A System level Framework for Evaluating High Share of Renewables in the Future Energy Mix

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***Abstract* - Keeping in view India's recent international commitment to expand the share of renewable electricity to 40% of total generation by 2030, this paper proposes a framework for planning and addressing the implications of high share of renewables in the energy portfolio. Of the planned capacity addition target of 175 Giga Watt (GW) for renewables, wind and solar energy sources form a predominant share of 160 GW. These sources are inherently intermittent in nature. For effective integration of these sources, a system-level framework is required to understand the impact – in terms of resource availability, land utilization, technology options, economics, evacuation infrastructure and the need for storage.**

There are multiple stakeholders involved in the planning and implementation of policies, both at the state and central levels. This framework will aid stakeholders to envision the impact of varying the share of renewables in the future energy mix over the medium to long-term period. Additionally, it can test specific policy levers to plan for a high share of renewables (up to 100%) in the energy mix. The framework is expected to facilitate the decision making process by incorporating inputs from multiple energy and power sector entities, thereby providing an integrated visual representation of the current and future energy situation in India. This framework is demonstrated for the state of Karnataka.

Keywords— Decision Support framework, Renewable Integration, Policy levers, Intermittency

INTRODUCTION

Recently, the Government set a national target for renewable energy as 175 GW by 2022, which is expected to include 160 GW of wind and solar capacity. The draft Karnataka Renewable Energy Policy 2014-20 [1] envisages a minimum non-solar renewable capacity addition of 3600 MW by 2020 in a phased manner.[1] Further, the Karnataka Solar Policy, 2014-21 [2] targets a minimum grid connected and rooftop solar capacity addition of 2000 MW by 2021.

In order to meet the ambitious national and state level targets for wind and solar capacity addition, there are several factors that need to be considered in the planning stage. These include land and resource availability, proximity to a robust grid framework, must-run status of plants, and available backup generating capacity to meet the hourly demand when wind and solar output is low.

Renewable sources are intermittent sources of generation and exhibit seasonal as well as diurnal variability. Fluctuations of high magnitude are observed in wind generation at sub-hourly levels. For an installed capacity of 1,800 MW in August, 2011 it was observed that there was loss in generation of the order of 100 – 150 MW (5 - 8% of installed capacity) within 15 minute time intervals [3]. This poses serious problems to grid operators and the utility to manage the intermittency.

In this context, power sector stakeholders are often faced with the challenge of identifying suitable strategies to mitigate the intermittency and supply-demand mismatch as a result of increasing penetration levels of renewables in the generation mix. The stakeholders typically include Karnataka Electricity Regulatory Commission (KERC), Karnataka Power Corporation Ltd. (KPCL), Karnataka Power Transmission Corporation Ltd. (KPTCL), State Load Dispatch Centre (SLDC), and Electricity Supply Companies (ESCOMs).

Going forward, there is a need to engage in dialogue with potential stakeholders to discuss the country's future energy situation (especially in the context of increasing penetration of renewables). To enable the same, this paper describes an analytical decision support framework to visualize the impact of different policy levers and energy strategies, particularly focusing on the state of Karnataka.

DECISION SUPPORT FRAMEWORK

The framework is designed to provide the capability for incorporating user-specific inputs to aid in decision making at multiple levels. This will be carried out via visualization of the impact of different policy levers on key decision criteria. The objective of the framework is to enable engagement with stakeholders through various stages of a planning process to incorporate their constraints, thereby factoring complexities which are representative of reality. Figure 1 shows a schematic representation of the analytical framework.

[1] Sources include wind, small hydro, biomass, co-generation, and municipal solid waste

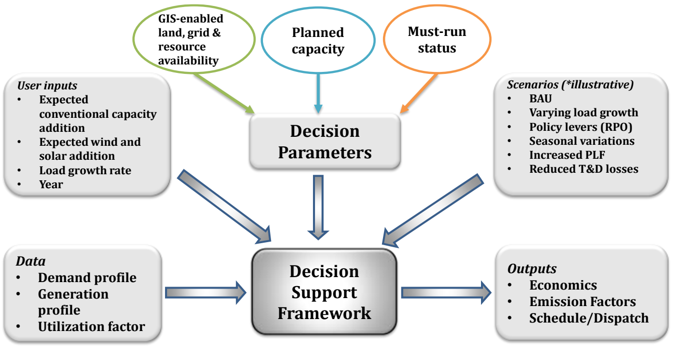

Figure 1: Schematic representation of the Decision Support Framework

Steps 1 through 6 below describe the various stages of the planning process as modeled in the framework:

Step 1-User Input Parameters: This step will allow a decision maker to input key parameters related to existing plans of capacity addition across different sources and the year for which multiple stakeholders would like to envision the impact of adding renewables. User inputs on annual load growth rate and year are used to project energy demand in that year. The load growth rate could be varied to project different demand scenarios.

Step 2-Location siting: The potential locations for installing wind and solar plants can be identified based on Geographical Information Systems (GIS) based assessment of resources and energy infrastructure planning. Selection of a good site for installation of renewable capacities is a crucial aspect and depends on a variety of decision parameters, such as, land availability, resource availability, proximity to road network and electric grid. For instance, as shown in Figure 2, the user can choose to distribute the wind capacities according to the land availability at different hub heights.

Step 3-Supply-demand curve: Based on the generation mix input in Step 1, the model will project a typical load curve for the user-defined year. This is done assuming that current variations in the load and wind/solar generation will apply to the projected load and wind/solar availability. The magnitude of load will increase based on the user-specified growth rate in Step 1. However, the framework will allow for flexibility to incorporate uncertainties in the projected load and generation with appropriate methodologies.

Wastelands suitable for wind power		Agricultural lands suitable for wind power	
Area (sq. km)	8,676	Area (sq. km)	87,362
Potential (MW)	34,133	Potential (MW)	12,900

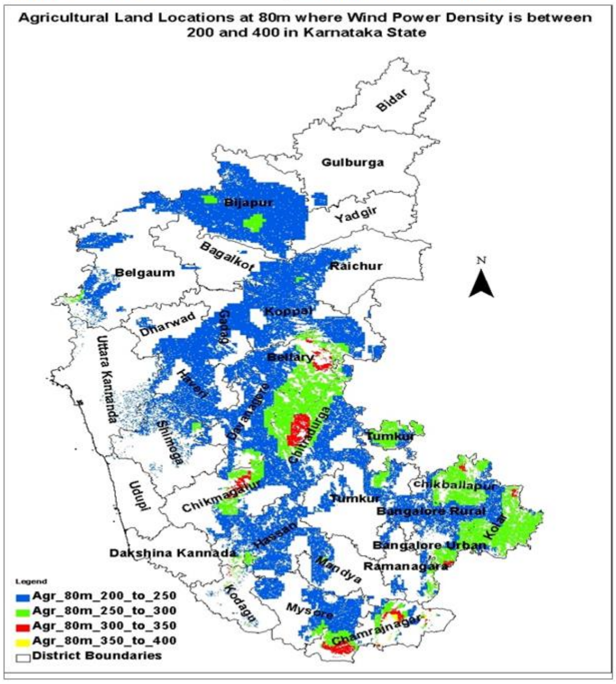

Figure 2: Wind Location Siting

For instance, the intermittency of wind generation for a planned installed capacity can be seen in parallel with the variation in load demand, as shown in Figure 3. Typical of seasonality associated with wind generation, the installed capacity may be adequate to meet anticipated demand more adequately in the monsoon months.

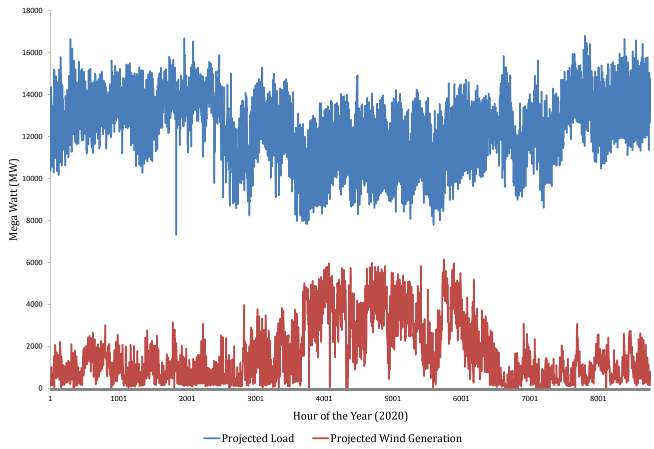

Figure 3: Projected Load vs. Projected Wind in 2020

Step 4-Daily Load Pattern: The user will be able to visualize the sub-hourly/diurnal variations in generation profiles based on trends of historic patterns, for a typical day, as illustrated in Figure 4. This information will also help decision makers to evaluate the complementarity of wind and solar resource profiles, as well as estimate the need for fast-ramping and flexible generation options in order to manage intermittency arising from wind and solar integration. Additionally, the framework will allow for flexibility to analyze the variations at user-specified (e.g. 15 minute intervals).

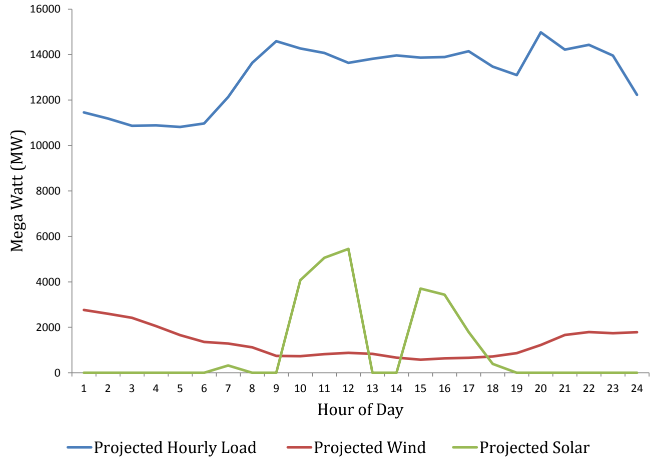

Figure 4: Projected Hourly Load vs. Projected Wind and Solar for a typical summer day in 2020

Step 5-Hourly demand vs supply schedules: The user will be able to visualize an hourly load schedule of sources for the planned generation mix in the year of interest at a preliminary level (Figure 5). The supply-demand mismatch can be evaluated for a best and worst-case scenario of days with good and poor resource (wind/solar) availability. The decision maker can foresee the possibility that, even if annual aggregate demand is met by an addition of wind or solar-based capacity in the generation mix, the sub-hourly variations in wind or solar power output may still result in shortfalls. The schedule can be modeled with real-world constraints of stakeholders, such as uncertainties in Central Generation Stations (CGS) imports, lack of flexibility in reducing base load from coal generation, and the impact of adding storage at the utility level.

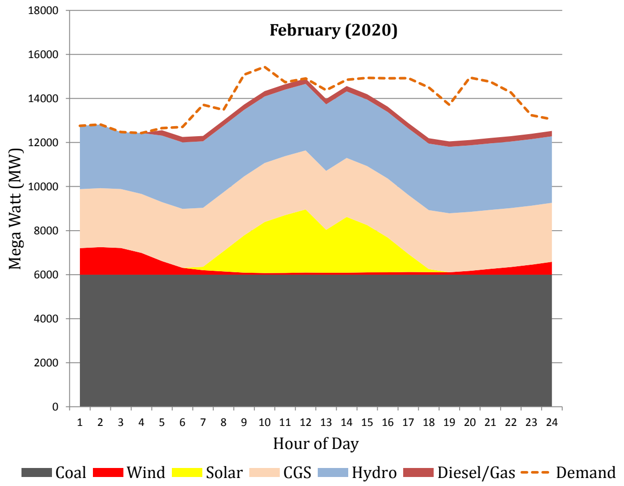

Figure 5: Projected Hourly Load Schedule for a typical day in February, 2020

Step 6–Output: Based on the input parameters and load schedule analysis, this step will quantify the impact of adding wind and solar based capacities to the generation mix on key decision criteria of availability, cost, and emissions.

DATA AND ASSUMPTIONS FOR BASE CASE

The following data and assumptions have been considered to set up the base case:

Demand

- 2011 is used as the base year for estimating hourly load projections
- Yearly rate of growth of demand is assumed to be a Compounded Annual Growth Rate (CAGR) of 7.9% based on Karnataka's actual growth of demand from 2012 to 2015 and estimated growth of demand from 2016 to 2020 [4].

Supply

- Conventional sources used for the analysis include coal, hydro, gas, diesel, and state's share in CGS
- Planned installed capacity for conventional sources is obtained from KERC. As a conservative estimate, it is assumed that plans would achieve partial completion based on historic trends. Hence, it is assumed that 70% of coal, gas and diesel each and 50% of CGS would be commissioned. It is assumed that 100% of planned hydro plants will be available for generation
- As intermittent sources are of primary interest for this analysis, only wind and solar capacity addition is considered from renewable sources
- Wind and solar capacity addition is based on capacity addition plans of KREDL/Government of Karnataka (GoK)

Table 1 below shows the current and planned capacities for sources used in the analysis:

Table 1: Current and Planned Capacity (MW)

Sources	**Current (2015)**	**Planned (2020)**[2]
Coal (State & Pvt)	5,380	2,390
Hydro	3,674	302
Gas	0	840
Diesel	226	0
CGS	2,258	2,181
Conventional (Total)	11,538	5,713
Wind	2,086	825
Solar	91	500

Source: PCKL, KERC

T&D Losses

T&D loss is assumed to be 21% based on current status as per KPTCL.

[2] Based on yearly plans for user-specified year of interest; illustrated here for 2020

Hourly demand vs supply schedule

- Annual average Capacity Utilization Factors (CUFs) have been considered for coal, hydro, gas, diesel and CGS.[3] Monthly CUFs have been used to estimate generation from hydro.[4] Hourly CUFs have been used to estimate generation from intermittent sources of wind and solar.[5]

- Load schedule is created as per the following order:
  1- Available coal, wind and solar
  2- CGS
  3- Must-run hydro
  4- Hydro and gas, to the extent available, have been used as levers to meet anticipated peak shortfalls as these sources can be dispatched flexibly.

- Coal is not backed down during monsoon months.

SCENARIO ANALYSIS AND DISCUSSIONS

In this section, the following policy scenarios are analyzed for 2020 using the decision support framework:

Scenario 1: Current Plans (BAU scenario)

As per the assumptions listed in the previous section, it is anticipated that there would be an energy requirement of 109 Billion Units (BU) with available generation/supply of 87 BU, resulting in an overall shortfall of 20% in the BAU scenario.

Maximum wind resource is available from July to September, while it is typically low from January to March. Hence, projected load schedules have been illustrated for 2 typical days in January and August (Figures 6 & 7). In the projected year, shortfalls observed are spread across nearly 6,600 hours. The maximum shortfall is observed to be 5,720 MW for January. Wind generation increases by nearly 45% during the monsoon months. Hence, the shortages are relatively lower in August.

If coal is backed down by 25% during the monsoon months due to increased hydro availability, a number of hours of shortfall across the year increases to 7,300 hours from 6,600 hours and the maximum amount of shortage is still observed in January.

[3] Coal (67%), Gas (30%), Diesel (30%), CGS (80%) (Source: CEA, KERC, and NITI Aayog)
[4] Monthly hydro CUFs are derived from daily generation data obtained from KPTCL for 2011
[5] Hourly CUFs for Wind and Solar are derived from daily generation data obtained from KPTCL for 2011

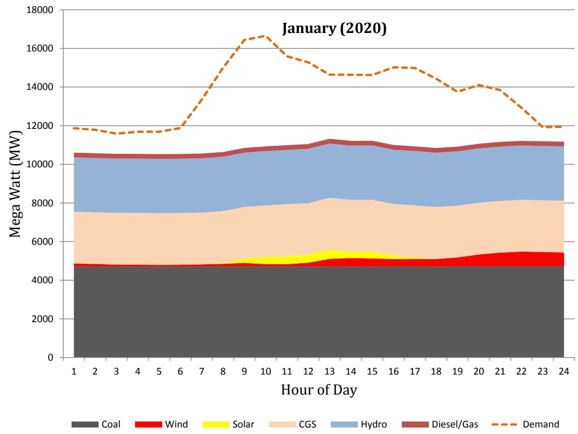

Figure 6: Projected Hourly Load Schedule for a typical day in January, 2020 (BAU)

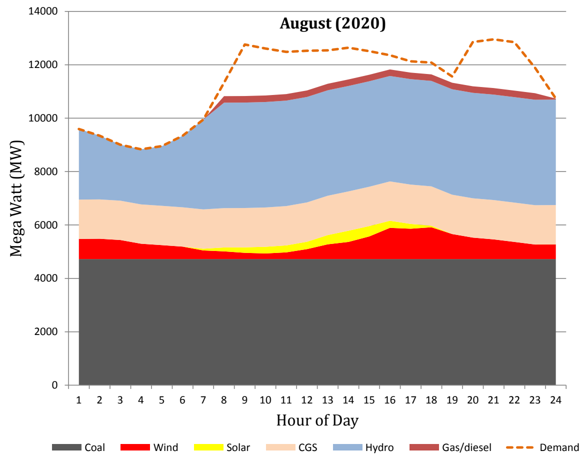

Figure 7: Projected Hourly Load Schedule for a typical day in August, 2020 (BAU)

Scenario 2: Increased Coal Plant Load Factor (PLF)

The PLFs of state-owned thermal power plants have remained low (around 63 – 66%) over the recent years in Karnataka. This may be due to a shift from the usage of washed coal to unwashed coal, frequent equipment failure and coal availability challenges. If appropriate measures to address the same are taken, PLF can be improved to about 85%.

An increase in PLF of state coal plants from current levels by 20% could reduce the number of hours of shortfalls by about 32% from the BAU case, and result in additional generation of nearly 11,100 MUs annually from the planned capacity.

Scenario 3: Reduced T&D losses

In Karnataka, the T&D losses have ranged from 16% to 25.5% across the five ESCOMs in 2014, which results in an average loss of nearly 21% for the state[6]. If appropriate measures are taken to reduce these losses to 12%[7], savings of up to 11,000 MUs will be achievable in terms of energy requirement.

In this scenario, the total number of hours of shortage reduces to 4,450 hours as compared to 6,600 hours in the BAU case. For a typical day in August, wind and hydro (as a lever) availability is adequate to meet the projected peak demand for most of the day, except during the morning and evening peak hours (9 am to 1 pm and 8 pm to 11 pm) (Figure 8).

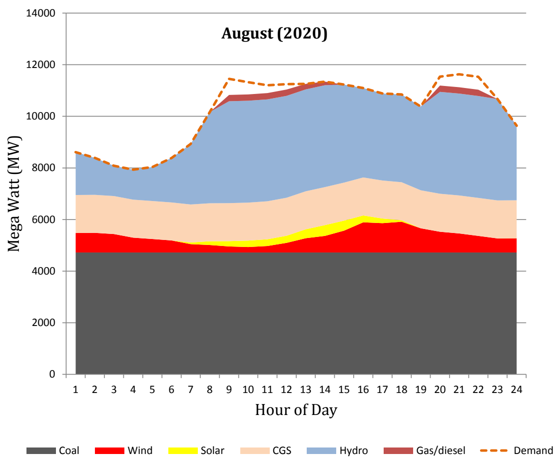

Figure 8: Projected Hourly Load Schedule for a typical day in August, 2020 (Reduced T&D losses)

Scenario 4: Renewable Purchase Obligations (RPO) trajectories

At present, ESCOMs are obligated to purchase 0.25% of their projected energy requirement from solar-based generation sources and 7 - 10% from non-solar based renewable generation sources of wind, biomass, and small hydro [8]. However, the Ministry of New and Renewable Energy (MNRE) plans to revise the RPO targets to achieve procurement of 10.5% of the demand in 2022 from solar-based generation [9]. Further, it is estimated that up to 30% of generation of the state can be met by renewable sources by 2030 [10]. Considering generation from a 10.5% solar-RPO target by 2022, we examine the possibility of meeting the remaining generation requirement for achieving a total of 30% generation from renewables by 2030 from wind sources, as the state has the wind potential necessary to meet the same. This translates to about 14.1 GW of wind and 16.7 GW of solar-based capacity to be added by 2020.

Based on the assumptions mentioned above, the total number of hours of shortage significantly reduces to about 790 hours as compared to 6,600 hours in the BAU case. Further, a surplus situation is observed for about 4,000 hours of the year. Since wind resource is concentrated in a few southern and western states, this opens up the possibility of exporting the surplus energy to neighbouring states through appropriate power purchase mechanisms.

As can be observed in Figures 9 and 10, for a typical day in the monsoon month of August, peak demand is fully met, with a potential surplus of nearly 9,280 MW. On the other hand, for a typical day in the month of February the evening peak demand may remain unmet even with a surplus generation from solar during the day. Hence, options for utilising surplus generation from ambitious wind and solar RPO targets, for powering storage and fast ramping sources (such as pumped hydro) could be explored in order to meet peak demand.

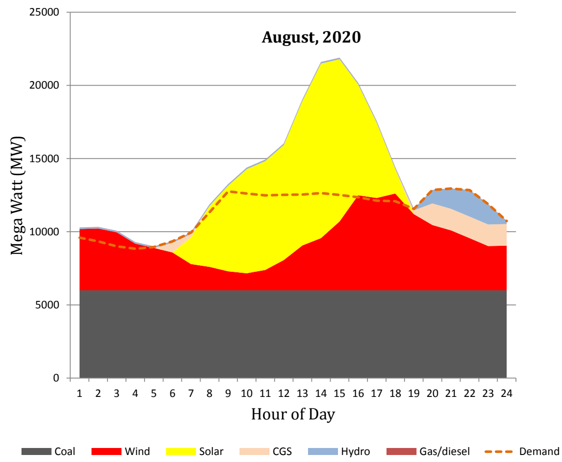

Figure 9: Projected Hourly Load Schedule for a typical day in August, 2020 (RPO trajectories)

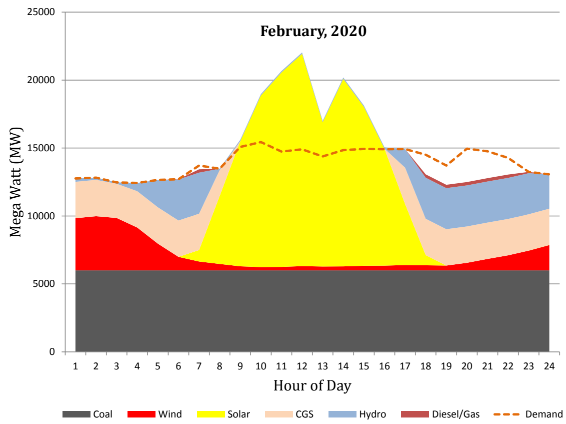

Figure 10: Projected Hourly Load Schedule for a typical day in February, 2020 (RPO trajectories)

Scenario 5: Maximum Wind Capacity Addition

In this scenario, we examine the impact of realizing the full wind potential in the state. As per MNRE's recent reassessment of wind power potential for a higher turbine hub height of 100

[6] By adding 3.8% of Transmission loss [5] to ESCOM-wise distribution loss reported by KERC for 2014 [6]

[7] Based on lowest T&D losses in the state of Pondicherry for 2011 [7]

m, up to 55 GW of wind potential is available to be harnessed in waste and agricultural land in Karnataka. If this potential is assumed to be fully tapped, along with BAU plans for solar capacity addition, the number of hours of shortage during 2020 would reduce to nearly 680 hours.

However, as seen in Figure 11, during a typical day in the month of February (when wind availability is lower compared to the monsoon season), it would result in shortfalls during the day (8 am to 8 pm) while there is surplus power available during the night (1 am to 5 am). Hence, there is a need to optimally plan and schedule wind and solar generation, by taking into account any complementarity between the two resource profiles. This would enable their individual diurnal variations to be averaged out to a more manageable level, in order to meet the demand throughout the day.

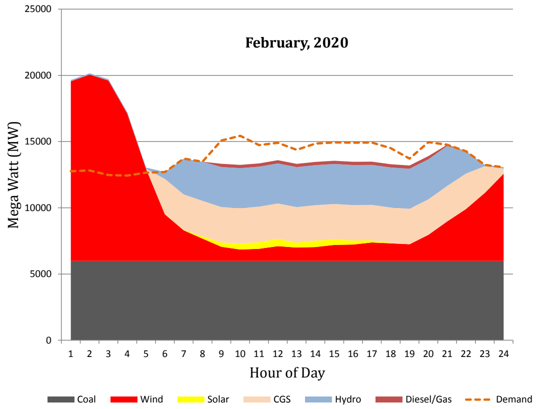

Figure 11: Projected Hourly Load Schedule for a typical day in February, 2020 (Max Wind)

KEY RESULTS

Table 2 presents the key results of evaluation of various scenarios, in terms of their impact on the decision criteria of average grid emission factor, average cost of generation, and number of hours of shortages. The current emission factor and cost of power of the grid is estimated to be 0.68 kg.CO_2/kWh and INR 3.06/kWh respectively.

Table 2: Key Results of Scenario Analysis

		Average Grid Emission factor [11] (kg.CO_2/kWh)	Average Cost of Power (INR/kWh)[8]	No. of hours of shortage
Scenarios	1	0.60	2.92	6,596
	2	0.67	3.03	4,482
	3	0.62	2.94	4,451
	4	0.47	4.27	789
	5	0.36	4.07	683

[8] KERC, [12], state reverse bids received for grid-connected solar projects

As can be seen from Table 2, high wind and solar capacity addition scenarios (4 and 5) results in the maximum reduction in emissions factor (up to 47%) and shortages.

The load demand in the previous section is determined based on a CAGR-based growth of demand. Table 3 below compares the supply availability resulting across multiple demand forecasts:

Table 3: Demand Forecast Methods and Supply Availability for 2020

Demand Forecast Basis (for 2020)	Load Growth Rate (%)	No. of hours of shortage	Max. shortage (MW)	No. of hours of surplus
18th EPS	7.0	7,371	7,420	0
Gross State Domestic Product (GSDP)	5.5	154	1,407	159
Employment Alignment (EA) Scenario II (a)	5.3	72	1,152	209

Note: In the GSDP-based estimate, the elasticity of electricity consumption with Karnataka's GSDP is used to project the future demand

In the EA scenario estimated by GoK [13], it is assumed that GSDP grows to 10.3% by 2022. This is based on net annual movement of 3, 20,000 workers out of agriculture sector, and a net annual movement of 2, 20,000 and 5, 00,000 workers into industry and services sectors respectively.

As can be seen above, the choice of demand methodology has a significant impact on the decision criteria. Uncertainties are inherent in demand forecasts depending on the choice of methodology. Hence, the framework can be used to inform planners of the range of outcomes possible from various demand estimation methodologies.

For increasing rates of growth of demand, it is observed that beyond 13%, a constant shortage situation could be anticipated throughout the year (Figure 12).

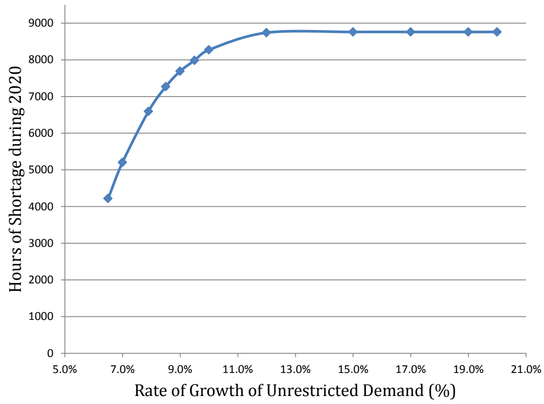

Figure 12: Sensitivity of Anticipated Shortages to Rate of Growth of Demand

CONCLUSION

The current installed capacity in Karnataka is predominantly from thermal and large-hydro sources (contributing to nearly two thirds of the capacity). These conventional sources form the base load for meeting energy demand. However, there are challenges associated with securing long-term fuel linkages for coal plants, uncertainties in price variability of fuels, and high emissions from thermal generation. Hence, it is expected that rapid capacity addition from renewable sources would be required to meet the growing demand, as reflected in state plans. Further, the large-hydro potential in the state is almost fully utilized, thus limiting its contribution to base load going forward.

In this context, a holistic framework would provide the decision makers with the ability to envision the impact of high penetration of renewables in the energy mix in the medium to long terms. This can be done taking into account real-world constraints in the planning process, such as uncertainties regarding the state's future share in CGS, and must-run regulations for some sources. It would help to engage individual stakeholders in constructive dialogue regarding key decision parameters as it enables them to jointly visualize the outcome of specific policy levers. The current analysis does not consider uncertainty in demand projections and generation profiles. However, for future use, the framework can include inputs from alternate methodologies of demand estimation, and stochastic generation profiles. This would aid in planning for optimal capacity in order to minimize mismatch between demand and supply. Considering that there is also a national commitment to provide 24x7 Power for All by 2019 [14], such a framework can help state level stakeholders to plan for reliable supply of power.

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