Flexible Resources Initiative of the

U.S.-India Clean Energy Finance Task Force

Least Cost Pathway for Power Sector Investments in Karnataka through 2030

Submitted to

Lawrence Berkley National Laboratory

BERKELEY LAB
Bringing Science Solutions to the World

Prepared by

Idam
Idam Infrastructure Advisory Pvt. Ltd.
An ISO 9001:2015 Certified Company

February 2023

Disclaimer

This report is prepared by Idam Infrastructure Advisory Pvt. Ltd. (Idam Infra) and is primarily based on information available from primary and secondary sources. Idam Infra has taken due care and caution in compilation of data as has been obtained from various sources which it considers reliable and first-hand. However, Idam Infra does not guarantee the accuracy, adequacy or completeness of any information and is not responsible for errors or omissions or for the results obtained from the use of such information, and especially state that they shall have no financial liability whatsoever to the subscribers/users of this report. No part of this report can be reproduced, stored in a retrieval system, used in a spreadsheet, or transmitted in any form or by any means without the permission of Idam Infra. While performing the work, the genuineness of all signatures and the authenticity of all original documents is assumed. The correctness or authenticity of the same has not been independently verified.

In connection with our report or any part thereof, Idam Infra does not owe duty of care (whether in contract or in tort or under statute or otherwise) to any person or party to whom the report is circulated to, and Idam Infra shall not be liable to any party who uses or relies on this report. Idam Infra thus disclaims all responsibility or liability for any costs, damages, losses, liabilities, and expenses incurred by such third party arising out of or in connection with the report or any part thereof.

Table of Contents

List of Figures

List of Tables

Abbreviations

BESCOM	:	Bangalore Electricity Supply Company Limited
CAGR	:	Compound Annual Growth Rate
CEA	:	Central Electricity Authority
CERC	:	Central Electricity Regulatory Commission
DR	:	Demand Response
EPS	:	Electrical Power Survey
GESCOM	:	Gulbarga Electricity Supply Company Limited
HESCOM	:	Hubli Electricity Supply Company Limited
HRECS	:	Hukkeri Rural Electric Co-operative Society
IPP	:	Independent Power Producer
InSGS	:	Intra-State Generating Stations
ISGS	:	Inter-State Generating Stations
KERC	:	Karnataka Electricity Regulatory Council
KPCL	:	Karnataka Power corporation limited
KPTCL	:	Karnataka Power Transmission Corporation
LBNL	:	Lawrence Berkeley National Laboratory
LGB	:	Load Generation Balance
LT	:	Long Term
MESCOM	:	Mangalore Electricity Supply Company Limited
MNRE	:	Ministry of New and Renewable Energy
MSEZ	:	Mangalore Special Economic Zone
O&M	:	Operations & Maintenance
PCKL	:	Power Company of Karnataka Limited
RE	:	Renewable Energy
RoR	:	Run-of-river
SLDC	:	State Load Dispatch Center
ST	:	Short Term
TPC-D	:	Tata Power Distribution
VC	:	Variable Cost
vRE	:	Variable Renewable Energy
yr	:	Year

Acknowledgements

We are thankful to the U.S. Department of State for funding this work. This study would not have been possible without the collaboration with India's Ministry of Power (MOP), Ministry of New and Renewable Energy (MNRE), Central Electricity Authority (CEA), Grid Controller of India Limited (Grid-India), Central Electricity Regulatory Commission (CERC), and Karnataka State's Karnataka State Electricity Commission (KERC) , Karnataka State Load Dispatch Centre(KSLDC), Karnataka Power corporation limited (KPCL), Karnataka Power Transmission Company (KPTCL), Bangalore Electricity Supply Company Limited (BESCOM), Mangalore Electricity Supply Company Limited (MESCOM), Chamundeshwari Electrical Supply Corporation (CESC), Hubli Electricity Supply Company Limited (HESCOM), Gulbarga Electricity Supply Company Limited (GESCOM), and Power Corporation of Karnataka (PCKL).

In particular, we sincerely thank the following individuals for providing helpful and critical reviews and suggestions at each stage of this study: Mr. Ghanshyam Prasad (Chair Person CEA and former Joint Secretary, MOP), Mr. Amitesh Sinha (Former Joint Secretary, MNRE), Mr. Dinesh Jagdale (Joint Secretary, MNRE), Mr. S.R. Narasimhan (CMD, Grid-India), Mr. Praveen Gupta (Chief Engineer, CEA), Dr. Sushanta Chatterjee (Chief Regulatory Affairs, CERC), Mr. Nallarasan (Head NRLDC, Grid-India), Mr. Rajiv Porwal (Grid-India), Mr. Sandeep Naik (Director, MOP), Ms. Esther Kamala (CEA), Ms. Ammi Toppo (CEA), Mr. Apoorva Anand (CEA), Mr. Saif Rahman (Grid-India), Mr. Priyam Jain (Grid-India), Ms. Rashmi Nair (CERC), and Mr. Ravindra Kadam (CERC). We also thank Dr. Hyungkwan Kim and Dr. Jiang Lin of Lawrence Berkeley National Laboratory (LBNL) for their helpful reviews of the report. We thank Mr. Aditya Khandekar of LBNL for his assistance on solar and wind site selection analysis, Idam Infrastructure Advisory Pvt Ltd for the background research on solar panel safeguard duty and variable costs of existing coal power plants, Mr. Alberto Diaz-Gonzalez of LBNL for providing project management support, and Mr. Jarett Zuboy for editorial support. Finally, we are grateful to Ms. Ruth Ku and Mr. Moises Behar of the U.S. State Department for helpful reviews as well as project management to keep this study on track.

The views and opinions expressed in this report are solely of the authors and do not necessarily reflect the views of the organizations and people supporting this work.

The work described in this study was conducted at Idam Infra and is a part of the "Flexible Resources Initiative" (FRI) under US-India Clean Energy Finance Task Force co-led by Department of State, United States and Ministry of Power, Government of India.

Executive Summary

Karnataka has a peak load of 14.4 GW and annual electricity consumption of 68.8 TWh in 2021, which is expected to increase by 78 % by 2030. Karnataka is also a renewable energy (RE) rich state with solar and wind potential of 24.7 GW and 55.9 GW respectively. RE installed capacity in Karnataka is 7.6 GW solar and 5.1 GW wind as on March 2022, with RE contributing to 28.1 % in total electricity generation for FY 22(CEA). As share of RE increases, the system would need more flexible resources to address increased variability and intermittency. The objective of this study is to find the least-cost and operationally feasible resource mix for Karnataka to meet its load reliably through 2030, in sync with the national grid, and by considering key flexible resources such as energy storage and demand response solutions including agricultural load shift as well as flexibility provided by thermal generators and hydro resources. The study uses the latest RE and battery cost data, an industry-standard power system modelling platform (PLEXOS), and exhaustive analytical methods (optimal capacity expansion and power plant-level hourly grid dispatch simulations).

Key Study Findings:

1. **Karnataka's electricity demand by 2030 will largely be met by a generation mix consisting of large amounts of RE and energy storage as well as existing thermal, nuclear, and hydro assets.**

    - **Using the CEA EPS load projections for 2030** (peak load of 29.73 GW and energy consumption of 128.4 TWh/yr by 2030) and limiting the RE capacity addition to 6 GW/yr (three times the historical levels), the **Primary Least Cost (PLC) investment pathway for Karnataka** consists of a combination of 46.5 GW of RE comprising of 24.7 GW_{DC} solar and 21.8 GW wind, 9.2 GW coal (including central sector allocation), 0.7 GW of nuclear, 3.8 GW of hydro, and 5 GW of agricultural and industrial load shifting to solar hours and 2.9 GW of 4-Hrs storage is found to be economical.

    - **Using load forecast by the state utilities / regulator** (peak load of 28.0 GW and energy consumption of 121.0 TWh/yr by 2030), **Primary Least Cost investment** consists of a combination of 60.5 GW of RE comprising of 24.7 GW_{DC} solar and 35.8 GW wind, 9.2 GW coal (including central sector allocation), 0.7 GW of nuclear, 3.8 GW of hydro, and 2.9 GW of 4-hrs battery storage, and 5 GW of agricultural and industrial load shifted to solar hours. Higher limits on RE capacity addition, 8.0 GW/yr results in increase in RE installation by 2030.

    - Limited economic viability of additional energy storage is driven by the following factors:

        a. Large base of existing thermal assets available for ramping and cycling,

        b. Nearly 3GW of dispatchable hydro resources contribute during peak load hours,

        c. 5 GW of agricultural load shifted from night to solar hours reduces the need for additional firm capacity during non-solar hours, particularly late-night / early morning, and

        d. Sharp increase in the afternoon peaking space cooling load resulting in better coincidence with solar generation.

    - **If RE installation continues at the historical rate of 5.1 GW/yr (current policy scenario) and using the 2019 CEA EPS load forecast,** a combination of 40.2 GW of RE**,** comprising of 24.7 GW_{DC} of solar and 15.5 GW of wind, 9.2 GW coal, 0.7 GW of nuclear, 3.8 GW of hydro, and 2.4 GW of 4-Hrs storage is found to be economical.

- **If RE installation increases on higher rate of 8.0 GW/yr and using CEA EPS load projections for 2030,** a combination of 61.5 GW of RE comprising of 24.7 GW_{DC} solar and 36.8 GW wind, 9.2 GW coal, 0.7 GW of nuclear, 3.8 GW of hydro, and 2.4 GW of 4-Hrs storage is found to be economical.
- **Considering 3000 MW of PSH installation by 2030 with CEA EPS load projections for 2030,** a combination of 45.1 GW of RE comprising of 23.4 GW_{DC} solar and 21.8 GW wind, 9.2 GW coal, 0.7 GW of nuclear, 3.8 GW of hydro, and 2.4 GW of 4-Hrs storage is found to be economical. The limits on RE capacity addition, 6.0 GW/yr results in increase in RE installation by 2030.
- The average generation cost in 2030 in the Primary Least Cost Case (EPS) is around 47 % lower than in 2020 owing to the inflation-proof, low-cost RE and improved coal capacity factors for existing units.

Table 1: Installed Capacities by 2030 for Various Scenarios (2020-2030) (GW)

S. No	Technology	Actual (2020)	Primary Least Cost (State load)	Primary Least Cost (EPS load)	Current Policies Scenario	High RE Installation	State Sensitivity
1	Coal (including central sector allocation)	9.2	9.2	9.2	9.2	9.2	9.2
2	Nuclear	0.7	0.7	0.7	0.7	0.7	0.7
3	Hydro	3.8	3.8	3.8	3.8	3.8	3.8
4	Hydro PSH	0.0	0.0	0.0	0.0	0.0	3.0
5	Solar	9.1	24.7	24.7	24.7	24.7	23.4
6	Wind	6.0	35.8	21.8	15.5	36.8	21.8
7	Biomass	2.4	1.0	1.0	1.0	1.0	1.0
8	Small Hydro	0.5	0.5	0.5	0.5	0.5	0.5
9	Battery	0.0	2.9	2.9	2.4	2.4	2.3

- Inflation-proof, low-cost RE are the primary drivers of these results. Agricultural and industrial load shifting from night to solar hours significantly reduces the night-time load and, in turn, the requirement for new base load coal-fired capacity.

2. No new thermal power plant is found to be economical in the state by 2030

- In the Primary Least Cost cases and also in the current policy case, we do not find any new thermal power plant addition in the state to be cost-effective despite near doubling of electricity demand between 2020 and 2030. This is primarily because the load growth is balanced by solar and wind generation. Agricultural load shifted from night to solar hours also reduces the need for additional firm capacity during non-solar hours, particularly late at night and early in the morning. In addition to this, peaking hydro is also supporting to meet the demand.
- By 2030, average utilisation of coal plants drops to 19% from around 45% in 2020. Average utilization for coal power plants with VC > 4 Rs/kWh would be less than 10.2% and that for power plants with VC > Rs 3/kWh would be less than 20 %.

3. Karnataka's electric grid will be dependable even without any new thermal capacity additions

- Existing thermal plants, nuclear, hydro, and RE and energy storage capacity along with import from other states will suffice the load growth of Karnataka by 2030
- Deployment of renewable and flexible resources with new interstate transmission capacity can avoid new thermal power built, while maintaining reliability of the grid.
- Imports from bilateral contracts or wholesale electricity markets and variable monthly PLF of thermal plants can provide seasonal balancing.
- Flexible resources like agricultural shift provide diurnal balancing of the grid.

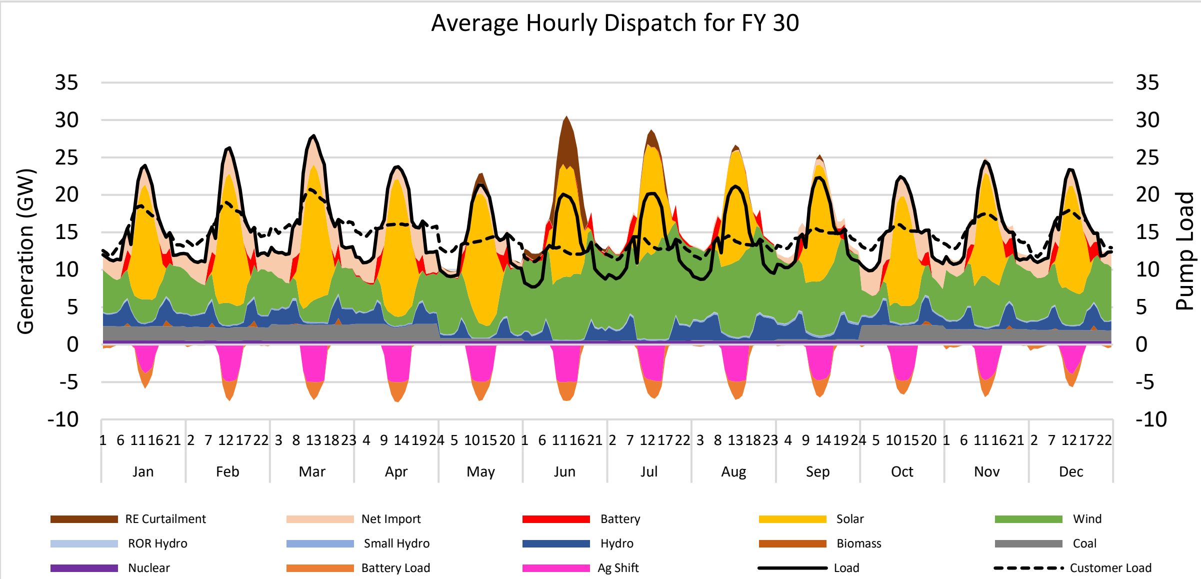


Figure 1: Dispatch in 2030

4. Karnataka is marginal importer in EPS projections and would be net exporter in State projections till 2030

- Though cheaper vRE power generation increases within the State, Karnataka will remain net importer till 2030.
- The state would import 3 TWh out of 128.4 TWh load (2.6%) in EPS projection scenario and would export 38.9 TWh out of 121 TWh load (32%) in State projections scenario as shown in figures below.
- Imports from bilateral contracts or wholesale electricity market, variable operation of thermal plants provides seasonal balancing. The state is net importer majorly throughout the year but becomes net exporter during monsoon (low demand / high wind).
- As cheaper power is available in neighbouring states such as Chhattisgarh, Madhya Pradesh, and Jharkhand, the state imports high energy to meet its energy needs. Moreover, most of the central sector generation plants have a lower VC than state generation plants, so they are dispatched first on merit.
- Import is going to be higher in the EPS projections due to different load profiles and imported power would be high on the merit order.

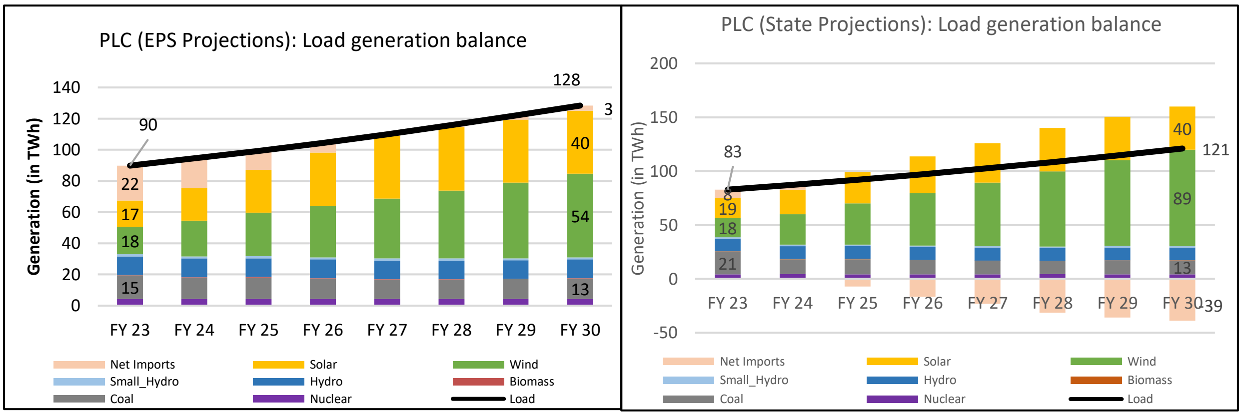


Figure 2: Annual Generation and Load by Resource Type Primary Least Cost (PLC) (EPS Projections) and Primary Least Cost (PLC) (State Projections) FY 2023-30

5. State Level Challenges

- In order to deploy renewable energy at this scale and maintain grid reliability, important new policy and regulatory frameworks would need to be put in place, including resource adequacy, capacity markets, long-term planning, broader and deeper energy markets, etc.

1 Introduction

1.1 Background and Objectives

India has set an ambitious clean energy target for the power sector, namely 175 GW of renewable energy (RE) installed capacity by 2022. In 2021, Prime Minister Modi increased this ambition by announcing a target of 500 GW of installed non-fossil capacity by 2030. India has made rapid progress towards achieving these goals. Between 2015 and 2021, India's renewable energy capacity more than doubled from 40 GW to 100 GW, supplying nearly 28 % of the total electricity generated in the fiscal year 2021-22 (CEA, 2021-22). Over the last decade, India has been successful in achieving some of the lowest RE costs in the world. Between 2010 and 2020, it saw the largest reduction of 85% in country-level solar levelized cost of energy (LCOE), while the average solar tariff in 2020 was 34% lower than the global weighted average. India also had the lowest country-level installed cost for solar and wind in 2020 (BNEF, 2020a).

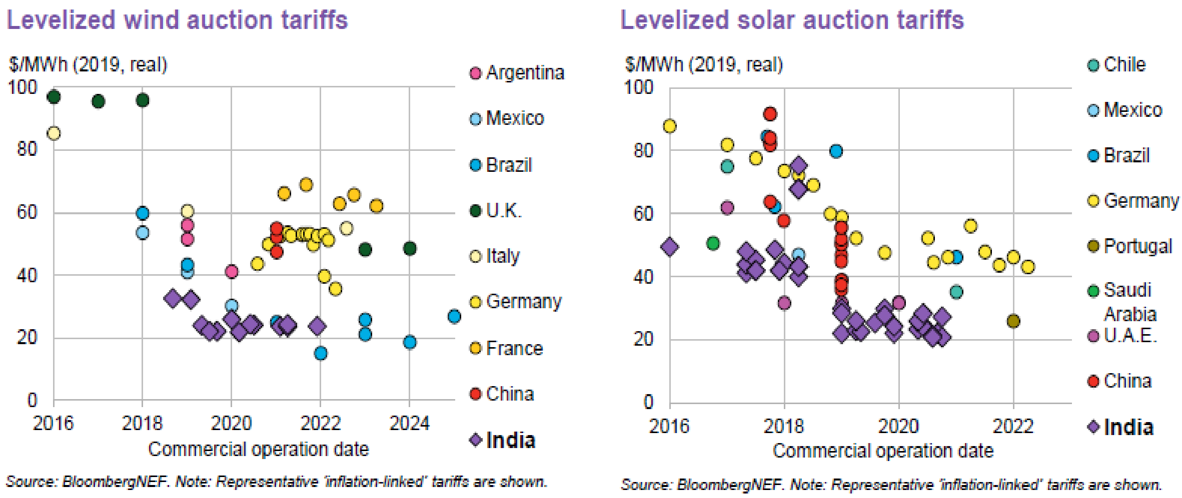


Figure 3: Solar and Wind Energy Prices in Key Countries, incl. India[1]

It is well accepted that renewable electricity costs have dropped below coal costs on a levelized basis. Nonetheless, many countries around the world, including India, continue to invest in new coal power plants primarily because: (a) RE generation is intermittent and may need significant system flexibility for grid integration, (b) RE generation does not coincide with peak electricity demand periods which is in the evening for India, and (c) legacy planning and regulatory frameworks may not fully capture the value and capabilities of RE and energy storage technologies. In this context, the dramatic decline in battery storage costs — 90% cost reduction at the battery pack level since 2010 — could serve as a turning point, because it enables the cost-effective supply of low-cost renewable electricity during peak times (Figure 4). Notably, several large utility-scale RE + storage projects are underway globally and, in several cases, offer electricity generation prices well below that from fossil power plants. For example, a recent solar + storage auction by Los Angeles Department of Water and Power (LADWP) resulted in a combined PPA price of $39/MWh (Rs 3/kWh) for storing over 50% of the solar energy in batteries in 2020.

[1] BNEF (2020a)

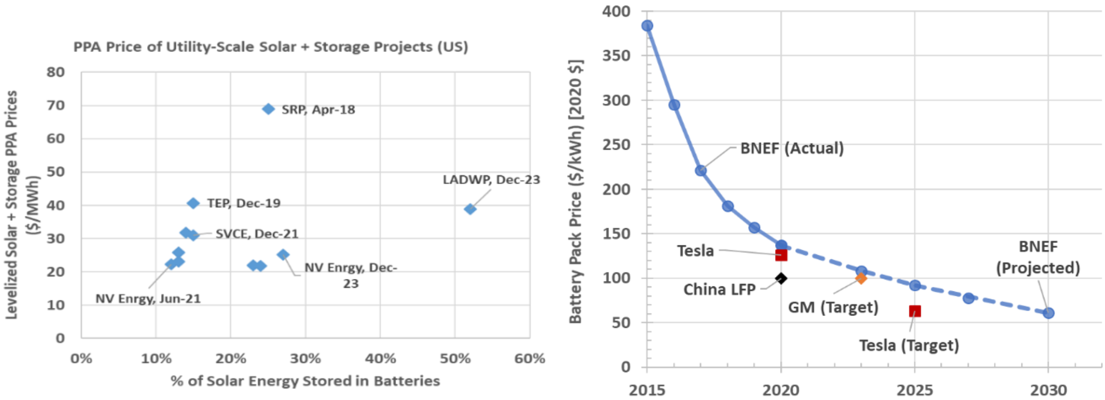


Figure 4: Global Average Battery Pack Price (Left) and Solar + Battery Storage PPA Prices in the United States (Right)

Source: BNEF (2020b) and Deorah, et al (2020)

Indian utilities are also using several other flexible resources such as demand response for integrating renewable energy. Several states (e.g., Maharashtra, Karnataka, and Gujarat) have already started shifting a major part of their agricultural load from nighttime to solar hours (over 6 GW total in 2020). Electricity market reforms in India and demand response also offer some important flexibility options to the grid.

Given that a large part of India's electricity grid infrastructure is yet to be built, such cost reductions offer India a unique opportunity to leapfrog to a more flexible, robust, and sustainable power system. Several recent studies have assessed a similar question (e.g., CEA (2020), NREL (2020 & 2021b), TERI (2020), BNEF (2020a), and IEA (2021)).

Objective of the Study:

The objective of the study is to assess the least-cost resource mix for Karnataka to meet its load reliably by 2030, as it is one of the RE-rich states with solar and wind potential of 64.3 GW and 45 GW respectively (MNRE Statewise Potential) and with installed capacity of only 3.39 GW solar and 5 GW wind as on 30th September 2022. It is one of the leading states in terms of high RE installation. The study majorly focuses on the followings:

- Developing a spatially and temporally resolved capacity expansion and economic dispatch model using an industry standard platform, PLEXOS, that assesses the least cost resource mix at the state level, interstate transmission requirement, and power plant level hourly economic dispatch
- Using the latest renewable energy and storage cost estimates and trends, informed by prices observed in the market, and
- Including demand side resources, in particular, shifting of the agricultural and heavy industry load from night-time to solar hours.

1.2 State Background

Karnataka has five Distribution Companies (ESCOMs) which are Bangalore Electricity Supply Company Limited (BESCOM), Mangalore Electricity Supply Company Limited (MESCOM), Chamundeshwari Electrical Supply Corporation (CESC), Hubli Electricity Supply Company Limited (HESCOM), Gulbarga Electricity Supply Company Limited (GESCOM), one Rural Electricity Co-operative Society Hukkeri Rural Electric Co-operative Society (HRECS) and two special economic zones MSEZ and AEQUS SEZ who are responsible for distribution in the State, out of which BESCOM jurisdiction consumption is around 48%, the highest among all distribution companies. Primary responsibility of power procurement in the state is with Power Company of Karnataka Limited (PCKL) which is the energy trader and is responsible for carrying out capacity addition on behalf of ESCOMs. Further, KPCL is the government owned power generation company of Karnataka whereas Karnataka Power Transmission Corporation (KPTCL) is responsible for transmission.

Karnataka has been able to reduce deficit in peak demand from 6.79% in FY16 to nearly zero in FY22, and decrease deficit in the energy supply from 5.18% in FY16 to nearly zero in FY21. The decrease in energy requirement during 2019-20 and 2020-21 was due to the Coronavirus pandemic which causes major break on industrial production and other services whereas peak demand was same as people were opting work from home for providing services and due to high rush in hospitals, as shown in figures below (CEA[2]):

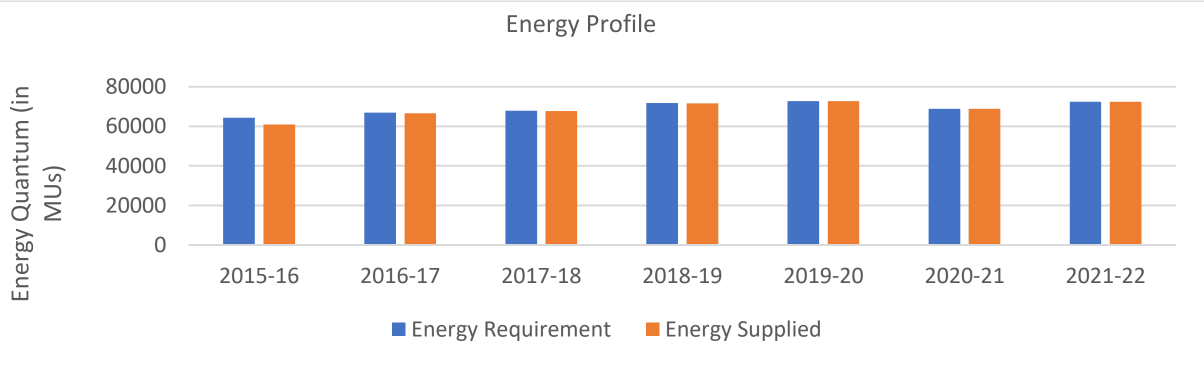


Figure 5: Karnataka Historical Energy Profile

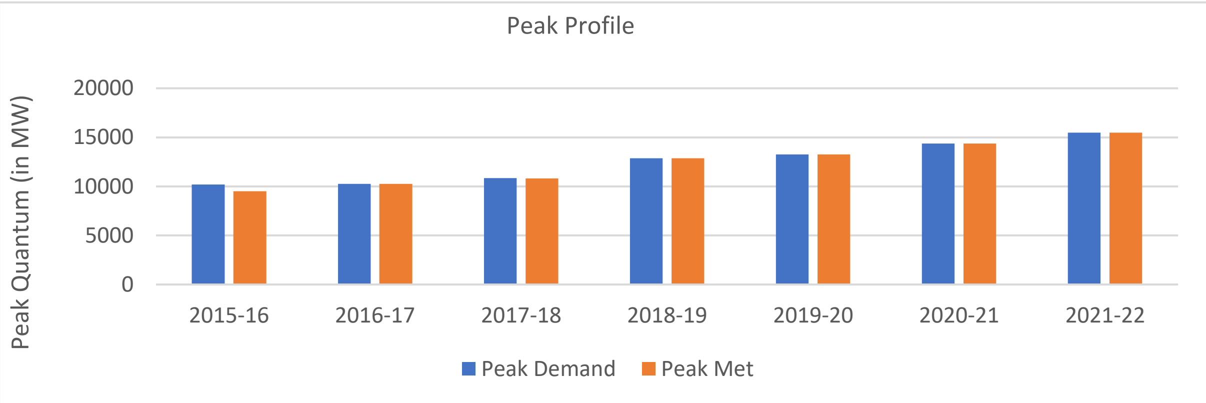


Figure 6: Karnataka Historical Peak Demand Profile

The installed capacity in Karnataka is 29,884 MW as on September 2022. (CEA, September 2022):

[2] (CEA LGBR FY16, FY17, FY18, FY19, FY20, FY21)

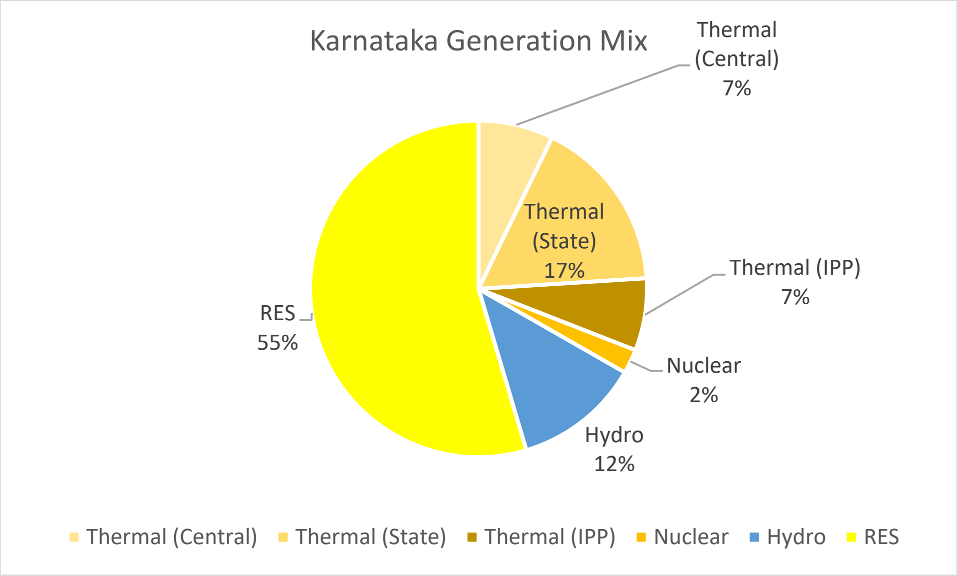


Figure 7: Karnataka State Generation Mix (Sep – 2022)

2 Methods, Data, and Assumptions

2.1 Modelling Philosophy

A capacity expansion model minimizes the total system cost to meet system load considering technical limits of generation, and a production cost model solves the optimal power flow formulation by taking into consideration generation limits and operational constraints such as ramp rates, technical minimum and transmission limits.

PLEXOS is an industry standard tool used in various applications such as Long-Term Capacity Expansion Planning, Production Cost Modelling, Transmission Planning Analysis, Demand Modelling, System Security and Adequacy, Ancillary Services and Energy Co-Optimisation, Optimally Times Maintenance etc.

The capacity expansion model for Karnataka is built on PLEXOS to understand the optimal way to include more RE in Karnataka's system, followed by analysing the production cost for the year 2030 as shown below in Figure 8.

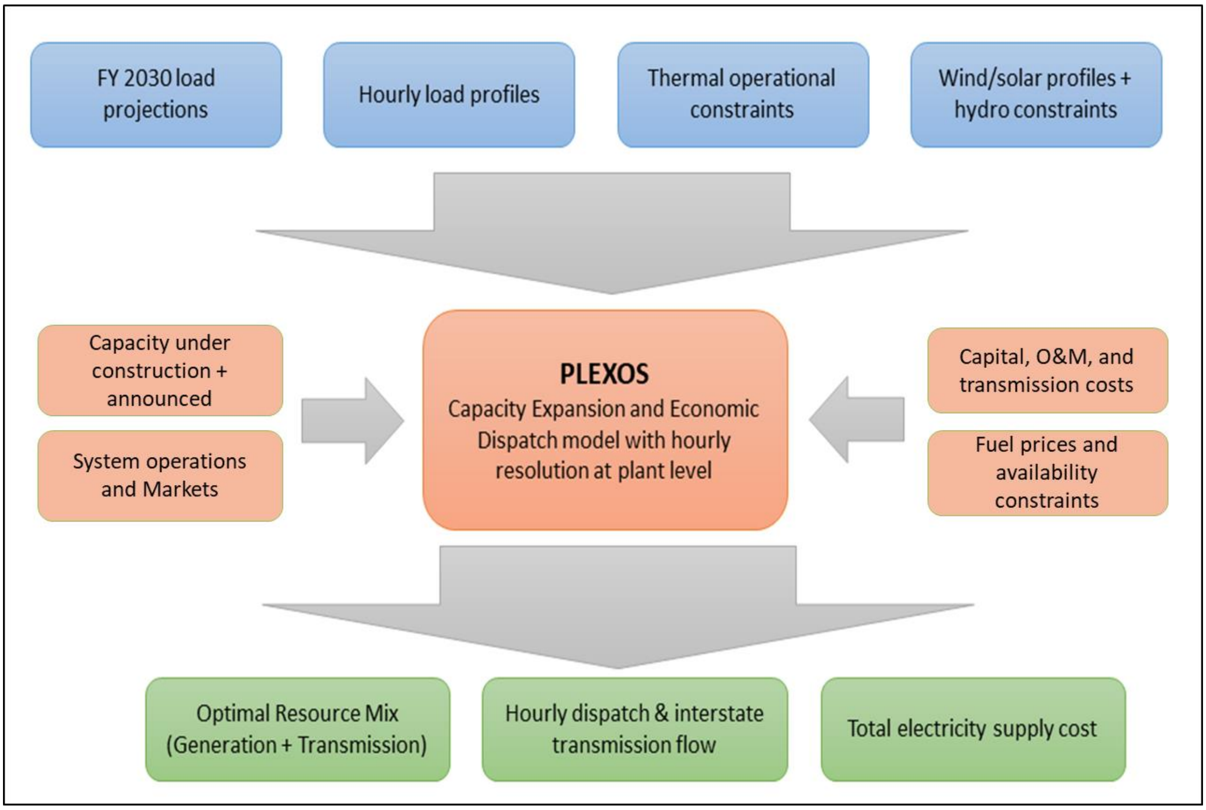


Figure 8: Modelling Philosophy

2.2 Capacity Expansion Model

The capacity expansion model optimizes capital and generation costs and consists of the following stages as shown below in Figure 9:

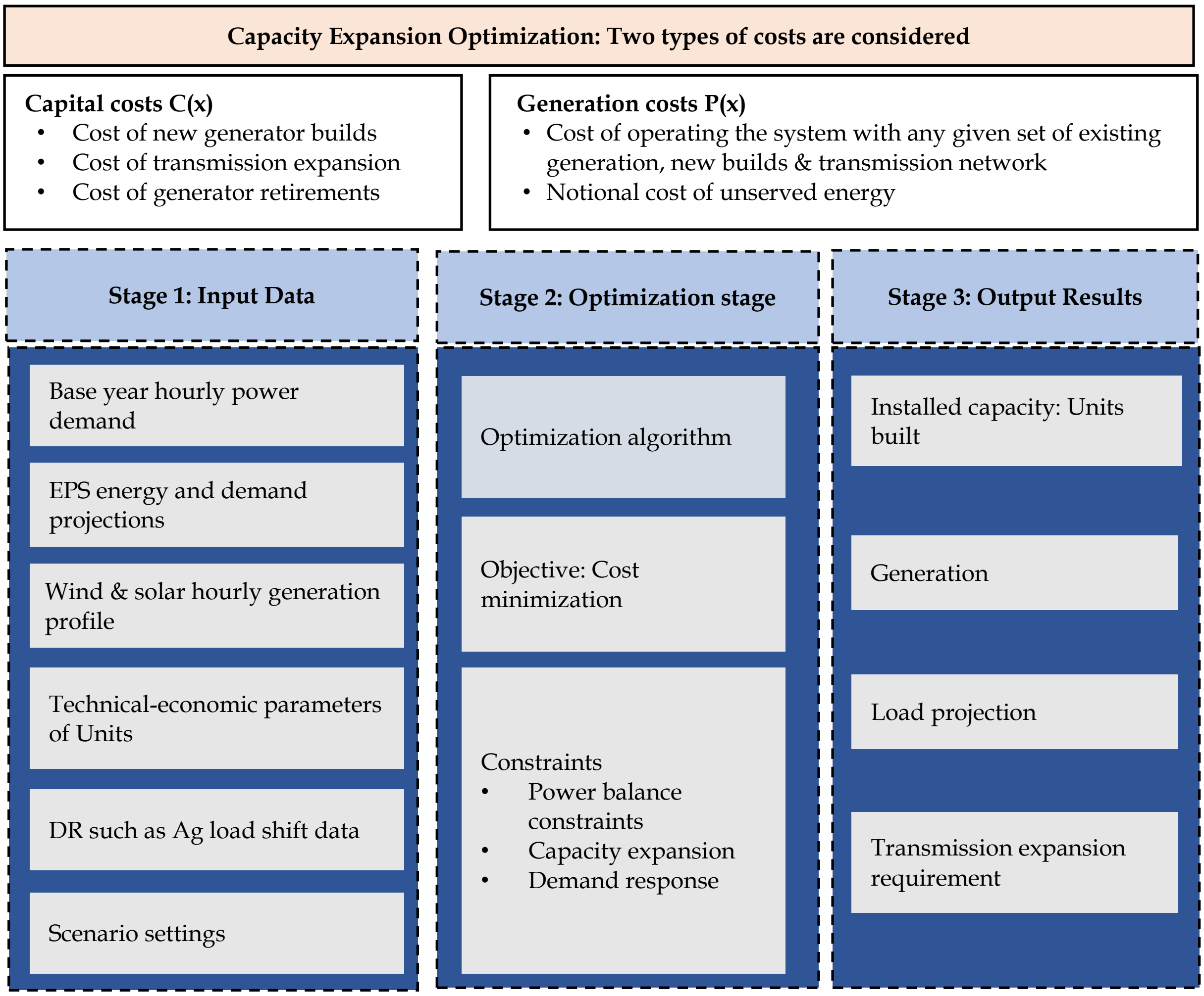


Figure 9: Overview of LT Expansion Modelling

2.3 Production Cost Modelling

Production cost modelling intends to assess the generator-wise dispatch with the objective of minimizing the total production cost. In other words, it is the process of allocating the required load demand between the available generation units such that the cost of operation is minimized. Production cost modelling captures all the costs of operating a fleet of generators and is developed into an hourly, chronological, and security-constrained unit commitment and economic dispatch simulation which minimizes costs while simultaneously adhering to a wide variety of operating constraints. It helps the utilities to manage fuel inventories and budget for required operations.

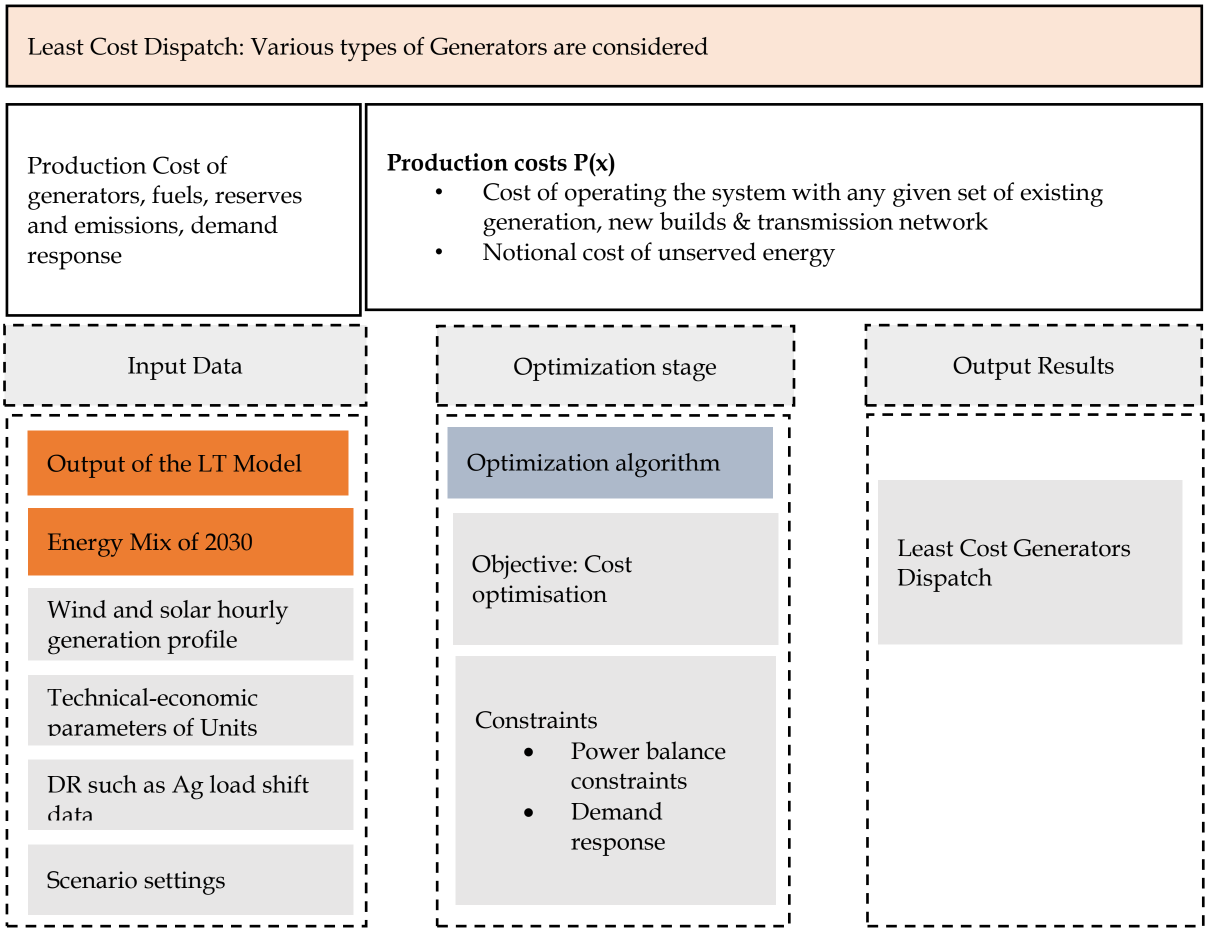


Figure 10: Overview of Production Cost Modelling

The production cost has been analysed for the scenario considering moderate cost of vRE and energy storage with state power projections as shown in figure below:

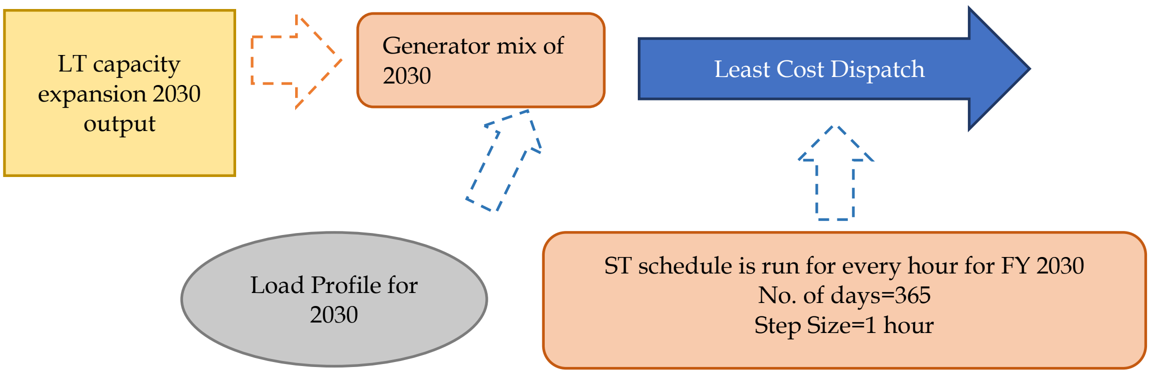


Figure 11: Least Cost Dispatch Modelling Approach

2.4 Scenarios Considered

Based on the cost of vRE and demand projections (lower and higher), following scenarios are developed to understand impact of cost and load projections. In all the scenarios, it is considered that agricultural load will be shifted from night to solar hours.

Table 2: Scenarios Considered for Capacity Expansion

	Criteria	Current Policy Scenario	Primary Least Cost Case	Primary Least Cost Case	High RE Installation Case	Sensitivity Case
Capacity Expansion	Load	EPS projections	State projections	EPS projections	EPS projections	EPS projections
	Capital Cost of solar (Rs Cr/MW)	4.20 in 2020 to **2.94** by2030	4.20 in 2020 to **2.94** by 2030	4.20 in 2020 to **2.94** by 2030	4.20 in 2020 to **2.94** by2030	4.20 in 2020 to **2.94** by 2030
	Capital Cost of wind (Rs Cr/MW)	6.62 in 2020 to 5.96 by 2030	6.62 in 2020 to 5.96 by 2030	6.62 in 2020 to 5.96 by 2030	6.62 in 2020 to 5.96 by 2030	6.62 in 2020 to 5.96 by 2030
	Capital Cost of battery (Rs Cr/MW)	6.30 in 2020 to **3.77** by 2030	6.30 in 2020 to **3.77** by 2030	6.30 in 2020 to **3.77** by 2030	6.30 in 2020 to **3.77** by 2030	6.30 in 2020 to **3.77** by 2030
	Yearly PLF (Thermal Plants)	55% PLF for minimum dispatch (25% minimum yearly PLF) for plants starting 2023	55% PLF for minimum dispatch (25% minimum yearly PLF) for plants starting 2023	55% PLF for minimum dispatch (25% minimum yearly PLF) for plants starting 2023	55% PLF for minimum dispatch (25% minimum yearly PLF) for plants starting 2023	55% PLF for minimum dispatch (25% minimum yearly PLF) for plants starting 2023

The hourly dispatch model is built on 2030 result of the primary least cost case (EPS Projections).

2.5 Karnataka State Model

Karnataka is modelled as a part of Indian grid in the model as in figure below with further details of Karnataka power system. While the generation of all other states excluding Karnataka has been considered lumped, generators of Karnataka has been modelled in detailed.

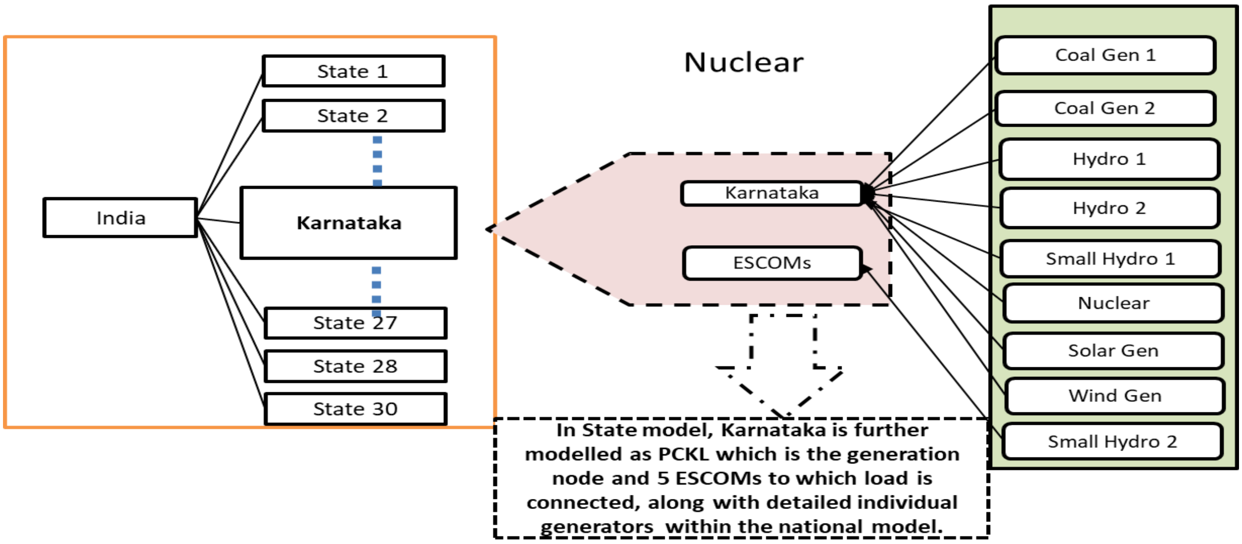


Figure 12: Karnataka as a part of the whole Indian grid

2.6 Generators

Different approaches have been considered to model different technologies as detailed below.

2.6.1 Thermal Generators

Thermal InSGS, ISGS and IPPs are modelled station-wise whose generation is procured by PCKL on behalf of all Karnataka Discoms as shown in the figure below:

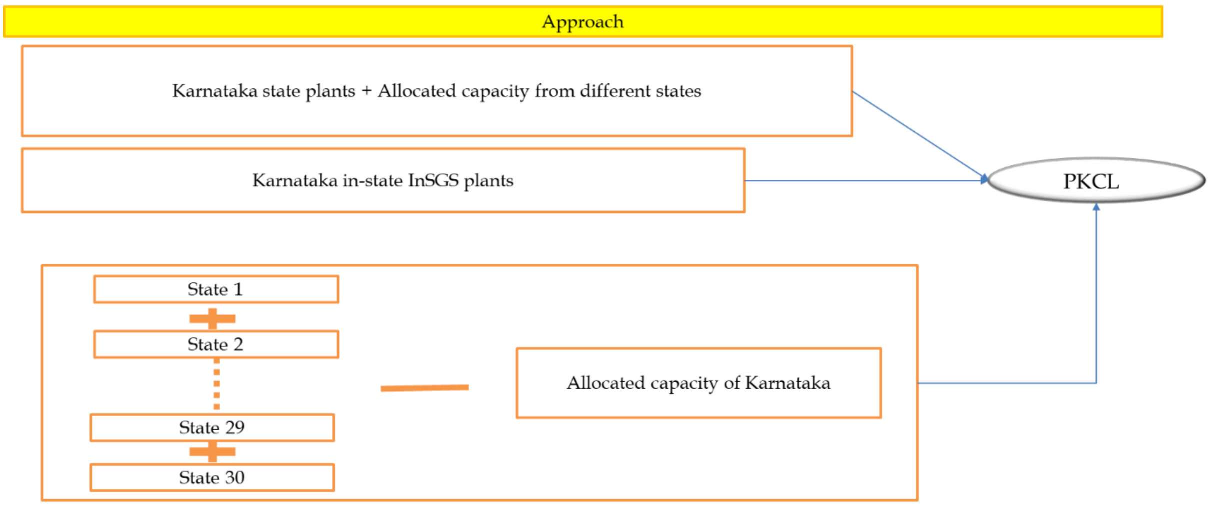


Figure 13: Thermal Generator Modelling Approach

2.6.2 Hydro Generators

Hydro generators were classified as RoR, reservoir based, PSH, or as small-hydro and are modelled with constraint on the max energy that can be produced by a hydro plant in a month as available in CEA's monthly hydro generation status.

2.6.3 Nuclear Generators

Nuclear generators are modelled similar to thermal generators. Basic properties such as ramp rates, fuel price etc. (decrement or increment in fuel price is not considered) are given as input to the system.

2.6.4 RE Generators

Historical installed capacity of solar and wind generators as received from state was used to model generators of vRE in the state.

2.6.5 Battery

As Karnataka has multiple DISCOMs with different load profile, the need of battery would be different. Thus, to have a better understanding of battery needs of each DISCOM, the need of batteries was modelled for each DISCOM.

2.6.6 Agricultural Shift

Ag shift has been modelled as a virtual pumped storage which reduces the load during night and increases the demand during the day for specific hours. As Ag load varies seasonally, the quantum of Ag shift considered is different for different months.

3 Key Findings

3.1 Incremental Demand Met Through Increase in Generation from Renewable Sources

Incremental demand through 2030 could be met by investments in RE and storage resources. No new thermal plant is optimal, and the grid is dependable with the existing thermal resources and new RE and storage resources. The primary least cost mix (state projections) in 2030 includes ~35.8 GW of wind and ~24.7 GW of solar respectively with ~2.9 GW of energy storage and primary least cost mix (EPS projections) in 2030 includes ~21.8 GW of wind and ~24.7 GW of solar with ~2.9 GW of energy storage respectively.

No new thermal is cost effective and required in any of the cases considered. Table below shows installed capacity mix by 2030 for all scenarios considered.

Table 3: Technology-wise Installed Capacity in the Optimal Generation Mix 2030

	Installed capacity (GW)		
Technology	**Current Policies Scenario**	**Primary least cost of scenario (State Projections)**	**Primary least cost of scenario (EPS Projections)**
Coal	9.2	9.2	9.2
Nuclear	0.7	0.7	0.7
Hydro	3.8	3.8	3.8
Hydro PSH	0.0	0.0	0.0
Solar	24.7	24.7	24.7
Wind	15.5	35.8	21.8
Biomass	1.0	1.0	1.0
Small Hydro	0.5	0.5	0.5
Battery storage	2.4	2.9	2.9
Total	**57.8**	**78.6**	**64.6**

With this mix, the share of non-fossil resources in total installed capacity is 40.2 GW in current policy scenario and is 60.5 GW and 46.5 GW in the Primary Least Cost scenario (state projections and EPS projections respectively).

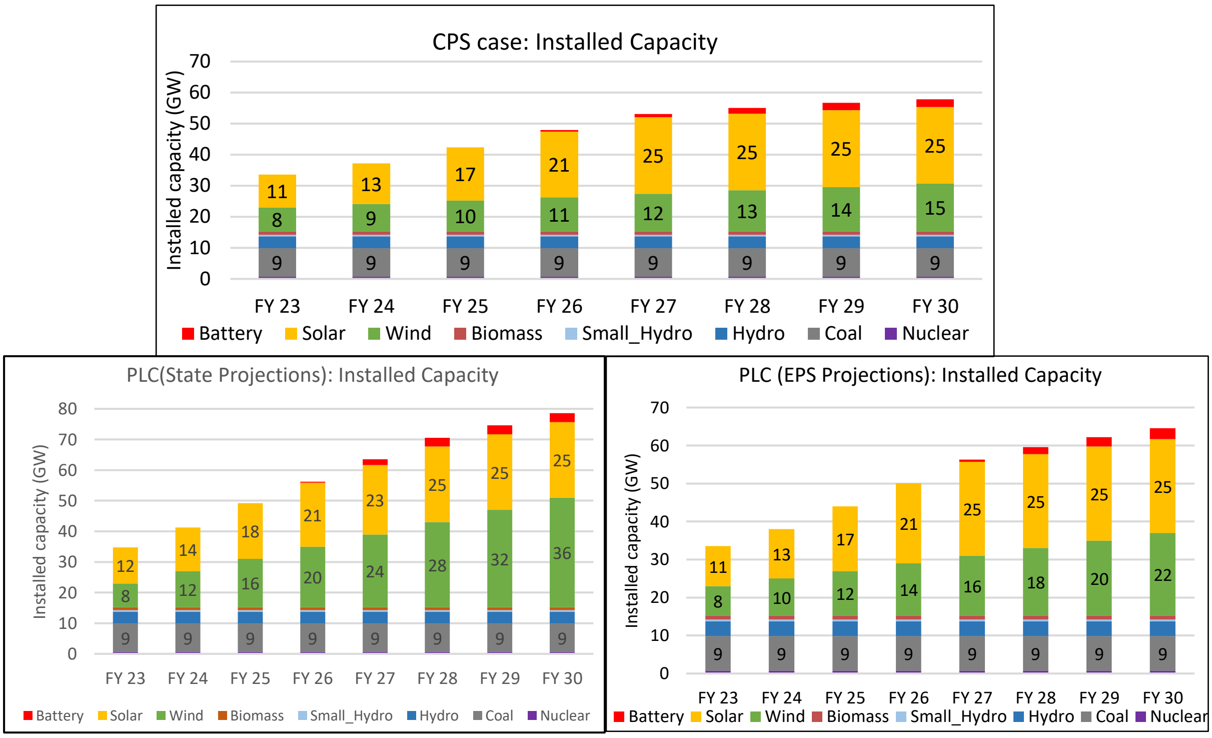


Figure 14: Installed Capacity by Resource Type in CPS (Top), PLC (State-Projections) (Bottom - Left) and PLC (EPS Projections) (Bottom-Right) FY 23-30

a. Non-fossil generation constitutes more than half of total generation

With increase in RE and storage capacity, generation from thermal decreases from 15 TWh to 13 TWh in the CPS case, 21 TWh to 13 TWh in the primary least cost case (state projections) and 15 TWh to 13 TWh in the primary least cost case (EPS projections). This decrease is compensated by increase in generation from RE sources with increasing contribution of storage generations which enhances the value of solar energy in the grid. Table below shows generation from different sources in all different cases considered.

Table 4: Yearly Generation from Different Technologies in 2030

	Generation in TWh		
Technology wise generation	**Current Policies Scenario**	**Primary least cost of scenario (State Projections)**	**Primary least cost of scenario (EPS Projections)**
Coal	13.1	12.7	13.1
Nuclear	4.4	4.4	4.4
Hydro	12.0	12.0	12.0
Hydro PSH	0.0	0.0	0.0
Solar	40.4	40.1	40.4
Wind	37.5	89.5	53.7
Biomass	0.2	0.2	0.2
Small Hydro	1.3	1.3	1.3

Technology wise generation	Generation in TWh		
	Current Policies Scenario	Primary least cost of scenario (State Projections)	Primary least cost of scenario (EPS Projections)
Net Import	19.3	-38.9	3.3
Total	**128.2**	**121.0**	**128.4**

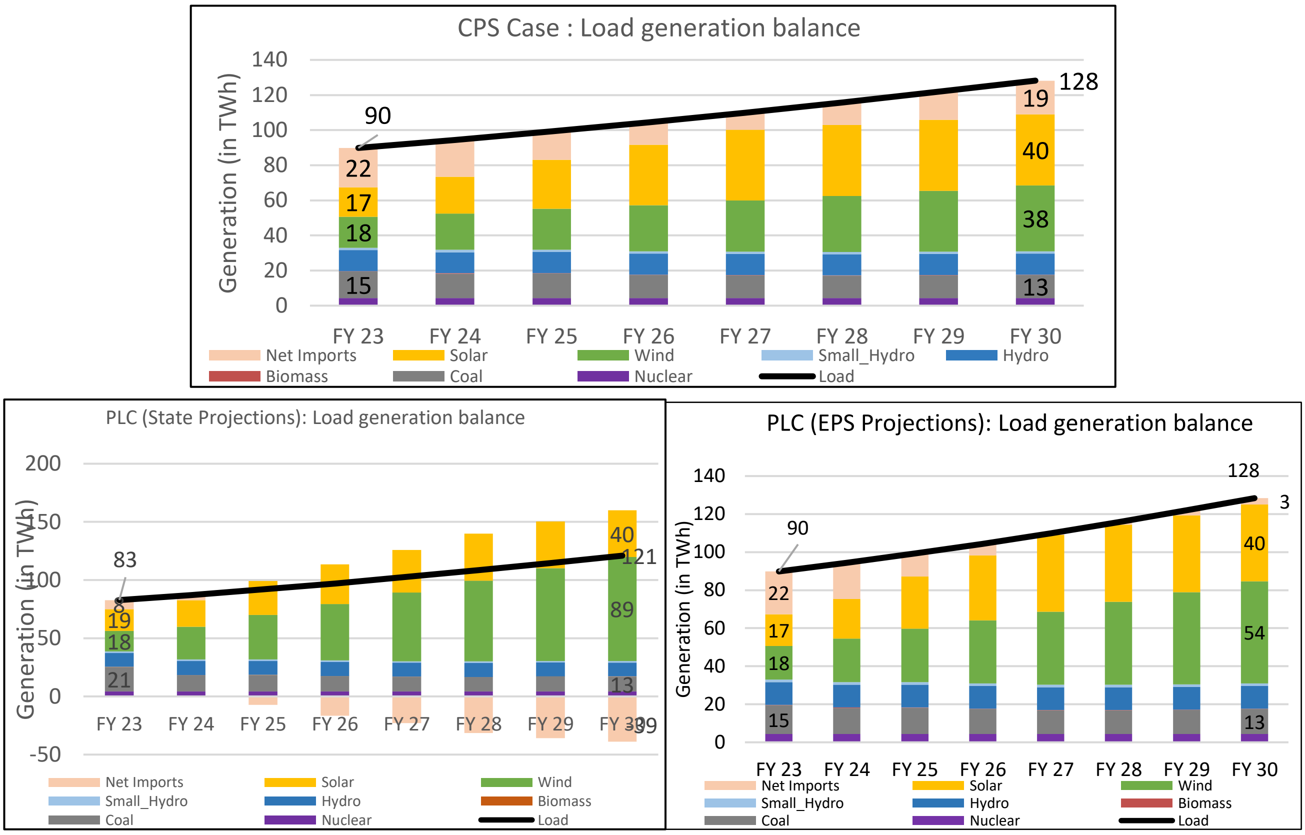


Figure 15: Annual Generation and Load by Resource Type in CPS (top), Primary Least Cost (PLC) (State Projections) (bottom - left) and Primary Least Cost (PLC) (EPS Projections) (bottom-right) FY 2023-30

In case of current policy scenario, the import of power would increase to compensate for increasing load suggesting availability of lower cost power outside the state and the same case is with the primary least cost case (EPS projections). But in the primary least cost case (state projections) the import of power is low with lower thermal generation and increased generation from RE sources**.**

b. The average cost of electricity generation is lower than today's cost of generation

The average cost of electricity includes the fixed costs (annualized capital service and O&M) of all existing and new power plants, battery assets (including battery pack replacement costs), and the transmission network, fuel costs of thermal, biomass, and nuclear generators, and any startup/shutdown costs. A CAGR based increase in variable costs of thermal plants is considered (further details in Annexure I)

Table 5: Scenario-wise APPC for FY 2023-30

	Units	Current Policies Scenario	Primary least cost case (State Projections)	Primary least cost case (EPS Projections)
FY 2023	INR/kWh	3.66	3.78	3.66

	Units	Current Policies Scenario	Primary least cost case (State Projections)	Primary least cost case (EPS Projections)
FY 2030	INR/kWh	3.12	2.79	2.96
Decrease	%	**~5%**	**~ 26%**	**~ 19%**

In CPS case, the average cost decreases because of increase in RE power (34 TWh to 78 TWh), (34 TWh to 94 TWh) for primary least cost case (EPS Projections) and in primary least cost case (State Projections) high RE generations (36 TWh to 130 TWh) makes state to export around 39 TWh.

Reasons for least cost in primary case (state projections):

1. *Plummeting costs of solar, wind, and batteries drive the system average cost down*: As generation from solar and wind increases the total cost of the system decreases.

2. *5 GW of demand response reduces the night-time baseload requirement***.** Shifting of agricultural load, which is primarily supplied during night hours (10 PM to 6 AM), to solar hours would reduce significantly the night-time baseload power requirement typically met by coal power plants. Such load shift to solar hours also facilitates cost-effective grid integration of 47 GW of new solar capacity.

3. *Cheap grid-scale battery storage enhances the capacity value of vRE*: Batteries provide di-urinal flexibility by generating during peak hours and charging during off-peak hours. This interplay between vRE and battery also enables vRE to provide firm capacity and meet reserve requirements.

4. *Decrease in import of power:* With increase in cheaper RE sources within the State, import of power decreases (from 21 TWh to 3.3 TWh) in primary least cost case (EPS Projections) leading to further decrease in average cost of power by 2030.

c. Emission intensity from power generation

The emission intensity decreases by 46% in current policy scenario whereas it decreases by 72% in the primary least cost scenario (state projections) and 53% in the primary least cost scenario (EPS projections). Figure below shows emission intensity for different scenarios till FY 2030.

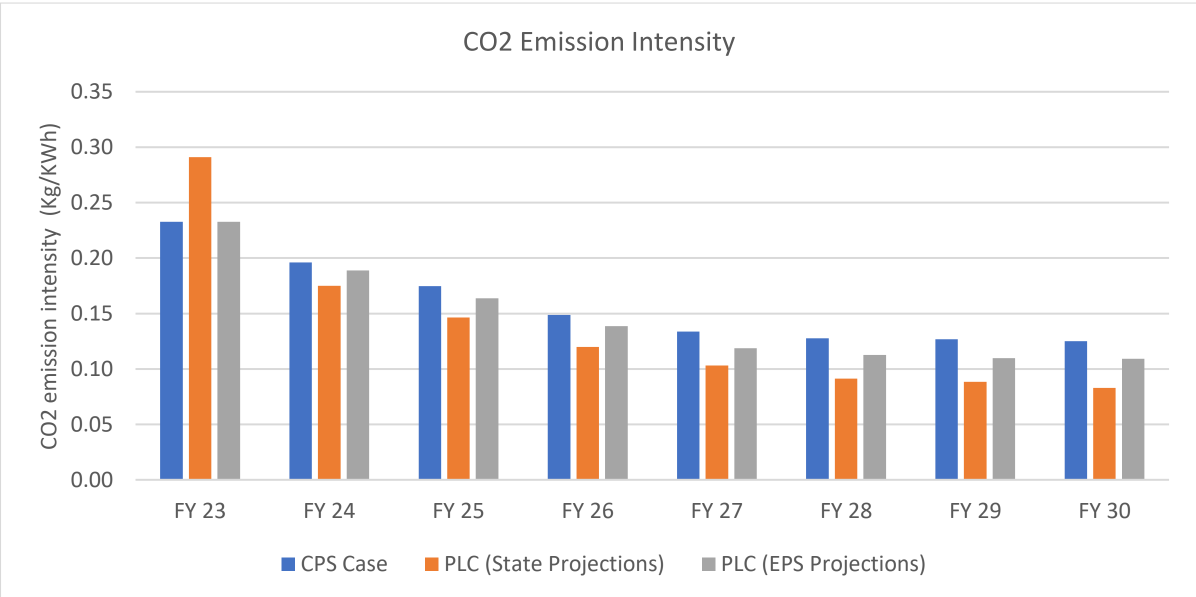


Figure 16: CO2 Emission Intensity (kg/kWh), FY 23-30

3.2 The grid is dependable even with significant RE addition

While the long-term studies for the year 2029-30 are required to assess the optimal mix in terms of investment decisions, short term generation dispatch study on hourly basis is required to assess the adequacy of the system and it validates that the optimal resource mix can meet demand in every hour of the year in 2030.

All the operational and technical parameters as discussed in chapter 3 have been considered to derive an optimum least cost hourly generation portfolio for the year 2030 for the primary least cost scenario.

Figure below shows average hourly system dispatch in FY 2030 for all months in the Primary Least Cost Case (EPS Projections).

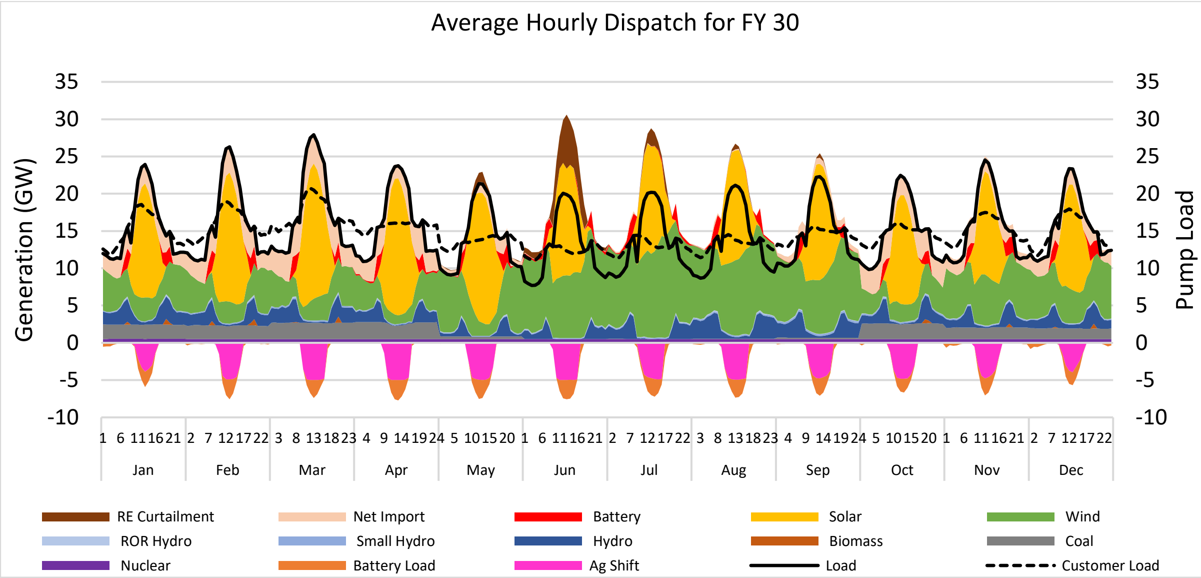


Figure 17: Monthly Average Dispatch for FY 2030

The flexible resources work in tandem to maintain grid dependability. Agricultural load shifting is critical for diurnal balancing of the grid, while variable monthly PLF of thermal plants along with import and export of power are critical for seasonal balancing. Agricultural load shifting reduces the nighttime base load requirement minimizing the requirement of base thermal generation.
Energy storage, including batteries and pumped hydro, charges during the day and discharges during evening and morning peak hours, while also providing the ramping support during the most critical ramp events. Thermal plants operate mostly during the low RE season (October through December) and are critical for seasonal balancing of the grid.

a. Load shift helps reduce the nighttime load

Figure below shows load curve for May FY 2030. The orange line shows shifted load, if 5 GW of load nighttime load is shifted to solar hours.

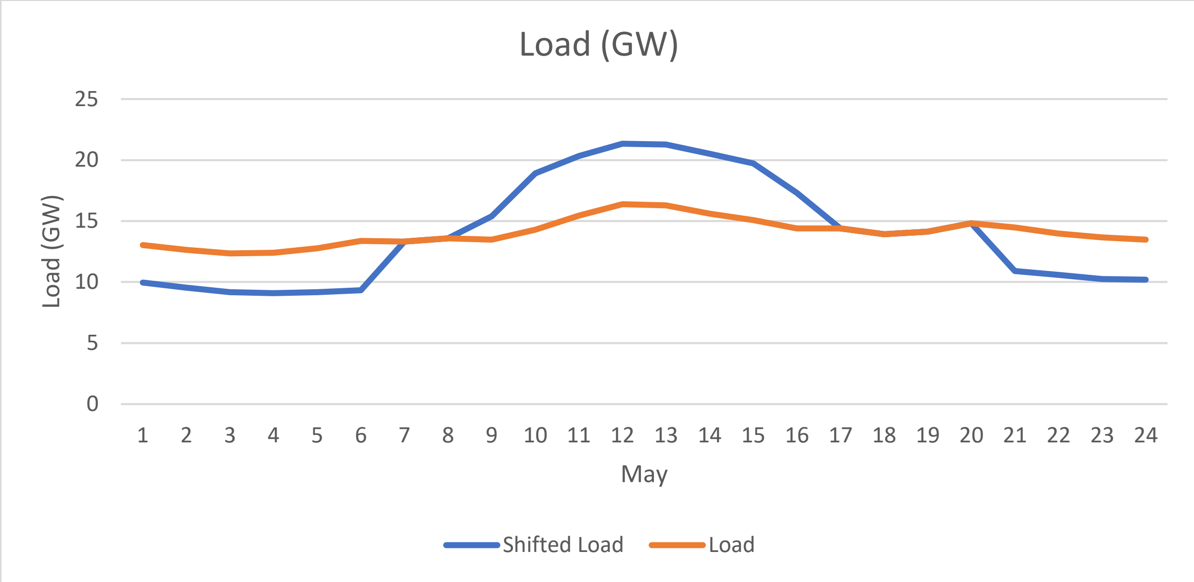


Figure 18: Average load (blue line) and shifted load (orange line) curves, FY 2030, in the Primary Least-Cost scenario (EPS Projections)

b. Variable monthly thermal PLF aids in seasonal balancing

Existing thermal plants operate at variable PLF providing seasonal balancing. Plants with VC greater than 4 Rs/kWh operates only during low wind/solar months and thus retiring them will increase PLF of efficient thermal plants. Figure below shows average coal generation as percentage of total generation from coal.

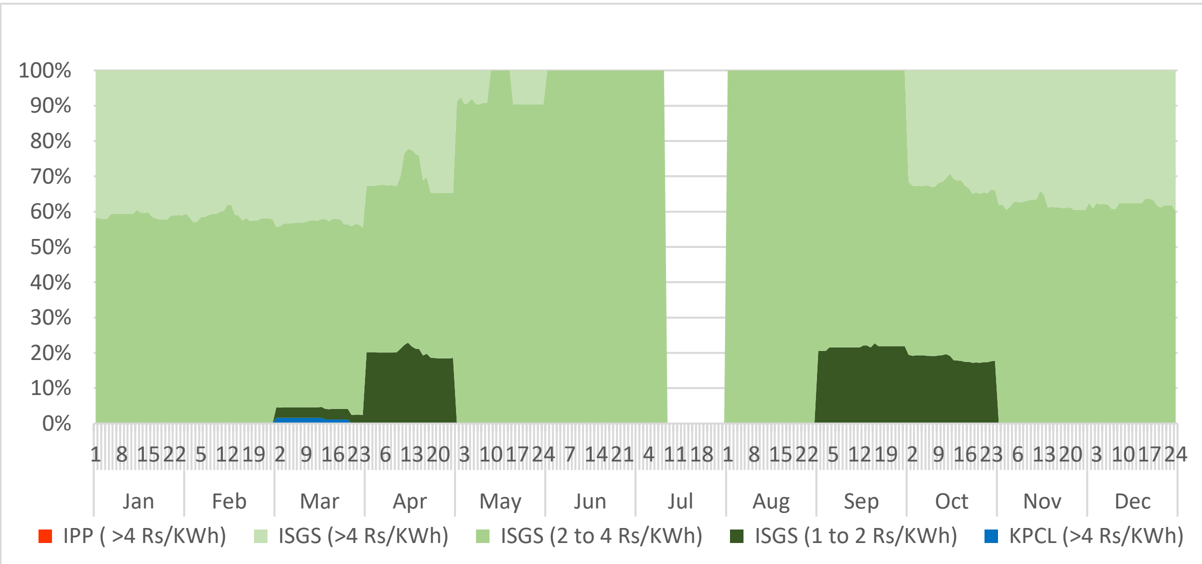


Figure 19: Average Coal Generation from Different Plants as Percentage of Total Coal Generation in the State

c. The grid has sufficient capacity to run dependably during “high-stress” periods

To understand the operation of grid during high stress periods multiple stress days were examined as mentioned below:

Table 6: Selected dispatch days

Sr. No.	Selected Day	Date
1	Max Net Load Day	12th Mar, 2030
2	Least Demand Day	16th Aug, 2029
3	Max vRE Day	2nd Sep, 2029

Max Net Load Day

Peak of 30 GW would occur at 12:00 Hrs on 12th March, 2030 and is met by about ~67.4% RE and ~8.2% conventional sources and rest 24.3% by imported energy. During the peak day, the State imports electricity for almost 24 hrs, coal generation provides base load.

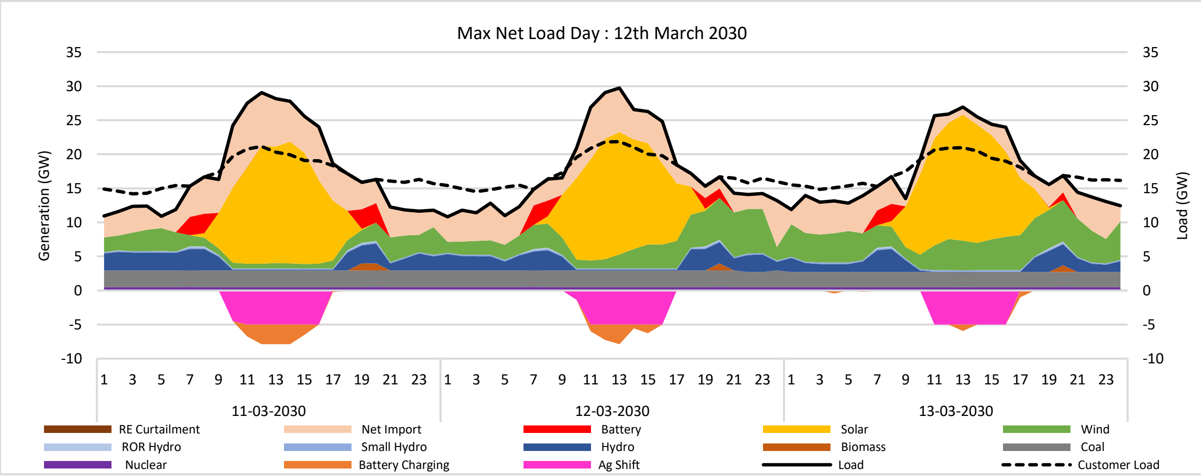


Figure 20: Max Net Load Day on 12th March, 2030

Lowest Demand Day

Lowest demand of ~5 GW is observed at 05.00 AM on 16th August, 2029 and as is seen in figure below the state exports throughout the day.

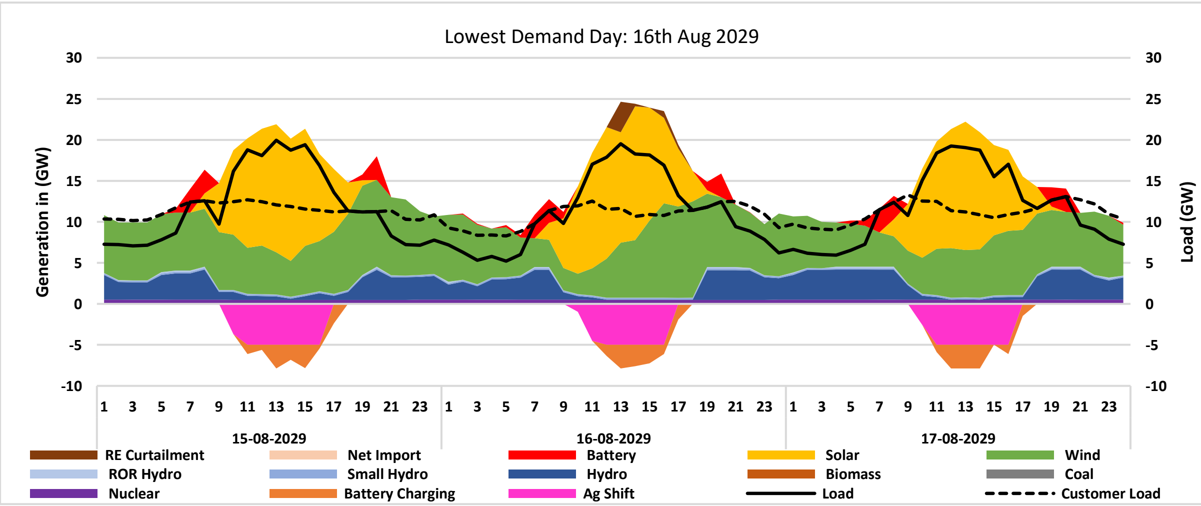


Figure 21: Least Demand Day on 16th August 2029

Max vRE Day

System has to be resilient on the day when the maximum generation from RE (wind + solar) is likely to occur and it is observed that maximum generation from vRE sources occurs on 2nd September 2029 with wind and solar contributing ~147% of peak load at 1:00 PM.

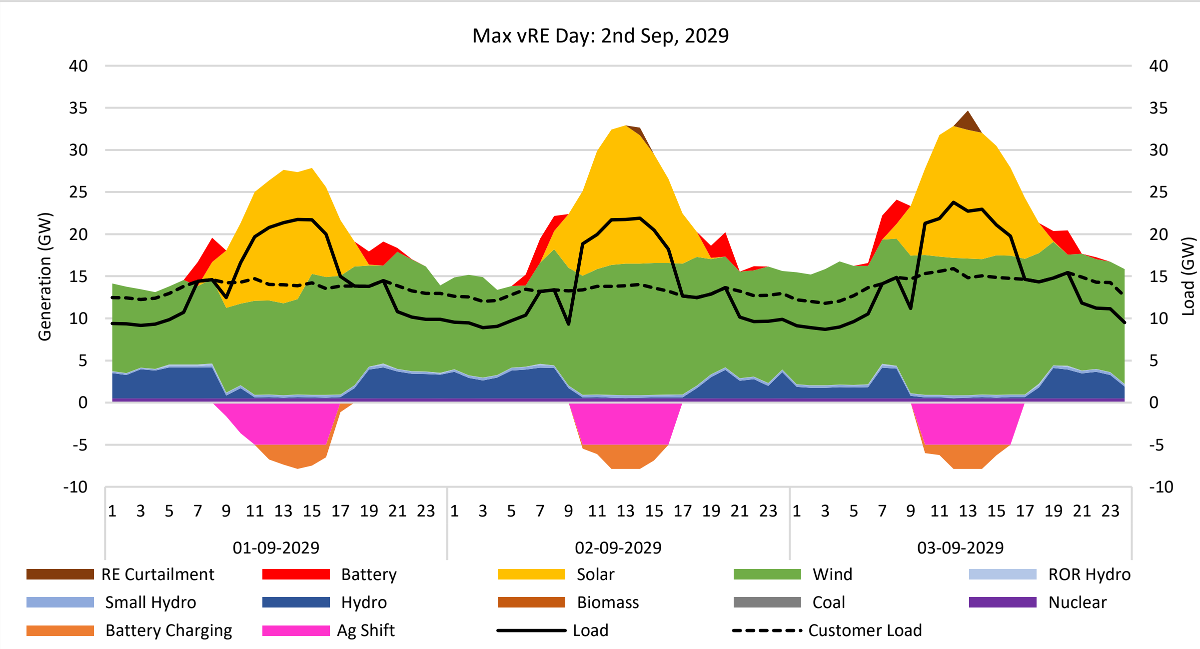


Figure 22: Highest vRE Day on 2nd September, 2029

It is important to understand that the study has simulated hourly grid operations using a DC Optimal Power Flow formulation. This implies that some of the operational issues that may arise in an AC power system such as reactive power compensation and impact on line voltages and grid frequency could not be assessed in this study. Deeper analyses using appropriate simulation tools (such as Power System Simulator for Engineering (PSSE)) would be needed to fully understand such impacts.

4 Sensitivity Analysis

We assess the sensitivity of our results on key assumptions of (1) clean technology costs and disruptions to the solar / batteries supply chain and (2) demand growth. Table below summarizes these alternate pathways, and key insights set forth below:

Table 7: Technology wise Installed capacity in the optimal generation mix 2030

Scenario Description	Primary Least Cost (State Projections)	Primary Least Cost (EPS Projections)	High RE Installation	State Sensitivity Case
Coal	9.2	9.2	9.2	9.2
Nuclear	0.7	0.7	0.7	0.7
Hydro	3.8	3.8	3.8	3.8
Hydro PSH	0.0	0.0	0.0	3.0
Solar	24.7	24.7	24.7	23.4
Wind	35.8	21.8	36.8	21.8
Biomass	1.0	1.0	1.0	1.0
Small Hydro	0.5	0.5	0.5	0.5
Battery	2.9	2.9	2.4	2.3
Total	**78.6**	**64.6**	**79.1**	**65.7**

Sensitivity Case: High RE Installation

Compared to primary least cost case, it is seen that with increase in predicted demand the installed capacity increases to almost 79 GW with about 77.75% of vRE capacity and about 2.4 GW of 4-hrs of battery storage to meet. Table below shows generation from different sources in all different cases considered.

Sensitivity Case: State Sensitivity Case

Compared to primary least cost case (EPS projections), the state sensitivity case considers additional 3000 MW of additional PSH installation by 2030. Table below shows generation from different sources in all different cases considered.

Table 8: Yearly generation from different technologies for primary least cost and high RE installation scenarios by 2030

Technology wise generation	Primary least cost of scenario (State Projections)	Primary least cost of scenario (EPS Projections)	High RE Installation case	State Sensitivity Case
Coal	12.7	13.1	13.2	16.7
Nuclear	4.4	4.4	4.4	4.4
Hydro	12.0	12.0	12.0	12.0
Hydro PSH	0.0	0.0	0.0	1.0
Solar	40.1	40.4	40.4	38.2
Wind	89.5	53.7	92.4	53.3
Biomass	0.2	0.2	0.1	0.3

Technology wise generation	Primary least cost of scenario (State Projections)	Primary least cost of scenario (EPS Projections)	High RE Installation case	State Sensitivity Case
Small Hydro	1.3	1.3	1.3	1.3
Net Import	-38.9	3.3	-35.2	2.5
Total	**121.0**	**128.4**	**128.0**	**128.7**
APPC	2.79	2.96	2.78	2.89

5 Conclusion

Dramatic cost reductions over the last decade for wind, solar, and energy storage position Karnataka to have a more flexible, robust, and sustainable power system — most of which is yet to be built — for delivering affordable and reliable power to serve increasing demand. In this study, we assess a cost-effective and operationally feasible investment pathway for Karnataka's electricity grid by enhancing system flexibility and robustness through renewable energy (RE) and a spectrum of flexible resources, such as energy storage and demand response (load shifting). The study achieves this objective by using an industry standard power system modelling platform (PLEXOS) and comprehensive electricity grid data at the individual power plant level.

5.1 Modelling Results

The study carried out through PLEXOS modelling gives Karnataka's least cost resource mix in 2030 which primarily consists of RE and flexible resources. These least cost mix does consider that Karnataka will be able to shift additional ~5GW of load from night to solar hours.

- **Current Policy Scenario (CPS):** 24.7 GW Solar, 15.5 GW of wind and 2.4 GW of 4-Hrs storage with ~5 GW of additional load shift to solar hours by 2030.

- **Primary Least Cost Scenario (EPS Projections):** 24.7 GW Solar, 21.8 GW of wind and 2.9 GW of 4-Hrs storage along with ~5 GW of additional load shift to solar hours by 2030.

- **Primary Least Cost Scenario (State Projections):** 24.7 GW Solar, 35.8 GW of wind and 2.9 GW of 4-Hrs storage along with ~5 GW of additional load shift to solar hours by 2030.

- **High RE Installation Scenario:** 24.7 GW of solar, 36.8 GW of wind, 2.4 GW of 4 Hrs storage along with ~5 GW of additional load shift to solar hours by 2030.

These results imply that Karnataka can meet its demand through 2030 largely by new investments in renewable energy and storage assets. Further, it is also seen that it is optimal to import power from other states till 2030 and thus the State should consider import of cheaper power whenever available to have a least cost scenario.

Overall, as Karnataka's grid attains higher penetrations of renewables, balancing its variability through a spectrum of flexible resources – such as energy storage, demand response (agricultural load shifting), along with import from other States becomes increasingly important for ensuring the affordability, stability, and reliability of grid power. The flexible resources work in tandem to maintain the hourly supply-demand balance. During the high RE generation season (June through September for wind and March through June for solar), energy storage and agricultural load shifting provide diurnal grid balancing. Batteries charge during the daytime (coincident with solar generation) and discharge during the morning and evening peak periods (4-6 hours total each day). They also help to meet steep system ramps. Shifting agricultural load to solar hours increases the day-time load while reducing the night-time load and thereby the base load capacity requirement. As a result, thermal power plants are mostly dispatched as a base load resource.

5.2 Policy Recommendations

While this study indicates a direction to a least cost resource mix in 2030, critical policy and regulatory changes must be expeditiously implemented in order for Karnataka to move on to that pathway. If prompt initiative to promote RE is not undertaken, it would be difficult for Karnataka to meet the least cost resource mix by 2030, and instead would have to significantly import from other states. The following policy and regulatory recommendations should be considered by Karnataka to ensure promotion of RE while maintaining grid stability:

- Solar potential gets exhausted in 2027. The state should initiate solar mapping.
- State RE penetration can go as high as 80%.
- Karnataka can become “Net Zero” is green seasoning storage technology is identified.
- Cheaper coal power is available from States such as Chhattisgarh, Madhya Pradesh and Jharkhand.
- Nuanced resource adequacy framework required to drive planning and procurement strategies, and to avoid potential future stranded assets
- Focus on demand side management and other flexible resources.

References

BNEF (2020a). *India's Clean Power Revolution: A success story with global implications.* Bloomberg New Energy Finance. Authors: Gadre, Rohit, et al.

BNEF. (2020b) *Battery Pack Prices Cited Below $100/kWh for the First Time in 2020, While Market Average Sits at $137/kWh*. Bloomberg New Energy Finance. Retrieved from: https://about.bnef.com/blog/battery-pack-prices-cited-below-100-kwh-for-the-first-time-in-2020-while-market-average-sits-at-137-kwh/

Martinez-Anido, C B, Benjamin Botor, Anthony R. Florita, Caroline Draxl, Siyuan Lu, Hendrik F. Hamann, Bri-Mathias Hodge. (2016), "The value of day-ahead solar power forecasting improvement", *Solar Energy* (129) *pp192-203*.

CEA (2010). Monthly Energy Generation Reports – January through December 2010. Central Electricity Authority (Operation Performance Monitoring Division), Ministry of Power, Government of India.

CEA (2011). Monthly Energy Generation Reports – January through December 2011. Central Electricity Authority (Operation Performance Monitoring Division), Ministry of Power, Government of India.

CEA (2012). Monthly Energy Generation Reports – January through December 2012. Central Electricity Authority (Operation Performance Monitoring Division), Ministry of Power, Government of India.

CEA (2013). Monthly Energy Generation Reports – January through December 2013. Central Electricity Authority (Operation Performance Monitoring Division), Ministry of Power, Government of India.

CEA (2014). Monthly Energy Generation Reports – January through December 2014. Central Electricity Authority (Operation Performance Monitoring Division), Ministry of Power, Government of India.

CEA (2015). Monthly Energy Generation Reports – January through December 2015. Central Electricity Authority (Operation Performance Monitoring Division), Ministry of Power, Government of India.

CEA (2016a). Monthly Energy Generation Reports – January through December 2016. Central Electricity Authority (Operation Performance Monitoring Division), Ministry of Power, Government of India.

CEA (2016b). Review of Performance of Thermal Power Stations 2014-15. Central Electricity Authority, Ministry of Power, Government of India.

CEA (2017a). Monthly Energy Generation Reports – January through December 2017. Central Electricity Authority (Operation Performance Monitoring Division), Ministry of Power, Government of India.

CEA (2017b). *Report on Nineteenth Electric Power Survey of India*. Central Electricity Authority, Ministry of Power (Government of India).

CEA (2018a). Monthly Energy Generation Reports – January through December 2018. Central Electricity Authority (Operation Performance Monitoring Division), Ministry of Power, Government of India.

CEA (2018b). *National Electricity Plan: Volume I*. Central Electricity Authority, Ministry of Power, Government of India.

CEA (2018c). Review of Performance of Thermal Power Stations 2015-16. Central Electricity Authority, Ministry of Power, Government of India.

CEA (2019a). Monthly Energy Generation Reports – January through December 2019. Central Electricity Authority (Operation Performance Monitoring Division), Ministry of Power, Government of India.

CEA (2019b). Review of Performance of Hydro Power Stations 2017-18. Central Electricity Authority, Ministry of Power, Government of India.

CEA (2019c). Review of Performance of Thermal Power Stations 2017-18. Central Electricity Authority, Ministry of Power, Government of India.

CEA (2020a). Broad Status of Thermal Power Plants – January through December 2020. Central Electricity Authority (Operation Performance Monitoring Division), Ministry of Power, Government of India.

CEA (2020b). Monthly Energy Generation Reports – January through December 2020. Central Electricity Authority (Operation Performance Monitoring Division), Ministry of Power, Government of India.

CEA (2020c). Monthly Energy Generation Reports – January through December 2020. Central Electricity Authority (Operation Performance Monitoring Division), Ministry of Power, Government of India.

CEA (2020d). *Report on Optimal Generation Capacity Mix for 2029-30*. Central Electricity Authority Ministry of Power, Government of India.

CEA (2021). *CO2 Emissions Database from Power Sector*. Central Electricity Authority, Ministry of Power (Government of India).

CERC (2015). "Central Electricity Regulatory Commission (Terms and Conditions for Tariff Determination from Renewable Energy Sources) (Third Amendment) Regulations, 2015." Central Electricity Regulatory Commission (Government of India).

CERC (2016a). "Central Electricity Regulatory Commission (Indian Electricity Grid Code) (Fourth Amendment) Regulations, 2016." L-1/18/2010-CERC. New Delhi: Central Electricity Regulatory Commission (Government of India). http://www.cercind.gov.in/2016/regulation/124_1.pdf.

CERC (2016b). *Central Electricity Regulatory Commission (Deviation Settlement Mechanism and Related Matters) (Third Amendment) Regulations, 2016*. Central Electricity Regulatory Commission (Government of India).

CERC (2019). *Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2019*. Central Electricity Regulatory Commission (Government of India).

Deorah, Shruti, Nikit Abhyankar et al (2020). *Estimating the Cost of Grid-Scale Lithium-Ion Battery Storage in India*. Lawrence Berkeley National Laboratory, Berkeley.

Deshmukh, Ranjit, Grace Wu, and Amol Phadke. (2017). "Renewable Energy Zones for Balancing Siting Trade-Offs in India.", Lawrence Berkeley National Laboratory, Berkeley.

Denholm, Paul, Trieu Mai, Rick Wallace Kenyon, Ben Kroposki, and Mark O'Malley (2020). "Inertia and the Power Grid: A Guide Without the Spin". Golden, CO: National Renewable Energy Laboratory. NREL/TP-6120- 73856.

Hodge, B.M., A. Florita, J. Sharp, M. Margulis and D. Mcreavy. (2015). "The Value of Improved ShortTerm Wind Power Forecasting", National Renewable Energy Laboratory, Golden CO. NREL/TP-5D00-63175

IEA (2021). "Renewables Integration in India", International Energy Agency (IEA) and National Institution for Transforming India (NITI) Aayog, Government of India.

MERIT (2020), Database on Marginal Costs of Electricity Generation.Merit Order Dispatch of Electricity
for Rejuvenation of Income and Transparency. Ministry of Power. Retrieved from: http://meritindia.in/

MOSPI (2018), *Energy Statistics 2018*. Ministry of Statistics and Program Implementation, Government of India.

MOSPI (2019), *Energy Statistics 2019*. Ministry of Statistics and Program Implementation, Government of India.

MOSPI (2020), *Energy Statistics 2020*. Ministry of Statistics and Program Implementation, Government of India.

NREL (2020). *Least-Cost Pathways for India's Electric Power Sector.* National Renewable Energy Laboratory. Authors: Amy Rose, Ilya Chernyakhovskiy, David Palchak, Sam Koebrich, and Mohit Joshi.

Phadke, Amol, Nikit Abhyankar, Ranjit Deshmukh, Julia Szinai et al (2020), "Cost-effective decarbonization of California's Power Sector by 2030 With the Aid of Battery Storage", Lawrence Berkeley National Laboratory, Berkeley.

Grid-India (2020) "Variable Cost Data for Generators Providing Fast Response Ancillary Services", Grid Controller of India Limited (Grid-India), Ministry of Power, Government of India.

Shaner, M.R, S. J. Davis, N. S. Lewis, and K. Caldeira (2018), "Geophysical constraints on the reliability of solar and wind power in the United States," Energy Environ. Sci., vol. 11, no. 4, pp. 914–925, Apr. 2018.

TERI (2020). "*Renewable Power Pathways: Modelling the Integration of Wind and Solar in India by 2030".* The Energy and Resources Institute. Authors: Thomas Spencer, Neshwin Rodrigues, Raghav Pachouri, Shubham Thakre, G. Renjit(n.d.).

CEA (2016). Annually Load Generation Balance Report 2015-2016. Central Electricity Authority (Operation Performance Monitoring Division), Ministry of Power, Government of India.

CEA (2017). Annually Load Generation Balance Report 2016-2017. Central Electricity Authority (Operation Performance Monitoring Division), Ministry of Power, Government of India.

CEA (2018). Annually Load Generation Balance Report 2017-2018. Central Electricity Authority (Operation Performance Monitoring Division), Ministry of Power, Government of India.

CEA (2019). Annually Load Generation Balance Report 2018-2019. Central Electricity Authority (Operation Performance Monitoring Division), Ministry of Power, Government of India.

CEA (2020). Annually Load Generation Balance Report 2019-2020. Central Electricity Authority (Operation Performance Monitoring Division), Ministry of Power, Government of India.

CEA. (2020). Monthly Executive Summary Report-January through December 2020. Central Electricity Authority (Operation Performance Monitoring Division), Ministry of Power, Government of India.

CEA. (2021). Monthly Executive Summary Report-January through May 2021. Central Electricity Authority (Operation Performance Monitoring Division), Ministry of Power, Government of India.

MERC(2020). Annual Report2019-20. Karnataka Electricity Regulatory Commission. Government of Karnataka.

MERC(2017). Annual Tariff Order 2016-17. Karnataka Electricity Regulatory Commission. Government of Karnataka.

MERC(2018). Annual Tariff Order 2017-18. Karnataka Electricity Regulatory Commission. Government of Karnataka.

MERC(2019). Annual Tariff Order 2018-19. Karnataka Electricity Regulatory Commission. Government of Karnataka.

MERC(2020). Annual Tariff Order 2019-20. Karnataka Electricity Regulatory Commission. Government of Karnataka.

6 Appendix I: Key Assumptions, Data, and Limitations of the Model

6.1 Data Collections

With the constant support from Nodal agency i.e. KSLDC, data collection was being made from other stakeholders such as BESCOM, MESCOM, HESCOM, GESCOM, CESC, PCKL, KPTCL, KCPL. Modelling requires base data for Supply and Demand Side. Facilitation of various data related to financial and technical limits such as generator's installed capacity, Min stable level and variable cost etc. and for demand side, utility wise load profile, demand projections, financial contract details etc. were provided by the nodal agency.

Based on the available data certain assumptions were made to overcome issue of non-availability of data, if any. This section discusses various technical and other assumptions considered.

6.2 General Assumptions

A number of constraints related to distribution of batteries, development of wind, CEA battery and coal targets etc. are built up in the system which are shown in table below:

Table 9: Solar and Wind Build Constraints Considered

	Solar (MW)	Wind (MW)
Installed Capacity by end of 2020 (assumed)	9938	7759
Max Potential (excluding the existing solar installed capacity by 2022)	24700	55860
Max Capacity that can be built in Year (PLC – EPS projections)	4000	2000
Max Capacity that can be built in Year (PLC – State projections)	4000	4000
Max capacity that can be built in a year (CPS case)	4000	1100
Max capacity that can be built in a year (High RE Installation case)	4000	4000

Further, to model technical characteristics such as ramp up and ramp down limits, heat rate, O&M expenses etc., the assumptions as in table below have been considered.

Table 10: General Generator Assumptions

Properties	Coal	Gas	Nuclear	Hydro	Small Hydro	RE	Biomass
Min Stable Factor (%)	55	20					
Start Cost ($)	100000	20000	10000000				
Max Ramp Up (MW/min)	0.01 * Max Capacity	0.03 * Max Capacity	0.0001* Max Capacity				
Max ramp Down (MW/min)	0.01 * Max Capacity	0.03 * Max Capacity	0.0001*Max Capacity				
FO&M charge ($/KW/yr)	25	15	60	10	10	10	15

Properties	Coal	Gas	Nuclear	Hydro	Small Hydro	RE	Biomass
Maintenance Rate (%)	5	10	15	5	5		
Forced Outage Rate (%)	10	20	15	5	5		
Outage Rating (MW)	0	0	0	0	0		
Mean Time to Repair (h)	24	24	400	24	24		
Min Time to Repair (h)	6	6	24			0	
Max Time to Repair (h)	72	72	1000			0	
WACC	8	8	8	8	8		
Economic Life (yr)	25	30	30	30	30		
Units	1	1	1	1	1		
Min Up Time (hr)	18	6	96	0	0		24
Min Down Time (h)	18	6	0	0	0		24
Firm Capacity (MW)	0.84 * Max Capacity	0.925 * Max Capacity	0.7*Max Capacity			0 for solar and 0.1*Max Capacity for wind	0.5* Max Capacity
Min Capacity Factor Month (%)			70				
Max Capacity Factor Month (%)			71				

6.3 Load Assumptions

To understand the impacts of change in load and energy requirements, predictions based on

a) Predictions based on past data and tariff order: Tariff projections (Tariff) on energy requirement and load projection are based on past and projected data as described in Tariff Order. It was considered to project future growth till 2030. State's projected energy requirement and peak demand data of 5 years i.e., from 2021-25 were used to calculate CAGR and is projected till 2030. Figures below show energy projections considered for different scenario building.

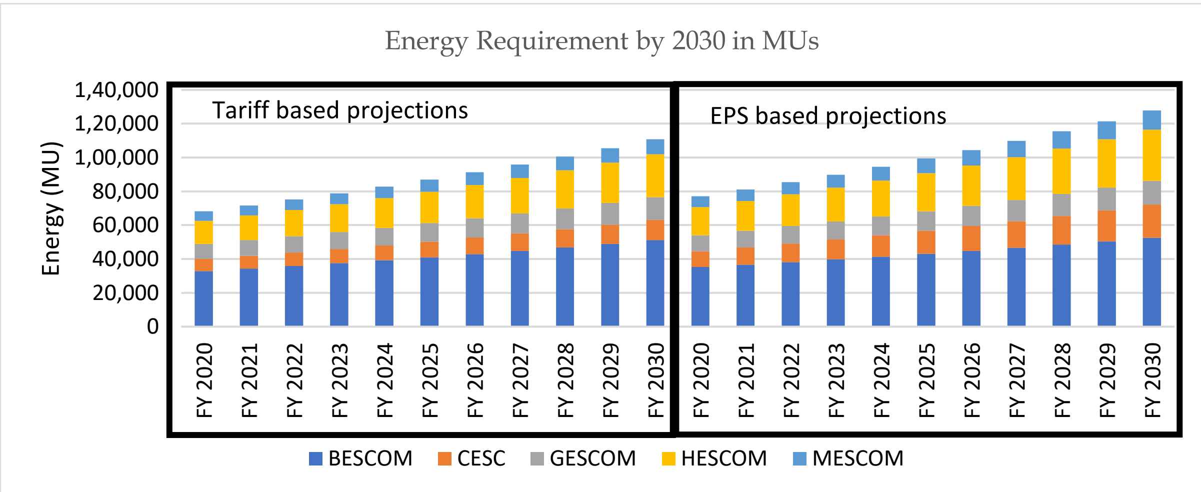


Figure 23: Tariff Orders and CEA 19th EPS Energy Requirement Projections

b) Predictions based on EPS based data: EPS based projections: EPS provides DISCOM wise energy and load projections till 2025-26, this data was used for a CAGR based projection for 2030 peak demand and energy requirement. CAGR is calculated for past 9 years i.e from FY 2017 to FY 2026 and is projected till 2030. Figures below show demand projections considered for different scenario building.

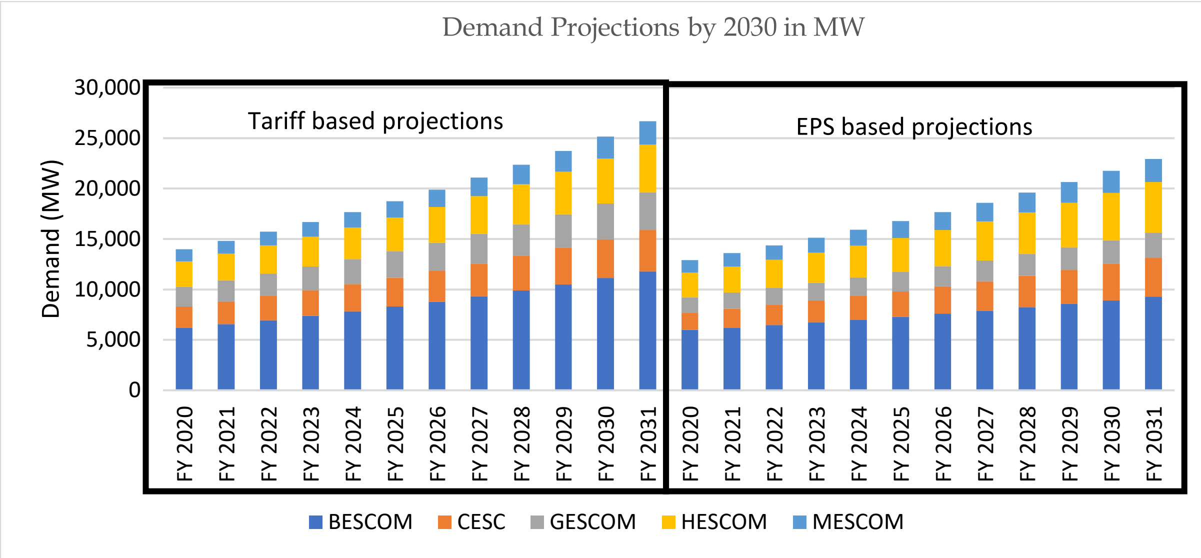


Figure 24: Demand Projection from Tariff Projections and EPS Projections

6.4 Cost Assumptions

Fuel cost and variable cost for future plants: It has been assumed that fuel prices for thermal power plants would increase and the following trend of fuel cost for any future addition of thermal power plants has been considered.

Table 11: Fuel costs and VC considered for future coal addition

FY	Coal Fuel Price (Rs/GJ)	VC in (Rs/kWh)[3]
2023	309	2.97
2024	312	3.00
2025	315	3.03
2026	318	3.06
2027	321	3.09
2028	324	3.12
2029	328	3.15
2030	331	3.18

6.4.1 Variable costs of existing power plants

Variable cost based on plant wise CAGR from 2015-2020 has been considered as shown in table 13. This variable cost has been converted to fuel prices considering a heat rate of 9.3GJ/MWh for coal and 7.6GJ/kWh for gas-based plants shown in figure below.

[3] Considering heat rate of 2300 Kcal/kWh

Table 12: Variable Cost Projections of Existing Thermal Power Plants (Rs/kWh)

Name	Sector	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29	FY 30
RTPS	KPCL	3.95	4.15	4.37	4.6	4.83	5.08	5.35	5.62	5.92	6.22
BTPS	KPCL	3.85	4.03	4.22	4.42	4.63	4.84	5.07	5.31	5.56	5.82
YTPS	KPCL	3.36	3.64	3.94	4.26	4.61	4.98	5.39	5.83	6.31	6.83
RSTP	ISGS	2.48	2.51	2.54	2.56	2.59	2.62	2.65	2.68	2.71	2.74
TALCHER	ISGS	1.74	1.82	1.9	1.99	2.08	2.18	2.28	2.38	2.49	2.61
SIMHADRI	ISGS	2.57	2.65	2.72	2.8	2.89	2.97	3.06	3.14	3.24	3.33
VALLUR_TPS	ISGS	3.34	3.58	3.85	4.13	4.43	4.75	5.1	5.48	5.88	6.31
NLC TPS_II	ISGS	2.68	2.79	2.9	3.01	3.13	3.26	3.39	3.52	3.66	3.8
NLC TPS II Exp	ISGS	2.5	2.58	2.66	2.75	2.84	2.93	3.03	3.13	3.23	3.33
NNTPS	ISGS	2.34	2.43	2.51	2.61	2.7	2.8	2.9	3	3.11	3.22
TUTICORIN_TPS	ISGS	2.39	2.4	2.4	2.41	2.41	2.42	2.42	2.42	2.43	2.43
MEJA_TPS	ISGS	2.46	2.53	2.6	2.67	2.74	2.81	2.88	2.96	3.04	3.12
KODERMA_TPS	ISGS	2.04	2.14	2.24	2.35	2.47	2.58	2.71	2.84	2.97	3.12
KUDGI	ISGS	3.15	3.28	3.42	3.56	3.71	3.87	4.03	4.2	4.38	4.56
BRBCL	ISGS	2.2	2.23	2.25	2.27	2.29	2.32	2.34	2.36	2.39	2.41
GADARWARA-I	ISGS	2.35	2.37	2.39	2.42	2.44	2.47	2.49	2.52	2.55	2.57
KHARGONE	ISGS	2.57	2.59	2.62	2.64	2.67	2.7	2.73	2.76	2.78	2.81
KSTPS	ISGS	1.42	1.43	1.44	1.46	1.47	1.49	1.5	1.51	1.53	1.54
LARA-I	ISGS	1.97	1.99	2.01	2.02	2.04	2.06	2.09	2.11	2.13	2.15
MOUDA	ISGS	2.8	2.82	2.85	2.88	2.91	2.94	2.97	3	3.03	3.06
SIPAT	ISGS	1.5	1.52	1.53	1.54	1.56	1.58	1.59	1.61	1.62	1.64
SOLAPUR	ISGS	2.94	2.98	3.01	3.03	3.07	3.1	3.12	3.16	3.19	3.22
VSTPS	ISGS	1.8	1.82	1.84	1.85	1.87	1.89	1.91	1.93	1.95	1.97
UDUPI_IPP	IPP	3.84	4.18	4.53	4.92	5.35	5.81	6.31	6.85	7.44	8.08

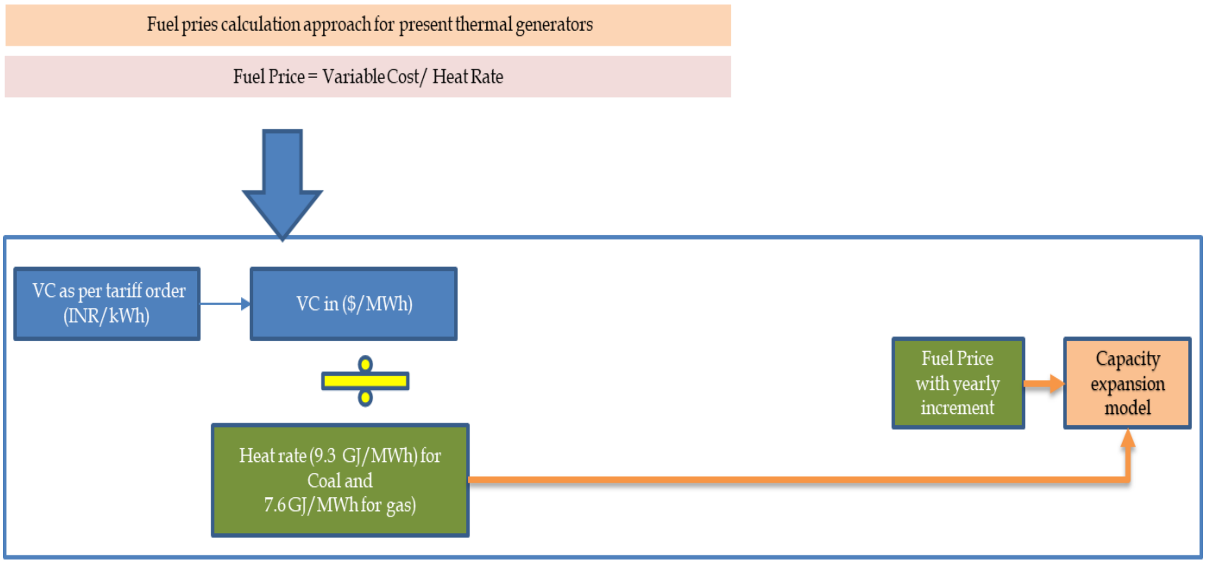
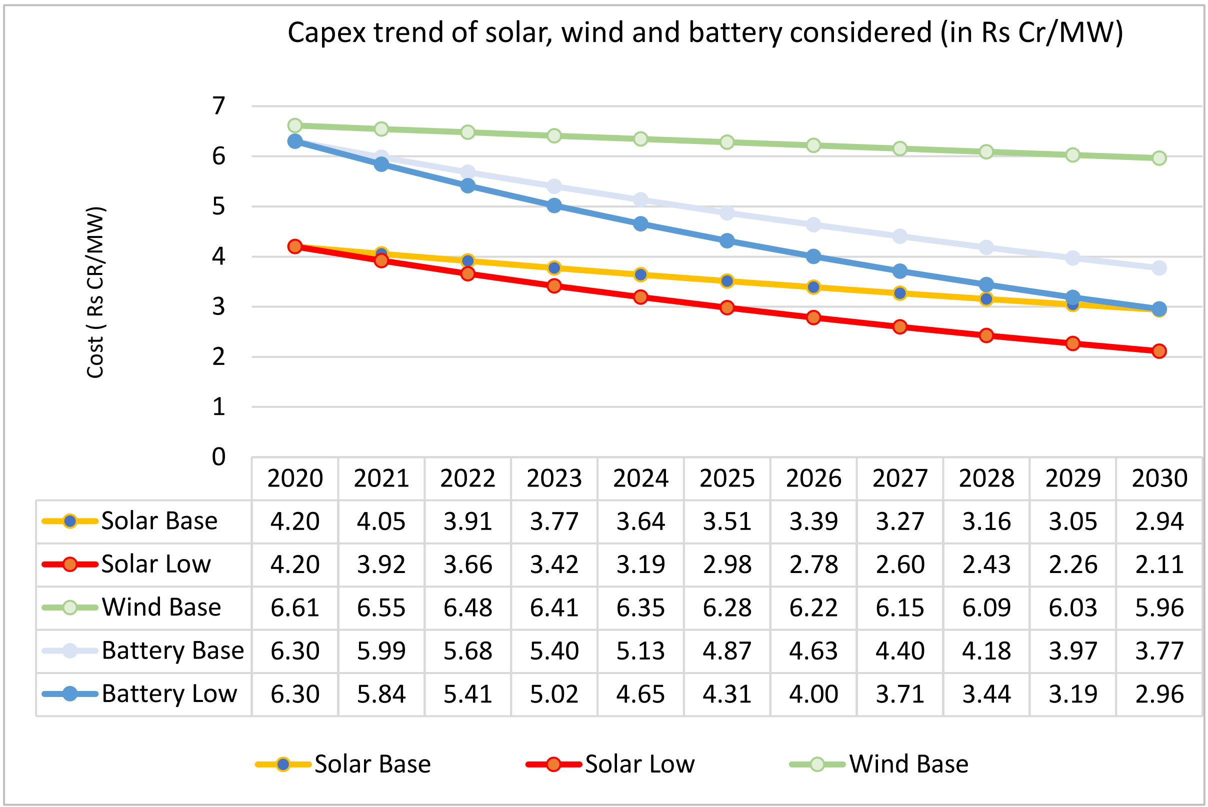


Figure 25: Future Fuel Cost Calculation for Existing Plants

6.4.2 Built Cost

New capital cost for coal and gas-based generators has been considered as 7.28 Cr/MW and 4.2 Cr/MW respectively. For solar, wind and battery two cases which are

a) Base case with a mid-cost trajectory for solar, wind and battery cost are considered



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Solar Base	4.20	4.05	3.91	3.77	3.64	3.51	3.39	3.27	3.16	3.05	2.94
Solar Low	4.20	3.92	3.66	3.42	3.19	2.98	2.78	2.60	2.43	2.26	2.11
Wind Base	6.61	6.55	6.48	6.41	6.35	6.28	6.22	6.15	6.09	6.03	5.96
Battery Base	6.30	5.99	5.68	5.40	5.13	4.87	4.63	4.40	4.18	3.97	3.77
Battery Low	6.30	5.84	5.41	5.02	4.65	4.31	4.00	3.71	3.44	3.19	2.96

Figure 26: Build Cost (CAPEX) of Different Generation Technologies

6.5 Transmission Capacity

As the Karnataka grid is connected to national grid present inter-state transmission lines has been modelled with possible increase in capacity as per optimal requirement

The Interstate transmission capacity considered to be built by year 2022 are:

Table 13: Interstate Transmission Capacity to be Built by 2022

From	To	Capacity (in MW)
Karnataka	Maharashtra	2,194
Karnataka	Odisha	1,250
Karnataka	Andhra Pradesh	4,956
Karnataka	Karnataka	280
Karnataka	Kerala	700
Karnataka	Tamil Nadu	1,801

By 2022, the considered transport capacity of power from Karnataka to other state is shown above. This will allow Karnataka to import as well as export the power to other states. This value will also increase as per the optimisation run.

6.6 Coal Prices and Variable Costs

For existing coal power plants, we take the variable costs of existing interstate generating stations (ISGS) from reports available under the Reserves Regulation Ancillary Services (RRAS) mechanism. Variable costs for state generators and IPPs are from regulatory orders by Indian state commissions. For plants with no recent data available from regulatory orders, the variable cost data from Ministry of Power's MERIT database has been used. For power plants with no data available (less than 5 GW), the average variable costs for that technology and size in their state / region has been used. Between 2020 and 2030, a 1% per year of real increase in the variable costs has been assumed, which is half the historical growth rate of Coal India Limited's actual coal prices. Figure 27 shows the supply curve of the coal fleet (at individual unit level) for FY 2020. Each point on the chart represents a thermal power plant unit in the country; the horizontal axis shows cumulative total installed capacity of the fleet in MW while the vertical axis shows the variable cost in Rs/kWh.

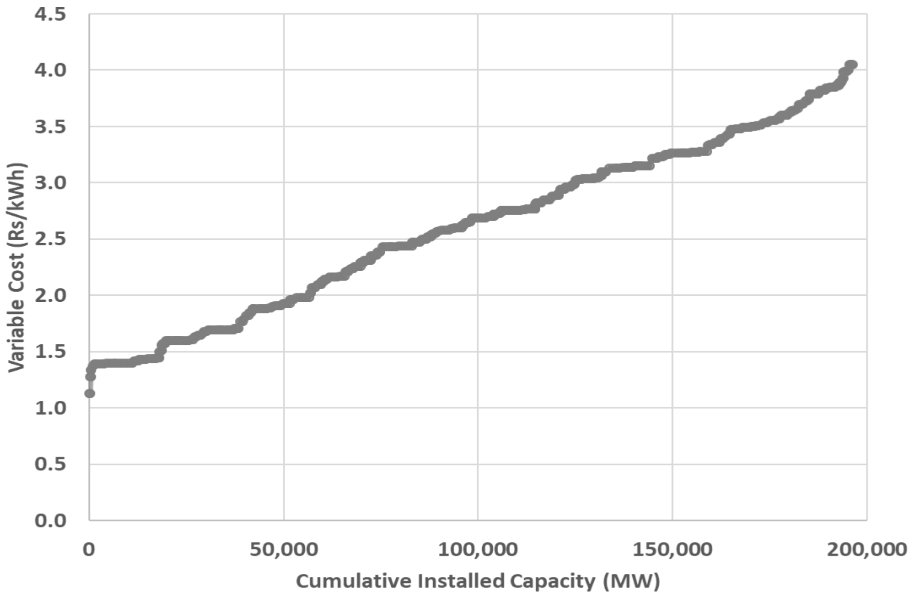


Figure 27: Supply Curve of the Existing Coal Capacity in FY 2020

It is interesting to note that in FY 2020, nearly 90 GW of the coal capacity had a variable cost of higher than Rs 2.76/kWh, the average solar reverse auction price including the safeguard duty. For new coal power plants, a pithead coal price of Rs 2000-2500/ton (incl taxes) has been assumed, which is equivalent to a variable cost of Rs 1.59/kWh, increasing at 1% per year (half the historical growth rate of Coal India Limited's actual coal prices) between 2020 and 2030. Imported coal prices are taken from global market reports at the Indonesian hub. Average delivered price imported coal is assessed to be $70/ton in FY 2020 increasing at 1% per year, which is equivalent to a variable cost of Rs 3.5/kWh for coastal power plants, after accounting for the improvement in heat rates due to imported coal.

6.7 Gas Prices and Supply Constraints

It has been assumed that the total domestic gas availability for power sector will remain constrained at the 2020 levels (8.4 bcm/yr or 23 mmscmd). Total LNG import capability would increase from 15 million tons per annum (MTPA) in 2020 to 50 MTPA in 2030. Domestic gas price in 2030 is assumed to remain almost the same as 2020 ($4.2/mmbtu). LNG price in 2020 is assumed to be $3.5/mmbtu (FOB) or $4.5/mmbtu (landed). For 2030, two LNG price scenarios are examined: 1) Base LNG price:

landed price of \$5.5/MMBTU (plus regasification cost of \$0.6/mmbtu and pipeline charges, as applicable), and 2) Low LNG price: landed price of \$4.5/MMBTU (plus regasification cost of \$0.6/mmbtu and pipeline charges, as applicable).

6.8 Heat Rate

Actual heat rate data is used for every power plant using several sources such as regulatory filings, CEA Thermal performance review, CEA CO2 Emissions Baseline etc. The heat rate is modeled as a function of generator loading, meaning that as the power generation from a unit drops, the heat rate will increase. The heat rate function is taken from the CERC regulations on compensating the generators for partial load operations. Figure 28 shows the heat rate function used for a new 660 MW super-critical power plant.

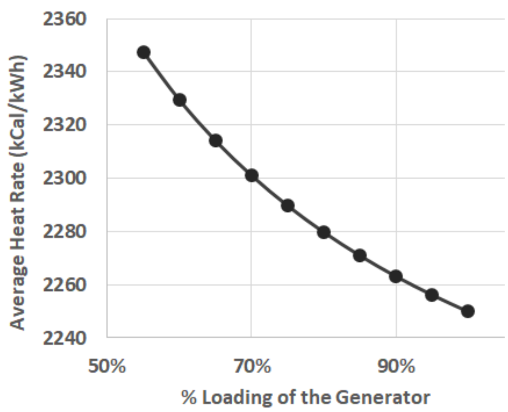


Figure 28: Average heat rate of a coal unit (660 MW super-critical) as a function of unit loading

At technical minimum level of 55%, the heat rate increases by over 4% of the design heat rate at rated capacity.

6.9 Limitations of the Model

- The Karnataka state is built as an integrated model within the National grid, but other states/UTs generation capacities are lumped together based on technology.
- In base and low RE case, CAGR based load projections has been considered for the State till 2030 and for all other States, EPS based projections are considered.