th}$ Plan is Rs 774,000 Cr/yr). This is equivalent to an increase in the average wholesale supply cost by 3p/kWh (1%) and 14p/kWh (4%) respectively for NAPCC and RE Missions scenarios; note that our analysis does not consider the environmental and energy security benefits of RE generation. In order to limit the cost increase due to RE penetration to the levels found in the study, the following strategies are crucial: (a) Transmission corridors, especially from/to the Southern region, are strengthened and used in both directions, (b) Cost of wind energy is reduced by developing highest quality wind resource through competitive bidding, (c) Power system dispatch is coordinated at the regional level using market or other mechanisms, and (d) Several market, policy, and regulatory mechanisms are in place such as RE forecasting or more flexible markets etc.

If the generation capacity is optimally planned in the 13th Plan (or slippage in the capacity addition targets), the wholesale supply cost of the 13$^{th}$ Plan portfolio reduces thereby increasing the cost differential in the NAPCC and RE Missions scenarios further. To the contrary, if the coal capacity addition in the RE Missions scenario stays the same as originally planned in the 13$^{th}$ Plan (making a “high coal and high RE” scenario), the capacity factor of the coal capacity drops resulting in an increase in the average wholesale supply cost. Also, it is found to be significantly less sensitive to fuel price and supply risks, which is crucial for ensuring energy security of the country.

Given the large RE potential and aggressive targets, studies that quantify their operational and economic impacts as well as discussions on the potential policy/regulatory frameworks for achieving such targets are crucial. This study serves as the first one of our forthcoming series on RE grid integration in India. However, note that this analysis is based on significant simplifications and assumptions regarding the transmission system and the deviation settlement mechanism. Therefore, it is likely that our results underestimate the incremental costs, RE curtailment, need for flexibility, and transmission system investments; these results should be viewed only as high-level indications. Significant refinement to this analysis would be necessary for actual power system planning purposes.

# Techno-Economic Assessment of Integrating 175GW of Renewable Energy into the Indian Grid by 2022

## 1 Introduction

Recently, several planning and policy initiatives have been proposed in India for large scale deployment of renewable energy (RE). For example, in 2009, India announced its National Action Plan on Climate Change (NAPCC) setting a target of sourcing 15% of its electricity requirement (by energy) by 2020 from renewable sources (PMO 2009). In 2014, India announced increasing the installed capacity of solar power projects from about 3 gigawatts (GW) in 2014 to 100GW by 2022 and increasing the wind power capacity from nearly 20GW to 60GW in the same timeframe.[1] The government and the private sector have already shown significant commitment to achieve these targets. For example, the government has approved setting up over 20GW of solar capacity in 25 "Ultra-Mega Solar Parks" spread across the country and has also offered a financial support of nearly US$650 million (MNRE 2014; PIB 2014).

Given the proposed addition to the renewable capacity, there is significant discussion on the policy, regulatory and commercial strategies to integrate RE in the Indian power system. Large scale RE grid integration has been analyzed widely in the US and European context (see for example: (Palchak and Denholm 2014; Cochran et al. 2015; Milligan et al. 2013; A. D. Mills and Wiser 2013; Andrew D. Mills 2014; Orans et al. 2013) etc.). However, there is limited literature in the Indian context. Few studies have assessed the variability and capacity value of renewable energy in India (Hummon et al. 2014; Phadke, Abhyankar, and Rao 2014; George and Banerjee 2009; Chattopadhyay and Chattopadhyay 2012); but they do not deal with the grid integration issues in detail.

Very few studies have conducted comprehensive grid dispatch modeling and investment planning analysis. The Report on Green Energy Corridors analyses the flexibility of the Indian power system for integrating a total of 72,400 megawatts (MW) of RE by 2022 (POWERGRID 2012). However, the analysis in that report is limited to the typical day per month and therefore, does not capture the entire range of annual hourly load and renewable generation variability. The Asian Development Bank, as a part of their technical assistance to the government of India, conducted a comprehensive cost-benefit analysis study of six major electric power interconnection projects in South Asia (ADB 2013). However, their analysis was primarily focused on assessing the cross-border energy trade and transmission investments using power flow modeling (to assess the actual power transfer capabilities). Shakti Sustainable Energy Foundation (Shakti 2013) analyzes the contribution of renewable energy towards meeting electricity shortages in India and overall economic growth. While the study employs grid dispatch modeling, it does

[1] India's peak electricity demand in 2014 was about 150 GW and the total installed capacity was about 230GW (CEA 2015d).

not include the new targets specified by the government. Also, the focus of the study is significantly broad (i.e. overall energy sector include coal mining, gas extraction, distribution etc, and the overall economy) and thus, they do not discuss RE grid integration issues in detail. The government of India has released a few reports that broadly assess the strategies to integrate RE most notably by CEA and NITI Aayog. India's Central Electricity Authority published a document in 2013 that laid out the key issues in RE grid integration and assessed the strategic solutions (CEA 2013a). NITI Aayog released a roadmap for accelerating the deployment of renewable energy in India that highlights the key issues facing RE deployment in India ranging from financing costs to integration risks (NITI 2015). These analyses, however, do not assess the technical feasibility or quantify the economic impacts of RE integration.

The objectives of our analysis are to assess the technical feasibility of integrating the large renewables capacity in India that has been planned for the near future, ascertain its impact on power sector investments and operations, and quantify the incremental cost of generation. More specifically, we intend to answer the following questions:

a) What is the impact of integrating RE on the capacity addition and capacity factors of conventional generators?
b) Are there any additional ramp requirements and if so how can they be met in a least cost fashion?
c) How do regional transmission flows and investment requirement change?
d) What is the impact on the wholesale electricity supply cost (at region boundary)?

We conduct the analysis by modeling the least cost generation investments and simulating economic dispatch for the financial year (FY) 2022 using PLEXOS[2] for a variety of renewable energy penetration scenarios. We use a five node model of the Indian electric grid (one node per region), which allows us to broadly identify transmission corridors across regions. We believe that our results would inform two important decisions. First, cost of integrating RE would be borne by certain players (primarily utilities) in the power sector. Quantifying these costs is essential for designing potential commercial arrangements to mitigate the adverse impact on any particular stakeholder. Second, our analysis will identify least cost investment and operational solutions to integrate large scale RE in India. Creating an appropriate policy and regulatory framework for such solutions would be crucial for achieving the RE deployment targets.

It is important to note that given the regional level resolution of the model, this analysis cannot answer questions on the intra-regional (interstate, i.e., across states within a region, and intra-state) transmission and dispatch issues. Hence the results can be interpreted as what is needed for RE integration once the intra-regional transmission constraints are resolved and the power system dispatch is coordinated at the regional level through market or other mechnisms.

The rest of the paper is organized as follows. Section 2 gives a broad overview of the Indian power sector. Section 3 describes our methodology, data, and assumptions followed by section 4 that discusses

[2] PLEXOS is a production cost and capacity expansion model that optimizes the investments and economic dispatch of power plants considering unit commitment etc. used widely by the utilities and system operators/planners across the world. For more information, please refer to (Energy Exemplar 2016).

the key results and section 5 that presents the sensitivity analysis. In section 6, we conclude the paper and discuss the opportunities for future work. Appendices provide more details on the assumptions and results.

# 2 Overview of the Indian Power Sector

With peak electricity demand of 150 GW and the total installed capacity of about 270GW, India has one of the largest electricity transmission and distribution systems in the world (CEA 2015d). More than half of existing installed generation capacity is owned by state government companies, and a third is owned by central (federal) government corporations. The remainder is owned by the private sector. By contrast, more than 87% of the distribution sector (by sales) is owned by state-government utilities, and the rest is owned by private and municipal utilities (CEA 2008).

## 2.1 Renewable Energy

Several studies have shown immense solar and wind energy potential in India. For example, at 20% capacity factor and above, total wind energy potential in India is in excess of 3000 GW (Phadke, Bharvirkar et al. 2012). Similarly, total solar PV potential in India is as high as 11,000 GW (Ramachandra, Jain et al. 2011; Sukhatme 2011; Deshmukh and Phadke 2012).

Almost all key states in India have specified Renewable Purchase Obligation (RPO) that mandate the load serving entities and captive users to purchase a fraction of their annual electricity requirements from renewable energy sources. The following table shows the RPO targets in the key states.

| State | RPO Target (2015) |
|---|---|
| **Maharashtra** | 9% |
| **Gujarat** | 8% (2015)<br>10% (2017) |
| **Tamil Nadu** | 9% (non-solar)<br>0.5% (solar) |
| **Karnataka** | 7-10% (non-solar)<br>0.25% (solar) |
| **Rajasthan** | 9% (2015)<br>11.4% (2017) |
| **Andhra Pradesh** | 4.75% (non-solar)<br>0.25% (solar) |
| **Madhya Pradesh** | 6% (non-solar)<br>1% (solar) |

Data source: (MNRE 2015)

In addition to RPO, renewable energy sources are offered feed-in tariffs. Moreover, the central government offers significant financial incentives such as generation based incentive or accelerated depreciation for aggressive deployment of renewable sources. India also allows trading of Renewable Energy Certificates in order to fulfill the RPO obligations of the utilities and other entities. As a result, the RE capacity has increased by nearly eight fold over the last ten years i.e. from 4,155 MW in 2005 to 33,550 MW in 2015 (CEA 2015d; CEA 2009b; CEA 2015a).

## 2.2 Electricity Grid and Transmission

The Indian power grid is an interconnected 50Hz network. Currently, there are five regional grids (all synchronized) – north, south, west, east and north-east; each region is made up of 5-7 states. In most cases, each state is an independent balancing area. The state grids are operated by the State Load Dispatch Centers, while the interstate system within a region (interstate generating stations and the transmission system) are operated by the Regional Load Dispatch Centers. The inter-regional transmission system is operated by the National Load Dispatch Center. India does operate a day-ahead electricity market. However, only about 3% of the total annual energy generation is traded on the day ahead market while 95% is based on long term PPAs and short-term bilateral contracts (IEX 2015). Although there is no formal real time market in India, the deviation settlement mechanism acts as the de-facto real time market, where the real time price is dependent on the system frequency. Such real time deviations of each utility relative to the day-ahead schedule are capped at 150 MW or 12% of the schedule, whichever is lower. Since May 2016, such deviation limit has been relaxed to 200 to 250 MW, depending on the installed wind and solar capacity in a state (CERC 2016). In April 2016, India has created a framework for ancillary services in market, wherein the un-requisitioned capacity of the central sector generating stations from the day-ahead schedule would be rescheduled to the regional pool; this power can then be scheduled by the National Load Dispatch Center with payments made from the deviation settlement pool.

The following tables show the current installed capacity in each region in India by technology.

**Table 3: Installed Capacity (MW) in India by region (March 2015)**

| | North | West | South | East | North-East | All-India |
|---|---|---|---|---|---|---|
| **Coal** | 39,431 | 66,220 | 30,343 | 28,583 | 60 | 164,636 |
| **Gas** | 5,331 | 10,915 | 4,963 | 190 | 1,663 | 23,062 |
| **Diesel** | 13 | 17 | 939 | 17 | 143 | 1,130 |
| **Nuclear** | 1,620 | 1,840 | 2,320 | - | - | 5,780 |
| **Hydro** | 17,067 | 7,448 | 11,398 | 4,113 | 1,242 | 41,267 |
| **Wind** | 3,053 | 8,517 | 10,891 | 4 | - | 22,465 |
| **Solar** | 962 | 1,638 | 416 | 62 | - | 3,078 |
| **Small Hydro** | 1,331 | 490 | 1,670 | 238 | 262 | 3,991 |
| **Biomass + Cogeneration** | 1,094 | 1,275 | 1,555 | 89 | - | 4,014 |
| **Total** | **69,902** | **98,360** | **64,495** | **33,296** | **3,370** | **269,422** |

Data source: (CEA 2015c)

With significant capacity additions in the recent years, the power shortage in India has reduced considerably. In the FY 2014-15 (April 2014 through March 2015), India faced nearly 5% peak shortage and about 3.5% of energy shortage as shown in the following table.

Table 4: Peak (MW) and Energy (GWh) Demand and Availability by Region (for FY 2014-15)

| Region | Energy (GWh) | | Peak (MW) | |
|---|---|---|---|---|
| | Demand | Availability | Demand | Availability |
| North | 332,453 | 311,589 | 51,977 | 47,642 |
| West | 317,367 | 314,923 | 44,166 | 43,145 |
| South | 285,797 | 274,136 | 39,094 | 37,047 |
| East | 119,082 | 117,155 | 17,040 | 16,932 |
| North-East | 14,224 | 12,982 | 2,528 | 2,202 |
| **All-India** | **1,068,923** | **1,030,785** | **148,166** | **141,160** |

Data Source: (CEA 2015b)

Since all states and regions are synchronized since 2014, the transmission constraints across state and region boundaries have started relieving significantly. The following table shows the existing transmission capacity in June 2015 between the regions in India.

Table 5: Existing inter-regional Transmission Capacity in India (June 2015)

| Corridor | Transmission Capacity (MW) (June 2015) |
|---|---|
| East-North | 15830 |
| East-West | 10690 |
| East-South | 3630 |
| East-North_East | 2860 |
| West-North | 8720 |
| West-South | 5720 |

Source: (MOP 2015)

Note that the numbers shown in this table are the total transmission capacity. The actual concurrent power transfer capability (considering congestion, reverse flows, and other technical constraints) may be much lower than this.

Over the next 15-20 years, Indian power sector is poised to expand significantly. For example, the peak power demand is expected to nearly double to about 287GW by 2022 and more than triple to nearly 500 GW by 2030 (CEA 2013c).

# 3 Methodology, Assumptions, and Data

We model the Indian electricity grid using 5 nodes – one node each for every region viz. north, east, west, south, and north-east. We project hourly demand by region in 2022 using the Central Electricity Authority's demand projections in their 18th Electric Power Survey (EPS) and the hourly demand patterns over the FYs 2010 through 2013 adjusting for rapid urbanization. We then created a variety of scenarios for renewable energy penetration. We use actual hourly generation and solar irradiance (DNI and GHI) data to project the hourly wind and solar generation for 2022. We develop assumptions regarding cost and performance of generation technologies, fuels, and transmission. We use a capacity expansion and production cost model called PLEXOS in order to assess the least cost generation and transmission investments and simulate economic dispatch for the financial year 2022 subject to a range of operational constraints as described in the following sections. We then conduct sensitivity analysis on key parameters to assess the robustness of our findings. The methodology is summarized in Figure 5 and the following section describes it in detail.

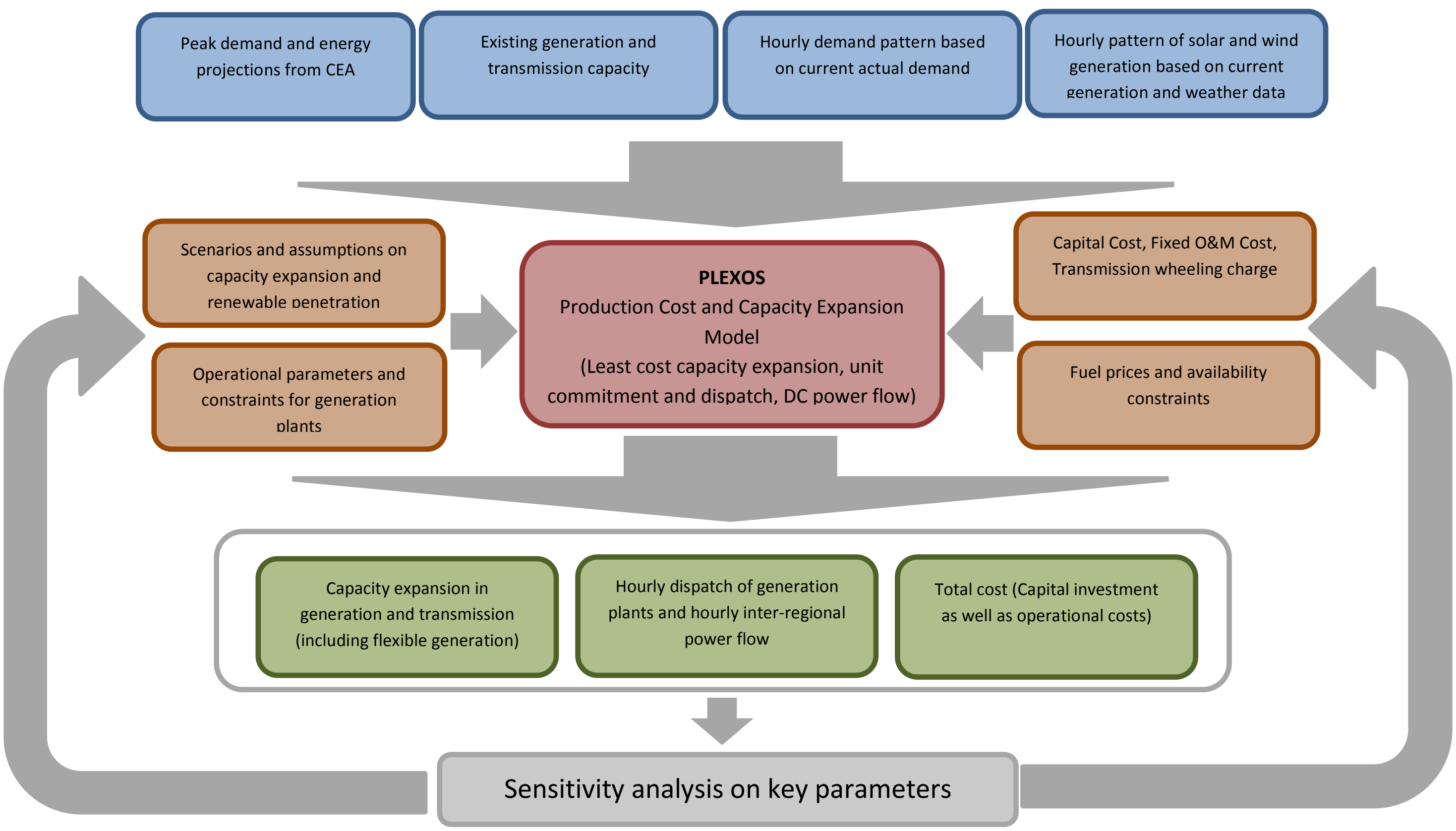



**Figure 5: Summary of the Methodology**

In PLEXOS, we run the capacity expansion model with FY 2022 as the terminal year i.e. the model is not assumed to have the foresight beyond FY 2022. The output of the capacity expansion model (total number of units in each region including the modeled additions until FY 2022) is used by the economic dispatch model. We run the economic dispatch model in two stages. The first stage is simulation of the day-ahead scheduling and market. In the day-ahead mode, the model takes the day-ahead RE and load forecasts and expected maintenance outages and makes the unit commitment decisions for thermal power plants. These RE and load forecasts are revised up to three hours in advance in order to reduce the forecast errors significantly and potentially revise the unit commitment schedule, if necessary and feasible. The second stage is simulating the hourly real-time grid operation and power plant dispatch. In the real-time mode, the model takes the unit commitment decisions from the day-ahead mode (revised up to three-hours ahead) and does the economic dispatch considering the actual (i.e. forecasts of the FY 2022 real-time) RE generation and load. The unit commitment and dispatch decisions are made to minimize the total system cost (production as well as start and shutdown costs) subject to a number of operational constraints such as maximum ramping rates, minimum stable generation levels, minimum up and down times etc. Also, note that these are energy only simulations and do not include ancillary services such as reserves etc.

## 3.1 Scenarios for RE Penetration

We created the following three scenarios for renewable energy penetration for the FY 2022:

1. ***13th Plan***: This scenario serves as the baseline for this analysis and uses the generation capacity additions for all technologies as projected in the Government of India's 12th Plan up to 2022 (end of the 13$^{th}$ Plan). Although the 12$^{th}$ plan provides detailed capacity addition projections only up to FY 2017, it does estimate the 2022 targets also (Planning Commission 2012). For RE, this scenario assumes the total installed capacity of 41GW of wind, 22GW of solar PV (i.e. India's original National Solar Mission), 14 GW of other RE (small hydro and biomass combined) by FY 2022; the total installed capacity including the conventional technologies is assumed to be about 425GW by FY 2022. This scenario translates to an total RE penetration of 8% by energy by 2022.

2. ***RE Missions***: This scenario models the recent announcement by the Government of India to increase the total installed capacity of solar PV projects to 100GW and wind projects to 60 GW by FY 2022. Note that out of the solar PV target of 100 GW, about 40 GW is expected to be distributed PVs. However, from the overall transmission grid perspective, there is little difference between the utility scale and distributed PV projects. In this analysis, for simplicity, we treat all the 100GW as utility scale solar PV plants. Note that since we are not modeling transmission constraints, this assumption would not change our results significantly. The other RE capacity targets are assumed to be the same as those in the 13th Plan scenario. For translating these national targets to the regional targets, we have used the state-level targets of the wind and solar capacity provided by MNRE. Overall, this scenario implies total RE penetration of about 18% by energy by 2022.

3. ***National Action Plan on Climate Change (NAPCC)***: This scenario models the renewable energy target described in India's NAPCC (2009). NAPCC targets renewable energy to provide 15% electricity (by energy) by 2020 (PMO 2009). If the same trend between 2009 and 2020 is projected up to 2022, RE capacity would provide ~20% electricity (by energy) by FY 2022. Keeping the installed capacity of the other RE (small hydro and biomass) the same as 13th Plan, we split the rest of the NAPCC target into wind and solar PV using 75:25 ratio (by energy and not capacity). The reason behind choosing this ratio is that the national installed capacity targets by 2022 translate to approximately 100GW of wind, about 60GW of solar, and 14GW of other RE; this makes the total RE capacity targets in the NAPCC scenario almost the same as those in the RE Missions scenario except the capacity shares of wind and solar are reversed, which lets us compare a wind-heavy system (NAPCC) with a solar-heavy one (RE Missions). Applying the ratio of the current RE capacity in different regions, these national targets are then translated to regional targets. Based on the wind

and solar resource potential data, the model then chooses the best solar and wind resources in each region as explained in the subsequent section.

The following table shows the total installed capacity (national) of RE technologies for each scenario.

**Table 6: Total RE installed capacity in GW in FY 2022 for each scenario[3]**

| | 13th Plan | NAPCC | RE Missions |
|---|---|---|---|
| **Wind** | 41 | ~107 (13% by energy) | 60 |
| **Solar** | 22 | ~58 (4% by energy) | 100 |
| **Small Hydro** | 6.6 | 6.6 (1.5% by energy) | 6.6 |
| **Biomass** | 7.7 | 7.7 (1.5% by energy) | 7.7 |
| **Total RE** | 77 (8% by energy) | 179 (20% by energy) | 175 (18% by energy) |

## 3.2 Assumptions on Capacity Expansion of Other Technologies

In the NAPCC and RE Missions scenarios, we assume that the hydro and nuclear capacity addition is the same as that in the 13th Plan scenario; capacity addition in coal and gas is optimized by PLEXOS. The following table shows our assumptions on capacity additions under each scenario.

**Table 7: Assumptions on Cumulative Capacity Additions in GW between FY 2015 and FY 2022 for non-RE Technologies under each Scenario**

| | 13th Plan | NAPCC | RE Missions |
|---|---|---|---|
| **Coal** | 79 | Optimized by model | Optimized by model |
| **Gas** | 0 | Optimized by model | Optimized by model |
| **Nuclear** | 19 | 19 | 19 |
| **Hydro** | 18 | 18 | 18 |

[3] In order to validate our projections of state/regional RE capacity expansion targets, we compared our approach (distribution based on the ratio of existing installed capacities) with two other studies looking at RE expansion plans in the future viz. (a) study by the Forum of Regulators (India) to assess the impact of the RPS targets on future retail rates (FOR 2012), and (b) Report by PowerGrid Corporation of India on Green Energy Corridors to assess the transmission needs of aggressive RE capacity addition (POWERGRID 2012). Our distribution of RE targets across regions closely matches with both these studies.

In 2012, the government of India decided that no sub-critical coal capacity would be added after 2017. Our model includes that constraint. Moreover, domestic coal and gas availability has a major bearing on the feasible capacity additions under all scenarios as explained in the Section 3.8.

## 3.3 Hourly Demand Forecast by Region

The following table shows the load factors (ratio of the annual average demand to peak demand) over the last seven years in all five regions and key cities that do not face significant power cuts.

**Table 8: Annual load factors in key cities and regions (financial years 2008 through 2015)**

| | 2008 | 2012 | 2013 | 2014 | 2015 |
|---|---|---|---|---|---|
| **Chandigarh** | 63% | 68% | 55% | 52% | 50% |
| **Delhi** | 65% | 61% | 52% | 54% | 56% |
| **Pondicherry** | 91% | 76% | 82% | 80% | 78% |
| **Mumbai** | 69% | 68% | 65% | #N/A | #N/A |
| **Northern Region** | 78% | 79% | 75% | 78% | 75% |
| **Western Region** | 84% | 80% | 82% | 83% | 83% |
| **Southern Region** | 88% | 84% | 86% | 82% | 84% |
| **Eastern Region** | 81% | 77% | 76% | 78% | 79% |
| **North-Eastern Region** | 68% | 64% | 66% | 66% | 67% |
| ***All India*** | ***87%*** | ***84%*** | ***84%*** | ***84%*** | ***83%*** |

Data Sources: (CEA 2015b; CEA 2015d; CEA 2012; CEA 2013b; CEA 2009a)

Across all regions and cities, load factors have been reducing over time; this implies that the demand is becoming peakier in nature. This may be happening due to two reasons viz. (a) availability of power has been increasing resulting in reduced shortages, and (b) due to rapid urbanization, electricity usage pattern and appliance ownership have changed significantly. This has an important bearing while projecting the hourly demand curve for the FY 2022. We simulated the hourly demand curve for each region based on the historical hourly demand patterns in the country, growing urbanization, and the projected load growth based on the CEA's 18$^{th}$ EPS. We understand that CEA, in its 19$^{th}$ EPS, has revised the load projections for 2022 downwards by nearly 15%-20%. However, official EPS numbers were not available by the time the grid dispatch simulations were made. Also, we believe that even with the revised load projections, the overall conclusions of the study will not alter. Therefore, we have used 18$^{th}$ EPS load projections in this analysis.

One of the key problems in projecting the future demand was accounting for the load curtailment (which was as high as 6% by energy in 2013). To address that, we used a mixed approach. We used the current restricted load data for each region to assess the seasonal load pattern in a region; and used hourly load data of the key load centers that do not experience load shedding (such as Delhi, Chandigarh, Gujarat, Mumbai, Pondicherry etc.) and the load centers that have the load shedding data available (such as Maharashtra, Tamil Nadu etc.) to assess the diurnal demand pattern. For estimating the FY 2022 demand, we apply the regional demand growth rates from CEA's 18$^{th}$ EPS. Next, to account for the growing urbanization in the country, load shapes of the urban load centers (such as Delhi, Mumbai, Pondicherry etc.) are given an additional 20% weight relative to the state level load curves in each region. This would make the resultant 2022 load curve peakier than the current (2015) one. Finally, the regional load curve is uniformly adjusted so that the peak demand and total energy demand match CEA's projections for FY 2022 in their 18th EPS. Demand forecast and load shape assessment is an area where future work is needed using a combination of bottom up and top down approaches.

The following charts show the projected load duration curves for each region for FY 2022.

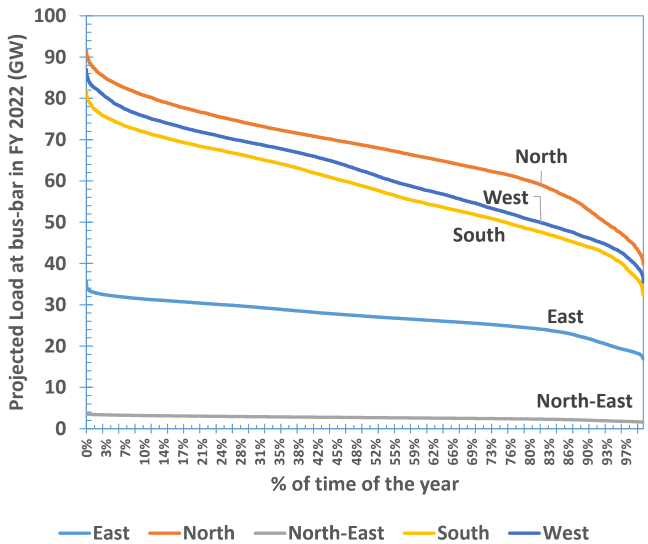



Figure 6: Load Duration Curves for Regions in India for the Financial Year 2022

The following table shows the projected energy demand, peak demand, and load factor for the FY 2022 in each of the regions.

Table 9: Projected energy demand, peak demand, and load factors for the financial year 2022

| **Region** | **Energy Demand (TWh/yr)** | **Peak Demand (GW)** | **Load factor (%)** |
|---|---|---|---|
| **Northern** | 594 | 92 | 78% |
| **Western** | 540 | 87 | 72% |
| **Southern** | 511 | 82 | 71% |
| **Eastern** | 237 | 36 | 75% |
| **North_Eastern** | 23 | 4.1 | 65% |
| ***All-India*** | ***1906*** | ***287*** | ***77%*** |

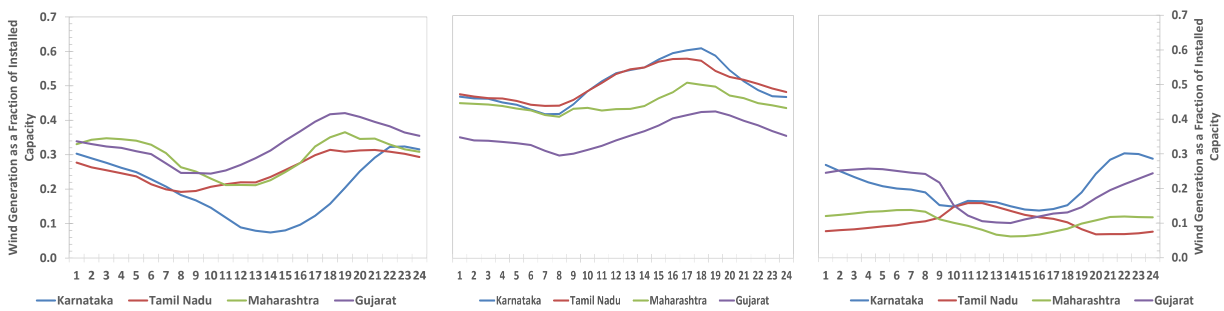
In Appendix 1, we have given the monthly peak and energy demand projections for each region.

## 3.4 Hourly Solar and Wind Generation Forecast by Region

### 3.4.1 Wind Energy Generation Profiles

India's current wind installed capacity is more than 21GW and has been growing consistently over the last 10 years or so. Indian wind energy generation is highly seasonal and peaks during monsoon. For FY 2022, hourly profiles of wind energy generation have been forecasted using the actual historical generation data for the FYs 2010 through 2013 from the states of Tamil Nadu, Karnataka, Maharashtra, and Gujarat. These states together cover over 80% of the existing wind installed capacity and over 75% of the total wind potential in India (CWET 2014; Phadke 2012). Hourly wind generation data was sourced from the websites of the respective state load dispatch centers. We understand that the reported wind generation does not take into account the curtailment. Therefore, actual data may not represent the true profiles of wind generation. Unfortunately, the data on exact amount and timing of curtailment is not available. Secondly, industry experts suggest that wind energy curtailment was quite limited until the FY 2012-2013 (Phadke, Abhyankar, and Rao 2014).

The following chart shows the seasonal averages of the wind energy generation (as a share of the installed capacity) in the key states mentioned above.




Summer (April-May) Monsoon (June-September) Winter (Dec-Feb)

**Figure 7: Average daily wind generation curve (of existing capacity) in key states for key states**

It can be seen that there is significant seasonal variation in wind generation in all states. Wind generation peaks in monsoon (June through September) and drops significantly in the winter. However the diurnal pattern of wind generation in a season is very similar across all states. In Monsoon and Summer, the wind generation peaks late afternoon or early evening which matches with the overall demand patterns in these seasons.

For future wind capacity addition, we used the wind energy potential numbers in each state from our previous study assessing the wind energy potential in India (Phadke 2012). For estimating the hourly wind generation profile for a future year (2022, in this case), the approach in other studies has been to use time-series data from meso-scale models. But in this study, we are scaling the actual generation data for the current year, which assumes that the additional capacity will be installed in the same regions, and hence will have the same profiles. However, in reality, capacity addition will occur in different areas, which is likely to reduce the overall variability of the wind generation at the regional level due to geographic diversity of the wind installations. However, given that verified hourly wind resource data was not available in the public domain, we could not use wind resource data from undeveloped sites. Thus, wind variability in this analysis would be high and the capacity value conservative; and could be seen as the worst-case scenario of the future wind capacity addition. More detailed analysis (for example using time-series meso-scale resource data) is needed to improve the profiles of wind generation used in this analysis.

### 3.4.2 Solar Energy Generation Profiles

Unlike wind, total grid connected solar PV capacity in India is only 3 GW albeit it is increasing rapidly given the dropping costs and favorable regulatory and policy environments. The largest capacity of 1.5 GW is operational in the state of Gujarat. However several studies have shown practically infinite solar energy potential in India. For estimating the hourly generation profile, we chose 100 sites spread over all 5 regions with best quality solar resource (measured in DNI and GHI kWh/m2) using the national solar energy dataset for India developed by the National Renewable Energy Laboratory that contains hourly irradiance data for every 5kmx5km grid in India. The solar irradiance data was then fed into the System Advisor Model (SAM) also developed by the National Renewable Energy Laboratory to get the solar PV output at the chosen 100 sites. The hourly PV output profiles of the sites in each region was averaged to arrive at the regional solar PV generation profile. The average generation profiles for each season are shown in the charts below.

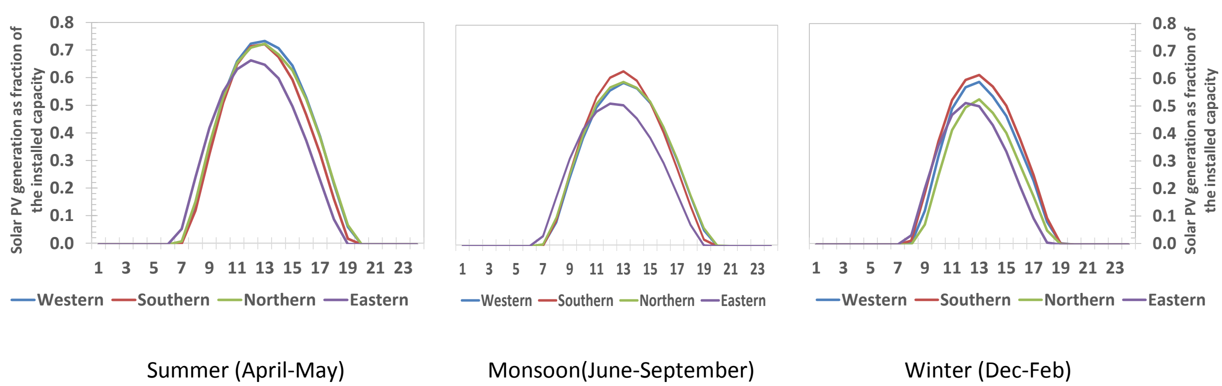



**Figure 8: Average daily solar generation curves for each region**

As can be seen from the charts that the solar resource peaks in the summer and drops in winter. However, the seasonal variation is not as dramatic as that in case of wind. It may appear that there is not much difference in the average resource quality of the western, northern and southern regions; however, resource quality would vary significantly at the individual site level. Most of India's best quality solar resource is concentrated in the western and the northern region. Note that averaging of the solar profiles over multiple sites may underestimate the total variability in solar PV generation. On the other hand, as explained in the previous section on wind energy, we assume that the future solar capacity is added at the sites selected for estimating the hourly generation profile. Therefore, it may not fully capture the benefits of geographic diversity and may overestimate the variability to some extent. A comprehensive GIS based analysis for site selection would correct these errors; however, that is outside the scope of this research and hence not considered.

## 3.5 Operational Parameters of Generators

Table 33 in Appendix 2 summarizes our assumptions on the operational characteristics (unit size, heat rates, ramp rates, minimum stable level, etc.) of the power plants. The values have been estimated using the actual hourly dispatch data, actual outage and other performance data, regulatory orders on heat rates and costs, other relevant literature, and actual practices in India. Currently, the combined cycle (gas) plants in India are not operated in the open cycle mode (gas turbine only; no waste heat recovery). However, by 2022, we assume that the gas turbines in the combined cycle plants could be operated independently in open cycle mode, which enhances the system flexibility considerably.

## 3.6 Hydro Capacity and Energy Model

Hydro capacity is modeled using a fixed monthly energy budget. Based on the historical dispatch and minimum flow and spill constraints we estimated the capacity factors of the hydro power plants for every month. Subject to such monthly capacity factor constraints, reservoir based hydro power plants are assumed to be optimally dispatched. The following table shows the monthly capacity factors for hydro plants in each region:

**Table 10: Monthly Capacity Factors of Hydroelectric Projects for Each Region**

| | East | North-East | West | South | North |
|---|---|---|---|---|---|
| **January** | 18% | 25% | 30% | 28% | 24% |
| **February** | 18% | 23% | 27% | 32% | 29% |
| **March** | 19% | 22% | 26% | 40% | 36% |
| **April** | 25% | 34% | 26% | 31% | 40% |
| **May** | 18% | 49% | 26% | 27% | 62% |
| **June** | 27% | 61% | 23% | 27% | 64% |
| **July** | 28% | 80% | 27% | 31% | 67% |
| **August** | 27% | 83% | 47% | 37% | 67% |
| **September** | 32% | 67% | 49% | 54% | 71% |
| **October** | 26% | 60% | 38% | 39% | 40% |
| **November** | 16% | 40% | 26% | 29% | 29% |
| **December** | 8% | 26% | 21% | 24% | 26% |
| ***Annual Average*** | ***22%*** | ***47%*** | ***30%*** | ***33%*** | ***46%*** |

Data sources: (CEA 2015b; CEA 2015d)

Hydro capacity factors depend on a variety of factors including high recharge season (such as summer or monsoon), irrigation and minimum flow requirements, etc.

More than 50% of India's current hydro capacity is run of the river; output of the run-of-the-river plants is assumed to be flat subject to the monthly capacity factor constraint. India has limited pumped storage capacity; they are modeled using a weekly energy balance i.e. the head and tail storage ponds return to their initial volumes at the end of each week. We ran a sensitivity case with daily energy balance but given the small pumped storage capacity, it does not make a large difference to the overall results.

## 3.7 Costs

The following tables show the assumptions on capital cost and fixed O&M costs for each technology. The current capital costs of renewable technologies have been taken from the Central Electricity Regulatory Commission's (CERC) tariff regulations 2015. CERC's tariff regulations for the conventional projects do not mention the capital cost norms. For coal based power projects, we have used CERC's interim order (2012) on benchmarking the capital costs of thermal projects (CERC 2012). For gas, diesel, and hydro projects, we have used industry norms per our previous report (Abhyankar et al. 2013). Capital and O&M costs of the nuclear projects have been taken from (Ramana, D'Sa, and Reddy 2005).

The following table shows the current year capital and O&M costs for all technologies considered in this analysis.

**Table 11: Capital cost (overnight; excluding interest during construction) and fixed O&M cost of the generating plants (2015Rs)**

| Generation Technology | Capital Cost Rs Cr/MW (2015) | Fixed O&M Cost Rs Cr/MW/yr (2015) | Fixed O&M Cost as % of Capital Cost |
|---|---|---|---|
| **Coal (>600 MW units)** | 5.37 | 0.14 | 2.7% |
| **Coal (500 MW units)** | 5.08 | 0.16 | 3.1% |
| **Gas CCGT (Combined cycle)** | 4.80 | 0.15 | 3.1% |
| **Gas CT (Open Cycle)** | 4.20 | 0.15 | 3.5% |
| **Diesel** | 3.60 | 0.13 | 3.5% |
| **Nuclear** | 5.71 | 0.11 | 2.0% |
| **Hydro (<200 MW)** | 8.00 | 0.32 | 4.0% |
| **Hydro (>200 MW)** | 8.00 | 0.20 | 2.5% |
| **Small Hydro** (between 5 and 25MW) - excluding Himachal Pradesh, Uttaranchal and North-Eastern States | 5.93 | 0.17 | 2.8% |
| **Small Hydro** (between 5 and 25MW) - Himachal, Uttaranchal and North-Eastern States only | 7.54 | 0.21 | 2.8% |
| **Biomass** (for rice straw and juliflora based projects with water cooled condenser) | 6.10 | 0.45 | 7.3% |
| **Wind (Onshore)** | 6.19 | 0.11 | 1.7% |
| **Solar PV** | 5.87 | 0.13 | 2.2% |

Data Sources: (CERC 2012; CERC 2015; CERC 2014; Abhyankar et al. 2013; Ramana, D'Sa, and Reddy 2005)

Note that the capital cost of coal units shown above does not include the additional investment needed to meet the new norms for Particulate Matter, SOx, and NOx emissions (2015); such investments may increase the capital cost of the coal units by over 10% or so.

The economic life of all generation assets has been assumed to be 25 years and the weighted average cost of capital is assumed to be 11.2% (i.e. weighted average of the 14% Return on Equity (ROE) and 10% interest rate assuming a debt to equity ratio of 70:30).

The solar PV cost in CERC regulations matches up with the prices quoted in the latest solar PV reverse auctions in India. In the state of Madhya Pradesh, a reverse auction concluded in July 2015 received a winning bid of Rs 5.05/kWh (Business Standard 2015). Using CERC's capital cost and O&M cost norms, WACC of 12.8%, and assuming a capacity factor of 21%, the levelized cost of electricity for a solar PV plant comes to Rs 5.07/kWh.

Given that most of the conventional technologies have already matured, their capital costs are not assumed to change until 2022. Renewable technologies especially solar PV still have high learning rates and thus their costs would reduce between 2015 and 2022. Our assumptions for such reduction are shown in the following table.

**Table 12: Wind and Solar PV Capital Cost Reduction in Future**

| | 2015 Capital Cost Rs Cr/MW | Average annual price reduction (%) | 2022 Capital Cost Rs Cr/MW |
|---|---|---|---|
| **Wind** | 6.19 | - | 6.19 |
| **Solar PV** | 5.87 | 4.7% | 4.18 |

For solar PVs, we used the capital cost trajectory projected in the Global PV Market Outlook 2015 by BNEF (BNEF 2015). Based on their capital cost projections, we estimated the average annual reduction in PV prices to be 4.7% between 2015 and 2020. We apply the same annual reduction up to 2022. Lawrence Berkeley National Lab's PV market assessment in the US reports similar cost reductions (Barbose, Weaver, and Darghouth 2014). For wind, we use the historical capital cost data in the US from LBNL's wind technologies assessment report (Wiser and Bolinger 2015). Although there have been significant annual fluctuations in the wind capital cost, the capital cost has not changed much over the last 10 years or so.[4] Therefore, going forward, we have assumed that wind capital cost would stay the same until 2022.

## 3.8 Fuel Availability and Prices

Domestic gas and coal availability is constrained in India. Coal availability for the power sector has been taken from the Ministry of Coal's projections in the 12th five-year plan up to 2017; the same trend has been projected up to 2022. Domestic gas availability is highly constrained too and several gas-based power plants are stranded because of non-availability of gas. We have assumed that the domestic gas availability for power sector in future remains the same as the current quantity. If the system needs more natural gas, it will have to be imported (LNG) at international prices. We have not assumed any restrictions on imported coal and gas, and other fuels such as diesel and biomass.

[4] Wind Power Purchase Agreement (PPA) prices have dropped significantly in the recent years though; in 2014, the average levelized wind PPA price in the US was $23/MWh including the Production or Investment Tax Credits (Wiser and Bolinger 2015). If the tax credits are excluded, the levelized price would be about $40/MWh (approximately Rs 2.5/kWh).

**Table 13: Fuel Availability and Calorific Value Assumptions (2022)**

| Fuel | Max Availability in FY 2022 | Gross Calorific Value |
|---|---|---|
| **Domestic Coal** | 750 Million Tons/yr | 4000 kCal/kg |
| **Imported Coal** | Unlimited | 5400 kCal/kg |
| **Domestic Gas** | 29 bcm/yr | 9000 kCal/m$^3$ |
| **Imported LNG** | Unlimited | 9000 kCal/m$^3$ |
| **Diesel** | Unlimited | 10000 kCal/lit |
| **Biomass** | Unlimited | 3000 kCal/kg |

Data source for coal and gas availability: (Planning Commission 2012)

Domestic coal price data have been taken from Coal India Limited's (CIL) annual reports as the average price of coal sold by CIL in that year (CIL 2011; CIL 2015).[5] Historical trends in the imported coal prices have been taken from the BP Statistical Review (Asian marker price) (BP 2015); current international. Domestic natural gas price has been taken from the Ministry of Petroleum and Natural Gas' orders in various years/months. Imported LNG price for the current year (2015) has been taken from the media reports on the international LNG market, while the historical trend in the imported LNG price in India has been taken from (Sen 2015). The fuel prices are assumed to increase at the long-run (10-year) compounded average growth rate. However, note that the historical fuel prices are listed in nominal dollars (or rupees, as the case may be). In order to assess the price trend in real terms, we deflated the nominal prices using the annual inflation rate (Wholesale Price Index (WPI)); the WPI data was sourced from (OEA 2015). The following table shows the current fuel prices, long-run growth nominal and real growth rates, and the projected 2022 fuel prices expressed as 2015 dollars or rupees.

**Table 14: Fuel Price Assumptions**

| Fuel | Fuel Price in 2015 (FOB) | Escalation in Nominal Price (10-yr CAGR) % | Inflation adjusted (real) escalation rate % p.a. | Fuel Price in 2022 (FOB) |
|---|---|---|---|---|
| **Domestic Coal (Rs/Ton)** | 1948 | 7.5% | 1.4% | 2141 |
| **Imported Coal ($/Ton)** | 77.89 | 6.9% | 0.7% | 82 |
| **Domestic Gas ($/mmbtu)** | 4.66 | 8.8% | 2.7% | 5.6 |
| **LNG ($/mmbtu)** | 11 | 6.2% | 0.1% | 11 |
| **High Speed Diesel (Rs/lit)** | 50 | 6.2% | 0.1% | 50 |

Data Sources: *Ibid*

Note: All price and cost numbers refer to 2015 real values.

[5] Coal India Limited controls more than 80% of India's total coal production and about 80% of its coal is sold to the power sector.

Note that these are the FOB (free on board) prices and do not include the fuel transportation and LNG regasification etc. costs. Those costs depend on the locations of the plant and the fuel sources. Domestic coal transportation costs have been taken from regulatory proceedings and tariff orders of the state and central generation utilities. Imported coal plants are assumed to be located on the shore and therefore would not incur any domestic transportation charge except in cases of northern and eastern regions. The following table shows the coal transportation costs to each of the regions:

**Table 15: Average Coal Transportation Costs to Each Region**

| | Domestic Coal (Rs/Ton) | Imported Coal | |
|---|---|---|---|
| | | International transportation ($/Ton) | Domestic transportation (Rs/Ton) |
| **North** | 1200 | 30 | 1500 |
| **West** | 1500 | 30 | - |
| **South** | 1800 | 30 | - |
| **East** | 1000 | 30 | 1500 |

Data source: Authors' estimates, Regulatory filings

Note: All price and cost numbers refer to 2015 real values.

Similarly, imported LNG based plants are not assumed to incur domestic gas pipeline charges, except in cases of northern and eastern regions; all LNG imports are assumed to incur a regasification cost of $0.5/MMBTU. In case of domestic gas, we have assumed two sources viz. (a) Bombay high field (off the western coast) near Mumbai and, (b) KG-D6 field off the eastern coast near Andhra Pradesh. The following table shows the domestic gas and LNG transportation charges from these sources to each of the regions. The following table shows the gas transportation costs to each of the regions:

**Table 16: Average Gas Transportation Costs to Each Region**

| | Domestic Gas ($/MMBTU) | | Imported LNG ($/MMBTU) | | |
|---|---|---|---|---|---|
| | Bombay High | KG D-6 | International transportation | Regassification | Domestic Pipeline |
| **North** | 1.5 | 2.0 | 1.0 | 0.5 | 1.5 |
| **West** | 0.5 | 1.5 | 1.0 | 0.5 | 0 |
| **South** | 1.5 | 0.5 | 1.5 | 0.5 | 0 |
| **East** | #N/A | 1.5 | 1.5 | 0.5 | 1.5 |

Data source: Authors' estimates, PNGRB website

Note: All price and cost numbers refer to 2015 real values.

## 3.9 Transmission

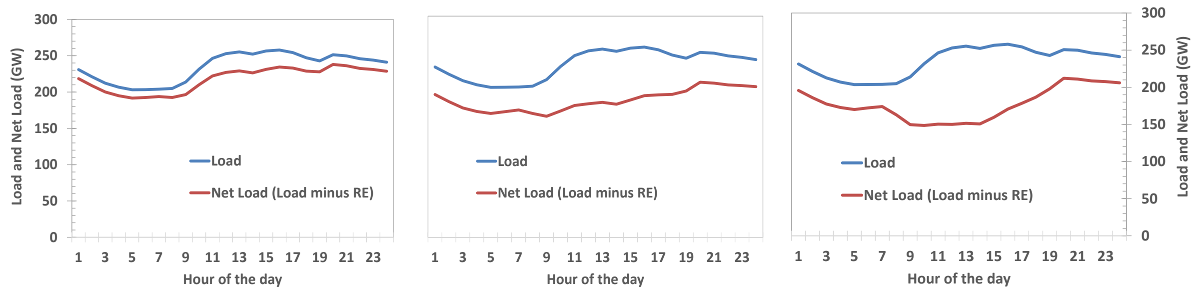
In 2013, southern regional grid in India was integrated with the northern regional grid. Additionally, there have been significant transmission investments planned in the near future. Going forward, we have assumed no constraints on transmission primarily to assess the transmission transfer capability requirements between the regions in future.

# 4 Results

In this section, we present the key results of our analysis. In order to develop an intuitive understanding of the results and keep them tractable, we are only going to present the results for an average day in each season.

## 4.1 Impact on Net Load to be Met by Conventional Generators

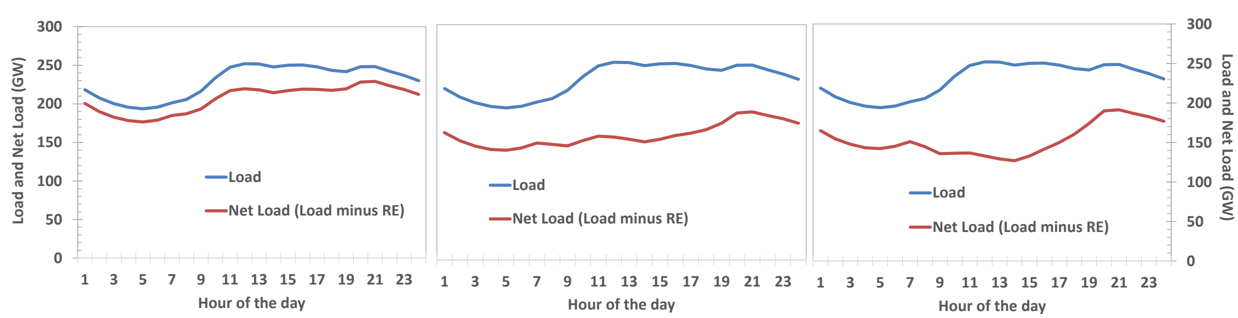
Since we define RE penetration scenarios exogenously, we first compare the characteristics of the net load (residual demand that the conventional generators have to meet) in order to provide an intuitive explanation of our modeling results discussed further. Net load (or the residual load) is estimated by subtracting the variable RE generation from load. The following charts show the national net load curves for an average day in each season. In the appendices, we provide detailed results for each region.




(a) 13th Plan (41GW Wind; 22GW Solar) (b) NAPCC (100GW Wind; 60GW Solar) (c) RE Missions (60GW Wind; 100GW Solar)

**Figure 9: Average Daily Load and Net Load Curves (National) during Summer 2022 (April-May)**

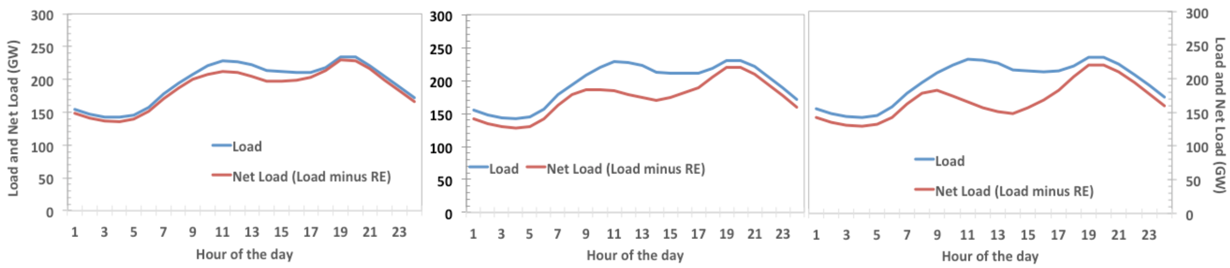
In summer (April-May), load peaks in the afternoon mainly because of the space cooling demand. There is a small peak in the evening because of the lighting demand and the demand remains high at night and early morning mainly due to the residential space cooling demand. Solar PV generation peaks in the summer and correlates well with the diurnal demand pattern especially until early afternoon. In the NAPCC scenario, it removes the afternoon peak and makes the net load look much flatter. In the RE missions scenario, the net load actually dips in the afternoon and introduces significant ramping in the evening when solar PV generation drops rapidly.




(a) 13th Plan (41GW Wind; 22GW Solar) (b) NAPCC (100GW Wind; 60GW Solar) (c) RE Missions (60GW Wind; 100GW Solar)

**Figure 10: Average Daily Load and Net Load Curves (National) during Monsoon 2022 (June-September)**

The load curve in monsoon is somewhat similar to that in the summer – afternoon peaking with significant demand in the night/early morning. Although the load in the western and southern region drops, the load peaks in the northern region of the country. Wind generation has a very high correlation with the load (especially in the northern region) in monsoon. In both scenarios – NAPCC and RE Missions, net load curves in monsoon are similar to those in the summer.




(a) 13th Plan (41GW Wind; 22GW Solar) (b) NAPCC (100GW Wind; 60GW Solar) (c) RE Missions (60GW Wind; 100GW Solar)

**Figure 11: Average Daily Load and Net Load Curves (National) during Winter 2022 (December-February)**

Winter load curve is significantly different. It has two distinct peaks – one in the morning mainly because of the water heating demand and the other one in the evening primarily because of the lighting demand. Overall, the demand in the winter is much lower than that in the summer or monsoon. Wind generation drops significantly in the winter. There is a drop in solar generation also but not as significant as wind. This drop in RE generation has a major bearing on the energy support that may be needed in winter as explained later. Also, in winter, the ramping requirement in the evening is much higher than the other two seasons due to the rapid drop in solar generation and increase in the evening demand.

## 4.2 Capacity Addition and Capacity Factors of Conventional Generators

The following table shows the capacity additions required by 2022 under all scenarios and the annual capacity factors of all technologies aggregated at the national level. Please refer to the appendices for detailed results by each region. The assumptions governing the additions in nuclear, hydro, and renewable technologies have already been explained in the previous section. Given those assumptions and the operational constraints, the model chooses the least cost investments in thermal capacity (coal, gas, and diesel).

**Table 17: Capacity Additions, Installed Capacities and Capacity Factors of All Technologies (National)**

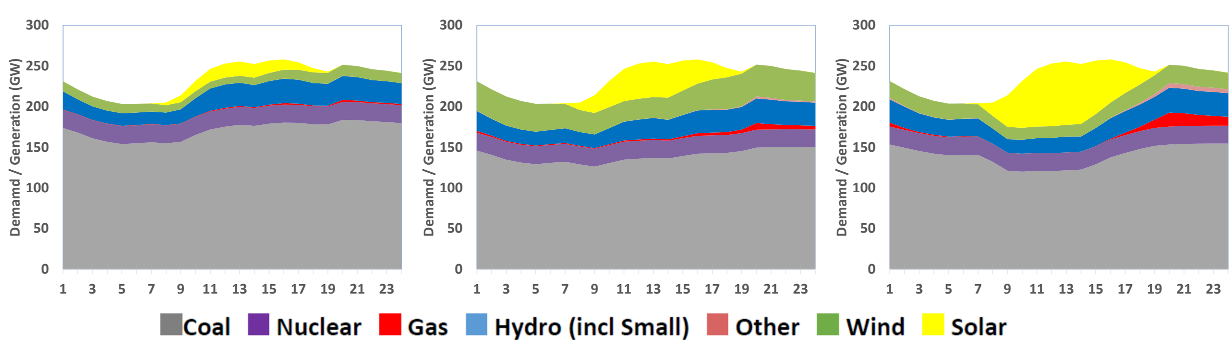
| | 13th Plan | | | NAPCC | | | RE Missions | | |
|---|---|---|---|---|---|---|---|---|---|
| | Capacity Addition in GW (2015-2022) | Total Installed Capacity in GW in 2022 | Annual Capacity factor (%) | Capacity Addition in GW (2015-2022) | Total Installed Capacity in GW in 2022 | Annual Capacity factor (%) | Capacity Addition in GW (2015-2022) | Total Installed Capacity in GW in 2022 | Annual Capacity factor (%) |
| **Coal** | 79 | 243 | 64% | 17 | 182 | 71% | 17 | 182 | 73% |
| **Gas** | 0 | 23 | 7% | 2 | 25 | 7% | 10 | 33 | 9% |
| **Diesel** | 0 | 1 | 0% | 0 | 1 | 0% | 0 | 1 | 0% |
| **Nuclear** | 19 | 25 | 89% | 19 | 25 | 89% | 19 | 25 | 89% |
| **Hydro (Reservoir)** | 9 | 30 | 35% | 9 | 30 | 35% | 9 | 30 | 34% |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Hydro (Run of the River)** | 7 | 23 | 39% | 7 | 23 | 38% | 7 | 23 | 38% |
| **Hydro (Pumped Storage)** | 2 | 6 | 17% | 2 | 6 | 12% | 2 | 6 | 15% |
| **Small Hydro** | 2 | 6 | 37% | 2 | 6 | 37% | 2 | 6 | 37% |
| **Biomass** | 4 | 8 | 1% | 4 | 8 | 2% | 4 | 8 | 2% |
| **Solar** | 18 | 22 | 20% | 55 | 58 | 19% | 97 | 100 | 19% |
| **Wind** | 18 | 41 | 25% | 85 | 108 | 29% | 39 | 62 | 29% |
| **Total** | **159** | **425** | | **207** | **472** | | **211** | **476** | |

In both the renewable energy dominant scenarios, significant new coal capacity could be avoided relative to the 13th Plan scenario (the baseline); however, moderate level of gas based capacity is added in the RE dominant scenarios. In all scenarios, gas plants operate with an annual capacity factor of less than 10% or so implying that they are primarily used as a peaking resource (i.e. supporting the system during peak demand periods) or for providing additional flexibility to the system. As noted previously, the system needs flexibility and peak support, and it need not be technology specific; if any other sources start providing such services (for example, more flexible hydro dispatch with lesser constraints on discharge, demand response etc.), the need for gas based capacity addition would reduce. The next section describes how each of these plants are dispatched for integrating RE.

## 4.3 How is the System Operated to Integrate RE

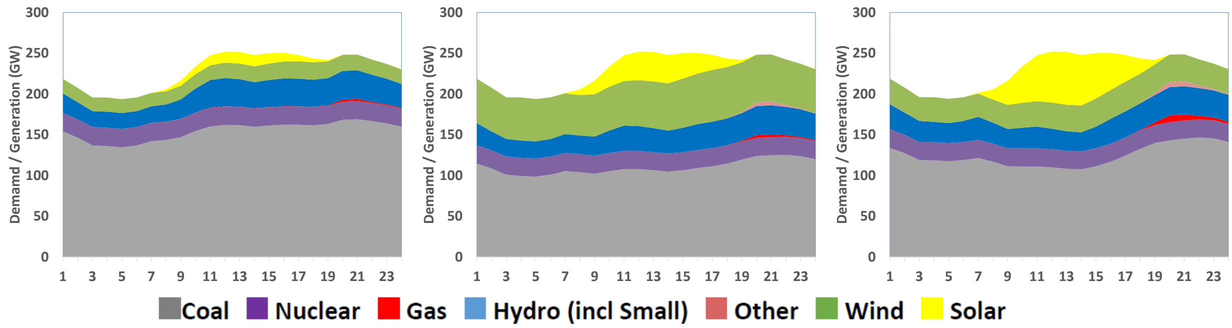
The following charts show how the average hourly dispatch in each season for the national grid (all regions combined).[6] They show how each generation technology contributes towards meeting the demand. For example, nuclear and coal power is used as the base load. Hydro is primarily used as a peaking resource but because of the run of the river plants, a large portion also runs as a base load (subject to the water flow constraints). Solar energy does contribute in the peak demand hours (afternoon cooling peak), while nationally wind energy contributes equally in peak as well as intermediate demand hours. In the NAPCC and the RE Missions scenarios, it can be seen that there is significant support needed from gas and hydro power plants for grid balancing and also during peak demand periods.




[6] Dispatch results for each region are provided in the appendices.

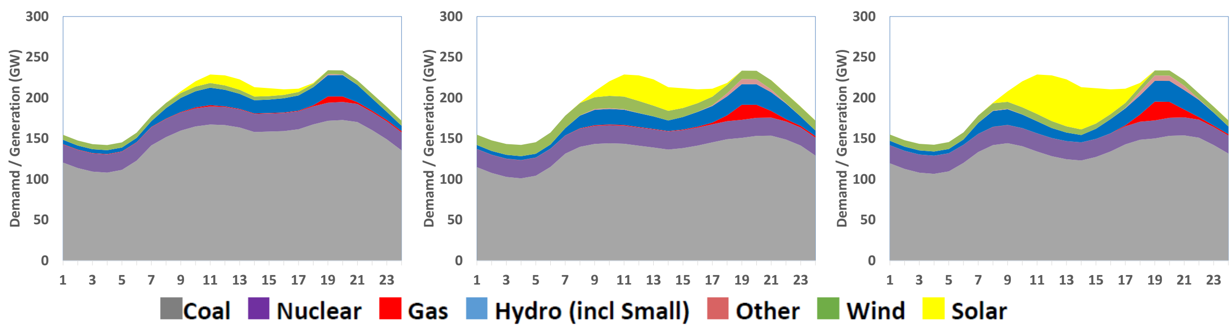
(a) 13th Plan (41GW Wind; 22GW Solar)  (b) NAPCC (100GW Wind; 60GW Solar)  (c) RE Missions (60GW Wind; 100GW Solar)

**Figure 12: Average Hourly Daily National Dispatch during Summer 2022 (April-May)**




(a) 13th Plan (41GW Wind; 22GW Solar)  (b) NAPCC (100GW Wind; 60GW Solar)  (c) RE Missions (60GW Wind; 100GW Solar)

**Figure 13: Average Hourly Daily National Dispatch during Monsoon 2022 (June-September)**




(a) 13th Plan (41GW Wind; 22GW Solar)  (b) NAPCC (100GW Wind; 60GW Solar)  (c) RE Missions (60GW Wind; 100GW Solar)

**Figure 14: Average Hourly Daily National Dispatch during Winter 2022 (December – February)**

In all scenarios and seasons, most of the coal units act as base load units. As observed in the previous section, both NAPCC and RE Missions scenarios can avoid the coal capacity addition (and hence generation) significantly. However, as mentioned previously, the 13$^{th}$ Plan scenario overbuilds the coal capacity. Therefore, the avoided coal capacity would be smaller if it were added optimally in the baseline (13$^{th}$ Plan scenario). In order to assess that, we ran the 13$^{th}$ Plan scenario with optimal coal capacity addition, which is explained in the sensitivity analysis section.

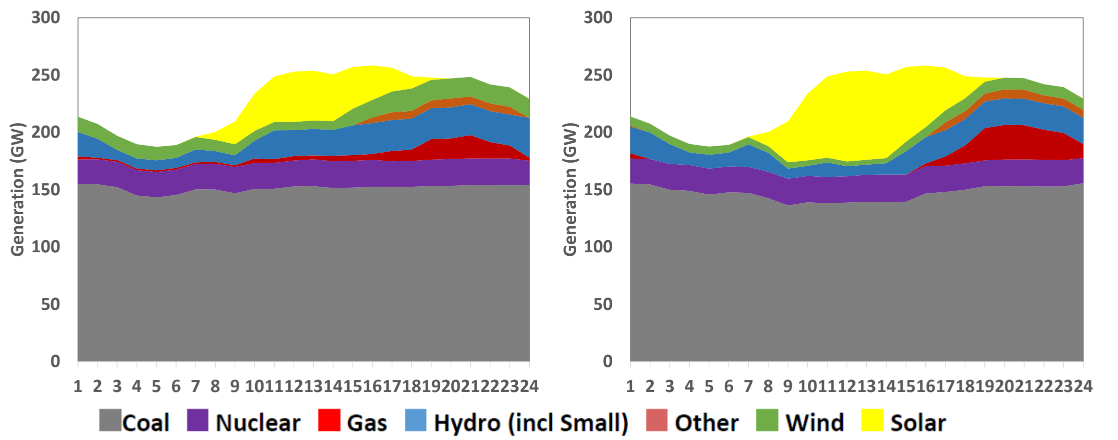
During summer (April-May) and monsoon (June through September) seasons, as seen in the net load charts, renewable energy can provide significant support during afternoon peak demand period during summer (mainly solar) and as well as monsoon (mainly wind). However, in both seasons, gas based generation (or some form of flexible generation) is necessary to provide the evening ramp-up support and meet the evening peak demand especially after the solar generation drops rapidly. In Winter, when solar and wind generation both drop, the need for energy and load following support from gas plants increases despite lower demand. This implies that the flexible resource used for grid integration of renewable resources in India should be able to provide cross-seasonal support and the energy in winter is crucial for reliable grid service.

## 4.4 How Would the System be Operated on Extreme Days

The key question relevant to system planners is how the system would be operated in case of extreme events/days such as very low renewable energy generation day, or sudden loss or increase in renewable energy generation (variability) etc. In this section, we present how the system would be dispatched on such events/days. The results shown here are for the national scale; for regional level results, please refer to the appendices.

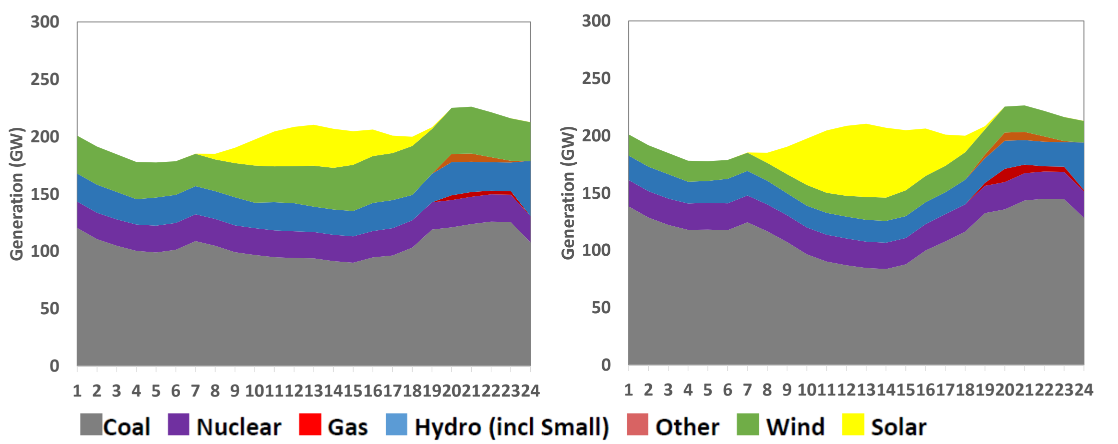
### 4.4.1 Low RE Generation

The following charts show the national dispatch for minimum renewable energy (nationally) generation day for each season. Given the seasonal nature of wind and solar generation, minimum RE generation in the summer implies minimum solar generation while that in the monsoon implies minimum wind generation.




(a) NAPCC (100GW Wind; 60GW Solar) (b) RE Missions (60GW Wind; 100GW Solar)

**Figure 15: Hourly National Dispatch for Minimum RE Generation Day (April 8th) – Summer 2022 (April-May)**



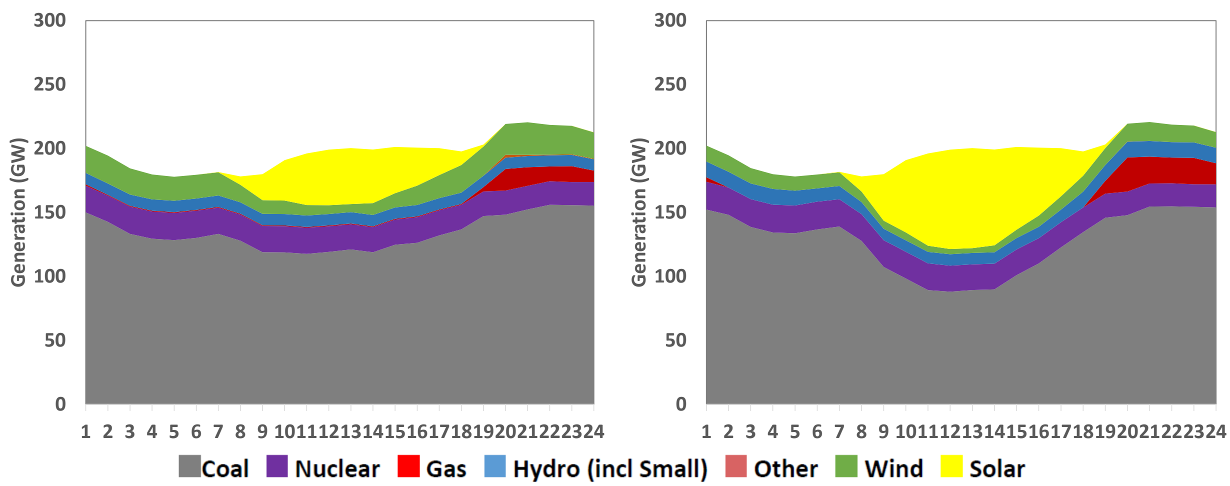

(a) NAPCC (100GW Wind; 60GW Solar) (b) RE Missions (60GW Wind; 100GW Solar)

**Figure 16: Hourly National Dispatch for Minimum RE Generation Day (August 22nd) – Monsoon 2022 (June – September)**

In summer, the drop in RE generation is compensated primarily by gas and hydro power plants. However, in monsoon, it is interesting to see that on the minimum RE generation day, the demand is also significantly lower than the average.

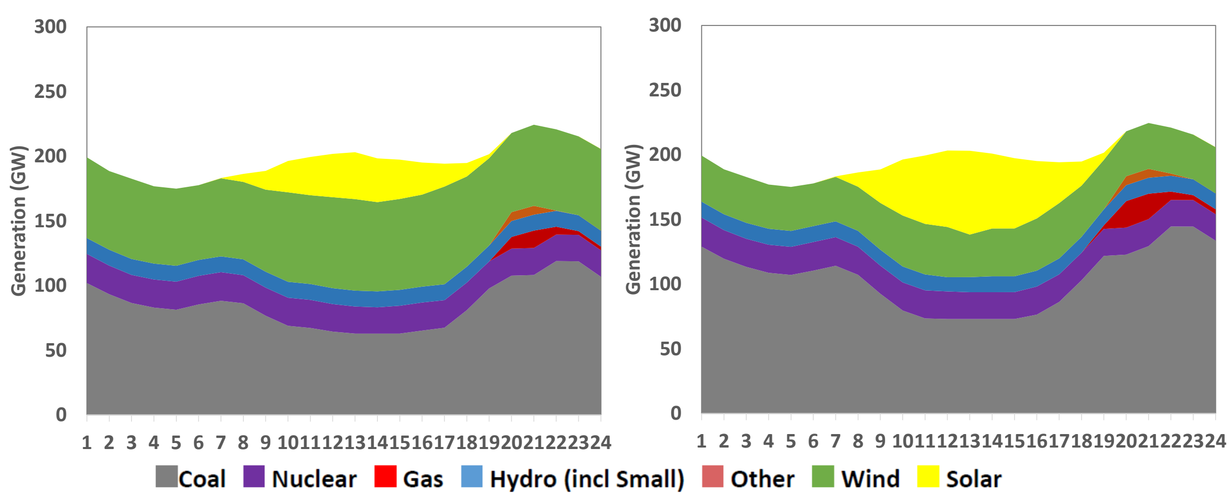
### 4.4.2 Low Demand and Potential RE Over-Generation

One of the other key concerns regarding RE is potential over-generation. In the following charts, we show the national dispatch for the minimum demand day in each season.




(a) NAPCC (100GW Wind; 60GW Solar) (b) RE Missions (60GW Wind; 100GW Solar)

Figure 17: Hourly National Dispatch for the Minimum Demand Day (April 4th) – Summer 2022 (April-May)



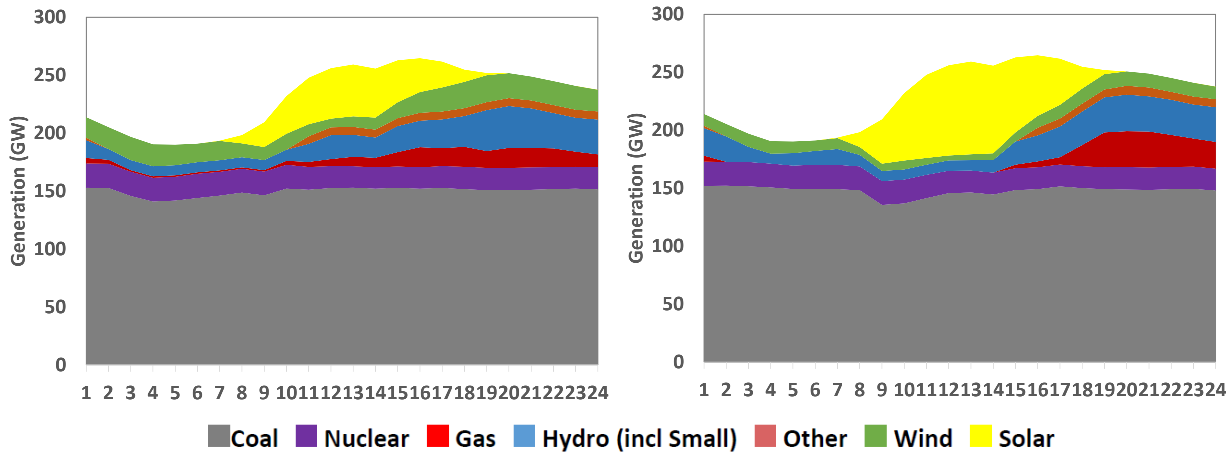

(a) NAPCC (100GW Wind; 60GW Solar) (b) RE Missions (60GW Wind; 100GW Solar)

Figure 18: Hourly National Dispatch for Minimum Demand Day (August 1st) – Monsoon 2022 (June – September)

It is interesting to see that on the minimum demand day in summer, the solar generation also drops. In monsoon, however, wind generation is still very high and the instantaneous RE contribution to the afternoon peak demand (1 PM) is as high as 55% in case of the NAPCC and 63% in case of the RE Missions scenario. Due to this, some coal units need to be backed down to 55% level, perhaps violating the current minimum load norm of 70% used by the system operators, but still meeting the norm of 55% specified in the CERC regulations in 2015; hydropower plants and gas plants operate on minimum load in case of both scenarios.

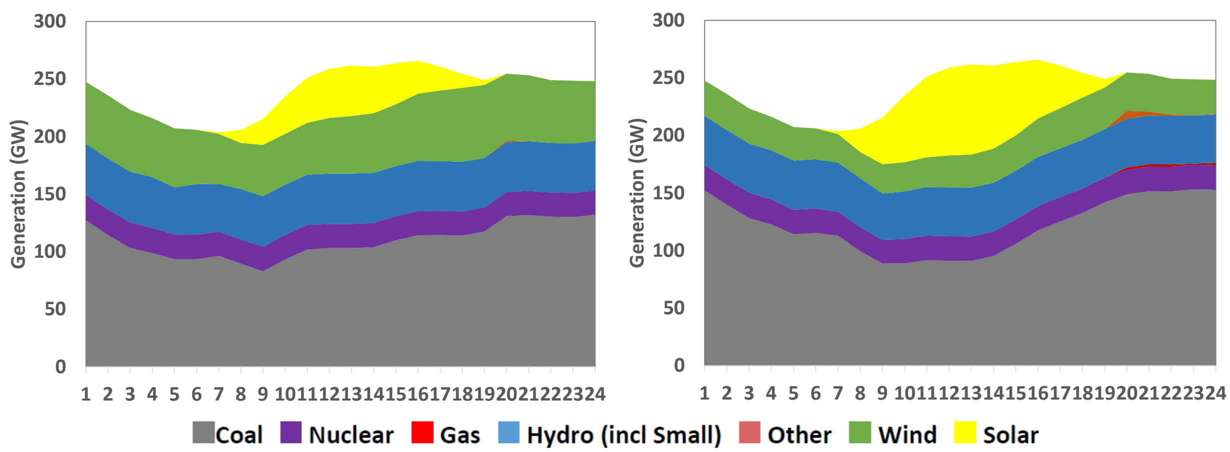
### 4.4.3 High Variability in RE Generation

The other major concern about renewable energy is the high variability. The following charts show the national dispatch in each season on the day with maximum variability (i.e. maximum hour to hour variation) in RE generation.




(a) NAPCC (100GW Wind; 60GW Solar) (b) RE Missions (60GW Wind; 100GW Solar)

**Figure 19: Hourly National Dispatch for the Maximum RE Variability Day (April 12th) – Summer 2022 (April-May)**




(a) NAPCC (100GW Wind; 60GW Solar) (b) RE Missions (60GW Wind; 100GW Solar)

**Figure 20: Hourly National Dispatch for the Maximum RE Variability Day (June 5th) – Monsoon 2022 (June – September)**

In both seasons and scenarios, ramping up of the solar generation in the morning introduces significant variability in RE generation (9 – 10 AM in the morning). The following table shows the maximum RE variability in each season:

Table 18: Maximum variability in Renewable Energy Generation (National)

| | Day and time of the maximum RE variability | NAPCC (100GW Wind; 60GW Solar) | RE Missions (60GW Wind; 100GW Solar) |
|---|---|---|---|
| **Summer** | April 13th at 9 AM | 14,943 MW/hr | 25,082 MW/hr |
| **Monsoon** | June 5th at 9 AM | 16,626 MW/hr | 24,931 MW/hr |

Note that in Winter, wind generation drops significantly while solar generation is somewhat lower than that in Summer and Monsoon. Therefore, the total variability in RE generation is significantly lower. For this reason, we have not shown similar charts for Winter.

### 4.4.4 Load and Net-load Variability (Ramps)

It should be noted that the load is significantly variable as well. For example, the maximum variability in national load in FY 2022 is projected to be 36,646 MW/hr (610MW/min). Therefore, from the system balancing perspective, the incremental variability added due to renewable energy generation is the key. An analysis by LBNL using actual wind generation data showed that the incremental variability added due to wind is fairly small in India i.e. 99th percentile incremental net load variability of 58 MW/hr for total installed wind capacity of 9000 MW in the state of Tamil Nadu (Phadke, Abhyankar, and Rao 2014). Similarly, NREL did analysis of the variability in solar PV generation in Gujarat which was found to be moderate (95th percentile ramp between 37.6 MW/5-min and 57.5 MW/5-min for installed solar PV capacity of 2,900 MW), albeit they did not estimate the incremental net load variability added due to solar (Hummon et al. 2014).

It is important to note that the regional diversity in renewable energy and its complementarity with demand as well as other RE resources help reducing the impact of extreme events. As mentioned previously, we have assumed the future capacity addition in the renewable energy resources happens on the same sites as the current installed capacity. This is a highly conservative assumption for diversity and hence will significantly overestimate the variability in RE generation. Despite such conservative assumptions, we find that the incremental hourly net load variability added due to wind and solar generation is none or only minor as shown in the following table.

Table 19: Maximum Hourly National Net Load Variability (MW/hour) in All Scenarios (2022)

| | Max Load Variability – National (MW/hour) | Max Net Load Variability - National (MW/hour) |
|---|---|---|
| **13th Plan** | 36,646 | 36,010 |
| **NAPCC** | 36,646 | 36,230 |
| **RE Missions** | 36,646 | 37,538 |

The following chart shows load ramps and the net load ramps for the entire year for all three scenarios.

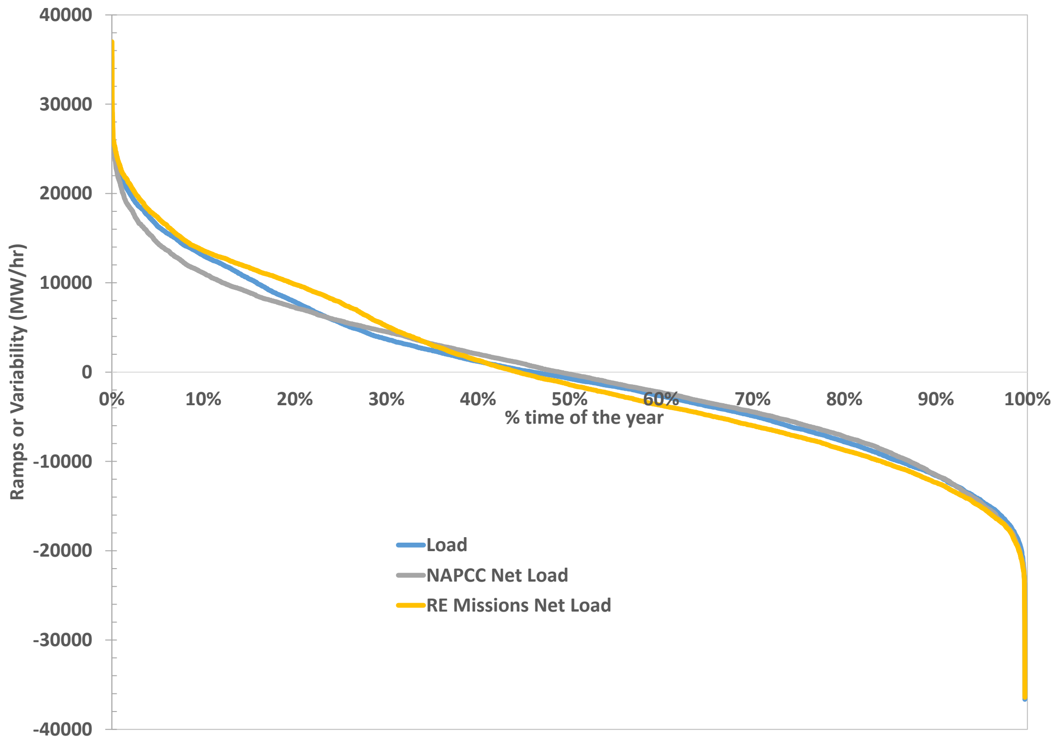



Figure 21: Load and Net-load Ramps (Hourly Variability) in 2022

As shown in Table 19, the maximum net load ramps in the RE Missions as well as NAPCC scenarios are almost indistinguishable from the load ramps, implying the maximum additional variability introduced due to the RE generation is relatively minor. However, during the intermediate load periods, the net load ramps in the RE Missions scenario are somewhat higher than the load ramps. In the same period, the net load ramps in the NAPCC scenario are actually lower than the load ramps, implying that the overall renewable energy generation in the NAPCC scenario has a better correlation with demand.

The analysis presented in this section shows that system can handle both extremes in RE – low and high generation and high variability. However, good RE forecasting practices are crucial to handle such events.

## 4.5 Inter-Regional Power Transfer

One of the key enablers of the reliable grid integration is the transmission network. The following table shows the inter-regional power transfer capacities estimated in each scenario.

Table 20: Inter-regional Power Transfer Capacities (MW) – Existing and Capacities Required by FY 2022 in Each Scenario

| | | Power Transfer Capacity requirement (Transmission capacity requirement may be significantly higher) | | |
|---|---|---|---|---|
| | **Existing Transmission Capacity (June 2015)** | **13th Plan (2022)** | **NAPCC (2022)** | **RE Missions (2022)** |
| **East-North** | 15830 | 15124 | 11215 | 12489 |

| | | | | |
|---|---|---|---|---|
| **East-South** | 3630 | 8656 | 16563 | 18354 |
| **East-West** | 10690 | 9171 | 8717 | 6772 |
| **NorthEast-East** | 2860 | 2914 | 2907 | 3195 |
| **North-West** | 8720 | 23173 | 17315 | 15654 |
| **West-South** | 5720 | 10896 | 14731 | 20285 |

Note that the existing (June 2015) capacity is the total transmission capacity. The actual concurrent power transfer capacity may be lower due to congestion, reverse flows, and a number of other technical constraints. Similarly, the numbers shown for 2022 represent the power transfer capacity requirement; actual transmission capacity requirement may be higher. Also note that, this study assumes significant regional coordination in scheduling and dispatch, and that there are no transmission constraints within each region. However, in reality, individual states/utilities may not coordinate their dispatches with each other and there may be several intra-state or intra-regional transmission constraints. Therefore, the results presented in the above table should be viewed as indicative only. Significant refinement in representation of the transmissions system as well as balancing areas would be necessary in order to use the analysis for actual planning purposes.

In order to integrate 175GW of renewable energy, the additional inter-regional power transfer capacity requirement (relative to the 13th Plan baseline) is found to be on the West-South (increase by 3000 to 4000 MW relative to the 13th Plan) and East-South (increase of 6000 to 8000 MW relative to the 13th Plan) links. One of the reasons for this is that the renewable resources are well distributed among northern (mostly solar and some wind), western (both solar and wind), and southern (mostly wind and some solar) regions. The transmission corridor between Western and Northern regions is also equally important and may need significant strengthening relative to 2015 levels in all scenarios including the 13$^{th}$ Plan.

Note that in the RE dominant scenarios, some of the transmission lines would have to be used in both directions because of the seasonal and diurnal RE generation patterns. This implies that in order for reliable RE grid integration, it is absolutely crucial to have an appropriate policy and regulatory framework for moving power across regions more freely. For example, deepening the existing day-ahead energy market (i.e. more utilities and generators participating from multiple regions participating in the market) or introducing the ancillary services market. Since 2015, India has started a 24x7 day-ahead energy market, and since April 2016, India has introduced a framework for the ancillary services market, the un-requisitioned capacity of the central sector generating stations from the day-ahead schedule would be rescheduled to the regional pool; this power can then be scheduled by the National Load Dispatch Center with payments made from the deviation settlement pool.

In the RE Missions and NAPCC scenarios, the net regional import/export (annual) would change significantly relative to the 13$^{th}$ Plan as shown in table .

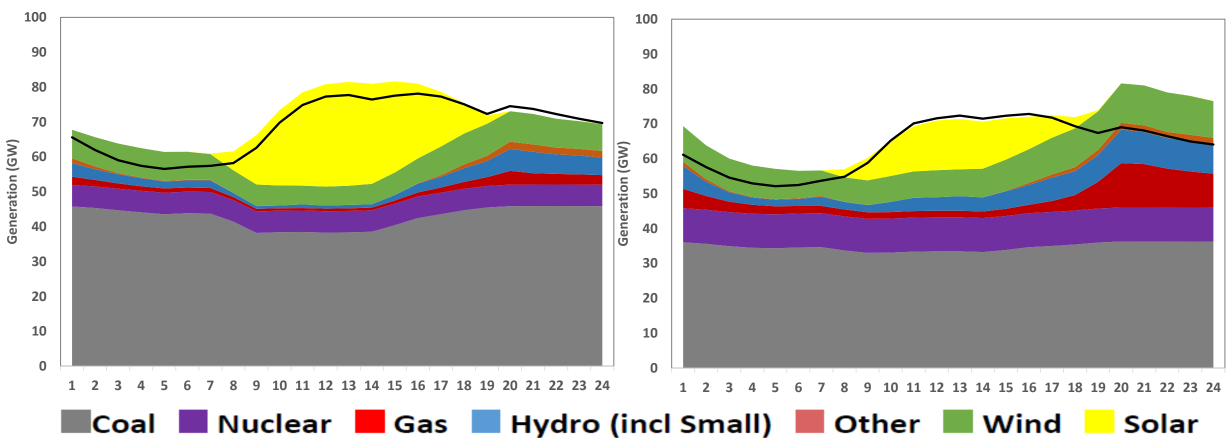
**Table 21: Annual Load, Generation, and Net Exports from Each Region by 2022**

| | 13th Plan | | | NAPCC | | | RE Missions | | |
|---|---|---|---|---|---|---|---|---|---|
| | Load (TWh/yr) | Generation (TWh/yr) | Net Exports (TWh/yr) | Load (TWh/yr) | Generation (TWh/yr) | Net Exports (TWh/yr) | Load (TWh/yr) | Generation (TWh/yr) | Net Exports (TWh/yr) |
| **East** | 237 | 261 | 23 | 237 | 182 | -55 | 237 | 186 | -52 |
| **North** | 594 | 456 | -138 | 594 | 646 | 52 | 594 | 629 | 36 |
| **North_East** | 24 | 10 | -14 | 24 | 10 | -14 | 24 | 10 | -14 |
| **South** | 510 | 501 | -10 | 510 | 548 | 37 | 510 | 675 | 165 |
| **West** | 539 | 678 | 139 | 539 | 520 | -19 | 539 | 407 | -132 |
| **Total (India)** | **1906** | **1906** | **0** | **1906** | **1906** | **0** | **1906** | **1906** | **0** |

Note: Totals may not match due to rounding.

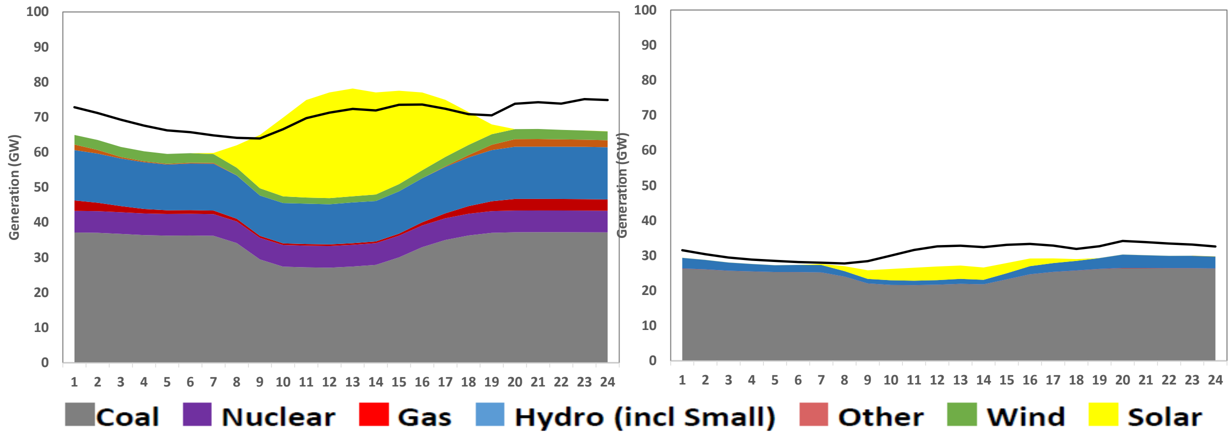
In the 13th Plan scenario, Eastern and Western regions are expected to be the net exporting regions and Northern and Southern regions to be net importers; Northern region is expected to import about 23% of its total annual load. In the NAPCC and RE Missions scenarios, the generation in the Southern region as well as Northern region increases significantly and that in the Western and Eastern Regions reduce due to avoided coal capacity. This flips the importing and exporting regions – with North and South as net exporters and West and East as net importers by 2022.

The following charts show the average hourly regional dispatch and transmission flows from one region to the other in Summer of FY 2022 for the RE Missions scenario. The black line in each chart shows the regional demand. Similar results for other scenarios and seasons could be found in the appendices.




(a) Western Region

(b) Southern Region




(c) Northern Region (d) Eastern + North Eastern Region

**Figure 22: Average Daily Dispatch and Average Hourly Load by Region in Summer FY 2022 (April-May) in the RE Missions Scenario (100GW Solar+60GW Wind)**

The difference in the demand (black line) and the total generation is either exported or imported by the region. Note that Western and Northern Regions are net-exporting in the afternoon due to significant solar generation while they are net-importing during other hours. The following chart shows the net transmission flows between regions. Note that positive and negative flow implies the direction of the flow.

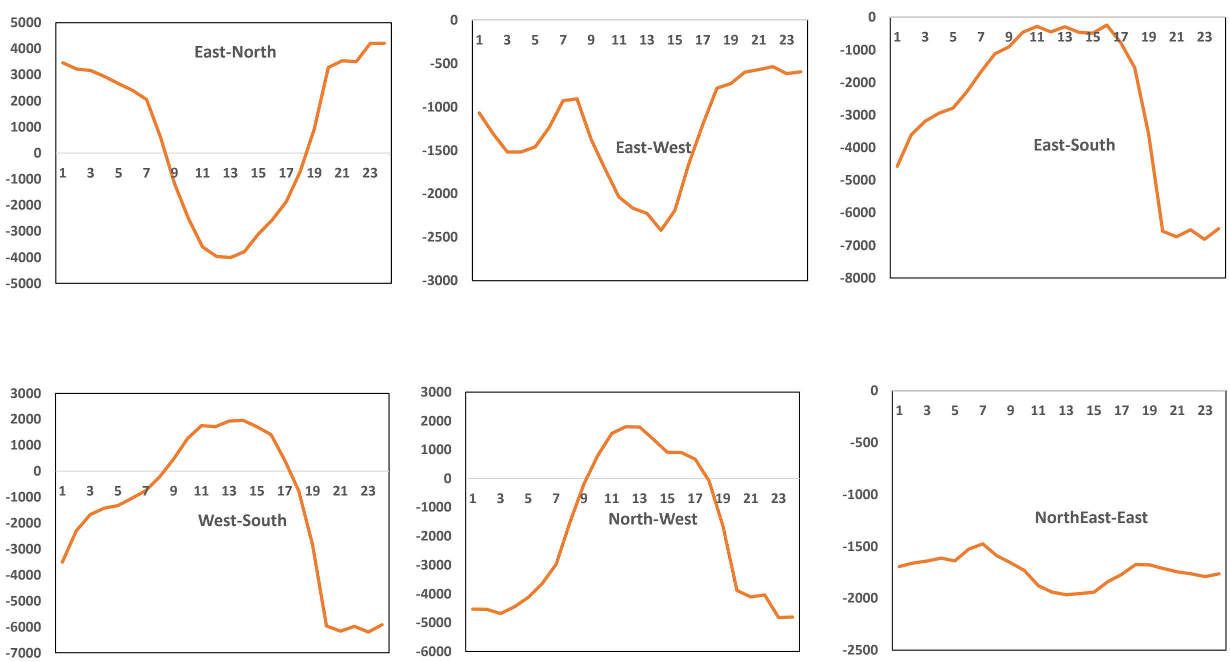



**Figure 23: Average Hourly Inter-regional Transmission Flows during Summer 2022 (April-May) in the RE Missions Scenario (100GW Solar+60GW Wind)**

Note: Sign of the flow indicates the direction. For example, East to North would be counted as positive flow while North to East would count as negative.

Because of the renewable energy generation, the flows on inter-regional lines change significantly (including the direction of flow) within a day and therefore, efficient markets or balancing area coordination is required in addition to the transmission investments.

## 4.6 Wholesale Electricity Supply Cost

The following chart shows total wholesale electricity supply cost at the region boundary – total annual as well as average in FY 2022 for all the three scenarios.

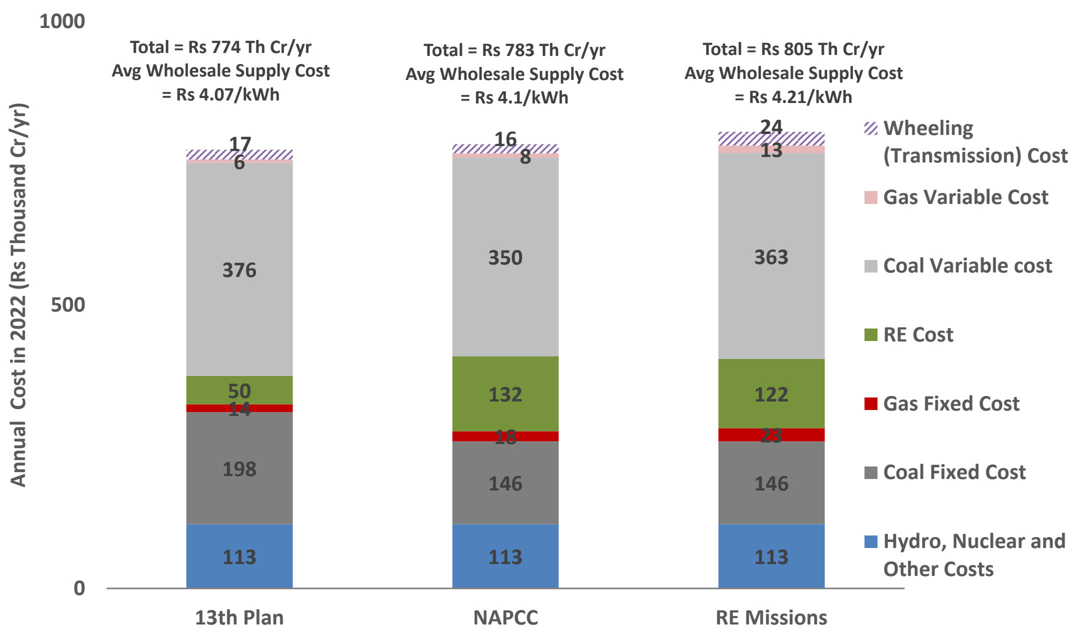



**Figure 24: Total Annual and Average Wholesale Electricity Supply Cost (at region boundary) in FY 2022 for all Scenarios**

Note: The annual wheeling (transmission) cost is estimated by using an average wheeling charge of Rs 1/kWh on all inter-regional lines. In reality, there would be interstate /intrastate wheeling charges in addition to these. The wheeling cost number shown here is only suggestive to indicate the scale of those costs relative to the total system costs.

By 2022, the total wholesale cost of electricity supply (at region boundary) in the 13$^{th}$ Plan scenario is Rs 774,000 Cr/yr; the same for NAPCC and RE Missions scenarios is Rs 783,000 Cr/yr and Rs 805,000 Cr/yr respectively. This implies that the incremental wholesale cost of electricity supply in NAPCC and RE Missions scenarios is Rs. 10,000 Cr/yr and Rs 32,000 Cr respectively over the 13$^{th}$ Plan cost; this is equivalent to an increase in the average wholesale supply cost by 4p/kWh (1%) and 14p/kWh (4%) respectively for NAPCC and RE Missions scenarios relative to the 13$^{th}$ Plan. The incremental RE generation by 2022 relative to the 13$^{th}$ Plan is 245 TWh/yr in case of NAPCC scenario and 197 TWh/yr in case of RE Missions scenario.

An intuitive explanation of the cost differential is as follows:

(a) Both NAPCC and RE Missions scenarios would potentially need lower coal capacity resulting in significant saving in fixed costs.

(b) There has been and will be deep reduction in the costs of renewable technologies (especially solar PV). Based on the CERC norms, we have assumed the current capital cost of solar PV to be

Rs. 5.87 Cr/MW (average cost of about Rs 5.1/kWh); by 2022, based on the global trends, we assume that it will reduce to Rs 4.18 Cr/MW (average cost of Rs 3.4/kWh). Since most of the solar capacity will be added in later years (post-2017), their incremental cost is minor relative to the new imported coal based plants. Similarly, in case of wind power plants, we assume that the quality wind resource is developed so the average cost of wind generation is Rs 3.3/kWh by 2022. However, if wind and solar costs continue to be the same as 2015 levels, the incremental wholesale electricity supply cost in NAPCC and RE Missions scenarios would further increase by Rs 10,000 Cr/yr and Rs 25,000 Cr/yr respectively.

(c) Both the RE dominant scenarios can avoid significant coal consumption and imports. Since imported coal prices are higher than the domestic coal prices, this results in a significant reduction of the fuel cost. The following chart shows the total coal and gas consumption and imports for all scenarios.

**Table 22: Coal and Gas: Total Consumption and Imports**

| | | 13th Plan | NAPCC | RE Missions |
|---|---|---|---|---|
| **Coal (million tons/yr)** | Domestic Coal | 715 | 710 | 715 |
| | Imported Coal | 49 | 0 | 17 |
| **Gas (bcm/yr)** | Domestic Gas | 2.6 | 3.6 | 6.2 |
| | Imported LNG | 0.0 | 0.0 | 0.0 |

(d) Both the RE dominant scenarios need additional investments in gas based capacity. However, the seasonal complementarity between solar and wind generation keeps the need for such additional investments in the flexible capacity (i.e. gas) moderate.

Note that our analysis does not consider any of the environmental of energy security benefits of RE generation. Also, the coal investment costs in all scenarios have been estimated without considering the new norms for Particulate Matter, SOx, and NOx emissions (2015), which may require additional investments; such investments may increase the fixed costs of coal plants by over 10% and reduce the cost-differential between the 13th Plan and RE Dominant scenarios further. On the other hand, given our assumptions of no transmission constraints and regional level balancing, the incremental cost numbers presented here are likely underestimated. If the transmission constraints and state level balancing (with significant barriers for inter-state power trading) were considered, the additional flexible generation requirement for the NAPCC and RE Missions scenarios may increase; there may also be a need for some RE curtailment. Both will likely result in a significant increase in the incremental costs. In our forthcoming analyses, we do consider these constraints for a more accurate estimation of these costs.

## 4.7 Electricity Market Prices

Although we do not simulate the day-ahead and real-time markets per se (mainly due to the lack of the bilateral/IPP contracts data), we still estimate the day-ahead and real time prices. Since we do not have all the existing contracts and self-scheduling modeled in the system, these prices are essentially the variable cost of the marginal generation unit on the system in each hour. The following chart shows the real-time prices for each scenario. One can see that in certain instances when the marginal unit on the system is gas or diesel based, the system price is very high. Also, note that we have shown an average electricity price for the entire nation. India does not have locational marginal prices, but instead it operates a zonal market. Therefore, in reality, the wholesale electricity prices would be different in each zone, if there are transmission constraints. However, since we have not assumed any transmission constraints, prices in all zones are almost identical; they only differ by the transmission wheeling charge between the two zones.

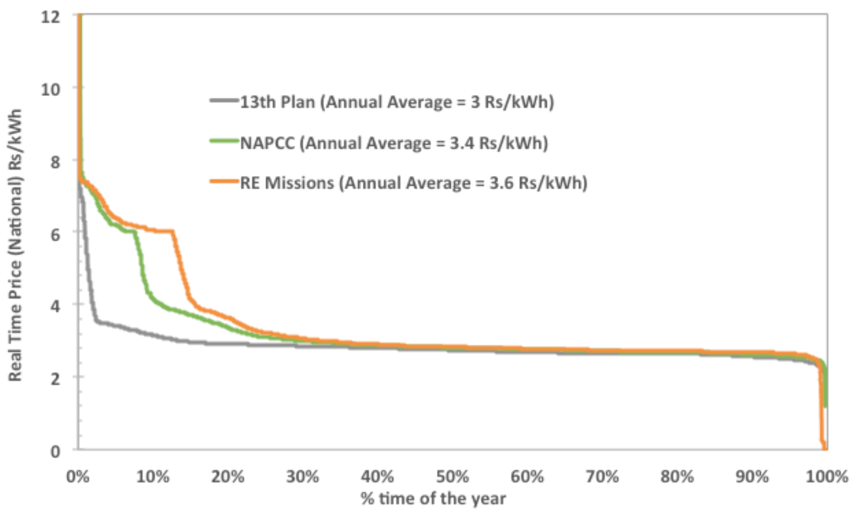



Figure 25: Real-time electricity market price duration curves

Note that the prices should not be confused with the wholesale electricity supply cost or average cost of generation. Prices only reflect the variable cost of generation while the average cost also includes the fixed costs (capital as well as O&M etc.). In both the RE scenarios, there are a few constrained hours on the system where the gas turbines or diesel plants need to be operated to balance the additional ramps introduced by RE. In such hours, the prices are significantly higher than the 13$^{th}$ Plan scenario, as seen in Figure 25. In the RE missions scenario, for a few hours (20 hours) in the year, the real time price actually becomes zero due to excess RE generation. This implies that all the thermal units already committed in the day-ahead market are generating at their minimum stable level and the marginal unit on the system is a renewable energy project or a hydro power plant (i.e. zero marginal cost). However, once the thermal units drop to their technical minimum, RE curtailment is still not necessary.

The following chart shows the day-ahead, intra-day (3-hour ahead), and real time prices in the RE Missions scenario. It can be seen that as expected, real time and the intra-day prices are significantly higher than the day-ahead prices, especially during the peak demand (high price) periods.

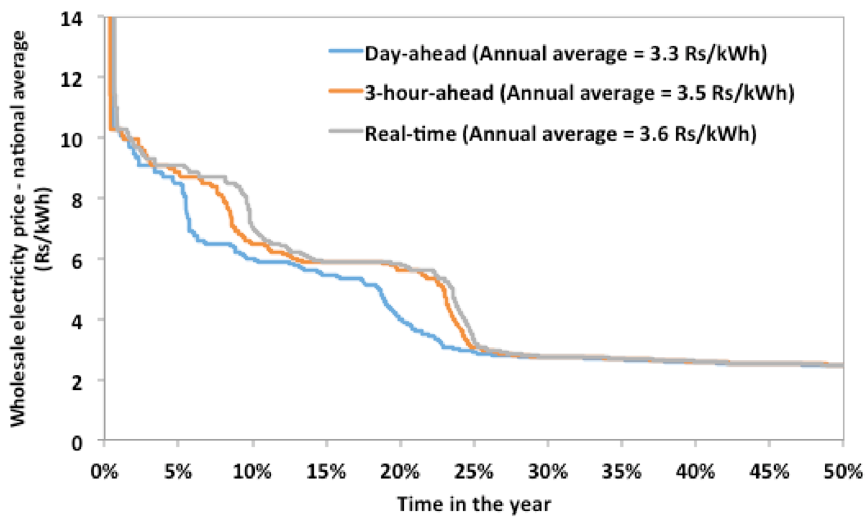



Figure 26: Day-ahead, intra-day, and real-time prices in the RE Missions scenario

For more details, please see Appendix 4.

## 4.8 Integration Cost

There is no standard definition of "integration cost" in the literature. Generally, integration cost is meant to reflect any additional costs to manage the variability and uncertainty of RE generation. Aggressive RE penetration may require additional investments in flexible capacity (such as gas turbines etc.) or operation of the expensive gas or diesel-based power plants, or operating coal power plants at partial loads. All such costs have already been included in the cost results presented so far. Note that in addition to these costs, utilities may have to procure additional reserves (spinning, contingency, or otherwise) or other ancillary services for reliable RE integration. Our analysis does not include such incremental ancillary services cost.

In several studies in the US and Europe, such incremental ancillary services cost for RE integration is found to be minor i.e. only about 5-10% of the RE generation cost. For example, (A. Mills, Phadke, and Wiser 2010) estimate that the incremental ancillary services cost to be $5/MWh of wind generation (Rs 0.3/kWh) for wind power and $2.5/MWh of solar generation (Rs 0.15/kWh) for solar PV power projects. (Luckow, Vitolo, and Daniel 2015) review several RE integrations studies in the US and report that even for aggressive penetration levels, wind integration costs are found to be less than $5-10/MWh (less than Rs 0.3-0.6/kWh) and solar integration costs are found to be less than $2-3/MWh (less than Rs 0.12 – 0.18/kWh) in most studies. Note that these costs depend on a range of factors including reserve requirements, total RE penetration, forecast errors, loss of load expectation (LOLE), and available conventional as well as flexible generation. Significant further analysis is needed to estimate the incremental ancillary services costs accurately in the Indian context. Our forthcoming paper on RE valuation in India attempts to estimate the total integration cost including the reserves and ancillary services cost.

# 5 Sensitivity Analysis

We assess the sensitivity of our results on the following key parameters:

1. *Slippage in capacity addition in the 13th Plan*
   We assess the impact on costs if the thermal capacity is planned in a least-cost manner in the 13th Plan period. This would imply lower coal capacity than originally planned in the 13th Plan. Therefore, it could also be considered equivalent to slippages in the 13th Plan capacity additions.
2. *High coal and high RE*
   In order to test the impacts of integrating RE in a more inflexible system, we increase the coal generation capacity in the RE Missions scenario to the 13th Plan level i.e. an increase of more than 60 GW.
3. *Non-Optimal Transmission Expansion*
   One of the key assumptions in this is that new inter-regional transmission capacity can be freely built. In order to test the importance of transmission, in the NAPCC and RE Missions case, we restrict the inter-regional power transfer capacity to that estimated in the 13th Plan scenario (baseline).
4. *Capital cost of the renewable energy technologies (especially solar)*
   Capital costs of the renewable energy technologies have been falling significantly over the last few years. Although we have assumed a reduction in their capital cost, we assess the impact of a change in that reduction. We create two sensitivity cases viz. (a) capital costs reduce 50% faster than anticipated, and (b) capital costs reduce 50% slower than anticipated.
5. *Fuel prices*
   Fuel prices (especially imported coal and gas) are significantly volatile. In order to address that, we create two sensitivity cases viz. (a) high fuel price case, where fuel prices in 2022 are assumed to be 25% higher than presented before, and (b) low fuel price case, where fuel prices in 2022 are assumed to be 25% lower than presented before.

### 5.1.1 Slippages in Coal Capacity Addition or Least Cost Thermal Capacity Addition

In order to assess the impact of slippages in thermal capacity addition, we ran the model to optimize the coal capacity addition by 2022 in a least-cost manner by holding the planned capacity additions in all other technologies constant. If coal capacity addition is optimized, by 2022, the total installed coal capacity by 2022 would be 203 GW. This is equivalent to a slippage of 30% in the coal capacity addition in the 12th and 13th Plan periods. This naturally reduces the total investment costs and also increases the capacity factors (PLF) of the existing as well as newly built plants. As a result the average wholesale cost electricity supply (at region boundary) would lower significantly as shown in the following table.

**Table 23: Total Coal Installed Capacity and Average Wholesale Electricity Supply Cost (at region boundary) – Sensitivity Analysis on Least Cost Thermal Capacity Addition**

| | 13th Plan (Baseline) | 13th Plan (Optimal Coal Addition Case) | NAPCC | RE Missions |
|---|---|---|---|---|
| **Total Coal Installed Capacity (2022) MW** | 243,475 | 203,375 | 182,375 | 181,375 |
| **Average Wholesale Electricity** | 4.07 | 3.99 | 4.10 | 4.21 |

| | | | |
|---|---|---|---|
| **Supply Cost (at region boundary) (Rs/kWh)** | | | |

If one uses the "optimal" coal capacity, the average wholesale electricity supply cost in the 13th Plan scenario would be Rs 3.99/kWh i.e. lower than the 13$^{th}$ Plan baseline by about 2%. This would in turn make the incremental cost of the NAPCC scenario to be 3.3% and that of the RE Missions scenario to be 5.8% higher.

### 5.1.2 High Coal and High RE

In order to test the feasibility of integrating the renewable energy in a more inflexible system, we increase the coal generation in the RE Missions scenario to that of the 13$^{th}$ Plan level i.e. an increase in the coal capacity of nearly 60 GW. The following table summarizes the total installed capacity in the original RE Missions scenario and the High Coal sensitivity case.

**Table 24: Total installed capacity in 2022 (GW)**

| | 13$^{th}$ Plan (Baseline) | RE Missions | High Coal and High RE case |
|---|---|---|---|
| **Coal** | 243 | 181 | 243 |
| **Wind** | 40 | 60 | 60 |
| **Solar** | 22 | 100 | 100 |

With additional 60 GW of coal capacity, the need for additional gas power plants for flexibility goes away entirely i.e. no additional gas based capacity is required for RE balancing. The system operates the additional coal power plants at reduced capacity to meet the net-load ramps. However, this implies that the capacity factor of the coal power plants drops significantly (as low as 50% in the Southern and Western region due to large RE capacity which implies that many coal units are just shut down for most of the year); as a result the average wholesale electricity supply cost (at region boundary) increases by 5% relative to the RE Missions scenario as shown in the following table.

**Table 25: Coal capacity factors and average wholesale electricity supply cost (at region boundary)**

| | 13$^{th}$ Plan (Baseline) | RE Missions | High Coal and High RE case |
|---|---|---|---|
| **Coal Installed Capacity (GW)** | 243 | 181 | 243 |
| **Coal Capacity Factor (%)** | 64% | 73% | 56% |
| **Average Wholesale Electricity Supply Cost (at region boundary) (Rs/kWh)** | 4.07 | 4.21 | 4.37 |

During the high RE generation periods, several coal power plants need to be either shut down or operate at their technical minimum levels. This is evident from the coal power generation duration curves shown in the following figure for the 13$^{th}$ Plan scenario and the High Coal and High RE case.

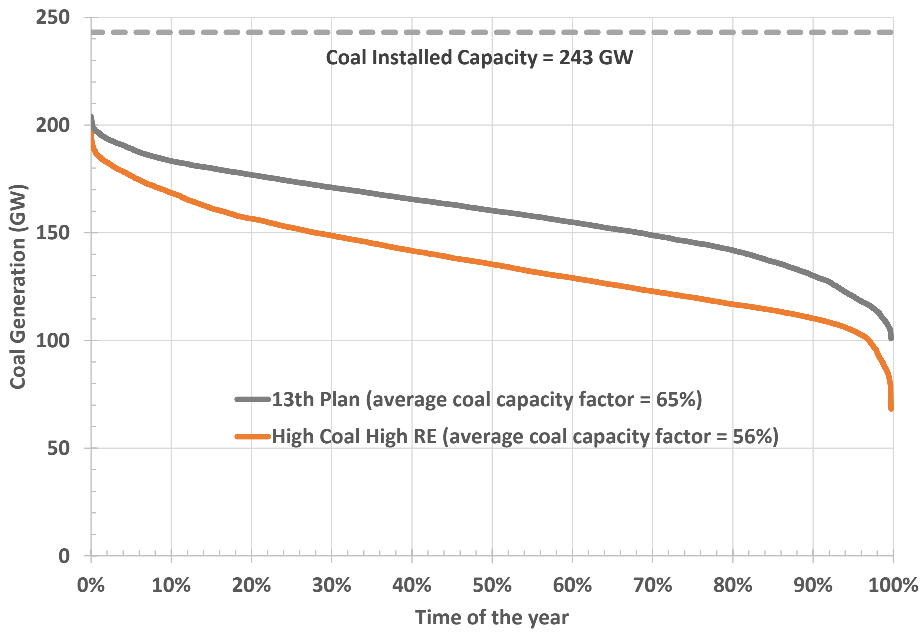



Figure 27: Coal Generation Duration Curves for the 13$^{th}$ Plan Scenario and High Coal High RE Case

Despite high inflexibility in the system, curtailment of the renewable energy is not found to be necessary.

### 5.1.3 Non Optimal Transmission Expansion

In order to test the importance of transmission in renewable integration, in the NAPCC and RE Missions scenarios, we restrict the inter-regional power transfer capacity to that estimated in the 13$^{th}$ Plan scenario (baseline). The following table shows the restricted inter-regional power transfer capacity:

Table 26: Restricted Inter-regional Power Transfer Capability

| | Existing (June 2015) | Required Power Transfer Capacity in 2022 | | Restricted Capacity in 2022 (Same as 13$^{th}$ Plan Scenario) |
|---|---|---|---|---|
| | | (NAPCC Scenario) | (RE Missions Scenario) | |
| **East-North** | 15830 | 11215 | 12489 | 15830 |
| **East-South** | 3630 | 16563 | 18354 | 8656 |
| **East-West** | 10690 | 8717 | 6772 | 10690 |
| **NorthEast-East** | 2860 | 2907 | 3195 | 2914 |
| **North-West** | 8720 | 17315 | 15654 | 23173 |
| **West-South** | 5720 | 14731 | 20285 | 10896 |

It can be seen that West-South and East-South are the only transmission links where the transfer capacity is restricted relative to the NAPCC and RE Missions scenario. Therefore, this sensitivity analysis could also be seen as assessing the value of easing the transmission constraints to the southern region above 13$^{th}$ Plan Scenario.

The following table shows changes in the regional generation investment pattern as a result of the constrained transmission to the southern region.

**Table 27: Coal and Gas Capacity Additions by Region in 2022 (GW) and Average Wholesale Electricity Supply Cost (at region boundary) (Rs/kWh) due to Constrained Transmission**

| | 13th Plan (Original) | | NAPCC | | | | RE Missions | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | Original | | Transmission Constrained | | Original | | Transmission Constrained | |
| | Coal | Gas | Coal | Gas | Coal | Gas | Coal | Gas | Coal | Gas |
| **North** | 11 | - | 9 | - | 9 | - | 7 | - | 8 | - |
| **West** | 39 | - | - | - | 3 | - | - | - | 3 | 2 |
| **South** | 14 | - | 7 | 2 | 4 | 2 | 9 | 10 | 5 | 7 |
| **East** | 15 | - | 1 | - | 1 | - | 1 | 0 | 1 | 1 |
| **North-East** | - | - | - | - | - | - | - | - | - | 0 |
| **Total** | **79** | **-** | **17** | **2** | **17** | **2** | **17** | **10** | **17** | **10** |
| **Average Wholesale Electricity Supply Cost (region boundary) (Rs/kWh)** | **4.07** | | **4.10** | | **4.11** | | **4.21** | | **4.22** | |

The total generation capacity investments do not change as a result of the transmission constraint; but the regional distribution of that capacity changes. For example, in the transmission constrained RE Missions and NAPCC cases, the there is a need of about 3GW of additional coal capacity and 2GW of additional gas capacity (RE Missions only) in the Western region since South to West transmission is constrained. Similarly, in the Northern region, there is a need for additional 1 GW coal capacity since the South to East (and hence East-to North) transfer capacity is constrained. As a result, the wholesale electricity cost increases – albeit the increase is very small. Average wholesale electricity cost due to constrained transmission increases by Rs 0.01/kWh or about 0.3%. In short, the value of enhancing transmission connectivity to the Southern region over and above the 13$^{th}$ Plan scenario is about Rs 0.01/kWh. Intuitive explanation for this is that the excess transfer capacity required in both the RE dominant cases (over and above 13$^{th}$ Plan) is only moderate as explained previously.

### 5.1.4 Capital Cost of Renewable Technologies

We assess the impact of faster or slower reduction in RE capital costs on the wholesale electricity supply cost in each scenario. The following table shows the solar PV capital costs in the sensitivity cases.

**Table 28: Capital costs of Solar PV (Rs Cr/MW) in the Sensitivity Cases**

| | 2015 Capital Cost | Annual Average | 2022 Capital Cost |
|---|---|---|---|

| | (Rs Cr/MW) | Rate of Reduction | (Rs Cr/MW) |
|---|---|---|---|
| **BAU Capital Cost** | 5.87 | 4.7% | 4.18 |
| **Slower Reduction in Cost** | 5.87 | 2.4% | 4.96 |
| **Faster Reduction in Cost** | 5.87 | 7.1% | 3.50 |

The following table shows the average wholesale electricity supply cost (at region boundary) in the baseline as well as sensitivity cases for all scenarios:

**Table 29: Average Wholesale Electricity Supply Cost (region boundary) for Capital Cost Sensitivity Cases in all Scenarios (in Rs/kWh)**

| | 13th Plan (Baseline) | 13$^{th}$ Plan (Optimal Thermal Capacity) | NAPCC | RE Missions |
|---|---|---|---|---|
| **Baseline** | 4.07 | 3.99 | 4.10 | 4.21 |
| **Slower Reduction in Cost** | 4.08 | 4.00 | 4.13 | 4.26 |
| **Faster Reduction in Cost** | 4.06 | 3.98 | 4.08 | 4.17 |

As expected, the average wholesale electricity cost in the RE dominant scenarios drops significantly if the solar PV costs drop faster than expected. In fact, the cost differential between the 13$^{th}$ Plan scenario and the NAPCC scenario drops to 0.4% if the solar costs drop faster than expected; the differential for RE Missions scenario would be 1.6% relative to the 13th Plan scenario. Conversely, if RE costs drop at a rate slower than the recent years (or highest capacity factor resources are not accessed), the average wholesale electricity cost would increase (relative to the 13th Plan scenario) by 1.3% and 3.4% in NAPCC and RE Missions scenarios respectively; this is equivalent to an increase in the annual system costs by Rs 10,000 Cr/yr and Rs 25,000 Cr/year by 2022 respectively.

### 5.1.5 Fuel Prices

In order to assess the impact of volatility in the imported fuel prices due to market dynamics as well as the exchange rate fluctuations, we change the 2022 FOB imported coal, LNG and Diesel prices by +/- 25%. The following table shows the fuel prices used in the sensitivity cases.

**Table 30: Imported Fuel Prices (FOB) in the Sensitivity Cases**

| | Baseline | High Fuel Price Case | Low Fuel Price Case |
|---|---|---|---|
| **Imported Coal ($/Ton)** | 82 | 102 | 61 |
| **LNG ($/MMBTU)** | 10.5 | 13.1 | 7.9 |
| **High Speed Diesel (Rs/lit)** | 50 | 63 | 38 |

The following charts show the total coal consumption and imports in each scenario for the sensitivity cases.

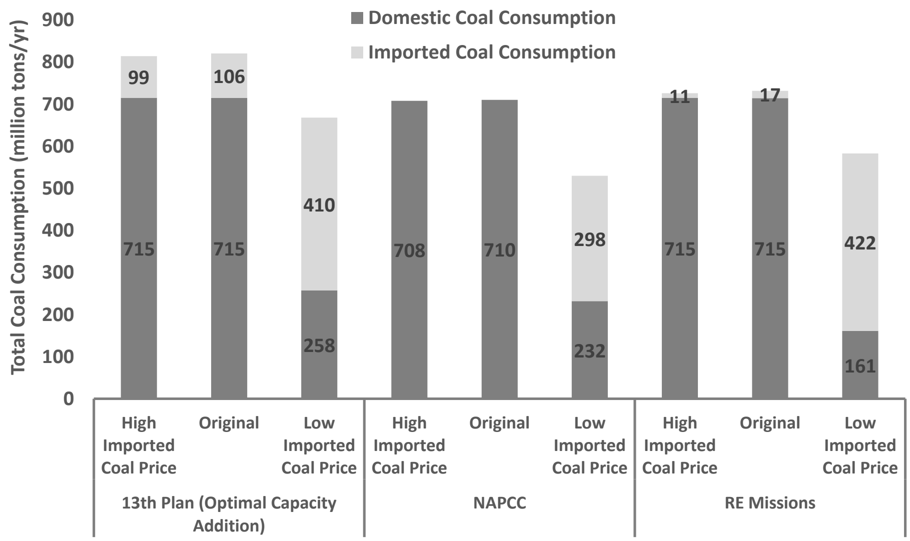



Figure 28: Sensitivity of Total Coal Consumption on Imported Coal Price

As expected, when the imported coal prices increase, its consumption drops and vice versa. Note that the imported coal calorific value is nearly 30% higher than that of the domestic coal; therefore, total coal consumption (in terms of million tons) would be lower in case imported coal consumption increases.

None of the scenarios need to import LNG for operating the gas power plants in the original as well as sensitivity cases. The domestic gas availability for the power sector, although constrained (10 bcm/yr or 27 mmscmd)[7], is enough to operate the gas power plants, which are mainly used as peaking or balancing support. The following chart shows the coal and gas capacity built (between 2015 and 2022) in each of the sensitivity cases.

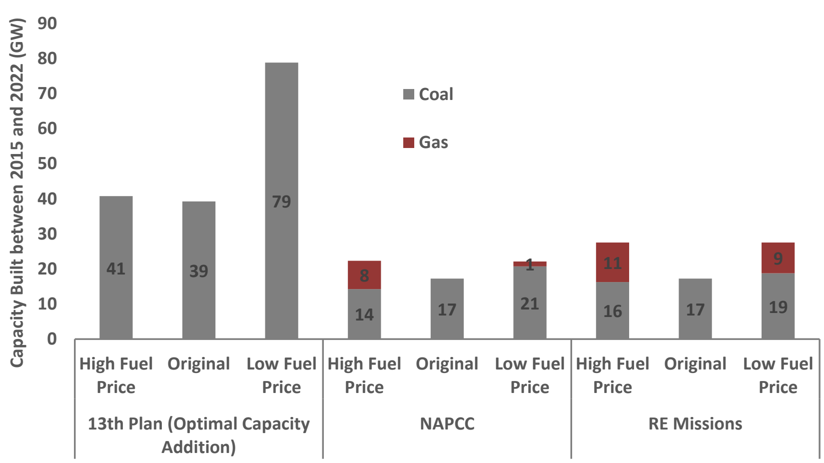



Figure 29: Capacity Built between 2015 and 2022 (GW): Impact of Changes in the Imported Fuel Prices

[7] Source: (PhillipCapital 2015)

As expected, when the imported fuel prices increase, the coal capacity addition based on imported fuel reduces significantly in all scenarios and vice versa. In the high fuel price cases, the coal capacity investments are replaced by gas based capacity addition. But note that even when the gas based capacity increases, the total gas consumption is still lower than the constrained domestic gas availability for the power sector. The following chart shows the sensitivity of the average wholesale supply cost in 2022 on imported fuel prices.

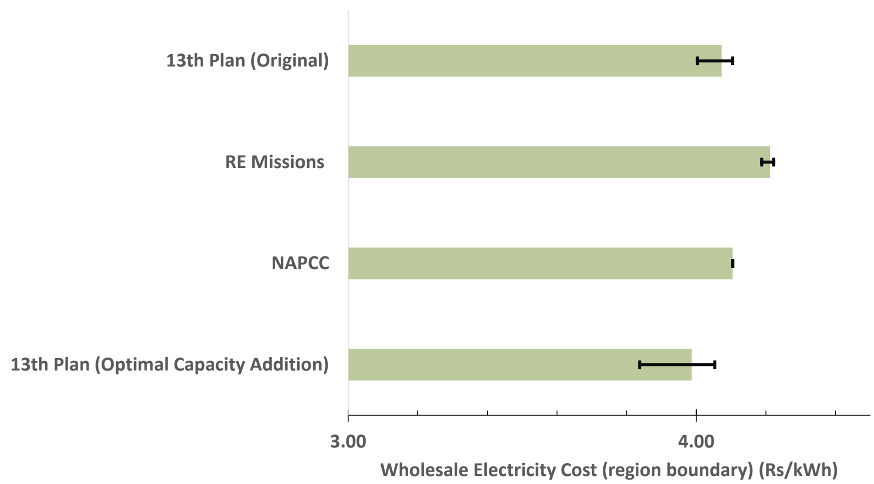



Figure 30: Sensitivity of Average Wholesale Electricity Supply Cost (at region boundary) on Imported Fuel Prices

In summary, both NAPCC and RE Missions scenarios are significantly less sensitive to the imported fuel price and supply risk relative to the 13$^{th}$ Plan scenario.

# 6 Conclusion

Given aggressive RE capacity targets set by India, there is significant discussion on the policy, regulatory and commercial strategies to integrate RE in the Indian power system. Although large scale RE grid integration has been analyzed widely in the US and European context, there is very limited literature in the Indian context. The objectives of our analysis are to assess the technical feasibility of integrating the large renewables capacity in India that has been planned in the near future, ascertain its impact on power sector investments and operations, and quantify the incremental cost of grid integration. We conduct the analysis by modeling the least cost generation investments and simulating economic dispatch for the FY 2022 using PLEXOS for a variety of renewable energy penetration scenarios. We use a five node model of the Indian electric grid (one node each for every region viz. north, east, west, south, and north-east), which allows us to broadly assess the inter-regional power transfer capacities that may be needed for integrating the RE generation reliably. It is important to note that given the regional level resolution of the model, this analysis cannot answer questions on the intra-regional (across states within a region) and intra-state transmission and dispatch issues and hence cannot quantify their associated costs. Hence the results can be interpreted as what is needed for RE integration once the interstate transmission constraints are resolved and the balancing area for generation dispatch is expanded to the regional level.

In this analysis, we created three scenarios for renewable energy penetration for the FY 2022 namely, (a) ***13th Plan***, that serves as the baseline and uses the generation capacity addition for all technologies as projected in the Government of India's 12th Plan (which has projections up to the end of the 13$^{th}$ Plan year, 2022), (b) ***National Action Plan on Climate Change (NAPCC)***, that models the renewable energy target described in India's NAPCC (2009); which, based on our projections would be ~20% electricity (by energy) by FY 2022, and (c) ***RE Missions***, that models the Government of India's announcement to increase the total installed capacity of solar projects to 100GW and wind projects to 60 GW by FY 2022.

We project hourly demand by region in 2022 using the Central Electricity Authority's demand projections in their 18$^{th}$ Electric Power Survey and the hourly demand patterns over the financial years 2010 through 2013 adjusting for rapid urbanization. We use actual hourly generation and solar irradiance (DNI and GHI) data to project the hourly wind and solar generation for 2022. We develop assumptions regarding operation and performance of generation technologies based on the historical actual data, capital and fixed cost based on existing regulations, and fuel prices based on long term historical trends. We then conduct sensitivity analysis on key parameters to assess the robustness of our findings.

By 2022, the coal capacity requirement in both NAPCC and RE Missions scenarios is significantly lower relative to the 13th Plan scenario (the baseline). However, significant gas based capacity needs to be added in both scenarios, which serves as a peaking resource and a major source of additional flexibility for managing the RE variability. During summer (April-May) and monsoon (June through September) seasons, renewable energy can provide significant support during afternoon peak demand period; solar PVs in summer and wind in monsoon. However, in both seasons, gas based generation (or some form of flexible generation) is necessary to provide the evening ramp-up support and meet the evening peak demand especially after the solar generation drops rapidly. In Winter, when solar and wind generation both drop, gas based generation provides round the clock energy and load following support despite lower demand. This implies that the peaking and flexible resource used for grid integration in India should be able to provide cross-seasonal support. Hydro energy projects (reservoir type) would be able to offer such support – however, there are significant barriers to timely completion of large hydro projects. Gas based projects would also be ideal for such cross-seasonal support - however, gas availability in India is a major concern. One solution to that could be building on-site gas storage facility so gas power plants do not have to always have to depend on the pipeline gas for power generation. Other solution is building more gas power plants on the shore based on imported LNG – however, such approach may involve significant price and supply risks.

As noted previously, the system needs flexibility and peak support for reliable RE integration, and it need not be technology specific; if any other sources start providing such services (for example, more flexible hydro dispatch with lesser constraints on discharge, demand response etc.), the need for gas based capacity addition would reduce significantly.

The regional diversity in renewable energy generation in India and its complementarity with demand as well as other RE resources help reducing the impact of extreme events such as sudden loss of RE generation or over-generation, etc. on the system. In this analysis, we have assumed future capacity addition in the renewable energy resources happens on the same sites as the current installed capacity. This is a highly conservative assumption for diversity and hence will significantly overestimate the variability in RE generation. Despite this, we found that the system can handle extreme events in RE generation – low and high generation and high variability. However, note that RE forecasting is absolutely crucial for handling such events and reliable grid integration. With newer state-of-the-art forecasting techniques, forecast errors have been reducing rapidly especially with the use of the real-time generation data. With installation of Renewable Energy Management Centers and the new forecasting regulations for the interstate RE generators, India has already started creating a robust framework for RE forecasting.

One of the key enablers of the reliable grid integration is the transmission network. In NAPCC and RE scenarios, there is a need to strengthen the transmission corridor to the Southern region. For example, moderate increases in the power transfer capacities would be required in the West-South corridor (increase by 3000 to 4000 MW relative to the 13th Plan) and East-South corridor (increase of 6000 to 8000 MW relative to the 13th Plan). One of the reasons for such moderate increase in the power transfer capacities is that the renewable resources are well distributed among northern (mostly solar and some wind), western (both solar and wind), and southern (mostly wind and some solar) regions. Note that in the RE dominant scenarios, some of the inter-regional interfaces would have to be used in both directions because of the seasonal and diurnal RE generation patterns. This implies that an appropriate policy and regulatory framework for moving power across regions more freely is crucial for RE integration. This could be achieved by creating robust markets and other measures such as intra-day and ancillary services market, imbalance markets or balancing area coordination etc.

The incremental wholesale cost of electricity supply (at region boundary) in NAPCC and RE Missions scenarios is Rs. 10,000 Cr/yr and Rs 32,000 Cr/yr respectively over the 13$^{th}$ Plan (total cost of 13$^{th}$ Plan is Rs 774,000 Cr/yr). This is equivalent to an increase in the average wholesale supply cost by 3p/kWh (1%) and 14p/kWh (4%) respectively for NAPCC and RE Missions scenarios. However, note that we have not considered the environmental and energy security benefits of RE generation. Note that, given our assumptions of no transmission constraints and regional level balancing, the incremental cost numbers presented here are likely underestimated. If the transmission constraints and state level balancing (with significant barriers for inter-state power trading) were considered, the additional flexible generation requirement for the NAPCC and RE Missions scenarios may increase; there may also be a need for some RE curtailment. Both will likely result in a significant increase in the incremental costs. In our forthcoming analyses, we do consider these constraints for a more accurate estimation of these costs.

We conducted sensitivity analysis to assess the impact of each of these factors on generation investments and cost. If the thermal generation capacity (i.e. coal, gas, and diesel) is optimally planned in the 13th Plan (or slippage in the capacity addition targets), the average wholesale electricity cost (at region boundary) reduces by 2%, which increases the cost differential in the NAPCC and RE Missions scenarios to 3% and 5.8% respectively. If the renewable energy costs drop faster than the BAU, then the cost differential would reduce to 0.4% and 2.6% respectively for NAPCC and RE Missions scenarios. Also, wholesale electricity cost in both these RE dominant scenarios is significantly less sensitive to the fuel price and supply risks relative to the 13th Plan; if by 2022, imported fuel prices are 25% more expensive than their projected prices, average wholesale electricity supply cost (at region boundary) for the $13^{th}$ Plan increases by 2.7% while that for the RE Missions and NAPCC scenarios increases by 0.4% and 0.1% respectively.

Given the ambitious targets of renewable energy in the country, such studies that quantify the impact of large scale integration of RE as well as discussions on the potential policy, regulatory, and institutional framework are crucial. This study serves as the first one of our forthcoming series on RE grid integration in India. However, note that this analysis is based on significant simplifications and assumptions especially regarding the transmission system and the deviation settlement mechanism. Therefore, it is likely that our results underestimate the incremental costs, RE curtailment, need for flexibility, and transmission system investments; these results should be viewed only as high-level indications. Significant refinement to this analysis would be necessary for actual power system planning purposes, which leaves significant scope for future work. For example, the renewable energy siting should be done using more rigorous approach like GIS sampling in order to better capture the diversity in generation. The transmission system is the key to cost-effective RE grid integration, which needs much better representation in the model and should consider technical constraints as well significant non-technical barriers to inter-state trade of electricity. The current version of the model simulates hourly grid operation, uses a deterministic framework, and does not include ancillary services; in order to capture the grid impacts of RE and flexibility requirements more accurately, sub-hourly simulation with reserves and stochastic elements (such as sudden drop in RE generation, contingency reserves etc) would be important. In our forthcoming analyses on the Indian power sector, we intend to include these elements.

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# Appendix 1: Monthly Energy and Peak Demand Projections in Each Region

**Table 31: Projected Monthly Peak Demands in GW (bus-bar) for the Financial Year 2022**

| Month | East | North | North_East | South | West | All-India |
|---|---|---|---|---|---|---|
| **April, 2021** | 33.2 | 77.8 | 3.1 | 81.8 | 87.0 | 279 |
| **May, 2021** | 34.3 | 86.7 | 3.5 | 81.4 | 86.6 | 287 |
| **June, 2021** | 34.1 | 91.6 | 3.6 | 81.7 | 84.9 | 287 |
| **July, 2021** | 33.8 | 90.6 | 3.5 | 74.1 | 77.0 | 277 |
| **August, 2021** | 34.0 | 88.6 | 3.5 | 74.8 | 77.2 | 270 |
| **September, 2021** | 35.6 | 87.7 | 3.4 | 76.0 | 79.8 | 271 |
| **October, 2021** | 34.6 | 80.2 | 3.2 | 77.7 | 82.7 | 275 |
| **November, 2021** | 33.2 | 72.3 | 2.9 | 72.8 | 78.2 | 258 |
| **December, 2021** | 30.6 | 74.7 | 2.9 | 70.7 | 76.4 | 247 |
| **January, 2022** | 31.3 | 84.3 | 3.2 | 66.8 | 72.4 | 251 |
| **February, 2022** | 31.5 | 75.4 | 2.9 | 70.0 | 73.8 | 246 |
| **March, 2022** | 33.6 | 78.5 | 3.1 | 77.9 | 81.8 | 265 |
| **Annual FY 2022** | 35.6 | 91.6 | 3.6 | 81.8 | 87.0 | 287 |

**Table 32: Projected Monthly Energy Demand in TWh (bus-bar) for Financial Year 2022**

| Month | East | North | North_East | South | West | All-India |
|---|---|---|---|---|---|---|
| **April, 2021** | 20 | 48 | 1.9 | 46 | 50 | 166 |
| **May, 2021** | 21 | 56 | 2.2 | 47 | 51 | 178 |
| **June, 2021** | 21 | 56 | 2.2 | 44 | 46 | 170 |
| **July, 2021** | 22 | 58 | 2.3 | 43 | 44 | 169 |
| **August, 2021** | 22 | 57 | 2.2 | 43 | 44 | 168 |
| **September, 2021** | 20 | 50 | 2.0 | 42 | 44 | 159 |
| **October, 2021** | 21 | 49 | 1.9 | 46 | 48 | 166 |
| **November, 2021** | 18 | 41 | 1.6 | 41 | 44 | 145 |
| **December, 2021** | 18 | 44 | 1.7 | 38 | 42 | 144 |
| **January, 2022** | 18 | 48 | 1.8 | 38 | 41 | 147 |
| **February, 2022** | 16 | 41 | 1.6 | 37 | 39 | 134 |
| **March, 2022** | 20 | 47 | 1.8 | 45 | 47 | 161 |
| **Annual FY 2022** | 237 | 594 | 23.2 | 511 | 540 | 1,906 |

# Appendix 2: Assumptions on Operational Characteristics of Generating Plants

### Table 33: Assumptions on Operational Characteristics of Generating Plants

| Generator Technology | Region | Generator_Name | Average Unit Size (MW) | Min Stable Factor (%) | Gross Heat Rate (GJ/MWh) | Start Cost ($) | Shutdo wn Cost ($) | Min Up Time (hrs) | Min Down Time (hrs) | Max Ramp Up (MW/min.) | Max Ramp Down (MW/min.) | Auxiliary Consump tion (%) | Planned Mainte nance Rate (%) | Forced Outage Rate (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Biomass+Cogen | East | ER_Biomass | 20 | 20 | 16 | 100 | 100 | 1 | 1 | 0.5 | 0.5 | 10 | 10 | 10 |
| Biomass+Cogen | North | NR_Biomass | 20 | 20 | 16 | 100 | 100 | 1 | 1 | 0.5 | 0.5 | 10 | 10 | 10 |
| Biomass+Cogen | South | SR_Biomass | 20 | 20 | 16 | 100 | 100 | 1 | 1 | 0.5 | 0.5 | 10 | 10 | 10 |
| Biomass+Cogen | West | WR_Biomass | 20 | 20 | 16 | 100 | 100 | 1 | 1 | 0.5 | 0.5 | 10 | 10 | 10 |
| Coal | East | ER_Old_<210 | 87 | 55 | 12 | 8741 | 8741 | 24 | 24 | 0.87 | 0.87 | 10.6 | 12.3 | 32.9 |
| Coal | East | ER_Old_210/250 | 220 | 55 | 11.2 | 22000 | 22000 | 24 | 24 | 2.2 | 2.2 | 9 | 2.8 | 11.9 |
| Coal | East | ER_Old_500/600 | 516 | 55 | 10.8 | 51579 | 51579 | 24 | 24 | 5.16 | 5.16 | 6.5 | 4.9 | 11.8 |
| Coal | East | ER_Old_660 | 660 | 55 | 10 | 66000 | 66000 | 24 | 24 | 6.6 | 6.6 | 8.1 | 5 | 11.8 |
| Coal | East | ER_Old_Other | 390 | 55 | 11 | 39000 | 39000 | 24 | 24 | 3.9 | 3.9 | 10.5 | 0.9 | 18.6 |
| Coal | East | ER_SuperCritical | 660 | 55 | 9 | 66000 | 66000 | 24 | 24 | 6.6 | 6.6 | 8 | 5 | 5 |
| Coal | North_East | NER_Old | 30 | 0 | 12 | 3000 | 3000 | 24 | 24 | 0.3 | 0.3 | 10.6 | 0 | 100 |
| Coal | North | NR_Old_<210 | 114 | 55 | 12.2 | 11378 | 11378 | 24 | 24 | 1.14 | 1.14 | 10.6 | 13.3 | 14 |
| Coal | North | NR_Old_210/250 | 222 | 55 | 11.4 | 22238 | 22238 | 24 | 24 | 2.22 | 2.22 | 9 | 3.6 | 8.4 |
| Coal | North | NR_Old_500/600 | 531 | 55 | 10.8 | 53077 | 53077 | 24 | 24 | 5.31 | 5.31 | 6.5 | 5.5 | 5 |
| Coal | North | NR_Old_660 | 660 | 55 | 9.7 | 66000 | 66000 | 24 | 24 | 6.6 | 6.6 | 8.1 | 5 | 5 |
| Coal | North | NR_Old_Other | 348 | 55 | 10.8 | 34750 | 34750 | 24 | 24 | 3.48 | 3.48 | 10.5 | 1.2 | 19.2 |
| Coal | North | NR_SuperCritical | 660 | 55 | 9 | 66000 | 66000 | 24 | 24 | 6.6 | 6.6 | 8 | 5 | 5 |
| Coal | South | SR_Old_<210 | 99 | 55 | 12.2 | 9925 | 9925 | 24 | 24 | 0.99 | 0.99 | 10.6 | 3.7 | 10.9 |
| Coal | South | SR_Old_210/250 | 215 | 55 | 11.4 | 21455 | 21455 | 24 | 24 | 2.15 | 2.15 | 9 | 5.6 | 5.7 |
| Coal | South | SR_Old_500/600 | 512 | 55 | 10.8 | 51176 | 51176 | 24 | 24 | 5.12 | 5.12 | 6.5 | 3.7 | 3.5 |
| Coal | South | SR_Old_660 | 660 | 55 | 9.7 | 66000 | 66000 | 24 | 24 | 6.6 | 6.6 | 8.1 | 5 | 3.5 |
| Coal | South | SR_Old_Other | 300 | 55 | 10.8 | 30000 | 30000 | 24 | 24 | 3 | 3 | 10.5 | 8.2 | 8.6 |
| Coal | South | SR_SuperCritical | 660 | 55 | 9 | 66000 | 66000 | 24 | 24 | 6.6 | 6.6 | 8 | 5 | 5 |
| Coal | West | WR_Old_<210 | 106 | 55 | 12.2 | 10603 | 10603 | 24 | 24 | 1.06 | 1.06 | 10.6 | 6.1 | 22.9 |
| Coal | West | WR_Old_210/250 | 220 | 55 | 11.4 | 21968 | 21968 | 24 | 24 | 2.2 | 2.2 | 9 | 6 | 7.2 |
| Coal | West | WR_Old_500/600 | 505 | 55 | 10.8 | 50500 | 50500 | 24 | 24 | 5.05 | 5.05 | 6.5 | 3.6 | 4.3 |
| Coal | West | WR_Old_660 | 774 | 55 | 9.7 | 77429 | 77429 | 24 | 24 | 7.74 | 7.74 | 8.1 | 0 | 15.4 |

| Generator Technology | Region | Generator_Name | Average Unit Size (MW) | Min Stable Factor (%) | Gross Heat Rate (GJ/MWh) | Start Cost ($) | Shutdown Cost ($) | Min Up Time (hrs) | Min Down Time (hrs) | Max Ramp Up (MW/min.) | Max Ramp Down (MW/min.) | Auxiliary Consumption (%) | Planned Maintenance Rate (%) | Forced Outage Rate (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal | West | WR_Old_Other | 312 | 55 | 10.8 | 31200 | 31200 | 24 | 24 | 3.12 | 3.12 | 10.5 | 1.3 | 10.8 |
| Coal | West | WR_SuperCritical | 660 | 55 | 9 | 66000 | 66000 | 24 | 24 | 6.6 | 6.6 | 8 | 5 | 5 |
| Diesel | East | ER_Diesel | 17.2 | 0 | 13.5 | 100 | 100 | | | 17.2 | 17.2 | 1 | 5 | 5 |
| Diesel | North_East | NER_Diesel | 60 | 0 | 13.5 | 100 | 100 | | | 17.2 | 17.2 | 1 | 5 | 5 |
| Diesel | North | NR_Diesel | 13 | 0 | 13.5 | 100 | 100 | | | 13 | 13 | 1 | 5 | 5 |
| Diesel | South | SR_Diesel | 50 | 0 | 13.5 | 100 | 100 | | | 50 | 50 | 1 | 5 | 5 |
| Diesel | West | WR_Diesel | 17.5 | 0 | 13.5 | 100 | 100 | | | 17.5 | 17.5 | 1 | 5 | 5 |
| Gas_CCGT | East | ER_CC_GT | 25 | 10 | 12 | 250 | 250 | 1 | 1 | 2.5 | 2.5 | 1 | 5 | 5 |
| Gas_CCGT | East | ER_CC_ST | 11 | 40 | 14 | 1100 | 1100 | 6 | 6 | 0.04 | 0.04 | 5 | 10 | 10 |
| Gas_CCGT | North_East | NER_CC_GT | 21 | 10 | 12 | 214 | 214 | 1 | 1 | 2.14 | 2.14 | 1 | 5 | 5 |
| Gas_CCGT | North_East | NER_CC_ST | 11 | 40 | 14 | 1100 | 1100 | 6 | 6 | 0.04 | 0.04 | 5 | 10 | 10 |
| Gas_CCGT | North | NR_CC_GT | 79 | 10 | 12 | 794 | 794 | 1 | 1 | 7.94 | 7.94 | 1 | 5 | 5 |
| Gas_CCGT | North | NR_CC_ST | 106 | 40 | 14 | 10589 | 10589 | 6 | 6 | 0.39 | 0.39 | 5 | 10 | 10 |
| Gas_CCGT | South | SR_CC_GT | 85 | 10 | 12 | 852 | 852 | 1 | 1 | 8.52 | 8.52 | 1 | 5 | 5 |
| Gas_CCGT | South | SR_CC_ST | 84 | 40 | 14 | 8380 | 8380 | 6 | 6 | 0.31 | 0.31 | 5 | 10 | 10 |
| Gas_CCGT | West | WR_CC_GT | 155 | 10 | 12 | 1552 | 1552 | 1 | 1 | 15.52 | 15.52 | 1 | 5 | 5 |
| Gas_CCGT | West | WR_CC_ST | 112 | 40 | 14 | 11250 | 11250 | 6 | 6 | 0.41 | 0.41 | 5 | 10 | 10 |
| Gas_CT | East | ER_CT | 50 | 10 | 12 | 0 | 0 | 1 | 1 | 5 | 5 | 1 | 5 | 5 |
| Gas_CT | North_East | NER_CT | 50 | 10 | 12 | 0 | 0 | 1 | 1 | 5 | 5 | 1 | 5 | 5 |
| Gas_CT | North | NR_CT | 50 | 10 | 12 | 0 | 0 | 1 | 1 | 5 | 5 | 1 | 5 | 5 |
| Gas_CT | South | SR_CT | 50 | 10 | 12 | 0 | 0 | 1 | 1 | 5 | 5 | 1 | 5 | 5 |
| Gas_CT | West | WR_CT | 50 | 10 | 12 | 0 | 0 | 1 | 1 | 5 | 5 | 1 | 5 | 5 |
| Hydro_Large | East | ER_Hydro_<=100 | 50 | 0 | 0 | 0 | 0 | | | 5 | 5 | 1 | 5 | 5 |
| Hydro_Large | East | ER_Hydro_>100 | 150 | 0 | 0 | 0 | 0 | | | 15 | 15 | 1 | 5 | 5 |
| Hydro_Large | North_East | NER_Hydro_<=100 | 29 | 0 | 0 | 0 | 0 | | | 2.9 | 2.9 | 1 | 5 | 5 |
| Hydro_Large | North_East | NER_Hydro_>100 | 139 | 0 | 0 | 0 | 0 | | | 13.9 | 13.9 | 1 | 5 | 5 |
| Hydro_Large | North | NR_Hydro_<=100 | 60 | 0 | 0 | 0 | 0 | | | 6 | 6 | 1 | 5 | 5 |
| Hydro_Large | North | NR_Hydro_>100 | 163 | 0 | 0 | 0 | 0 | | | 16.3 | 16.3 | 1 | 5 | 5 |
| Hydro_Large | South | SR_Hydro_<=100 | 29 | 0 | 0 | 0 | 0 | | | 2.9 | 2.9 | 1 | 5 | 5 |
| Hydro_Large | South | SR_Hydro_>100 | 118 | 0 | 0 | 0 | 0 | | | 11.8 | 11.8 | 1 | 5 | 5 |
| Hydro_Large | West | WR_Hydro_<=100 | 44 | 0 | 0 | 0 | 0 | | | 4.4 | 4.4 | 1 | 5 | 5 |
| Hydro_Large | West | WR_Hydro_>100 | 154 | 0 | 0 | 0 | 0 | | | 15.4 | 15.4 | 1 | 5 | 5 |
| Hydro_Small | East | ER_SmallHydro | 20 | 0 | 0 | 0 | 0 | | | 20 | 20 | 1 | 5 | 5 |
| Hydro_Small | North_East | NER_SmallHydro | 20 | 0 | 0 | 0 | 0 | | | 20 | 20 | 1 | 5 | 5 |
| Hydro_Small | North | NR_SmallHydro | 20 | 0 | 0 | 0 | 0 | | | 20 | 20 | 1 | 5 | 5 |
| Hydro_Small | South | SR_SmallHydro | 20 | 0 | 0 | 0 | 0 | | | 20 | 20 | 1 | 5 | 5 |
| Hydro_Small | West | WR_SmallHydro | 20 | 0 | 0 | 0 | 0 | | | 20 | 20 | 1 | 5 | 5 |

| Generator Technology | Region | Generator_Name | Average Unit Size (MW) | Min Stable Factor (%) | Gross Heat Rate (GJ/MWh) | Start Cost ($) | Shutdown Cost ($) | Min Up Time (hrs) | Min Down Time (hrs) | Max Ramp Up (MW/min.) | Max Ramp Down (MW/min.) | Auxiliary Consumption (%) | Planned Maintenance Rate (%) | Forced Outage Rate (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Pumped Storage | East | ER_Hydro_PS | 163 | 0 | 10 | 0 | 0 | | | 16.3 | 16.3 | 1 | 5 | 5 |
| Pumped Storage | North_East | NER_Hydro_PS | 142 | 0 | 10 | 0 | 0 | | | 14.2 | 14.2 | 1 | 5 | 5 |
| Pumped Storage | North | NR_Hydro_PS | 142 | 0 | 10 | 0 | 0 | | | 14.2 | 14.2 | 1 | 5 | 5 |
| Pumped Storage | South | SR_Hydro_PS | 130 | 0 | 10 | 0 | 0 | | | 13 | 13 | 1 | 5 | 5 |
| Pumped Storage | West | WR_Hydro_PS | 142 | 0 | 10 | 0 | 0 | | | 14.2 | 14.2 | 1 | 5 | 5 |
| Run of River | East | ER_Hydro_ROR | 48 | 0 | 0 | 0 | | | | 4.8 | 4.8 | 1 | 5 | 5 |
| Run of River | North_East | NER_Hydro_ROR | 63 | 0 | 0 | 0 | | | | 6.3 | 6.3 | 1 | 5 | 5 |
| Run of River | North | NR_Hydro_ROR | 68 | 0 | 0 | 0 | | | | 6.8 | 6.8 | 1 | 5 | 5 |
| Run of River | South | SR_Hydro_ROR | 21 | 0 | 0 | 0 | | | | 2.1 | 2.1 | 1 | 5 | 5 |
| Run of River | West | WR_Hydro_ROR | 46 | 0 | 0 | 0 | | | | 4.6 | 4.6 | 1 | 5 | 5 |
| Nuclear | East | ER_Nuclear | 410 | 70 | 10 | 100000 | 100000 | 96 | 96 | 0.1 | 0.1 | 10 | 10 | 10 |
| Nuclear | North | NR_Nuclear | 410 | 70 | 10 | 100000 | 100000 | 96 | 96 | 0.1 | 0.1 | 10 | 10 | 10 |
| Nuclear | South | SR_Nuclear | 410 | 70 | 10 | 100000 | 100000 | 96 | 96 | 0.1 | 0.1 | 10 | 10 | 10 |
| Nuclear | West | WR_Nuclear | 410 | 70 | 10 | 100000 | 100000 | 96 | 96 | 0.1 | 0.1 | 10 | 10 | 10 |

## Appendix 3: Renewable Energy Forecast

India has implemented a framework mandating the RE generators to provide day-ahead forecasts in early 2016. However, such forecast data is not yet available publicly. Therefore, we have created the day-ahead RE and load forecasts based on simple trend and persistence analysis. The following charts show the 3-hour ahead forecast errors (expressed as a fraction of the installed capacity).

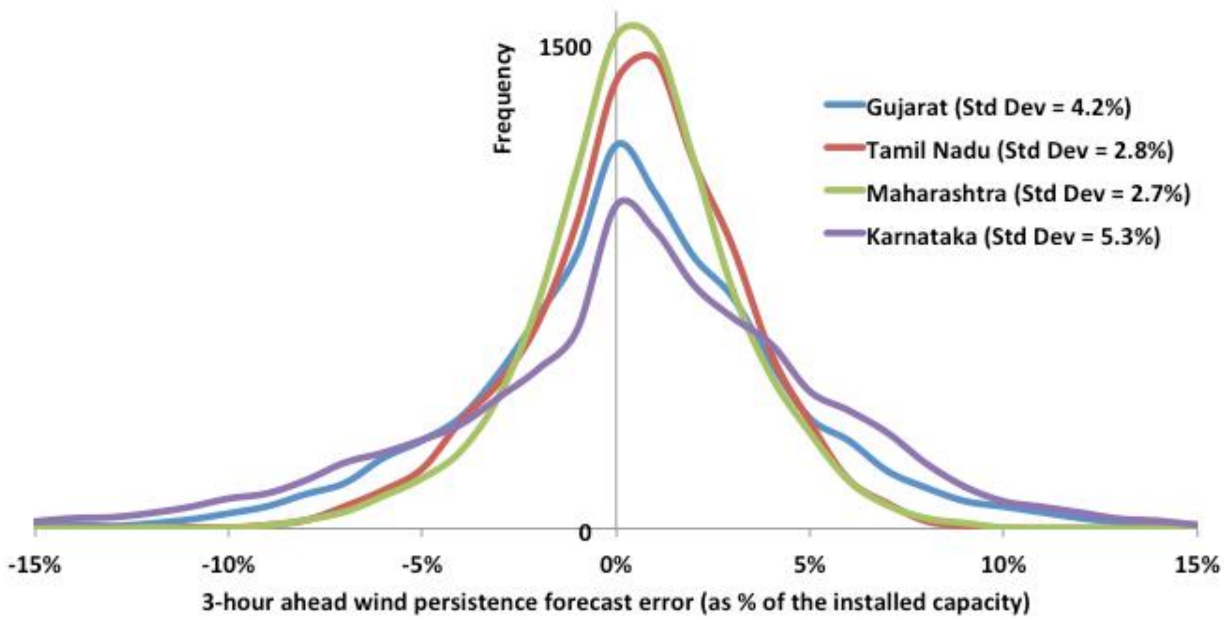



Figure 31: 3-hour Ahead Forecast Errors in Wind Generation in India based on Persistence Forecast

The standard deviation of the forecast errors range from 2.7% to 5.3% of the installed capacity depending on the state. This means that on any given day, there is a 68% chance that the 3-hour-ahead persistence forecast error would be 2.7% of the installed capacity in Maharashtra while there is 95% chance that the 3-hour ahead persistence forecast error would be 5.4% of the installed capacity in Maharashtra (2 standard deviations). Note that these forecasts are developed using simple persistence method; with state of the art weather forecast techniques using real-time weather data, the forecast errors could be reduced significantly. In 2015, using the state of the art forecasting techniques, the 3-hour ahead wind forecast errors in Texas are as low as 4-5%.

# Appendix 4: Day-Ahead and Real-Time Prices

The following charts show the day-ahead price duration curves in each scenario. Note that these prices are based on the schedules updated up to three hours in advance; therefore these could be considered as a three hour-ahead prices as well. Since we do not have all the existing contracts and self-scheduling modeled in the system, these prices are essentially the variable generation cost of the marginal unit on the system in each hour. One can see that in certain instances when the marginal unit on the system is gas or diesel based, the system price is very high. Also, note that we have shown a single electricity price for the entire nation. Indian does not have locational marginal prices, but instead it operates a zonal market. Therefore, in reality, the wholesale electricity prices would be different in each zone if there are transmission constraints. However, since we have not assumed any transmission constraints, prices in all zones are almost identical; they are only different by the transmission wheeling charge between the two zones.

The following chart shows the real time prices in each scenario. As explained previously, these prices should be taken indicatively since what they represent is essentially the variable cost of electricity generation of the marginal unit on the system in that hour.

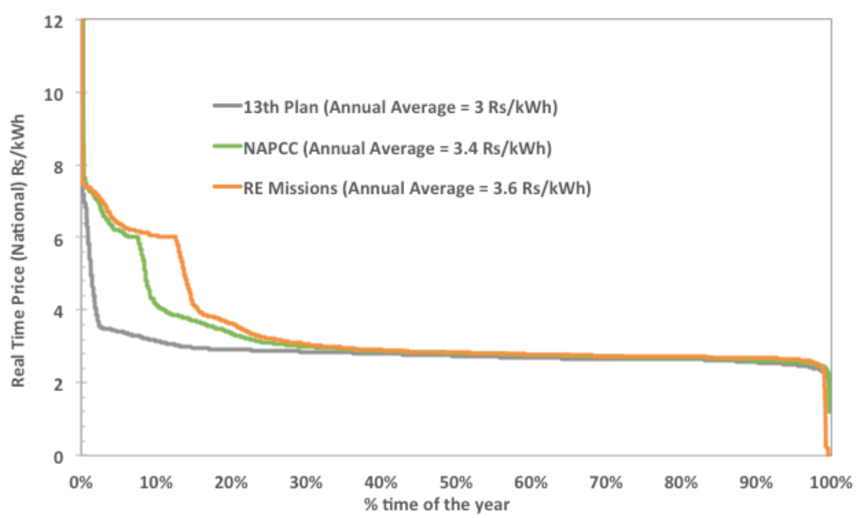



Figure 32: Real Time Price (National) Duration Curves in each Scenario

The following chart shows the differences in the day-ahead, intra-day and real time prices in the RE missions scenario:

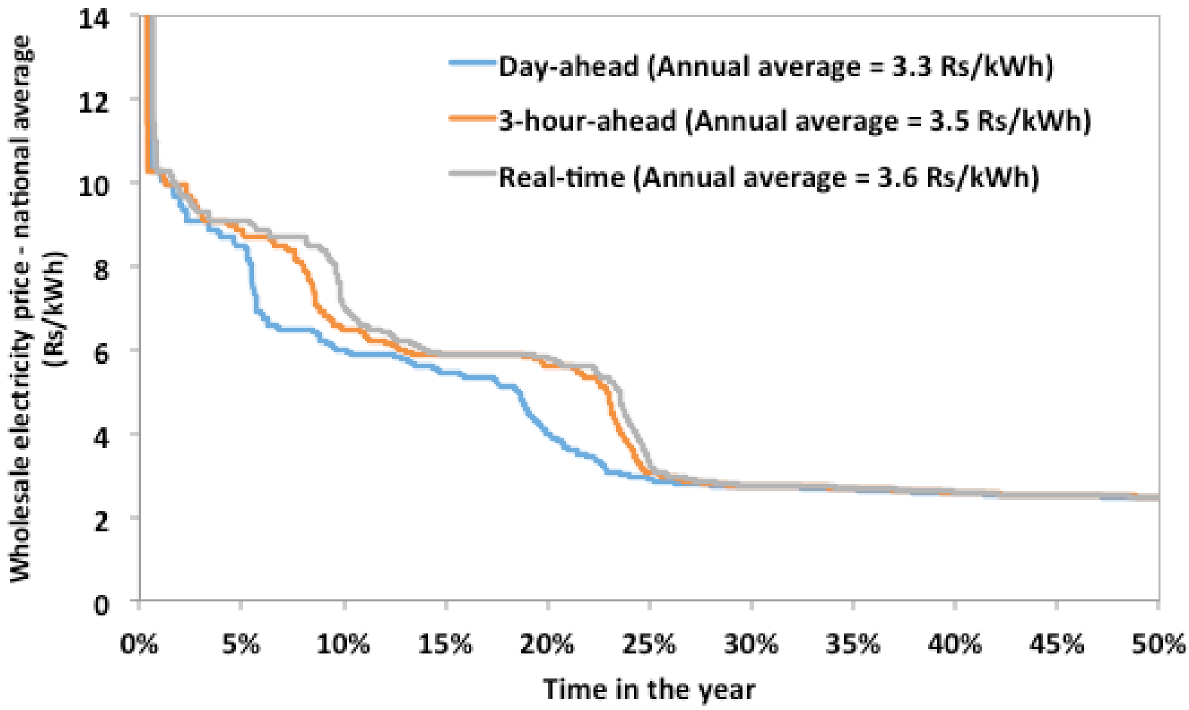
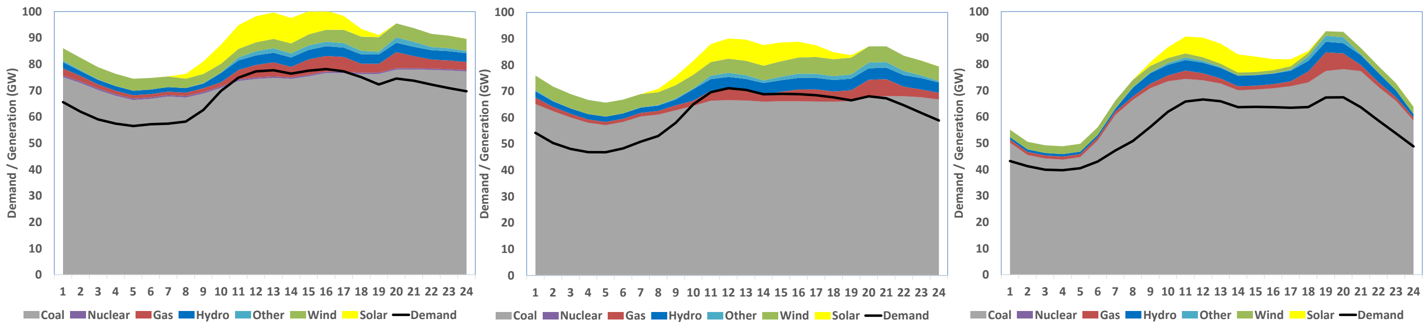



Figure 33: Day-ahead, Intra-day (3-hour ahead), and Real Time Price Duration Curves for the RE Missions Scenario

# Appendix 5: Generation by Region and Inter-Regional Flows in 2022

## 6.1 Hourly Regional Dispatch - 13th Plan Scenario

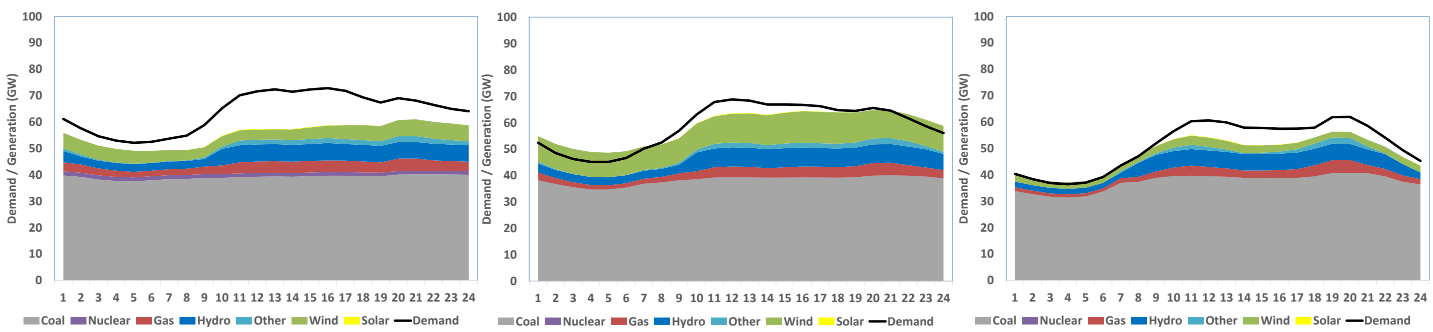
### 6.1.1 Western Region




**(a) Summer** **(b) Monsoon** **(c) Winter**

Figure 34: Average Regional Hourly Dispatch in the Western Region by Season in FY 2022 (13th Plan Scenario)

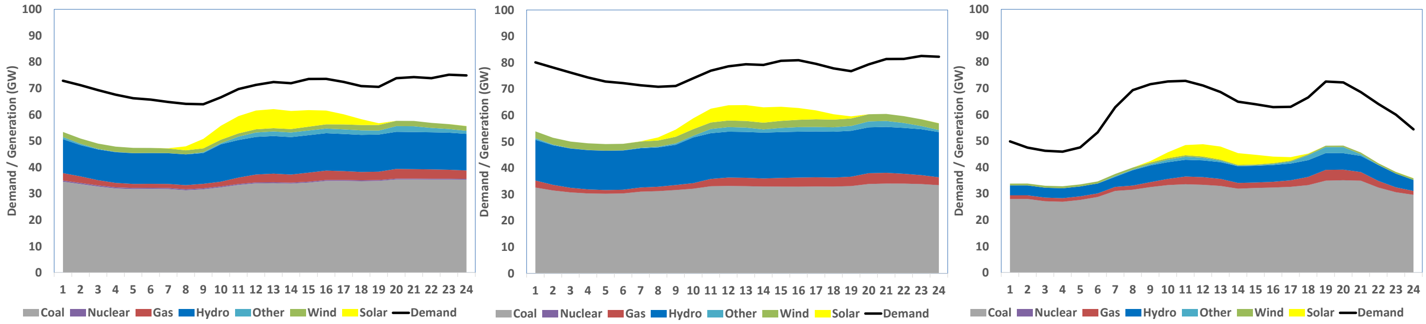
### 6.1.2 Southern Region




**(a) Summer** **(b) Monsoon** **(c) Winter**

Figure 35: Average Regional Hourly Dispatch in the Southern Region by Season in FY 2022 (13th Plan Scenario)

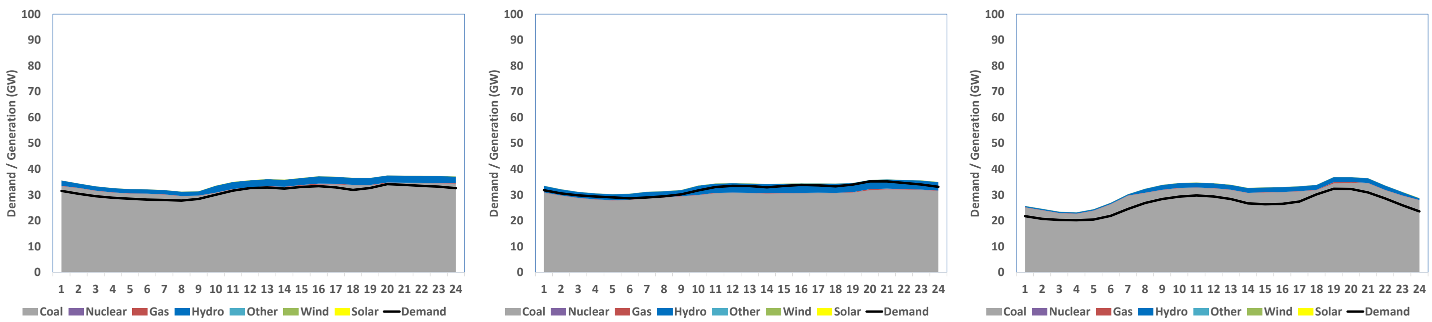
### 6.1.3 Northern Region




**(a) Summer** **(b) Monsoon** **(c) Winter**

**Figure 36: Average Regional Hourly Dispatch in the Northern Region by Season in FY 2022 (13th Plan Scenario)**

### 6.1.4 Eastern + North-Eastern Region




**(a) Summer** **(b) Monsoon** **(c) Winter**

**Figure 37: Average Regional Hourly Dispatch in the Eastern and North-Eastern Region by Season in FY 2022 (13th Plan Scenario)**

### 6.1.5 Inter-Regional Transmission Flows

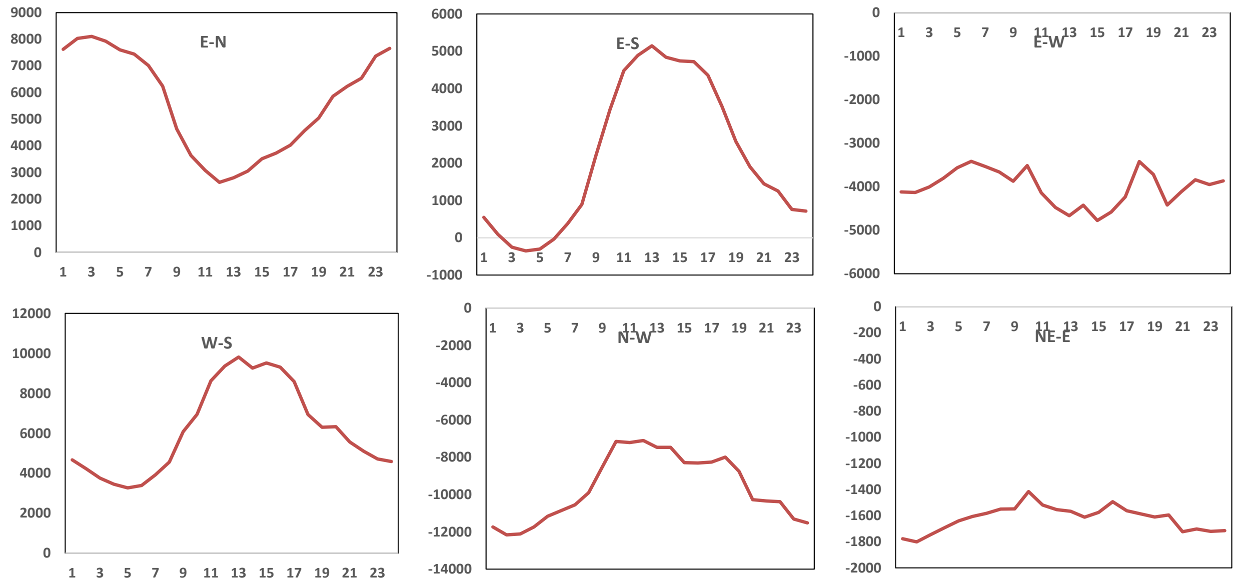



**Figure 38: Average Hourly Inter-Regional Transmission Flows during Summer in FY 2022 (13th Plan Scenario)**

Note: Sign of the flow indicates the direction. For example, East to North would be counted as positive flow while North to East would count as negative.

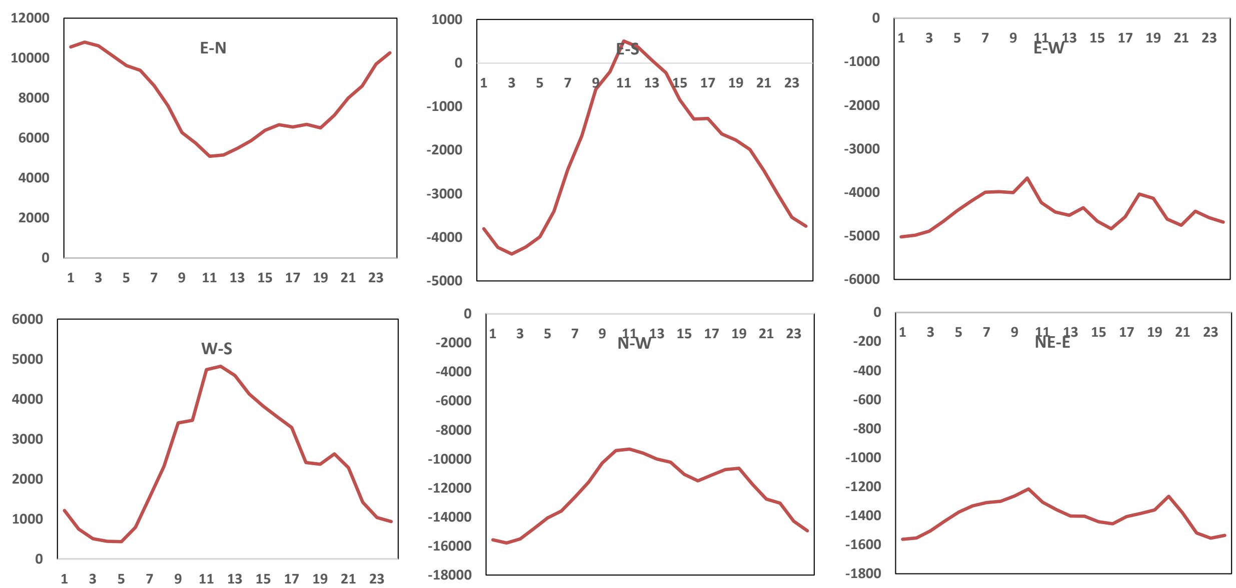



**Figure 39: Average Hourly Inter-Regional Transmission Flows during Monsoon in FY 2022 (13th Plan Scenario)**

Note: Sign of the flow indicates the direction. For example, East to North would be counted as positive flow while North to East would count as negative.

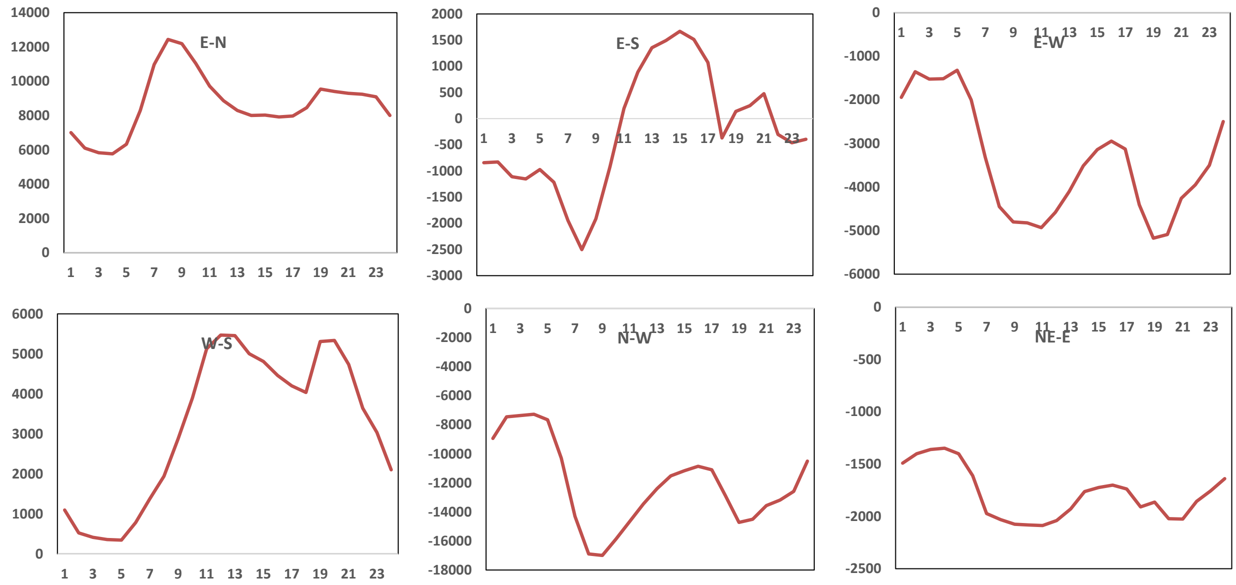
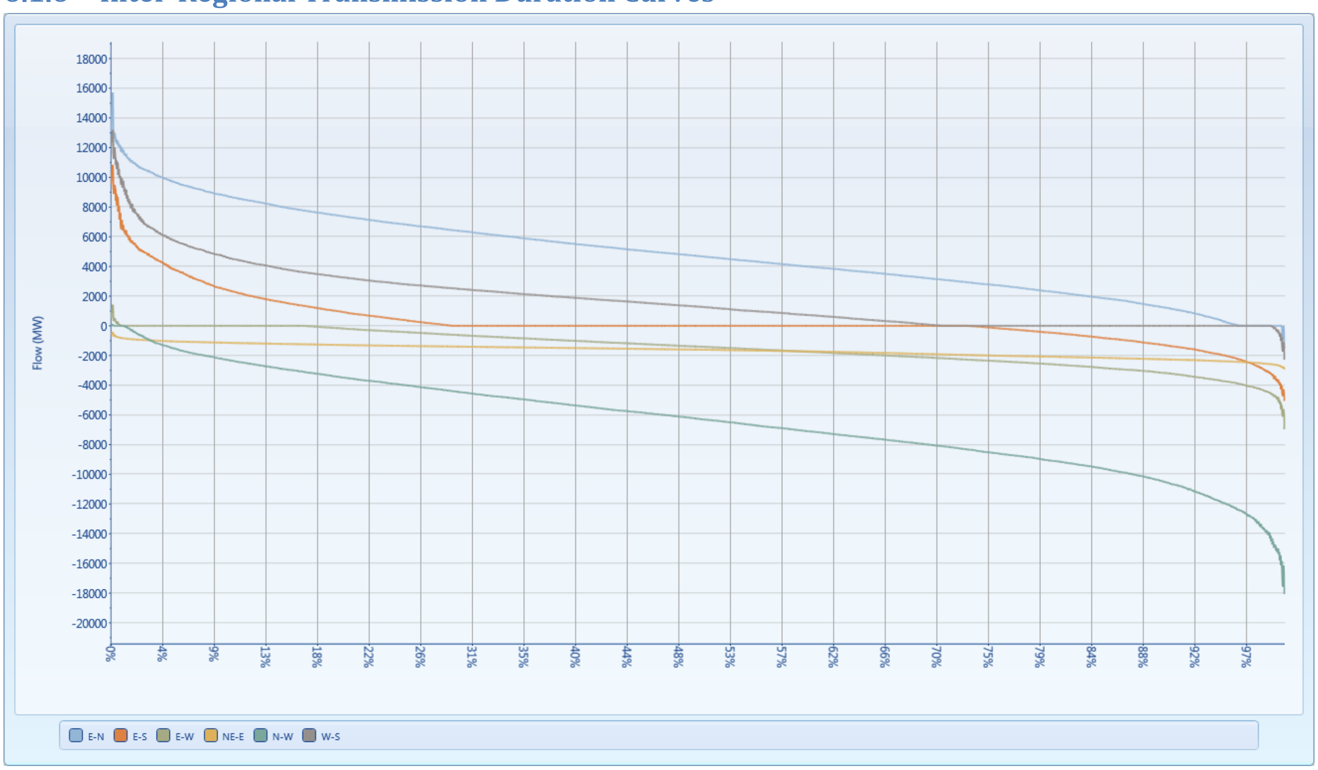



**Figure 40: Average Hourly Inter-Regional Transmission Flows during Winter in FY 2022 (13th Plan Scenario)**

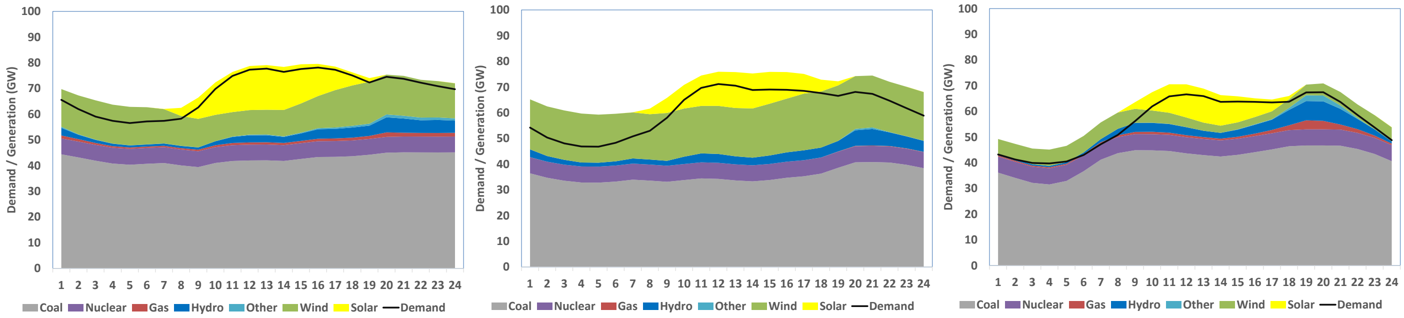
Note: Sign of the flow indicates the direction. For example, East to North would be counted as positive flow while North to East would count as negative.

### 6.1.6 Inter-Regional Transmission Duration Curves



## 6.2 Hourly Regional Dispatch - NAPCC Scenario

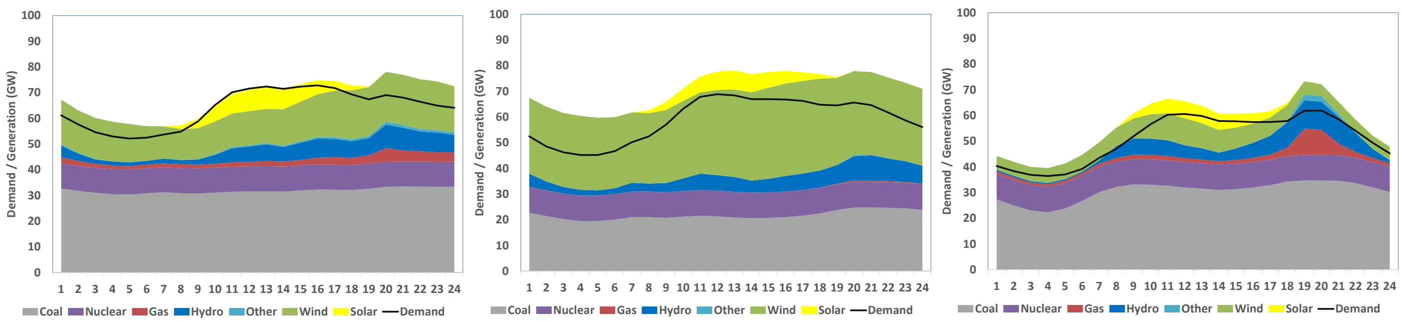
### 6.2.1 Western Region




**(a) Summer** **(b) Monsoon** **(c) Winter**

**Figure 41: Average Regional Hourly Dispatch in the Western Region by Season in FY 2022 (NAPCC Scenario)**

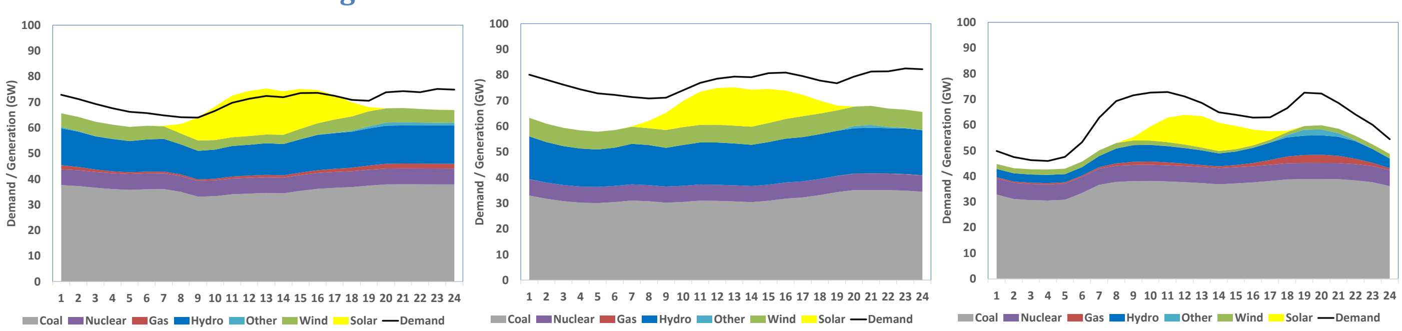
### 6.2.2 Southern Region




**(a) Summer** **(b) Monsoon** **(c) Winter**

**Figure 42: Average Regional Hourly Dispatch in the Southern Region by Season in FY 2022 (NAPCC Scenario)**

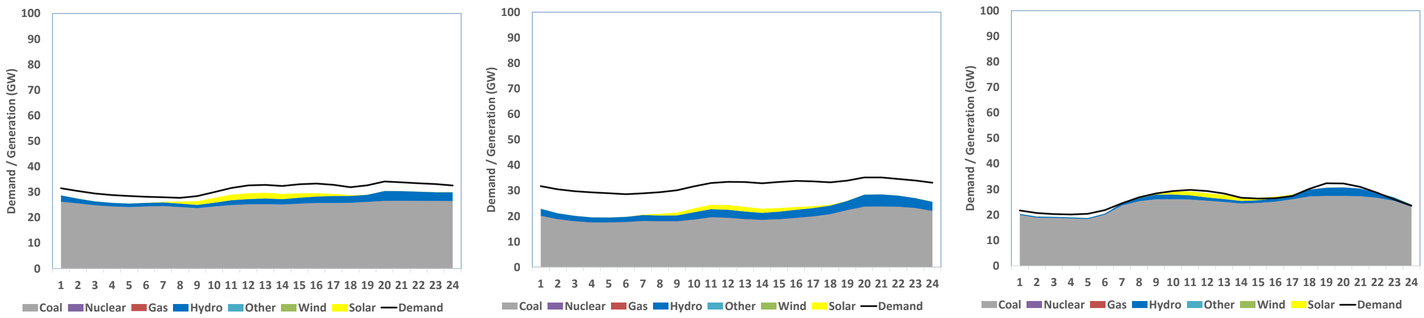
### 6.2.3 Northern Region




**(a) Summer** **(b) Monsoon** **(c) Winter**

Figure 43: Average Regional Hourly Dispatch in the Northern Region by Season in FY 2022 (NAPCC Scenario)

### 6.2.4 East + North_Eastern Regions (Combined)




**(a) Summer** **(b) Monsoon** **(c) Winter**

Figure 44: Average Regional Hourly Dispatch in the Eastern and North-Eastern Region by Season in FY 2022 (NAPCC Scenario)

### 6.2.5 Inter-Regional Transmission Flows

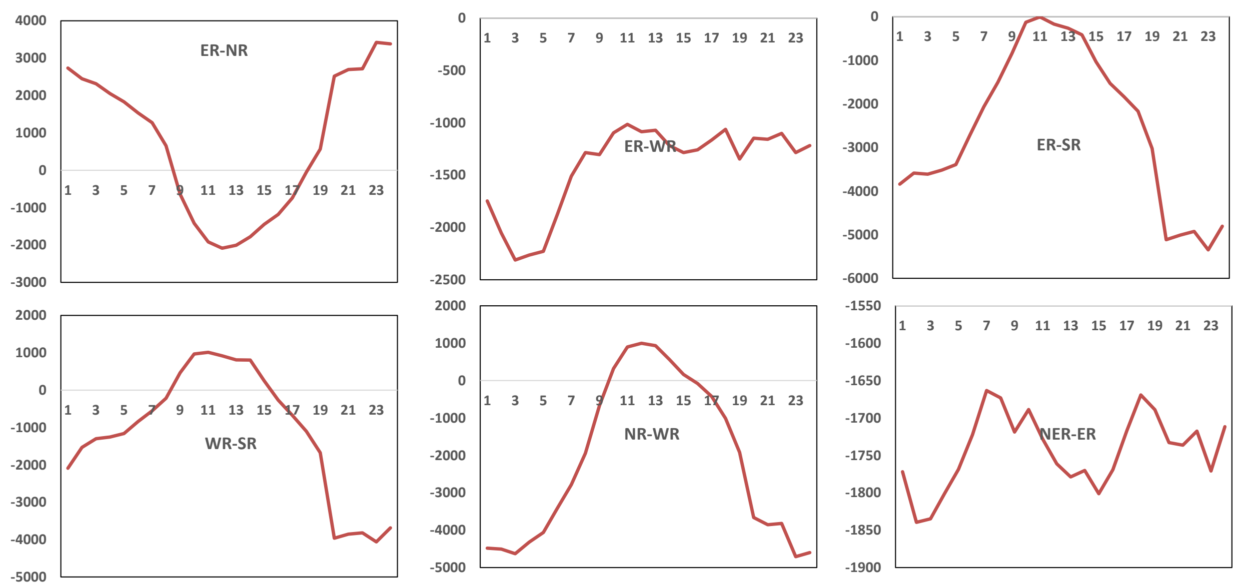



Figure 45: Average Hourly Inter-Regional Transmission Flows during Summer in FY 2022 (NAPCC Scenario)

Note: Sign of the flow indicates the direction. For example, East to North would be counted as positive flow while North to East would count as negative.

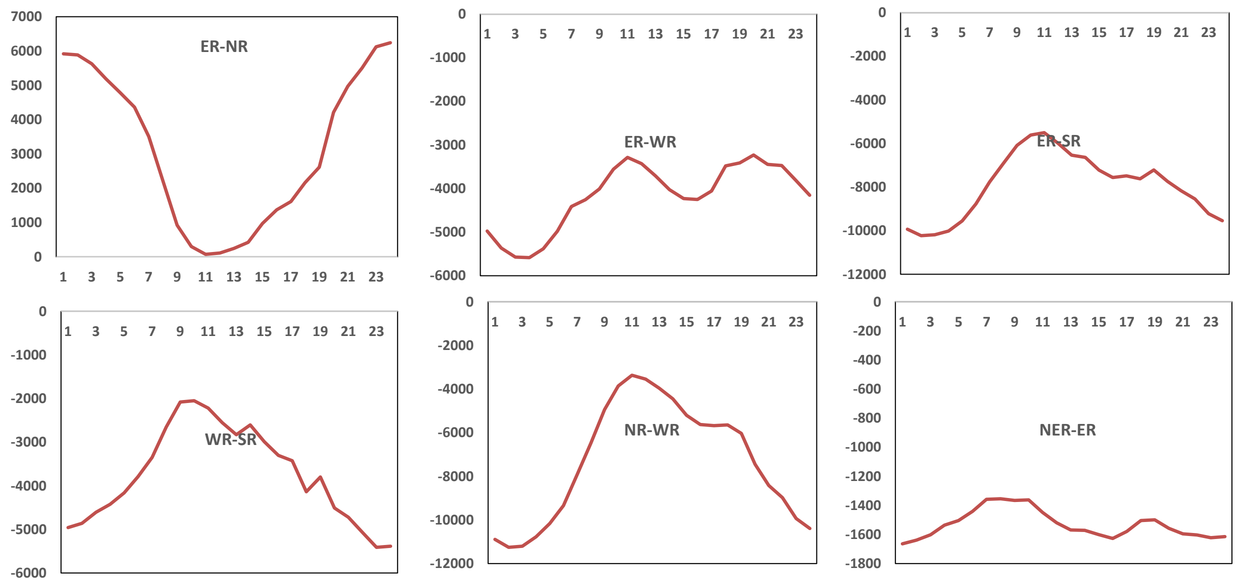



**Figure 46: Average Hourly Inter-Regional Transmission Flows during Monsoon in FY 2022 (NAPCC Scenario)**

Note: Sign of the flow indicates the direction. For example, East to North would be counted as positive flow while North to East would count as negative.

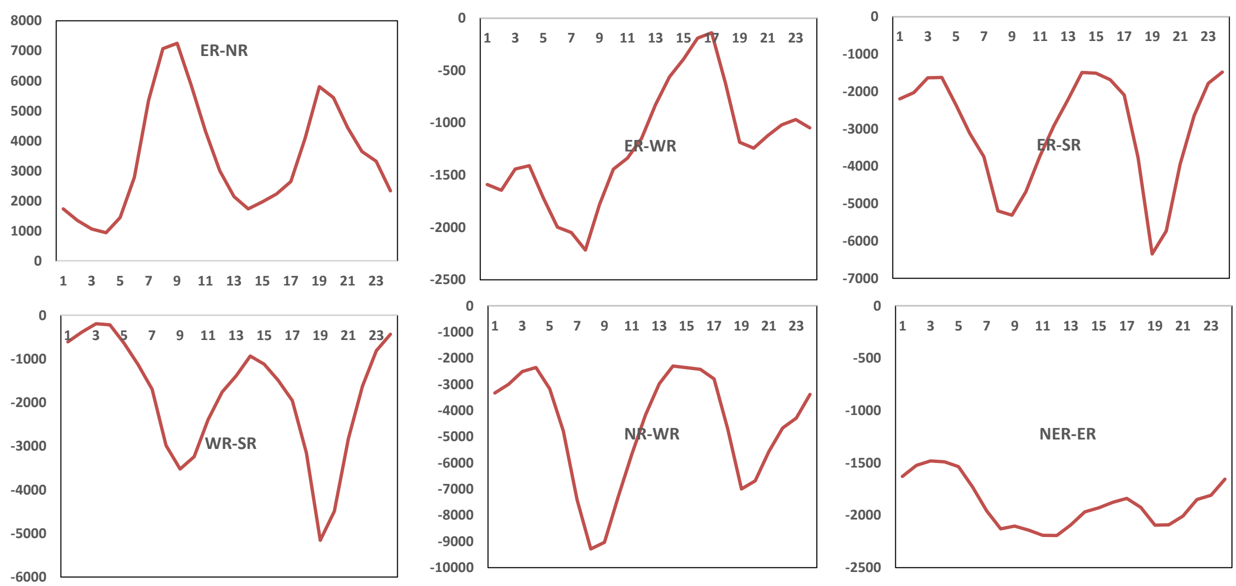
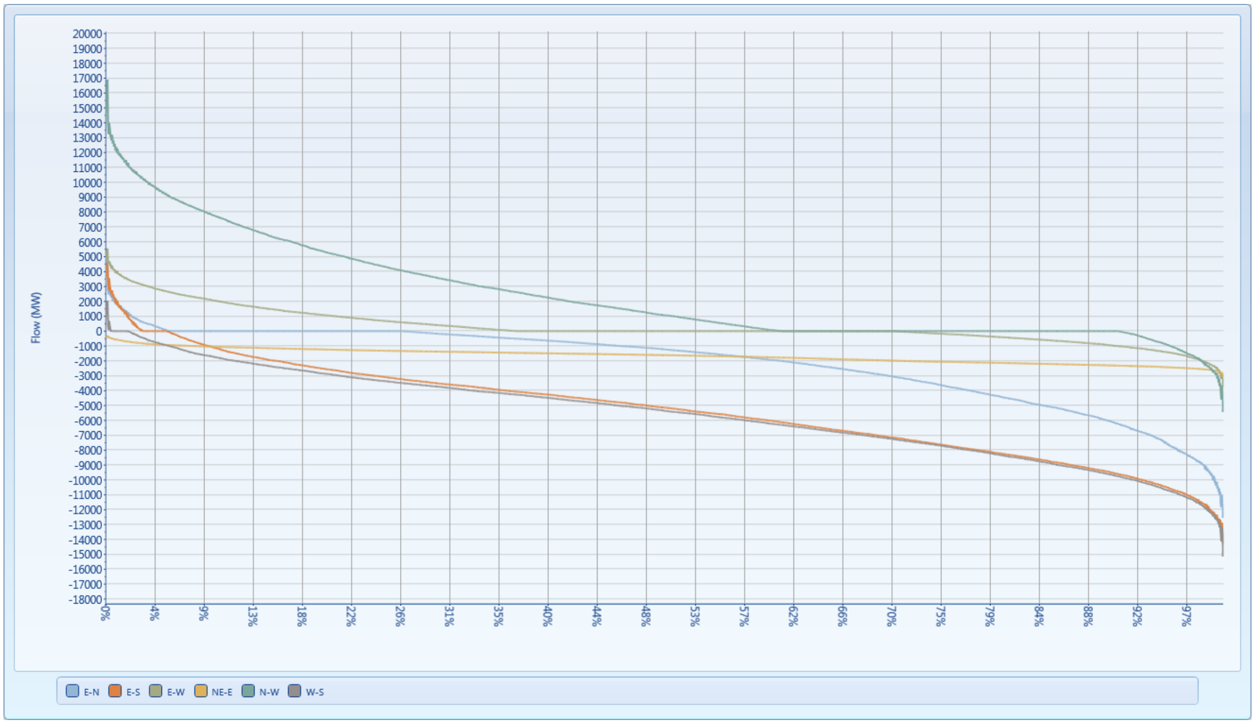



**Figure 47: Average Hourly Inter-Regional Transmission Flows during Winter in FY 2022 (NAPCC Scenario)**

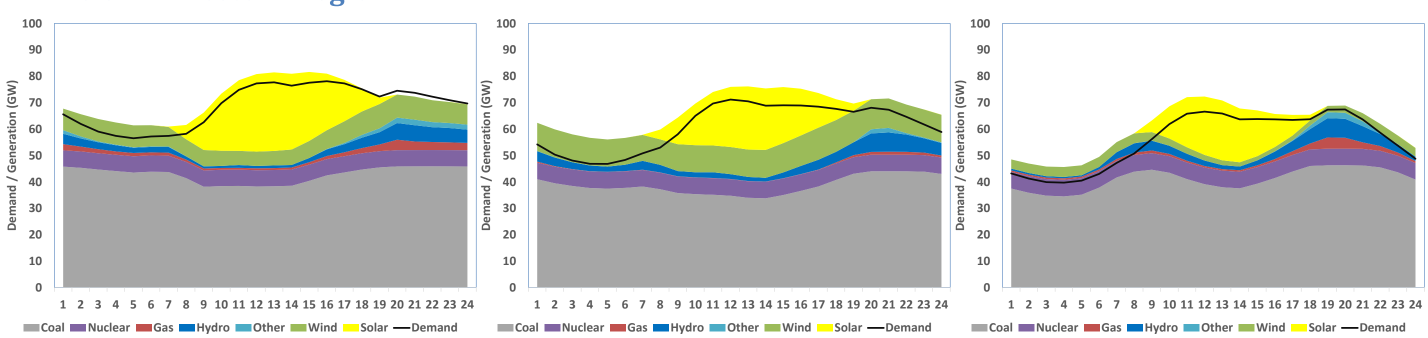
Note: Sign of the flow indicates the direction. For example, East to North would be counted as positive flow while North to East would count as negative.

### 6.2.6 Inter-Regional Transmission Duration Curves




## 6.3 Hourly Regional Dispatch – RE Missions Scenario

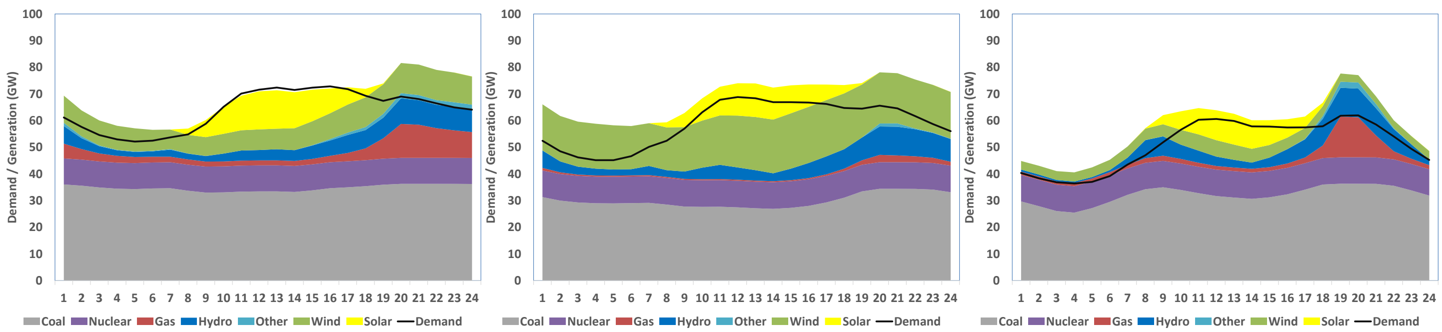
### 6.3.1 Western Region




**(a) Summer** **(b) Monsoon** **(c) Winter**

Figure 48: Average Regional Hourly Dispatch in the Western Region by Season in FY 2022 (RE Missions Scenario)

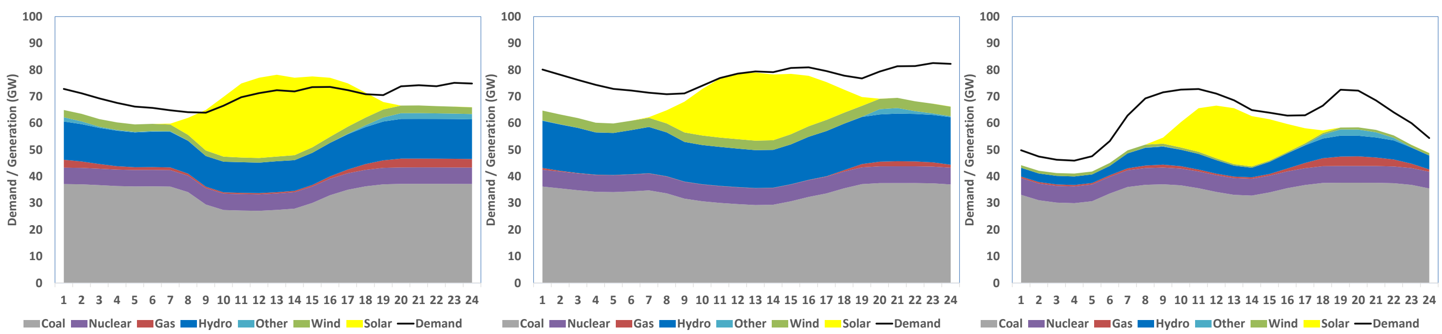
### 6.3.2 Southern Region




**(a) Summer** **(b) Monsoon** **(c) Winter**

**Figure 49: Average Regional Hourly Dispatch in the Southern Region by Season in FY 2022 (RE Missions Scenario)**

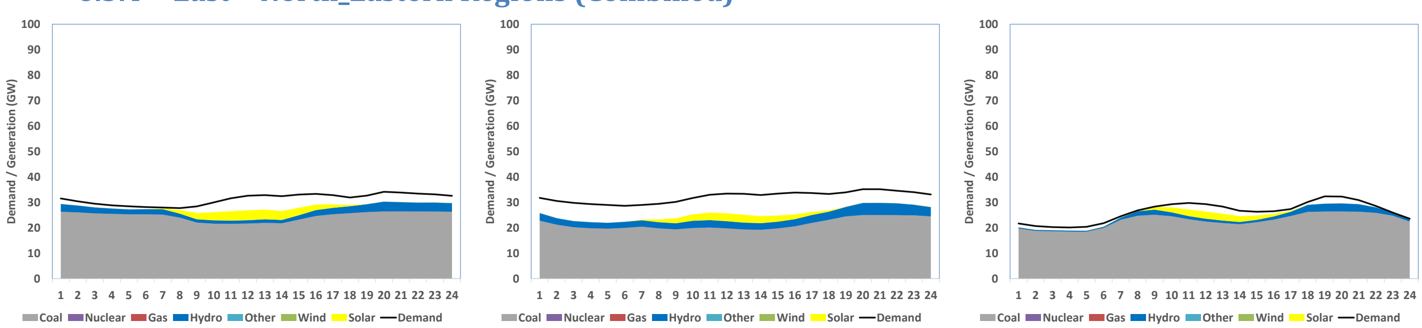
### 6.3.3 Northern Region




**(a) Summer** **(b) Monsoon** **(c) Winter**

**Figure 50: Average Regional Hourly Dispatch in the Northern Region by Season in FY 2022 (RE Missions Scenario)**

### 6.3.4 East + North_Eastern Regions (Combined)




**(a) Summer** **(b) Monsoon** **(c) Winter**

**Figure 51: Average Regional Hourly Dispatch in the Eastern and North-Eastern Region by Season in FY 2022 (RE Missions Scenario)**

### 6.3.5 Inter-Regional Transmission Flows

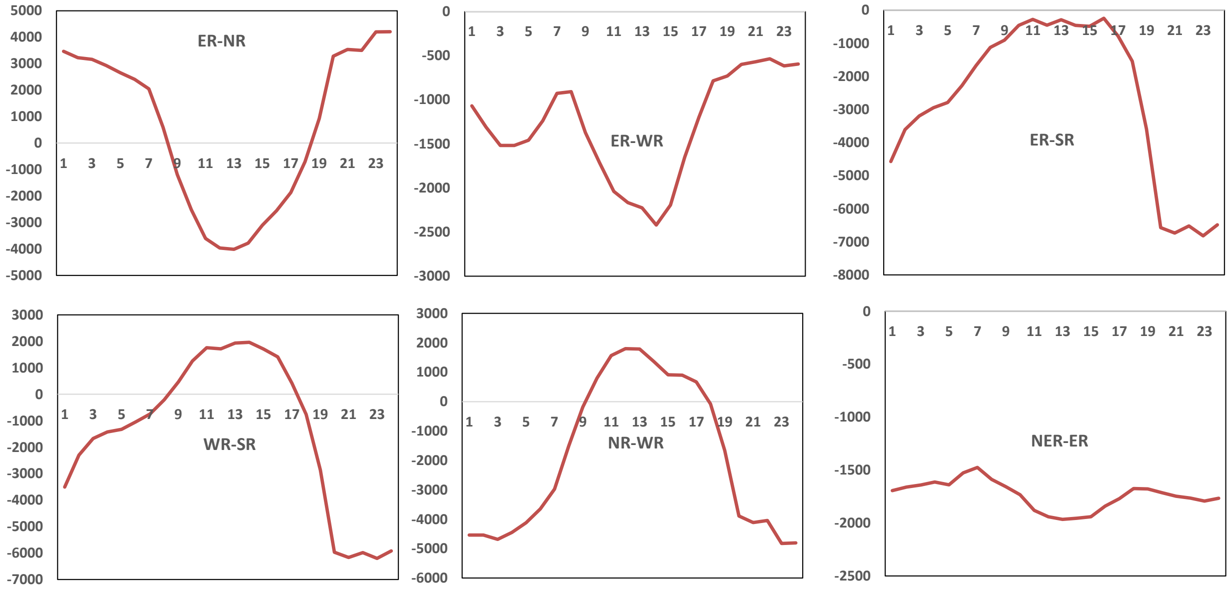



Figure 52: Average Hourly Inter-Regional Transmission Flows during Summer in FY 2022 (RE Missions Scenario)

Note: Sign of the flow indicates the direction. For example, East to North would be counted as positive flow while North to East would count as negative.

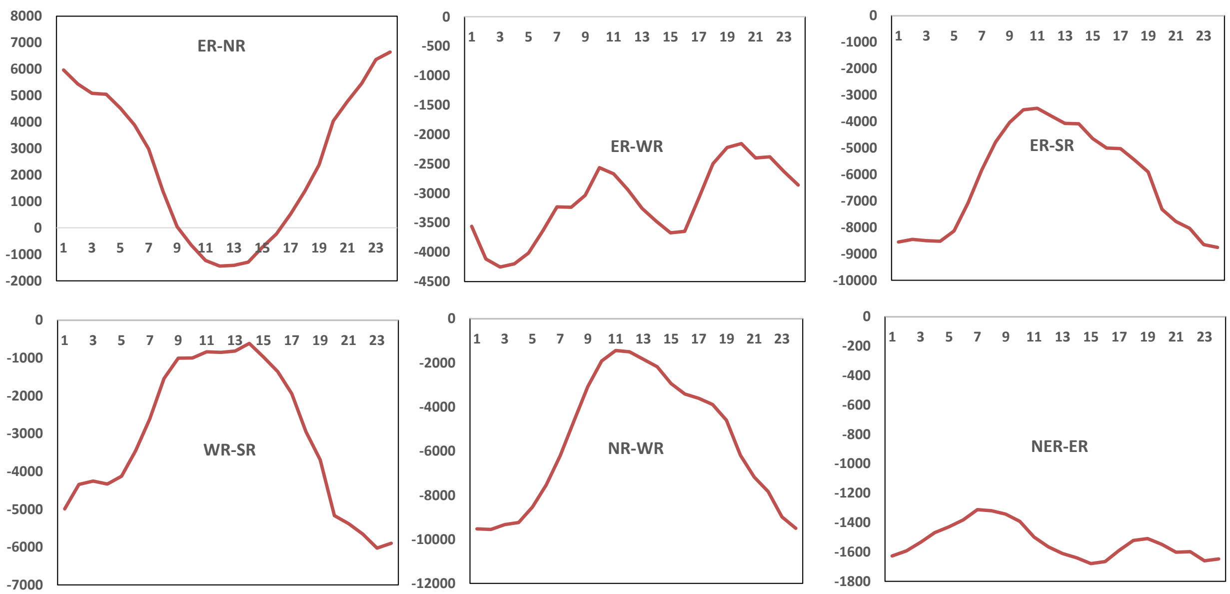



Figure 53: Average Hourly Inter-Regional Transmission Flows during Monsoon in FY 2022 (RE Missions Scenario)

Note: Sign of the flow indicates the direction. For example, East to North would be counted as positive flow while North to East would count as negative.

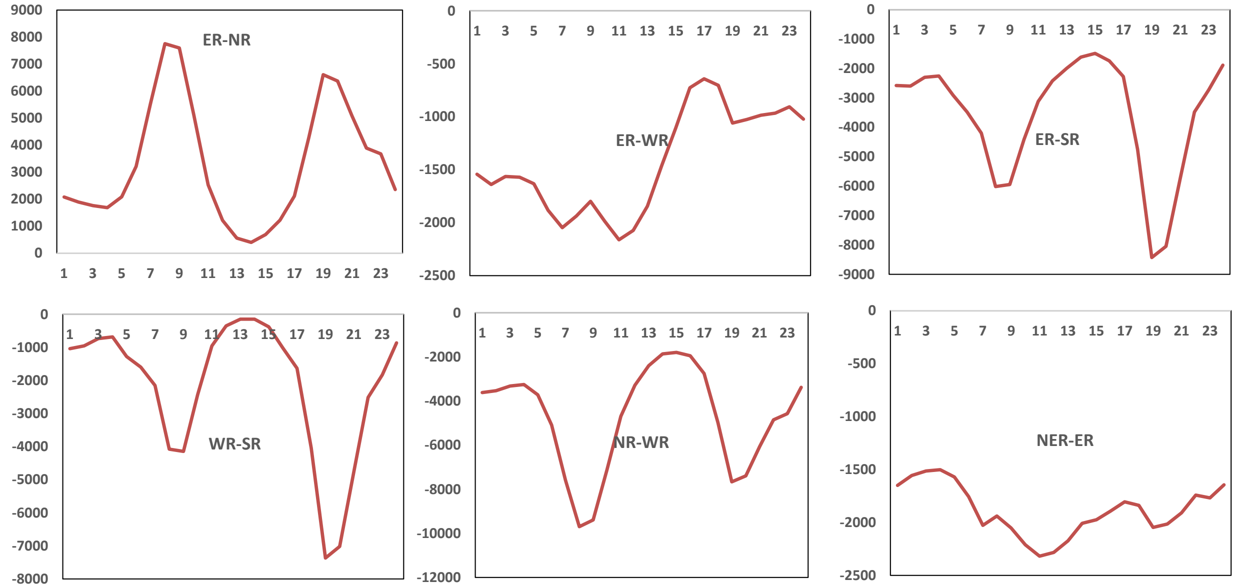
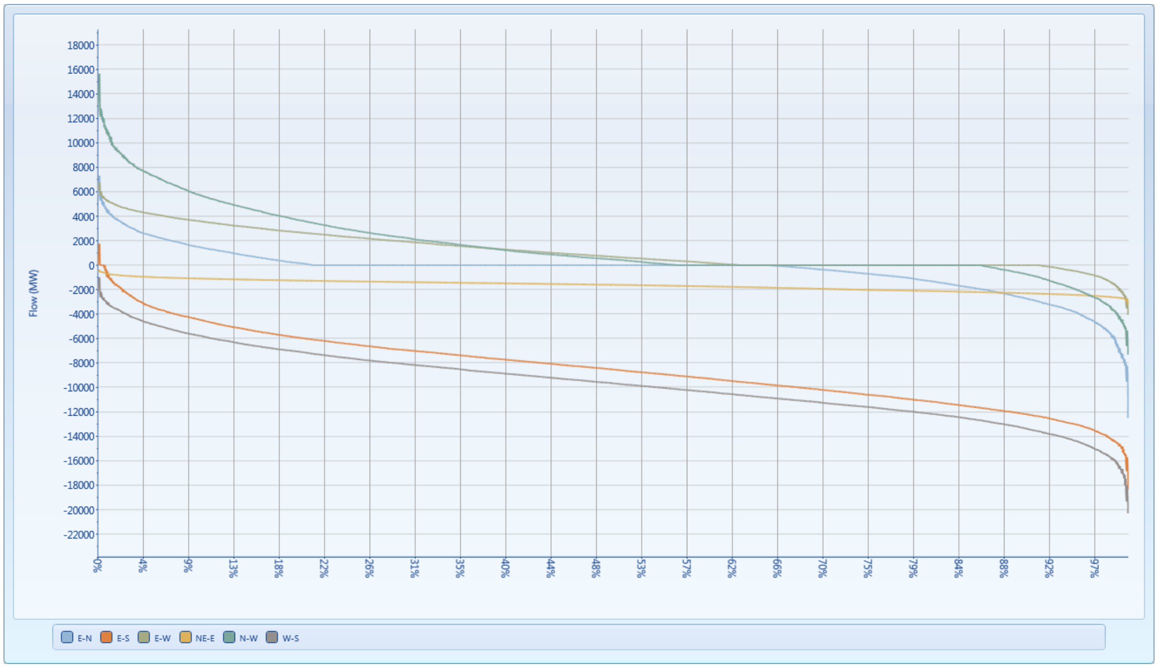



**Figure 54: Average Hourly Inter-Regional Transmission Flows during Winter in FY 2022 (RE Missions Scenario)**

Note: Sign of the flow indicates the direction. For example, East to North would be counted as positive flow while North to East would count as negative.

### 6.3.6 Inter-Regional Transmission Duration Curves



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The 21st Century Power Partnership aims to accelerate the global transformation of power systems.

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