THE ENERGY AND RESOURCES INSTITUTE
Creating Innovative Solutions for a Sustainable Future

Low Carbon Pathways for Madhya Pradesh

Prepared for
Energy Department
Government of Madhya Pradesh

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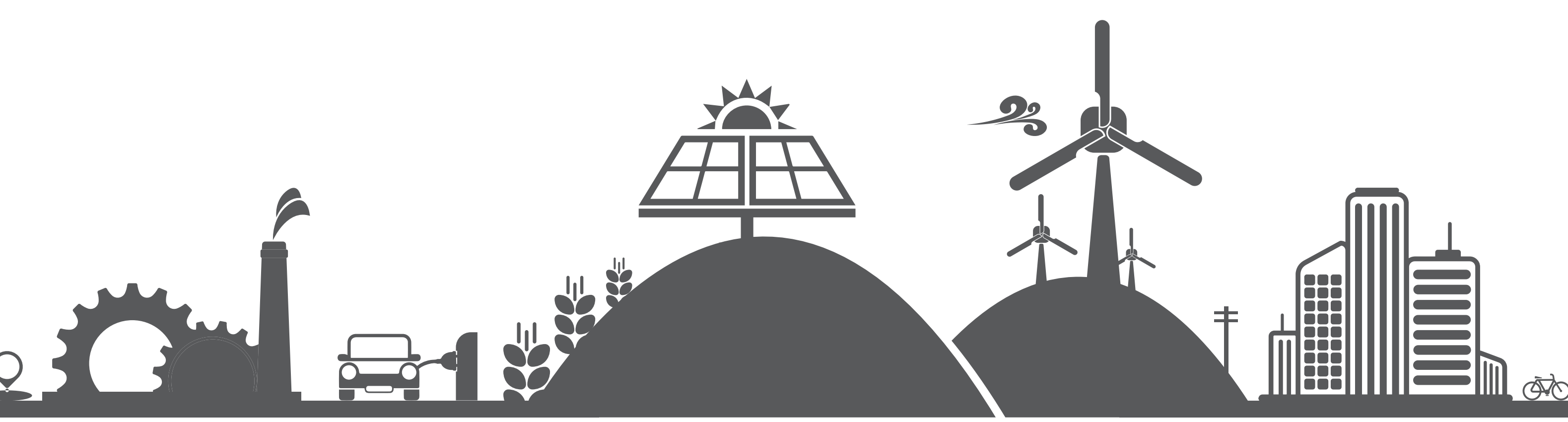

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Low Carbon Pathways for Madhya Pradesh

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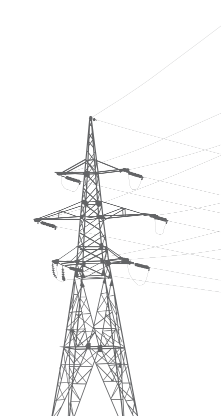

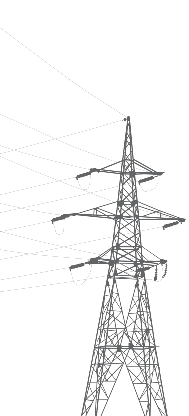

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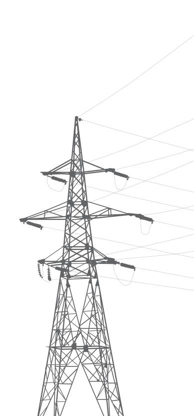
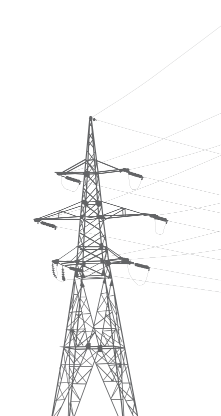


List of Abbreviations

AT&C	Aggregate Technical and Commercial
BESS	Battery Energy Storage System
CAGR	Compounded Annual Growth Rate
CEA	Central Electricity Authority
EoDB	Ease of Doing Business
GHG	Greenhouse Gas
GDP	Gross Domestic Product
GVA	Gross Value Addition
HBC	High Battery Cost
HDR	High Discount Rate
HrBC	Highest Battery Cost
INDC(s)	Intended Nationally Determined Contributions
ISGS	Inter-State Generating Stations
LCoE	Levelized Cost of Energy
LRC	Low RE Cost
MPERC	Madhya Pradesh Electricity Regulatory Commission
MPPCL	Madhya Pradesh Power Corporation Ltd.
PPA	Power Purchase Agreement
PSO-CP	Power System Operation and Capacity Planning
PyPSA	Python for Power System Analysis
RBI	Reserve Bank of India
RE	Renewable Energy
RECs	Renewable Energy Certificates
RPO	Renewable Purchase Obligation
SGDP	State Gross Domestic Product
SVA	Service Sector Value Added
VA	Value Added
VRE	Variable Renewable Energy
WACC	Weighted Average Cost of Capital



Executive Summary

1. Climate change, greenhouse gas (GHG) emissions, environmental pollution coupled with improvement in generation and storage technologies and drastic reduction in their costs are driving the energy transition across the world. The developing countries, however, need to adopt an approach which addresses the above concerns duly taking note of adequacy, accessibility, and affordability considerations.

2. Low carbon pathways for power sector has been a subject matter of study in India since India's Intended Nationally Determined Contributions (INDCs) included a target of 40% non-fossil fuel capacity by 2030 and reduction of carbon intensity of economy by 30-35% by 2030 as compared to 2005 levels.

3. A study report for Renewable Power Pathways for the country by 2030[#], carried out by The Energy and Resources Institute (TERI) was released in 2020 by the Hon'ble Union Minister of Power and New & Renewable Energy. TERI with the consent and support of the Energy Department of Government of the Madhya Pradesh, undertook a study for the state in February 2021 as the state level low carbon pathways being the building blocks of national-level low carbon pathways. In the meantime, at COP26 in November, 2021 the Hon'ble Prime Minister of India announced that by 2030 India will, inter alia, (a) take its non-fossil fuel energy capacity to 500 GW and (b) meet 50% of its energy requirements from renewable energy.

4. The high renewable energy pathways study undertaken by TERI for Madhya Pradesh in the above backdrop had primary objective of finding out least cost investment in new generation plants over and above the ones which have already been planned, to meet the anticipated demand profile with least cost despatch of the generation fleet in the short and medium term.

5. The planning studies for the country or any state are carried out taking into account the evolution of demand, evolution of generation technologies and their efficiencies as well as their costs trajectories and ability of the generation sources to meet the flexibility, variability and intermittency contingent upon degree of VRE penetration. The increasing demand and changing consumptive behaviour of consumers driven by their ability and willingness to pay are expected to influence the daily and seasonal demand patterns. Such studies, therefore, need to adopt a scenario-based approach so as to present the macro view, which is likely to emerge with current level of understanding and projection of technologies and their costs as well as demand patterns.

6. The study (in Section 7 of the report) answers the following key questions in the context of low carbon pathways for the state:

    i. Given the under construction and planned generation capacity, what is the least cost investment in new generation capacity to meet the projected demand for electricity in 2025 and 2030? (Section 7.1)

    ii. What would be the future outlook of power system operation consequential to the change in the generation capacity mix due to RE integration? (Section 7.9, Section 7.10)

[#] https://www.teriin.org/sites/default/files/2020-07/Renewable-Power-Pathways-Report.pdf

iii. How does the new generation mix impact the system cost? Are there ways and means to reduce system cost further? (Section 7.6, Section 7.12, Section 7.15)

iv. How does the state meet the evening/peak load duly making use of higher degree of renewable energy sources? (Section 7.10, Section 7.15)

v. What is the role of existing thermal power stations in the time horizon of the study? (Section 7.10)

vi. How can the flexibility-daily and seasonal–be met? (Section 7.9, Section 7.10)

7. The study brings out the following impressions:

i. New investment: Considering the planned/under-construction capacity yielding benefit to the state, solar PV emerges as the least cost investment option in 2025 as well as 2030. (Section 7.1, Section 7.2)

ii. Potential for decarbonization: There is significant potential for decarbonisation of power sector in Madhya Pradesh. The share of RE in generation mix is expected to increase from 10% in 2019 to 15%-24% in various scenarios in 2025. The RE integration gathers momemtum post 2025 due to build-up of least cost technologies like solar PV and wind. The non-fossil generation which stood at 10% in 2019, could reach up to 58% with the degree varying in the four main scenarios as presented in Table 1 below.

Table 1: Non-fossil to fossil generation mix for four main scenarios, 2030

Baseline scenario	Low RE cost scenario	RPO40 scenario	RPO50 scenario
39% : 61%	47% : 53%	49% : 51%	58% : 42%

Please refer to Section 7.2, Section 7.5, Section 7.6, and Appendix 3 for more details.

iii. System cost: The system cost is sensitive to multiple factors like weighted average cost of capital (WACC), battery energy storage system (BESS) costs, peak load, and electricity demand. In 2025, the system cost lies in the range of ₹3.76-3.82/kWh in various scenario as compared to average power purchase cost (APPC) of ₹3.49/kWh in FY 21-22 representing a CAGR of 2.5% to 3.1%. In 2030, the lowest system cost of ~ ₹3.90/kWh is observed in low RE cost (LRC) scenario, ₹3.99/kWh in baseline scenario and highest ~₹4.20/kWh in RPO50 scenario which correspond to CAGR of 1.9% and 2.3%, respectively. The lowest system cost observed in LRC scenario is primarily due to the fact that the capital costs of solar PV and wind are assumed to be ~30% and ~20% lower than baseline solar PV and wind capital costs, respectively. The system cost, however, can be reduced by shifting of load from non-solar hours to solar hours. For example, 50% agriculture load shift demonstrated ~6% reduction in system cost in RPO50 scenario yielding ₹3.96/kWh, which happens to be quite close to lowest system cost in LRC scenario. Variability gap funding for battery energy storage systems would be helpful in off-setting the increase in system cost, thereby fostering deployment of solar PV in the state. (Section 7.12, Section 7.15, Section 7.16)

iv. While shifting of agriculture load to solar hours can result in shaving of evening peak demand, the evening peak requirements is to be supported by non-pithead plants. (Section 8.1)

v. The study results suggest that the operation of non-pithead coal plants undergo a change from base load operations to two shift operations to provide the flexibility requirements by 2030. The pithead coal plants however continue to support baseload operations. (Section 7.10, Section 7.11)

vi. The bulk of the flexibility requirements of the system by 2030 will be met by a combination of non-pithead coal plants and BESS. (Section 8.3)

vii. To meet the system demand cost-effectively requires reduction in the cost for RE technologies. This can be done by (a) timely payment to RE generators, (b) ensuring that the payment security mechanism remains truly functional, (c) transparently being able to demonstrate that the curtailment of RE generation, if any, is only on account of grid security considerations, and (d) energy shifting from evening to daytime hours, can help in achieving this goal. (Section 8.1)

8. The study is based on data provided by the state power utilities and assumptions which were firmed up based on discussions with the state authorities, and current level of understanding of evolution of technologies, their operational profiles and cost trajectories. In a scenario where the variances in the aforesaid attributes are bound to occur; the degree of variances and the timeframe for the same being open, the results should be taken in broad terms rather than absolute numbers. The study is expected to provide insights to the state power utilities to plan for the impending power sector transformation.

9. The study has been organised in seven sections giving introduction, methodology, scenario framework, electricity demand projections, electricity supply scenarios, summary of findings, and key recommendations.

1. Introduction

India's power sector has seen a huge transition during the last few years, driven primarily by climate change and energy security concerns. India's Intended Nationally Determined Contributions (INDCs) envisaged 40% non-fossil fuel capacity and 30-35% reduction in emissions intensity as compared to the pre-industrial level. Since then, there has been substantial addition of renewable energy (RE) and transmission capacities; supported by policies of the Government of India and the state governments. Many state governments including Madhya Pradesh have led the RE transition. The installed RE capacity in Madhya Pradesh increased from 0.2 GW in January 2011 to 5.4 GW in January 2022.

The power sector in Madhya Pradesh has witnessed a transformation, the power supply position improved considerably from 11.4% energy and 17.7 % peak deficit during FY 2010-2011[1] to an energy and peak surplus of 3% and 2.7%, respectively during FY 2018-19. Total electrified households in the state rose from 68.9% in 2015 to 100% in 2019. The AT&C losses in the state have also come down from 32% in 2011 to 25% in 2020.

As the demand for electricity grew to 55 TWh in 2019 from 16 TWh in 2003 at a compounded annual growth rate (CAGR) of 7.6%, capacity addition took place at a rapid pace, mostly contributed by coal capacity additions. From 2010 to 2020, 8.2 GW coal-based capacity was added in the state.[2] The state also witnessed a 5X growth in the renewable capacity additions from 2014 to a cumulative capacity of ~5.4 GW as on January 31, 2022. However, the share of coal generation in the electricity mix of the state remained fairly constant around 78-80% .

To promote power generation from renewable sources like biomass, small hydro, wind, and solar, the Government of Madhya Pradesh came up with a policy targeting each technology through the years FY 2011–12. While biomass and small hydro policies intended to create a suitable framework to promote these technologies; wind and solar policies targeted capacity addition of ~5500 MW for wind and an unlimited capacity addition for solar projects. In addition to these policy measures by the state, Madhya Pradesh Electricity Regulatory Commission (MPERC) has also increased the Renewable Purchase Obligation (RPO) in order to promote renewable energy. RPO in the state has been increased from 0.8% for 2011 to 24.5% in 2027.

In order to examine the feasibility of scaling up RE capacity in the state and assess its implications on the power system operation as well as financial implications, a study aimed at least-cost investment and least-cost economic despatch is essential to inform the broad directional way forward to Madhya Pradesh Power Department.

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1 https://cea.nic.in/wp-content/uploads/2020/03/lgbr-2010.pdf

2 https://www.mppgcl.mp.gov.in/

This study aims to assess the future capacity and generation portfolio in the state of Madhya Pradesh in the short and medium term—2025 and 2030—to meet the anticipated demand profile. The study provides assessment of key aspects such as (a) the degree of VRE generation which can be integrated with state grid, (b) the attendant system costs, and (c) impact on operation of the coal fleet.

The following sections of this report provide methodology adopted to fulfil the objective of this study, scenario framework, demand forecast, supply scenarios, capacity constraints and operating parameters of different type of generators followed by agricultural load shift scenarios, findings of the study, and conclusions with the key recommendations.

2. Methodology

2.1 Model Framework

The Python for Power System Analysis (PyPSA) toolbox was used for the study. PyPSA is an open-source software toolbox for simulating and optimizing modern electrical power systems over multiple time horizons. We use the PyPSA toolbox through a workflow for multi-period myopic power system operation and capacity expansion. This power system operation and capacity planning (PSO-CP) model developed using PyPSA has been termed by us as PyPSA-India. This model was tuned to accurately represent power system operation in India, and an appropriate temporal and spatial representation while bearing in mind the computational complexity. This granularity depends on the type of foresight in planning, viz., a limited or a perfect foresight.

2.2 Perfect Foresight Optimization for Capacity Planning

In this study, the model is configured to run multi-year investment optimization with a perfect foresight, i.e., the decisions on capacity addition of generation and storage technologies are made with a certainty of the future investments such as future electricity demand, technology costs, fuel costs, operating parameters, etc. The capacity planning for Madhya Pradesh power sector was carried out to 2030, with 2025 and 2030 being the two investment horizons. Recent developments in the PyPSA toolbox made it possible to carry out multi-investment perfect-foresight optimization. Figure 1 presents the schematic of the perfect-foresight optimization framework considered in this study.

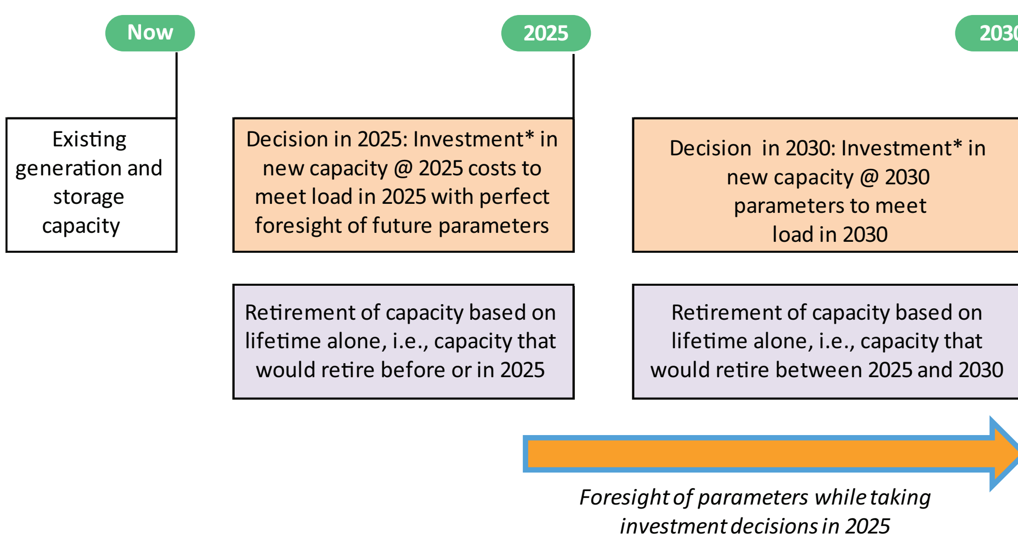

Figure 1: Perfect foresight optimization framework

2.3 Spatial and Time Scale Granularity

Spatial Granularity: In this study, the state of Madhya Pradesh is represented as one node in the model. The electricity demand is attributed to this node and all the generation and storage capacity is connected to this node, thus representing a copper plate model for the entire state.

Timescale Selection: The capacity build-up for each horizon year - 2025 and 2030 is optimized considering the time-varying electricity demand in the corresponding year. To reduce the computational horizon of the model, each month is represented by a continuous week (Monday–Sunday), considering a week that witnessed peak load for that particular month. Thus, reducing the number of hourly timestamps from 8760 to 2016 (7 days x 24 hours x 12 months). Peak load weeks are selected to ensure seasonality across the year as well as daily variation to meet the load across the day. Thereafter, the time series load data at an hourly resolution for the aforementioned representative weeks are appropriately stitched together to obtain a continuous load curve for the year.

Clustering of Despatchable Generators: The clustering of generators is done in order to reduce the computational complexities for the study[3]. The coal-based generating units (~42) having PPA (Appendix-1) with the state DISCOMs have been clustered based on their unit size, which by and large represents their operational characteristics (e.g., ramp rates, heat rate, minimum-up time). Similarly other plants like nuclear, hydro, gas are also clustered based on their operational characteristics.

Generation Portfolios: In capacity planning models, decisions are made to either build (or retire) generating units, storage, transmission capacity, etc., in any period. Furthermore, the decision to retire the asset (before the end of its useful life) can also be influenced by the avoided fixed O&M cost that the generating unit would have to pay had it been in operation, thus forcing the asset to retire before the end of its useful life[4]. In the present study, the retirement and addition of coal-based plants are however based on the retirement capacity as communicated by the MP State Planning Cell.

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3 B. Palmintier and M. Webster, "Impact of unit commitment constraints on generation expansion planning with renewables," 2011 IEEE Power and Energy Society General Meeting, 2011, pp. 1-7, doi: 10.1109/PES.2011.6038963.

4 The technical lifetime is the maximum operating age of the plant, after which it must be retired or refurbished.

Battery Energy Storage System: In this study, the BESS is modelled, as shown in Figure 2. Its inverter capacity (MW/MVA) and the storage capacity (MWh) are optimized while limiting the maximum inverter capacity to ensure a maximum discharge rate of 1C (typical of a Lithium-ion battery). BESS charges through a charging link and discharges through a discharging link to model charge and discharge through an inverter. The lifespan of the BESS is assumed to be ten years limiting the maximum throughput of the BESS system to 365 cycles per year.

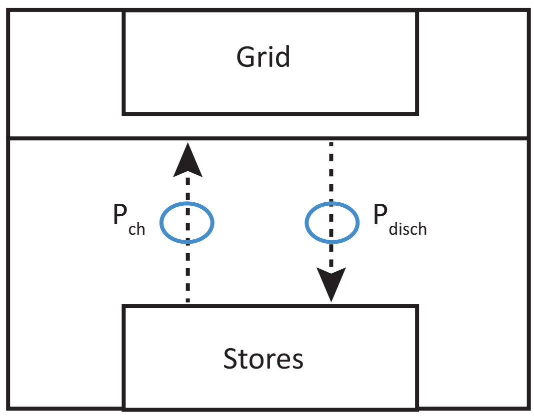


Figure 2: Representation of battery storage in the model

3. Scenario Framework

In this study, scenarios are framed considering the variables: capital costs of BESS and RE, cost of capital/ discount rate, electricity demand considering (baseline, high, low growth), and RPO. Different scenarios based on these variables are discussed in the following section along with input assumptions and their significance as summarized in Table 2.

Table 2: Scenario framework

Scenarios
Baseline Scenario (BCS)
Highest BESS Cost Scenario (HrBC)
High BESS Cost Scenario (HBC)
Low RE Cost Scenario (LRC)
High Discount Rate Scenario (HDR)
High Peak Load Scenario (PL)
High Electricity Demand Scenario (HD)
Low Electricity Demand Scenario (LD)
RPO50 Obligation by 2030 Scenario (RPO50)
RPO40 Obligation by 2030 Scenario (RPO40)
Agricultural Load Shift study

3.1 Scenarios Based on Cost

The Capital Cost of BESS: Most of the medium-term cost projections for BESS have considered current BESS costs as the starting point. However, it is underlined that there is a considerable difference even in the current costs assumed in many BESS capital cost projections[5,6] (PNNL, NREL). Due to the high level of uncertainty in regard to BESS cost trajectory, we have considered two scenarios, namely the High_BESS_cost scenario and the Highest_BESS_cost scenario. It may be noted that costs are considered for a 4-hour discharge duration BESS. Hence, any comparisons for BESS costs should be made considering the same duration.

The Capital Cost of RE: The consultations with various stakeholders in India suggested that the trajectory of capital costs of utility-scale solar PV and onshore wind may be relatively high considering past trends and associated forecasts. Hence, we considered it appropriate to assume a relatively high capital cost of

5 https://www.pnnl.gov/available-technologies/energy-storage

6 https://www.nrel.gov/docs/fy21osti/79236.pdf

solar and wind in the baseline scenario. Table 11 in Section5.2 shows that they are somewhat higher than cost projections assumed in the literature.

Cost of Capital: The cost of capital has a significant impact on investments in new technologies; risk perception being a major influencer. For the purpose of this study, weighted average cost of capital (WACC) of 10% has been considered for all the scenario families and one sensitivity scenario is assumed with a higher cost of capital of 15%[7] as presented in Table 3.

Table 3: Capital cost and discount rate assumptions for the scenarios based on costs

<table>
<tr><th>Parameter/Scenario</th><th>BCS</th><th>LRC</th><th>HrBC</th><th>HBC</th><th>HDR</th></tr>
<tr><td>Total Electricity Demand</td><td rowspan="6">BCS</td><td rowspan="2">BCS</td><td rowspan="3">BCS</td><td rowspan="3">BCS</td><td rowspan="5">BCS</td></tr>
<tr><td>Peak Demand</td></tr>
<tr><td>Capital Cost (RE)</td><td>As per Table 4 below</td></tr>
<tr><td>Capital Cost (BESS)</td><td rowspan="3">BCS</td><td>164$/kWh
131$/kWh</td><td>124$/kWh
94$/kWh</td></tr>
<tr><td>CUF (RE)</td><td rowspan="2">BCS</td><td rowspan="2">BCS</td></tr>
<tr><td>Cost of Capital</td><td>15% Discount Rate</td></tr>
</table>

Table 4: Capital costs assumptions in low RE cost (LRC) scenario

RE_Low_cost	2025	2030
Capital cost: RE - Solar (₹Cr/MW)	3.4	3.3
Capital cost: RE - Wind (₹Cr/MW)	5.3	5.2

3.2 Scenarios based on Electricity Demand and Peak Load

Energy Requirement and Peak Demand: Demand projection in this study depends on the assumed growth rates in each end-use sector, making it inherently sensitive to the uncertainty around various assumptions. For this purpose, we consider two additional scenarios depending on the aggregate electricity demand (TWh), namely the Low Demand scenario and the High Demand scenario. Additionally, we considered one more scenario namely "High Peak Load" to assess the impact of the load factor on the total demand. The electricity demand and peak demand assumptions considered in all scenarios are given in Table 5.

7 https://www.iea.org/articles/the-cost-of-capital-in-clean-energy-transitions

Table 5: Electricity demand and peak demand assumptions for scenarios based on electricity demand and peak load

<table>
<tr><th>Parameter/Scenario</th><th>BCS</th><th>Low demand</th><th>High demand</th><th>Peak Load</th></tr>
<tr><td>Total Electricity Demand (TWh)</td><td rowspan="6">Baseline</td><td>138</td><td>148</td><td>142</td></tr>
<tr><td>Peak Demand (GW)</td><td>23.9</td><td>25.7</td><td>27</td></tr>
<tr><td>Capital Cost (RE)</td><td rowspan="4">Baseline</td><td rowspan="4">Baseline</td><td rowspan="4">Baseline</td></tr>
<tr><td>Capital Cost (BESS)</td></tr>
<tr><td>CUF (RE)</td></tr>
<tr><td>Cost of Capital</td></tr>
</table>

3.3 Scenario Based on Renewable Purchase Obligation

RPO target for Madhya Pradesh for 2026-27 is 24.5%. Given the ambitious targets announced by India at the COP26 in November, 2021 it is considered necessary to explore the feasibility of higher RE generation/procurement by the state. Accordingly, we set out two distinct scenarios that consider RPO targets for 2030 as 40% and 50% as shown in Table 6.

Table 6: RPO assumptions for scenarios based on RPO for 2030

Parameters/Scenarios	BCS	RPO40	RPO50
All Parameters	BCS		
RPO	0%	40% (2030)	50% (2030)

*For BCS data, please refer Appendix 1

4. Electricity Demand

Demand forecasting is undertaken by states and Central Electricity Authority (CEA) to assess the generation, transmission, and distribution requirements. In the present scenario, when India is at the cusp of clean energy transformation, demand forecasting coupled with projection of granular daily demand profile across the year can be used to develop key insights like balancing power requirements, impact on coal fleet operations, energy storage requirements, etc. This enables the state governments to peep into the future and plan better with respect to the allocation of resources, take policy initiatives pro-actively to be future-ready.

While the focus on renewables has led to the need of higher analytical rigour in demand forecasting, COVID-19 pandemic has added complexities in forecasting. The multiple waves have created uncertainty in the recovery of economic growth with a varying impact on different sectors. These uncertainties required demand forecasting considering different growth scenarios.

The subsequent sections give a brief overview of the structure of economy for the state, status of the electricity sector, methodology and assumptions for demand estimation, sectoral level results, and findings.

4.1 Electricity Demand in Madhya Pradesh

State's electricity consumption in 2019 increased to ~56 TWh with a CAGR of 7.6% from ~16 TWh in 2004 as observed from Figure 3. The key drivers to this increased demand and their respective growth rates during the aforesaid period are residential (9.2%), agriculture (8.9%), industry (6.9%), and services (6.5%). The sectoral composition of demand in Madhya Pradesh in 2019 is presented in Figure 4. It is observed that agriculture continued to be the highest consumer of electricity with a share of ~ 41% in total electricity consumption followed, by residential (26%), industry (21%), and services (12%).

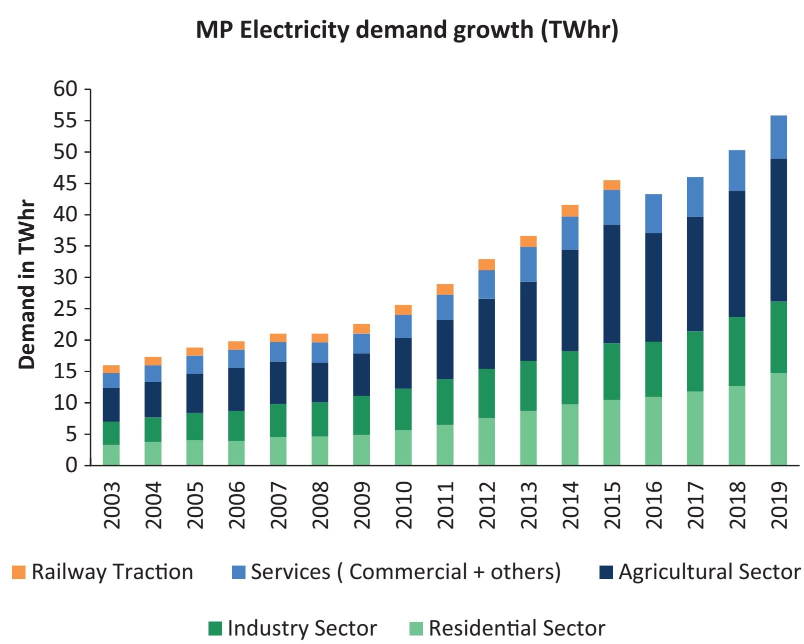


Figure 3: Historical electricity demand in Madhya Pradesh in 2019

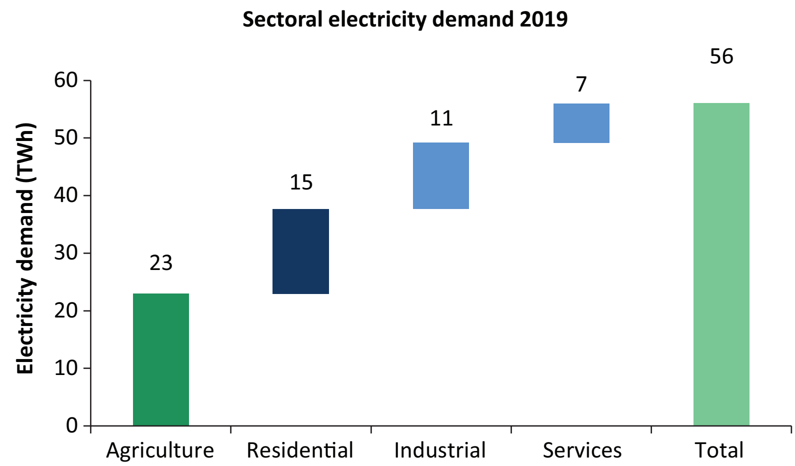


Figure 4: Sectoral composition of demand in Madhya Pradesh in 2019

A granular examination of the energy intensity of the state's economy provides an understanding of the contribution of electricity in demand driving sectors/ overall State Gross Domestic Product (SGDP). Madhya Pradesh's gross domestic product, at constant prices with the base year as 2011-12 was ₹5618 billion in 2019. While gross value added (GVA), i.e., GDP adjusted with taxes and subsidies of agriculture, industry, and services was ₹1200 billion, ₹1403 billion, and ₹2120 billion, respectively. Figure 5 presents the energy intensity of major demand drivers with agriculture as the leader amongst all the sectors. Agricultural energy intensity is high due to the fact that the gross irrigated area of Madhya Pradesh has increased from 6,193,000 ha in 2003 to 11,385,000 ha in 2019 and increased dependence on groundwater (than rainfall) irrigation. For other sectors, we see a marginal increase in energy intensity, which can be attributed to the improved energy efficiency in technologies and appliances.

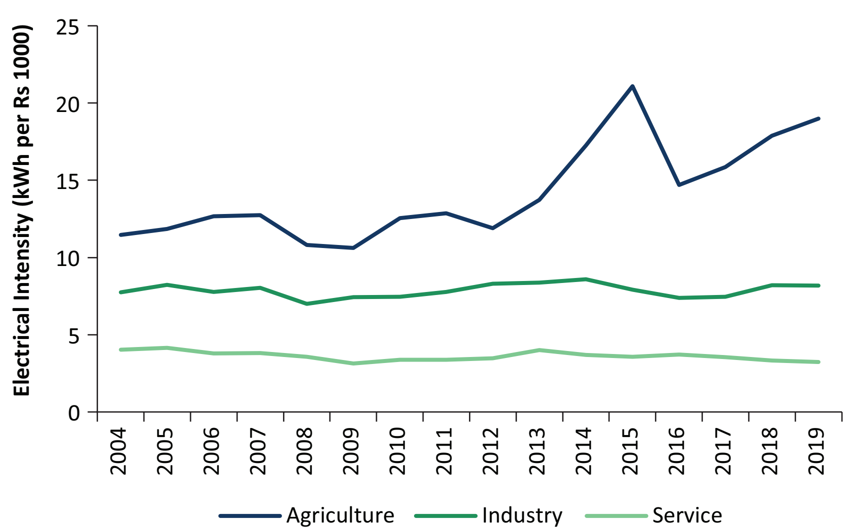


Figure 5: Electrical intensity trend for agriculture, industry, and services sector (kWh/₹1000)

4.2 Approach and Methodology

Econometric approach was adopted for the projection of electricity demand to 2030. This approach was necessary in order to appropriately investigate and represent the impact of COVID-19 on the state's economy and thereby electricity consumption. The data collection and demand projection approach comprised the following:

◊ Data in respect of electricity demand was collected from MP Power Planning Cell and the macro-economic data such as SGDP, sectoral value added (VA), gross irrigated area, etc., were sourced from Reserve Bank of India (RBI).

◊ Establishing historical relationships amongst key indicators with electricity demand.

◊ Developing scenarios for economic growth trajectories to project electricity demand by 2030 using the established relationship.

In the subsequent sections, we briefly explain the scenario framework and the methodology adopted for each sector.

4.3 Scenario Framework and Macro-economic Assumptions

Three different scenarios were developed to account for the uncertainty in mid-term economic growth pathways - low growth scenario, baseline growth scenario, and high growth scenario. These growth scenarios and their macro-economic assumptions are described in Figure 6.

Demand Scenario		
	Low growth scenario	• Economy growth assumed to be lower by 0.4 percentage points post COVID recovery. • The y-o-y agriculture value added would be relatively high with respect to other sectors.
	Baseline scenario	• Economy growth between 2023 and 2030 assumed to be same as pre COVID years. • "U" shaped recovery to take into account first and second waves of COVID-19. • Economy will resume its growth from FY 2023 onwards.
	High growth scenario	• Economy growth assumed to be higher by 0.4 percentage points post COVID recovery. • The y-o-y agriculture value added would be relatively low with respect to other sectors as a result of rapid urbanization.

Base year - 2019		Total GVA growth %	Industry VA growth %	Services VA growth %	Agriculture VA growth %
Historic	CAGR (2004-2019)	7.22%	7.02%	8.05%	6.18%
	2020-21	-4.00%	-4.00%	-8.00%	4.00%
COVID Recovery	2021-22	-0.50%	1.00%	-6.00%	5.00%
	2022-23	5.00%	5.00%	4.00%	6.00%
Future growth in each year between 2023 and 2030	Baseline growth scenario	7.22%	7.02%	8.05%	6.18%
	High growth scenario	7.60%	7.60%	8.60%	6.00%
	Low growth scenario	6.80%	6.40%	7.40%	6.40%

Figure 6: Scenario framework for demand estimation to 2030

Source: TERI assumptions

4.4 Sectoral Level Methodology, Assumptions and Results

4.4.1 Agricultural Sector

The agriculture sector demand accounts for the highest (~41%) of the state's total grid demand, and has grown at the CAGR of 8.9% between 2004 and 2019. This growth rate is primarily due to increased gross irrigated area and increased reliance on groundwater irrigation and reduced dependence on rainfall which can be erratic. This is evident from the increased pumping capacity and increased pumping hours between the period 2004 and 2019. Figure 7 represents both these trends.

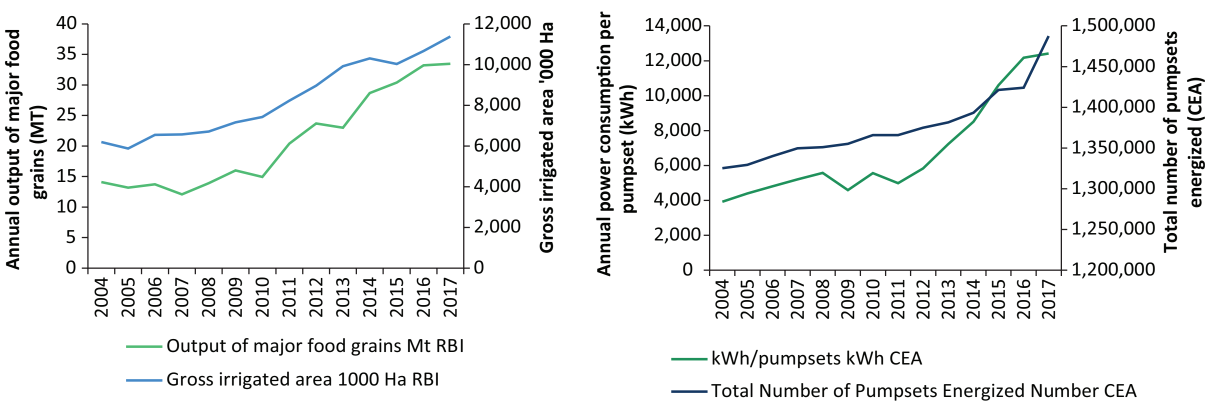


Figure 7: Gross irrigated area and food grains production; number of pump sets and load

For projecting the demand, the historical relationship of agricultural sector VA, gross irrigated area, and the output of major food grains, state's average rainfall, etc.; with respect to electricity consumption (Table 7) were explored. It was found that a robust fit (R^2=0.976) exists between the output of major food grains to agricultural sector consumption. Hence, this was chosen for projecting the agricultural sector electricity demand.

Table 7: Correlation matrix of variables in agricultural sector

	Agricultural value added	Electrical intensity of agricultural production	Output of major food grains	Average state rainfall	Gross irrigated area	Agricultural consumption
Agricultural value added	1					
Electrical intensity of agricultural production	0.581794	1				
Output of major food grains	0.960398	0.74756	1			
Average state rainfall	0.311109	0.025763	0.229502	1		
Gross irrigated area	0.969533	0.708156	0.968485	0.273008	1	
Agricultural sector consumption	0.914992	0.857488	0.976571	0.185522	0.956883	1

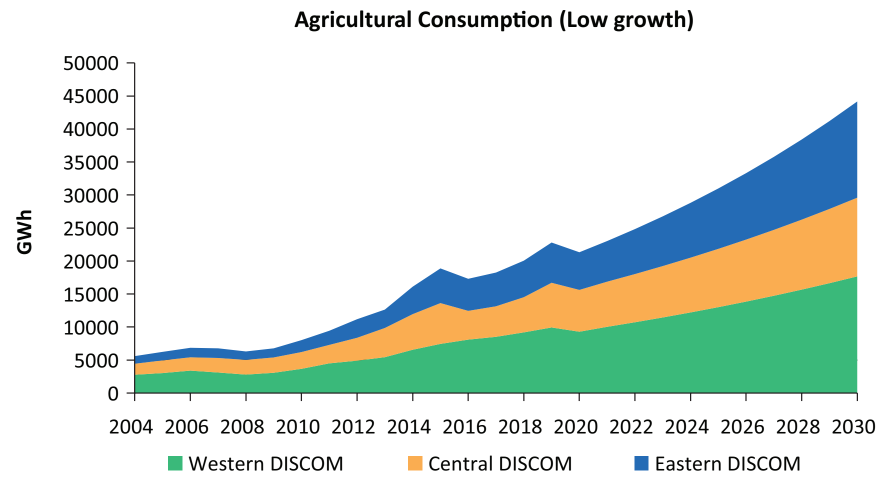
Source: TERI analysis based on RBI, 2020, CEA, etc.

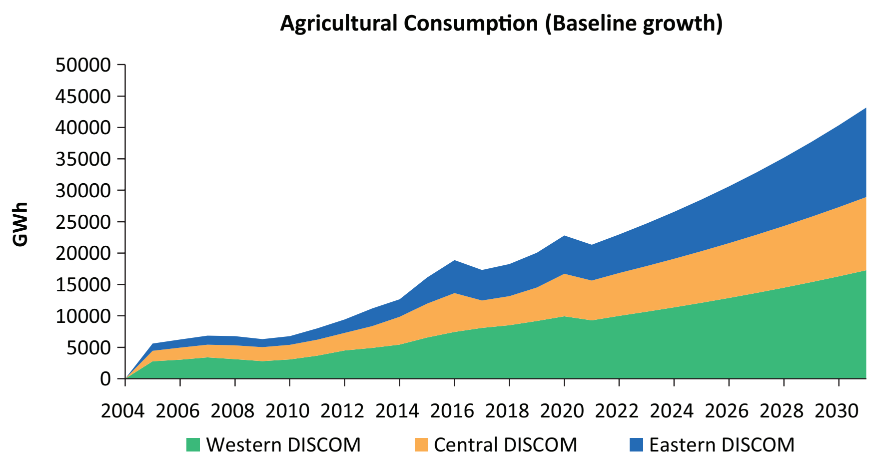
The output of food grains was then projected utilizing the relationships between agricultural GVA and gross irrigated area. The results suggest that, the agriculture sector demand is likely to grow at CAGR of 5.7%–5.3% reaching out to 44 TWh, 43 TWh, and 42 TWh by 2030 in low, baseline, and high growth scenarios, respectively. This is due to the general phenomenon that high growth scenarios result in higher industrial growth and negative agricultural growth. Figure 8 shows the agriculture demand projections in various scenarios.

4.4.2 Residential Sector

The residential sector is the second-highest electricity-consuming sector in the state with a share of 26% in the state's total grid demand and has grown at a CAGR of 9.2% between 2004 and 2019. The growth in consumption was mainly contributed by the rural households, which grew at CAGR of 13% since 2004 and contributed ~45% of the total residential demand in 2019. The state's growing per capita income has majorly driven this growth in household energy consumption.

For projecting the demand, the relationship between state's per capita income, SGDP and historical household electricity consumption was explored. A robust fit (R^2=0.99) exists between both these factors and hence SGDP was adopted to project the residential demand based on regression. The results suggest that, the residential demand in the state of Madhya Pradesh is expected to grow at CAGR of 5.5%–6.2% reaching out to 27 TWh, 29 TWh, and 30 TWh in the low, baseline and growth scenario respectively by 2030 as shown in Figure 9.





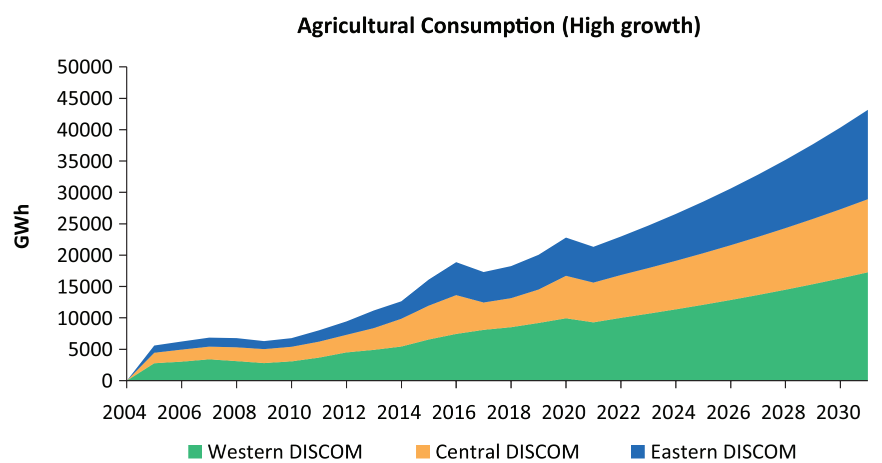


Figure 8: Electricity demand curve in baseline and high peak in 2030-31

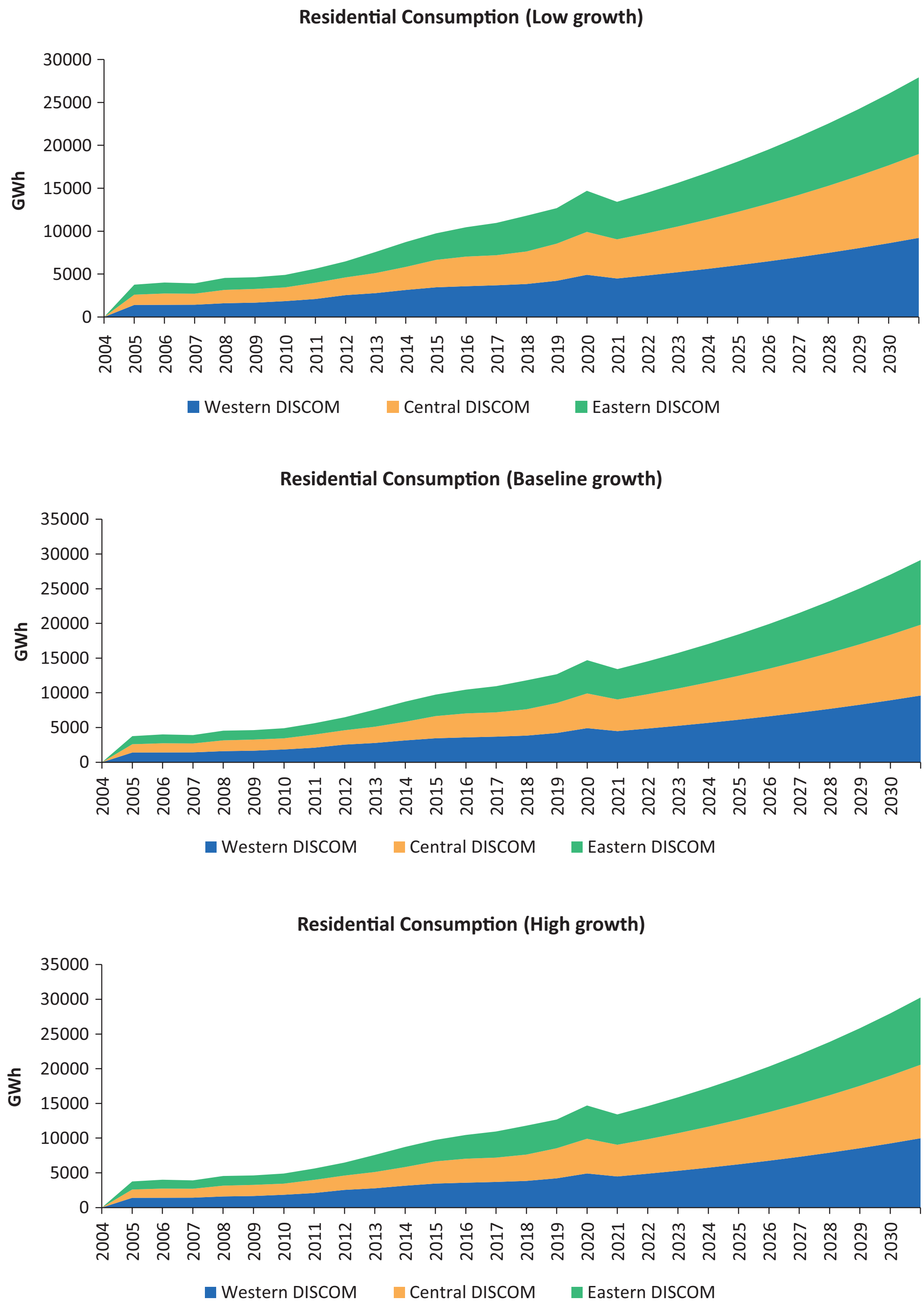


Figure 9: Results of residential demand projections in various scenarios

4.4.3 Industrial Sector

In terms of the total share in the state's electricity consumption, industrial sector (excluding captive) is third highest electricity consuming sector accounting for ~ 21% of the state's total grid demand. The sector has grown at a CAGR of 6.9% between 2004 and 2009. This growth, is likely to be due to the enabling business environment as can be seen from the ease of doing business (EoDB) rating. MP has been a consistent performer since the EoDB ratings were introduced in 2015 and figured twice in top 5 states and once in top 10 (MP's rank was 7) states.

To project the demand to 2030, the relationship between industry VA and historical industrial electricity consumption was explored. Having noted a robust fit (R^2=0.96), industry VA was chosen to project the sectoral demand based on regression. The results suggest that the industry sector demand is expected to grow at CAGR of 4.7%–6.1% reaching out to 20 TWh, 21 TWh, and 23 Twh in the low, baseline and high growth scenario, respectively to 2030. Figure 10 shows the industrial demand projections in various scenarios.

4.4.4 Service Sector

The service sector consists of the commercial and other segments including public water works, etc. The sector accounts for 12% of the total state demand, and has grown at the rate of 6.5% between 2004 and 2009. Within this sector, commercial sector has grown at the rate of 7.3% contributing ~47% of the total service sector demand in 2019. This demand is mainly driven by the state's growing urbanization rate, which was 27% of total population in 2004 and increased to 29% in 2019.

For projecting the demand, the relationship between service sector VA (SVA) and historical service sector electricity consumption was explored. SVA and the service sector's electricity consumption were found to have a robust fit (R^2=0.95), hence service VA is chosen for projecting service sector electricity demand. The results suggest that the service sector demand will grow at CAGR of 5.6%–6.9% reaching out to 13 TWh, 14 TWh, and 15 TWh in the low, baseline, and high growth scenario, respectively to 2030. Figure 11 shows the service demand projections in various scenarios.

4.4.5 Results

In overall terms, the state's electricity demand is expected to see a growth of 1.3 to 1.4 times by 2025 and 1.9 to 2.1 times by 2030 as compared to 2019 levels. In order to assess the total ex-bus electricity requirement, we assumed the T&D losses in the state would decrease to 22% by 2030 from ~24% (2019). Thus, we estimate that the total ex-bus requirement in low, baseline and growth would be 138 TWh, 142 TWh, and 148 TWh by 2030. This would translate to state's per capita electricity consumption of ~1414 kWh to 1516 kWh from the 2019 level of 892 kWh - increase of the order of 60% to 70%.

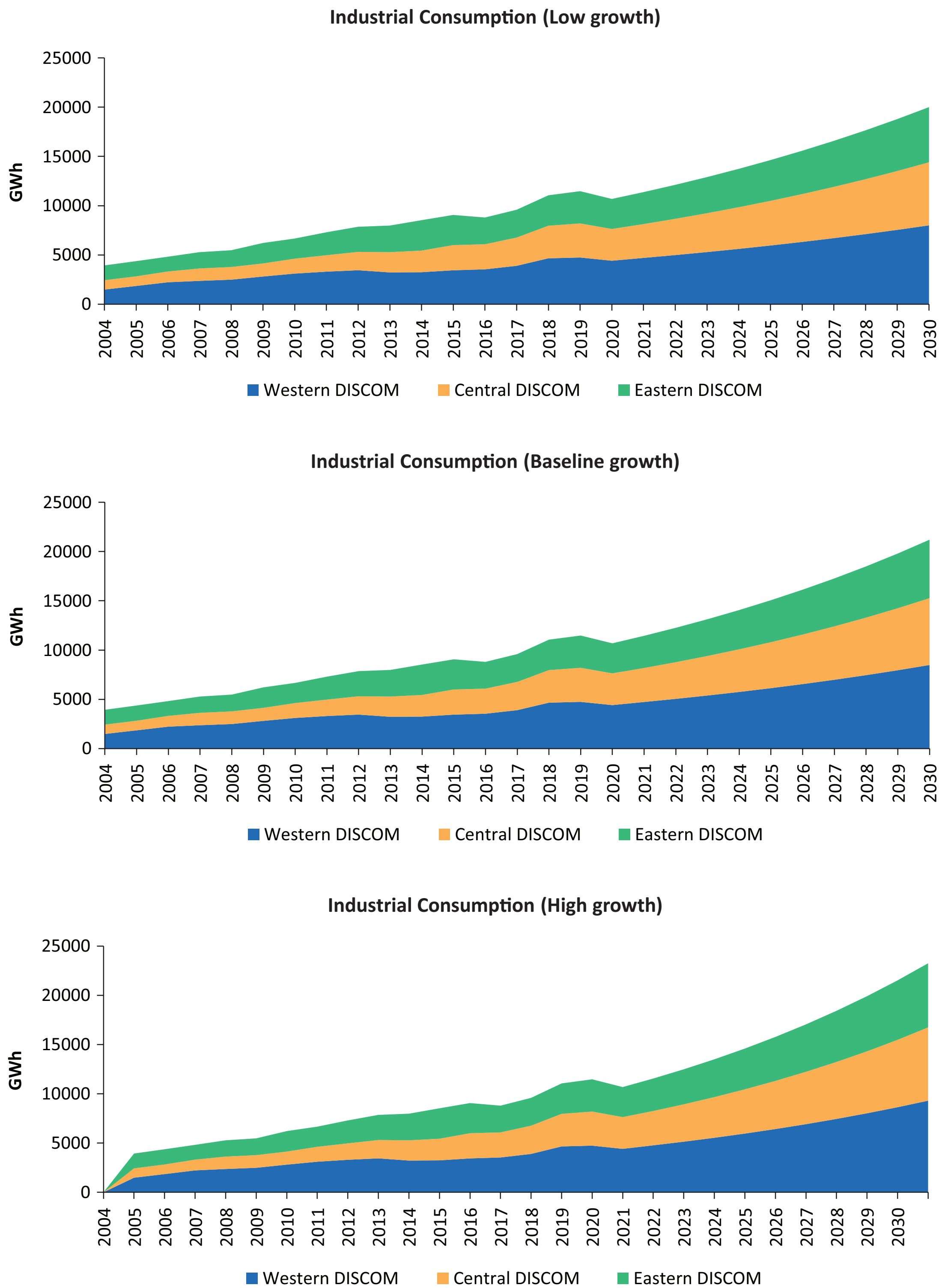


Figure 10: Results of industrial demand projections in various scenarios

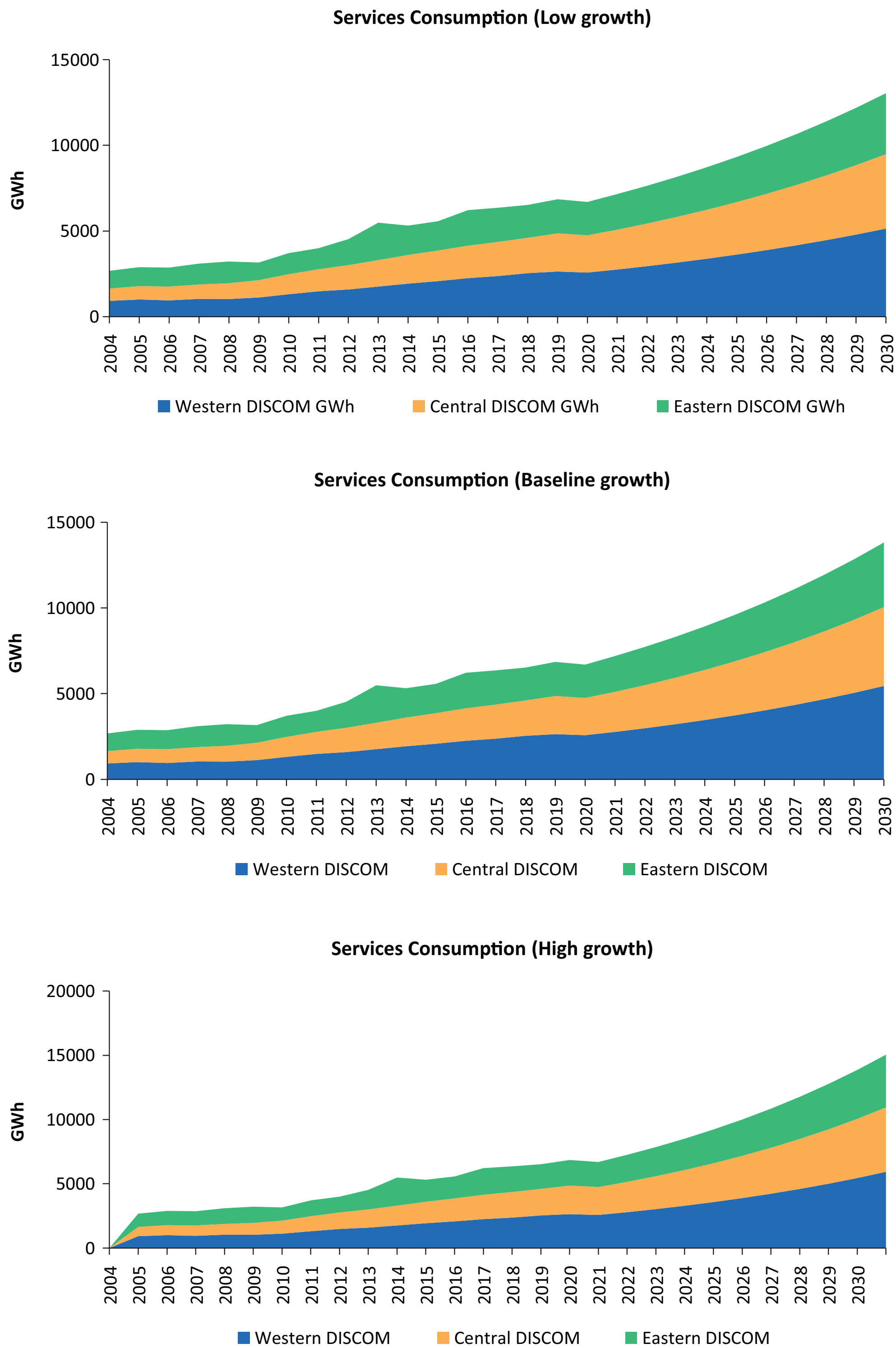


Figure 11: Results for service sector demand projections to 2030 in various scenarios

Table 8: Demand and energy requirement for Madhya Pradesh

Scenario	Year	Average demand (MW)	Peak demand (MW)	Load factor (MW)	Annual electricity demand (Ex-Bus) (TWh)
Base	2019	8,371	14,053	60%	73
Low growth	2025	11,345	17,937	63%	99
	2030	15,723	23,914	66%	138
Base line	2025	11,497	18,177	63%	101
	2030	16,200	24,639	66%	142
High growth	2025	11,740	18,562	63%	103
	2030	16,950	25,779	66%	148

Source : TERI analysis

4.4.6 Conclusions

The state's electricity consumption in 2030 is estimated to be of the order of 107–115 TWh, representing a CAGR of 5.6%-6.2% between 2019 and 2030. In terms of ex-bus requirement, this translates to 138–148 TWh in 2030 from 73 TWh level of 2019.

COVID-19 has impacted state's economy adversely, the SGDP terms declined by ~ 4% in 2020-2021. We considered three growth scenarios to account for a low, baseline, and high growth for four major demand sectors. The total demand along with its composition in terms of major demand sectors is presented in Figure 12.

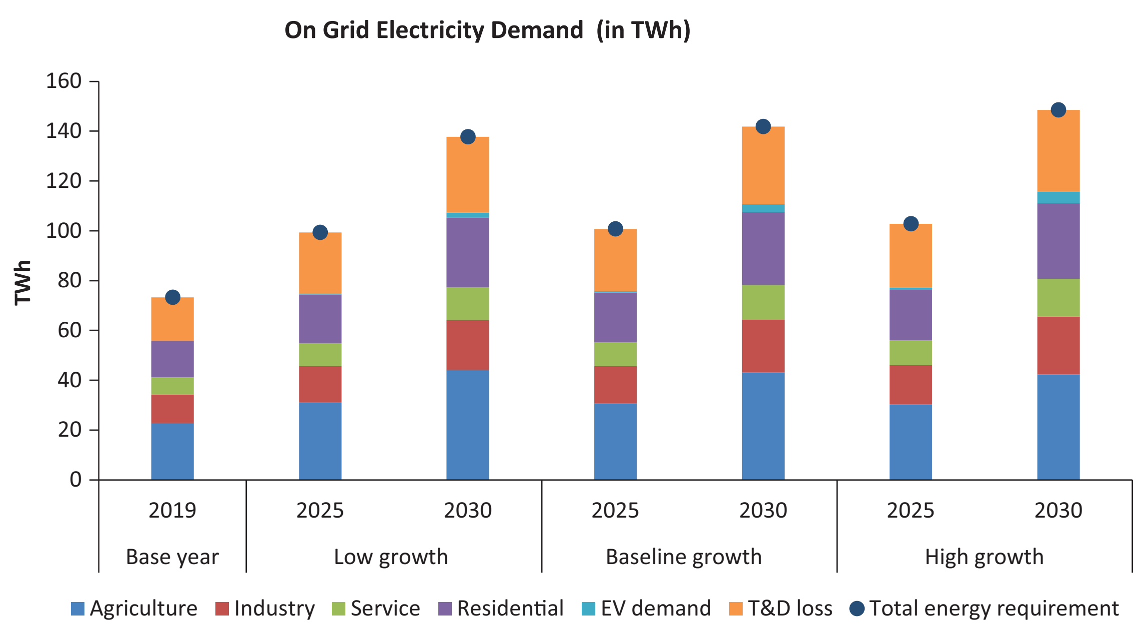


Figure 12: On grid electricity demand across the scenarios in 2025 and 2030

4.4.7 Load Curve

The electricity demand curve for 2019-20 depicted in Figure 13 forms the basis of projection of demand profile for 2025 and 2030. The base year profile is upscaled to shape the electricity demand profile for 2025 and 2030 considering the load factor for the respective year as per projections provided by the State Planning Cell for the high low growth, baseline growth and high growth scenarios.

Table 8 summarizes the findings related to average demand, peak demand and annual electricity consumption under the three scenarios considered in the study.

A sensitivity scenario considering a lower load factor of 60% has also been studied to include a high peak load scenario in the modelling exercise. The electricity demand and peak load are seen in Table 9.

The resultant demand curves for 2030 for the baseline and high peak load scenarios are presented in Figure 14, respectively.

Table 9: Electricity consumption and peak demand in high peak load (for baseline growth)

Scenario	Year	Average demand (MW)	Peak demand (MW)	Load factor	Annual electricity consumption (TWh)
High Peak Load	2025	11,497	19,162	60%	101
	2030	16,200	27,000	60%	142

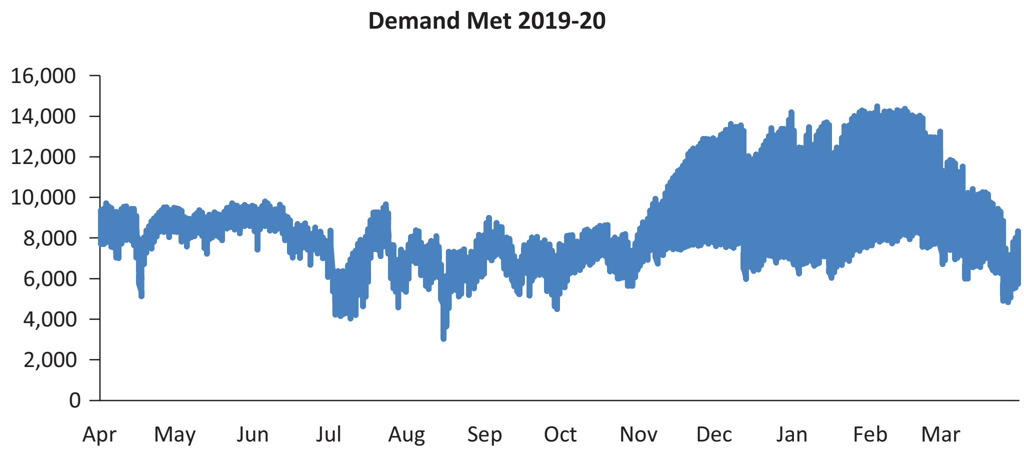
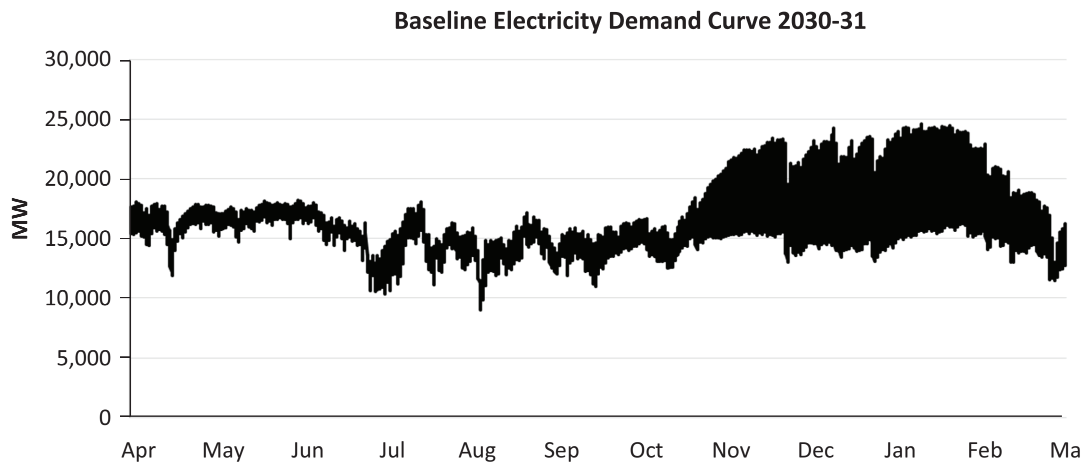


Figure 13: Electricity demand curve in 2019-20



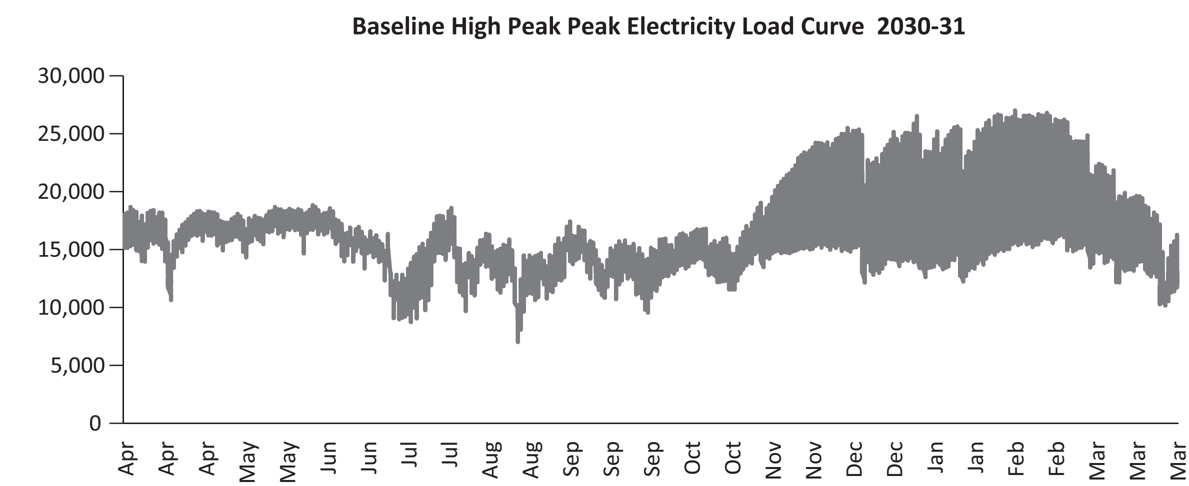


Figure 14: Electricity demand curve in baseline and high peak in 2030-31

5. Electricity Supply Scenarios

Post determination of the anticipated load profile in the target years, the next step in the modelling exercise is to identify and carry out technology-wise categorization of existing generation capacity. This is followed by exclusion of the plants for which a decision for retirement has been taken by the state authorities. Simultaneously, the pipeline capacity, i.e., new power plants which have been planned to be added were also to be considered as given. It may be noted that in the modelling exercise, usually a decision to retire a plant is taken based on useful life and capacity additions are based on LCoE while the capacity expansion model is run. However, in this study, the pipeline and retirement capacity provided by the MP State Planning Cell were considered as given.

5.1 Existing and Pipeline Generation Capacity

Table 10 shows the installed capacity of all generation technologies in 2020 and the proposed capacity addition and retirements by year 2030. Input data including existing capacity, planned capacity additions, and planned retirements have been duly considered in consultation with the Madhya Pradesh State Planning Cell.

Table 10: Existing generation capacity, planned retirements, and pipeline capacities

Particulars		Ex Bus Capacity (MW)
Existing Capacity@*		25,415
a	Coal	12,600
b	Gas	294
c	Nuclear	308
d	Hydro	3,358
e	Solar	5,877
f	Wind	2,978
Coal retirements by 2025**		830
Coal pipeline capacity 2025**		724
Coal pipeline capacity 2030**		3,427

@ including state sector & private sector power plants and share in inter-state generating stations

* Source: Madhya Pradesh Retail Tariff Order FY 20-21

** Source: Madhya Pradesh State Planning Cell

The cost-optimal decision on capacity addition depends on multiple factors including capital cost and useful life of each technology, exogenous constraints related to capacity addition, operating parameters, cost of capital or discount factor and cost of unserved energy. These parameters are elaborated in the succeeding sub-sections. It may be noted that discount factor for all the three growth scenarios is considered to be 10% and as mentioned in Section 3.1, a sensitivity is considered with high discount rate of 15%. We assume the cost of unserved energy to be ₹20/kWh, considered by CEA in their Optimal

Generation Mix Report for FY 2029-2030. Although the model meets 100% demand, it builds excess generation capacities for the last portion in the load duration curve to be met. Thus, the cost of unserved energy, serves as a deterrent for the model, i.e., in case there is a significant amount of unserved energy the model avoids building any such capacity and the total load shedding would have to be resorted for a small fraction of time.

5.2 Source-wise Capital Cost and Capacity Constraints

Table 11 shows the source-wise capital costs for the year 2025 and 2030 in the baseline scenario. It is to be noted that the capital costs are represented in real rupees (2020) without assuming inflation across the study horizon. Here, the plant lifetime assumes an economic lifetime over which the capital costs are annuitized till completion of its lifetime.

Table 11: Capital cost of useful life assumptions for various sources of generation in BCS (base year 2020)

Source	₹Crore / MW		Useful life (Years)
	2025	2030	
Solar PV Ground Mounted	4.8	4.7	25
Onshore Wind	6.8	6.6	25
Coal	8.0	8.0	25
Hydro Power (ROR)	9.5	9.5	40
Hydro Power (Pondage)	14.5	14.5	40
Gas	5.5	5.5	25
Nuclear (PHWR)	12.0	12.0	25
Nuclear (LWR)	19.0	19.0	25
BESS (in Million $ / MW) *	0.15	0.12	10

*Assuming 1 USD = ₹75

Source: TERI analysis based on NREL, BNEF, CEA Optimal Generation Mix Report FY 2029-2030

5.3 Operating Parameters

Table 12 shows the technology operating parameters such as technical minimum, minimum up-time and down-time, ramp rates, and start-up costs which have been used to model the unit-commitment constraints for thermal generators based on literature review[8] and actual operation of generating units. Along with these, we assume monthly energy constraints for hydro fleet based on the past 5 years generation data, thereby reflecting the seasonal variation in generation pattern defined by the monsoon.

Table 12: Operating parameters considered in the study

Parameter	Unit	Coal	Gas	Hydro
Technical Minimum	%	55%	40%	10%
Ramp Rate-Up	%/hr	60%	100%*	100%*
Ramp Rate-Down	%/hr	60%	100%*	100%*
Minimum Up-Time	Hours	6	3	0
Minimum Down-Time	Hours	6	3	0
Aux. Power Consumption (APC)	%	6%*	2.5%	1%
Outage %	%	10%	-	-
Start-up Costs	₹/MW	14,100	6,690	0

* The plants ramp up/down to full/zero capacity for gas and hydro is 12 minutes and 1 minute, respectively.

8 https://cea.nic.in/old/reports/others/planning/irp/Optimal_mix_report_2029-30_FINAL.pdf

6. Exploring Agricultural Load Shift

The demand forecast for Madhya Pradesh in Section 4 presents agriculture demand, with a share of 41%, 39% and 37% in total electricity demand, continues to be the highest consumption category in 2030 in low, baseline and high growth scenarios, respectively. From the demand profile projections it is also evident that agriculture sector demand plays a major role in state's peak demand profile as the peak demand period of the state is observed during peak pumping season of November to March. Thus, effective management of agriculture demand in the state assumes importance from system operation as well as power purchase cost perspective.

Considering the Hon'ble Prime Minister's announcements at COP26 in November, 2021; the DISCOMs would make best possible efforts to increase the share of renewable energy in the supply mix further. In such case of high RE share, the offset between agricultural peak demand and solar peak generation can result in high ramp-up and ramp-down requirements leading to high battery support requirement and consequently high system cost.

While MPERC recently specified RPO target as 24.5% for the year 2027, it was felt that a scenario of RPO50 also needs to be considered in a bid to examine the feasibility and implications of RPO as high as 50%. The system cost under this scenario was noted to be highest at ₹4.20/kWh mainly due to high BESS requirement, and increased fixed cost on account of high build-up of RE capacity.

In order to reduce the system cost in RPO50 scenario, an exercise was conducted to explore implications of shifting the agricultural load from non-solar hours to solar hours. Three scenarios were considered where 25%, 35% and 50% of the agricultural load was shifted to the solar hours for the year 2025 and 2030 for the baseline growth scenario–the most plausible scenario in our opinion.

The shift in agricultural demand is shaped in four main steps (a) agricultural demand profile is developed using 2018-19 MP load profile as reference, (b) the profile is then re-adjusted and re-scaled to match total agricultural demand of 42 TWh in 2030, (c) from this profile load to be shifted was arrived as a product of load during each hour, percentage of load shift required (25%, 35% & 50%) and the solar profile for the day and (d) the agricultural load shifted and the remainder agricultural load are added to the hourly load of other consumer categories to arrive at the new demand curve for the state.

The resultant demand profile for each of the aforementioned scenario of agricultural load shifting for 2025 and 2030 is depicted in Figures 15 to 20.

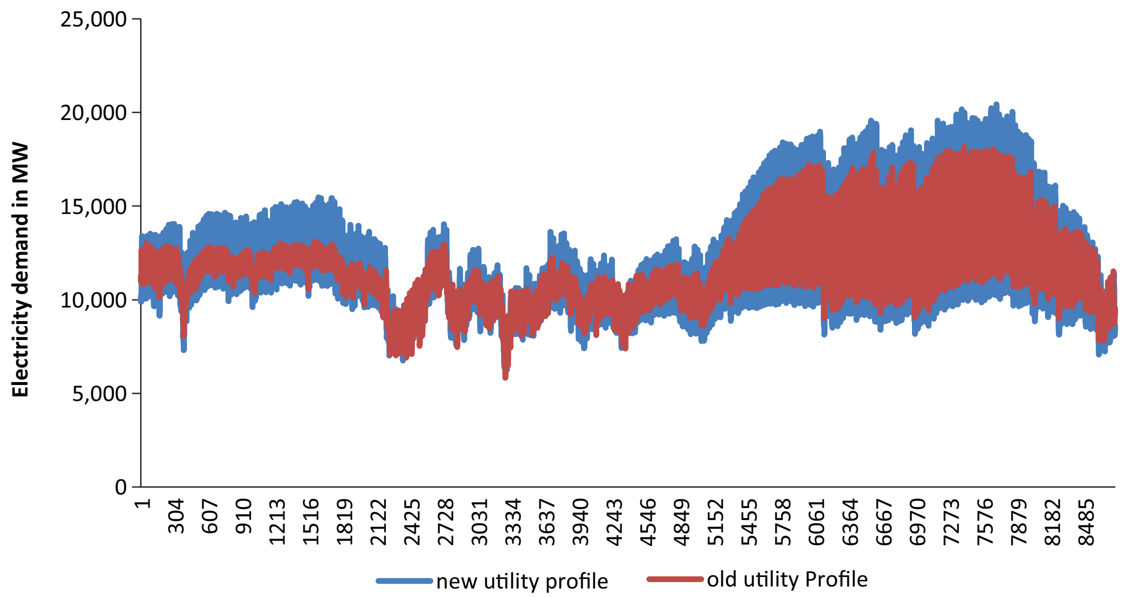


Figure 15: New demand profile for 2025 with 25% agricultural load shift

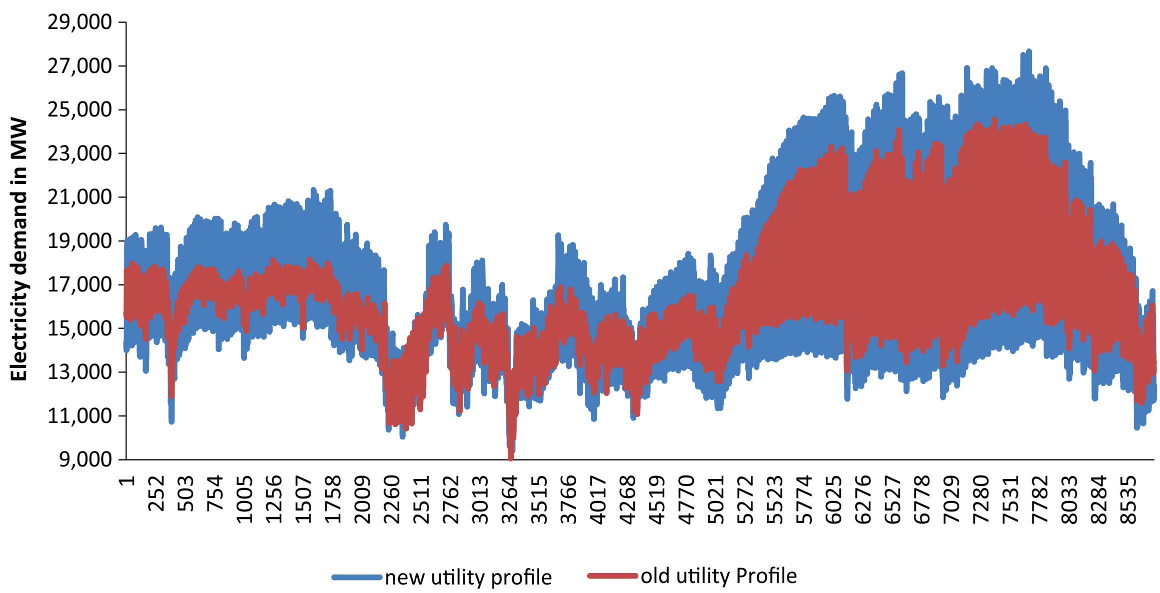


Figure 16: New demand profile for 2030 with 25% agricultural load shift

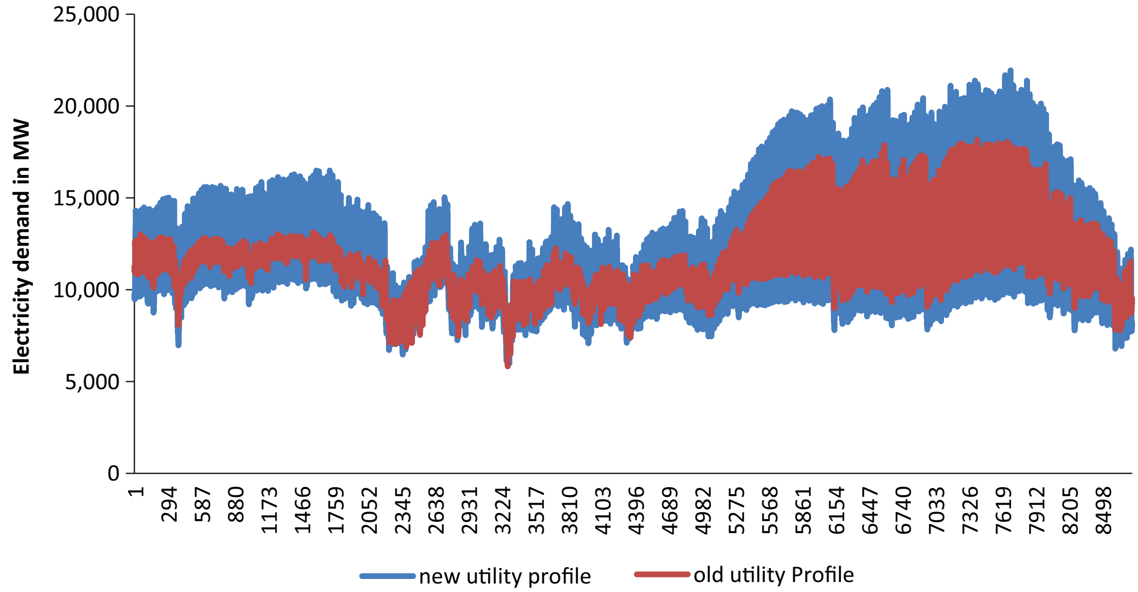


Figure 17: New demand profile for 2025 with 35% agricultural load shift

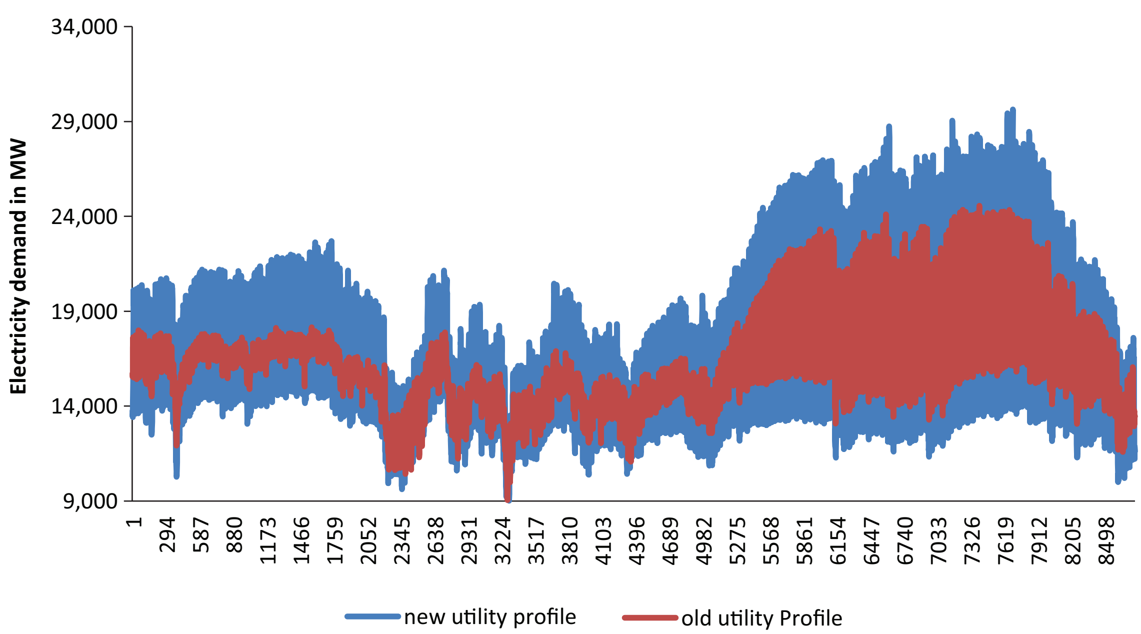


Figure 18: New demand profile for 2030 with 35% agricultural load shift

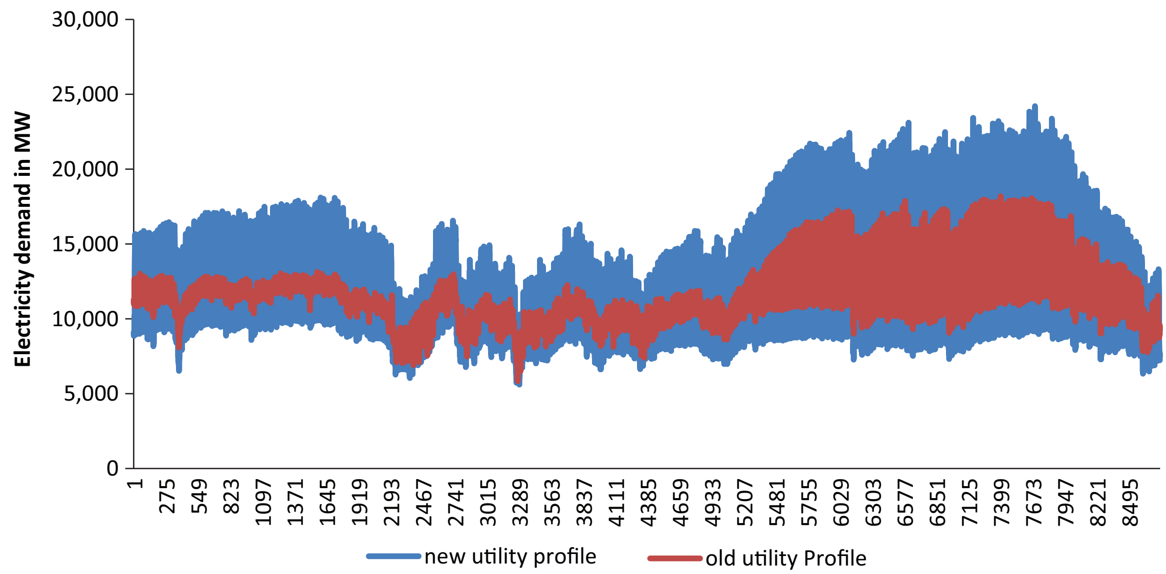


Figure 19: New demand profile for 2025 with 50% agricultural load shift

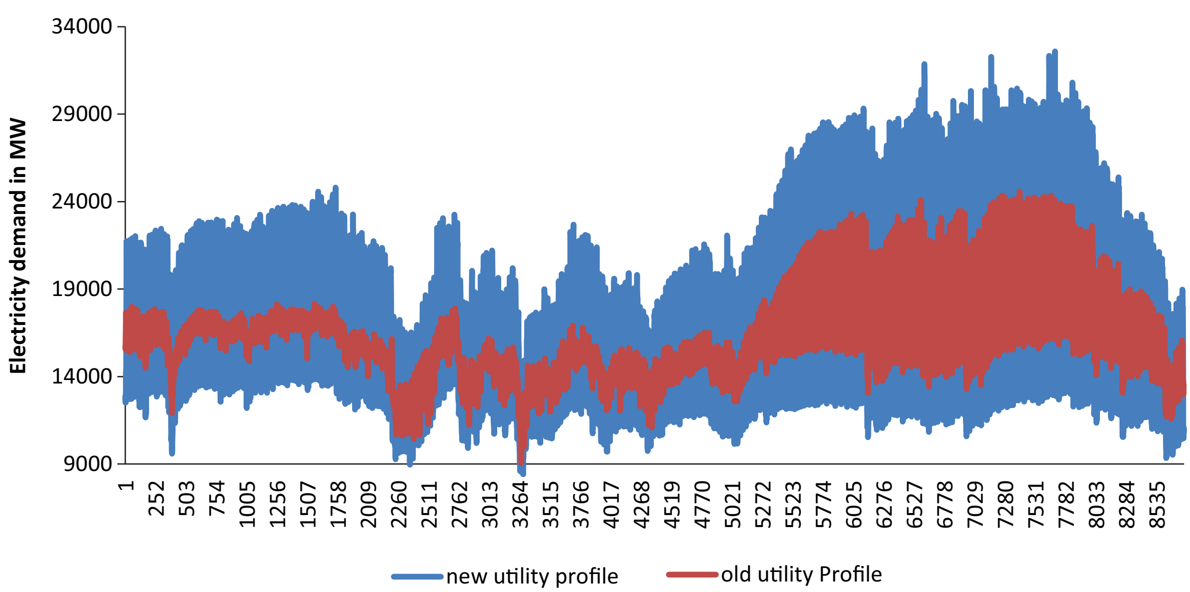


Figure 20: New demand profile for 2030 with 50% agricultural load shift

From these demand profiles it is apparent that as the amount of load shift increases, the load profile becomes more peaky or load factor reduces from 65% in no shift scenario to 59%, 55% and 49% in 25%, 35% and 50% load shift scenarios, respectively.

7. Key Findings of the Study

This section presents the results of the least cost investment and least cost despatch, which examines the development of the Madhya Pradesh power generation portfolio for 2025 and 2030 under various scenarios mentioned in section 5 that capture uncertainty in trajectory of capital costs, RPO mandates, electricity demand, etc.

Findings for 2025

7.1 RE generation could contribute 15-24%

The total generation capacity (including state's share in the inter-state generating stations) is estimated to be ranging from 26 GW (high discount rate scenario) to 30 GW (low RE cost scenario) from 25.4 GW as on 2022. The generation corresponding to these capacities is expected to be of the order of ~105–106 TWh with the share of RE and coal ranging from 15%–24% and 65%–71%, respectively. Coal continues to dominate the generation in 2025, primarily due to retirement of marginal coal-based capacity of ~830 MW envisaged in the state. The percentage share of various generation technologies in the total generation mix in 2025 is presented in Figure 21.

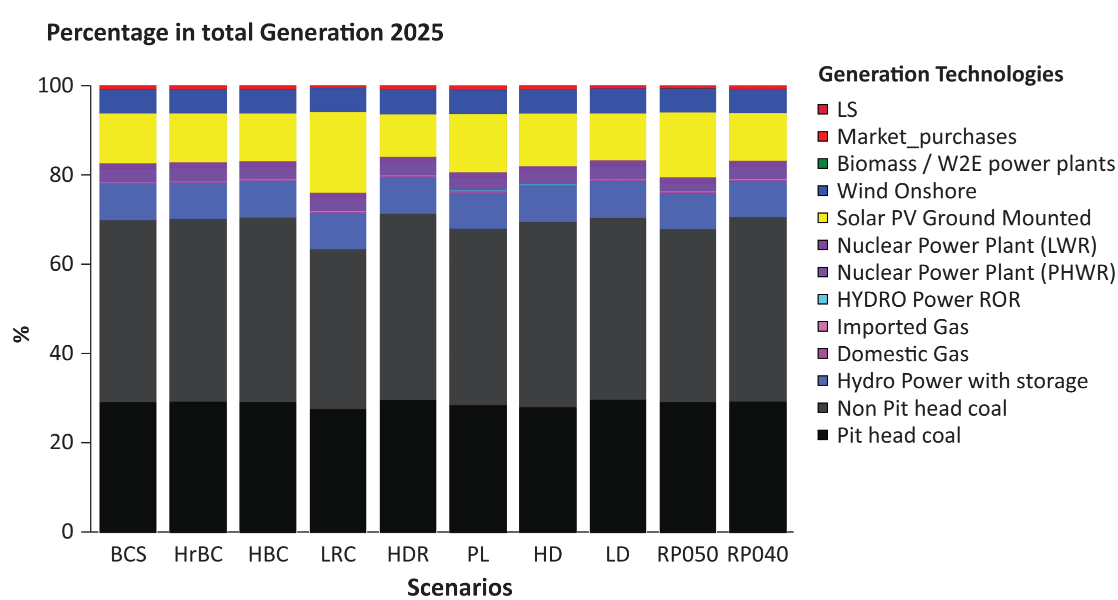


Figure 21: Generation mix in 2025

The model yields the system cost corresponding to 15% and 24% share of RE for high discount rate (HDR) and low RE cost (LRC) scenario as ₹3.76/kWh and ₹3.82/kWh, respectively. The system cost in LRC scenario is amongst the highest, the other scenarios with high system cost being high peak load (PL) and RPO50. However, the share of RE in total generation mix for high peak load (PL) and RPO50 is 19% and 20%, respectively. The RPO of the state as approved by Madhya Pradesh Electricity Regulatory

Commission (MPERC) for the year 2025 is 21.50%. Thus, the state can meet its RPO in 2025 only if the solar PV and wind technology costs fall by 30% to 21%, respectively (LRC scenario). The increasing importance of energy security may foster a decrease in costs globally on account of economies of scale but estimating the exact decrease is a challenging task. Alternatively, RPO50 scenario (with 20% share of RE in total generation mix) that uses baseline cost assumptions seems more plausible as the technology costs are aligned with the existing prices in which case the DISCOMS in the state are expected to fall marginally short of RPO compliance requirement albeit with ~ 0.5% lower system cost of ₹3.80/kWh as compared to ₹3.82/kWh system cost in LRC scenario. On further investigation it was noted that RPO50 + 25% agricultural demand shift is found to be a cost-effective way of meeting the RPO as approved by MPERC. The total generation under this scenario is similar to RPO50 scenario. However, 25% demand shift reduces curtailment of RE power and BESS requirement thus reducing the system cost to ₹3.70/kWh. This makes the RPO50 + 25% agricultural demand shift to be the most cost effective way of meeting the RPO of the state in 2025 amongst all the scenarios considered in the study.

Findings for 2030

By the year 2030, significant changes are expected in the power system operation as well as system costs. In the succeeding sub-sections, detailed description of various aspects is presented.

7.2 Generation capacity could increase by ~40–114% with RE capacity contributing ~43–63% of the capacity mix in 2030

By 2030, the installed generation capacity (including state sector, private sector power plants and share in ISGS is estimated to increase from 25.4 GW to a minimum of 35 GW in the high discount rate (HDR) scenario and a maximum of 54 GW in the RPO50 scenario, respectively. Figure 22 shows the capacity mix across all the scenarios considered in the study. The coal capacity addition and retirement planned by State Planning Cell has been considered in the study. The share of coal in the total capacity mix, therefore, remains same across the scenarios as no new coal capacity build up beyond this is found cost effective by the model. Apart from this, majority of new investments are contributed by solar, wind, and BESS. By 2030, this share may be of the order of 43-63% in different scenarios.

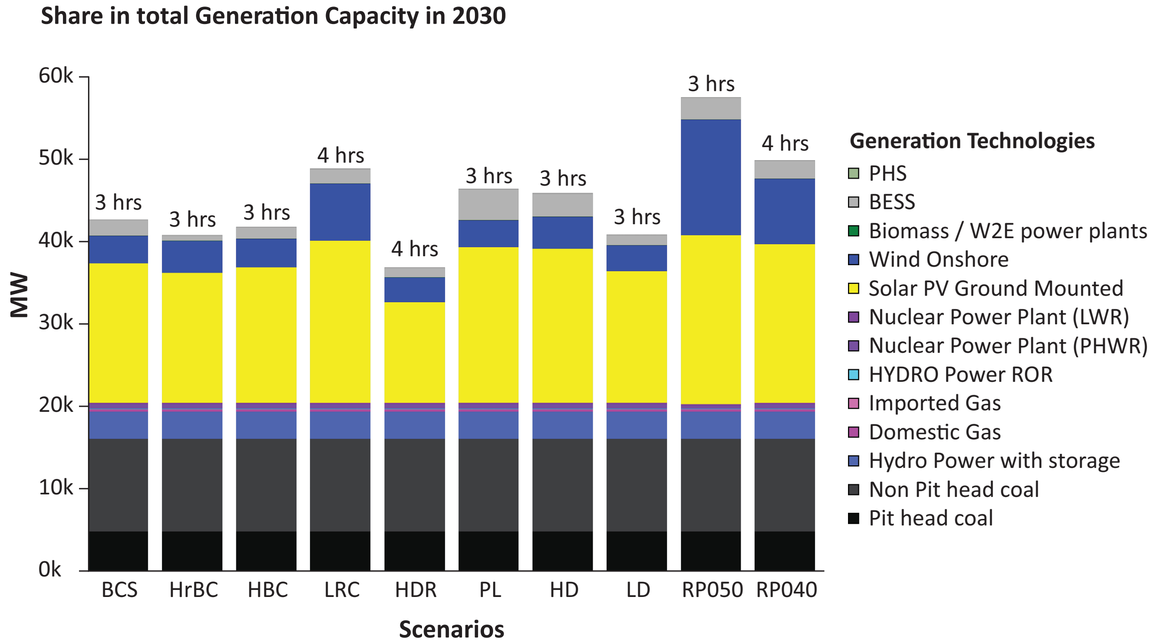


Figure 22: Installed capacity in 2030

7.3 Technology-specific capacity build-up is sensitive to technology costs but the cost of capital could significantly influence the integration of VRE

Figure 23 shows that in the low RE cost (LRC) scenario, the additional build-up of solar PV is ~19 GW. The impact of high battery costs is reflected in the High_Battery_Cost (HBC) and Highest_Battery_Cost (HrBC) scenarios, which yield lower solar PV and more wind capacity build-up. Similarly, under the high discount rate (HDR) scenario signifying higher cost of capital, RE capacity addition is subdued and beyond 2030 it will be detrimental to new RE generation capacity and battery storage.

7.4 The share of technology build-up is sensitive to not only electricity demand but also peak load

The peak load scenario (27 GW peak demand) yields a higher solar PV capacity build up for meeting the load and consequently finds higher battery capacity build-up. From Figure 24 it is apparent that Peak Load and High Demand scenario have almost the same capacity mix; the generation in Peak Load scenario is almost similar to baseline scenario, i.e., ~149.6 TWh. Thus, it can be inferred that capacity build up is not only a function of electricity demand but also the inherent characteristics of the system like load factor and peak demand. However, this also indicates that higher than the estimated peak load can lead to load shedding during peak hours as extra capacity required may not have been built. Further, in case the demand and peak load increase above the baseline estimations, the capacity build-up of solar PV and even wind increases along with BESS.

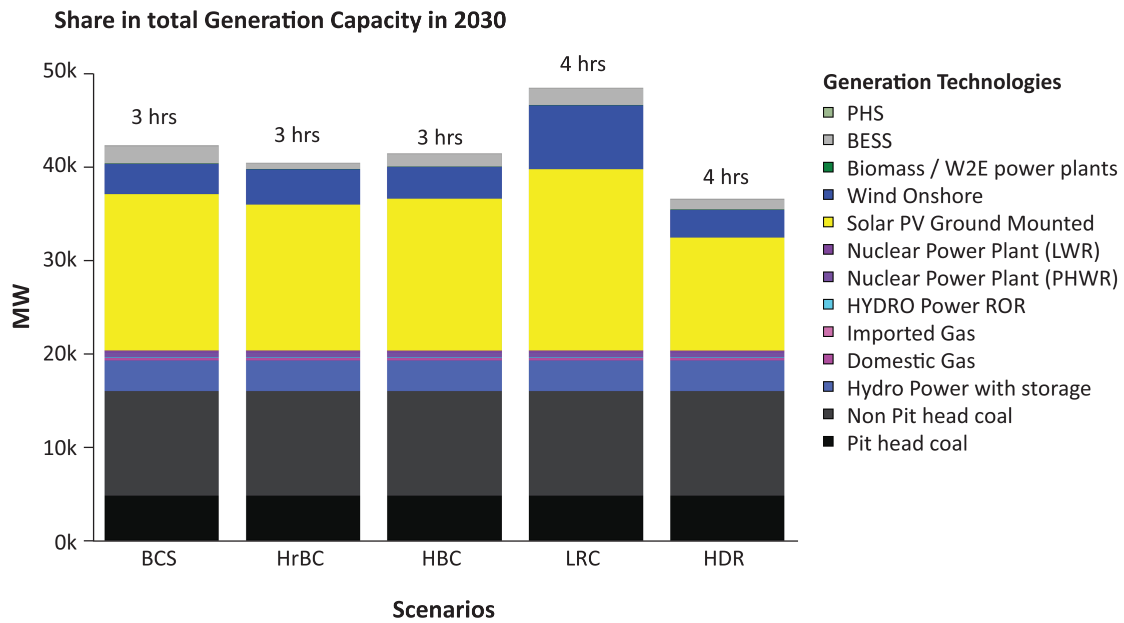


Figure 23: Installed capacity in LRC in comparison with other scenarios in 2030

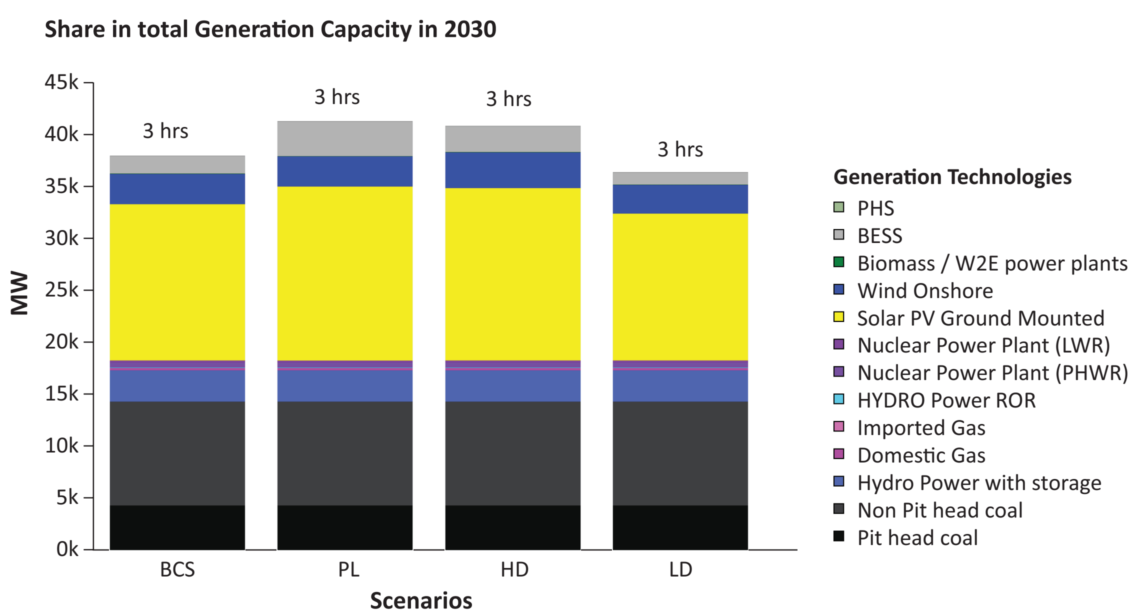


Figure 24: Installed capacity in high peak load (PL) scenario in comparison with other scenarios in 2030

7.5 More aggressive cost decline in solar and wind technologies could make RPO of 40% close to optimal

Across all the scenarios, LRC and RPO40 scenarios are noted to have almost similar generation capacity mix except for high wind in RPO40 to meet the estimated electricity demand as observed from Figure 25. However, it is important to evaluate the capacity mix from the perspective of overall system cost, which is discussed in Section 7.12.

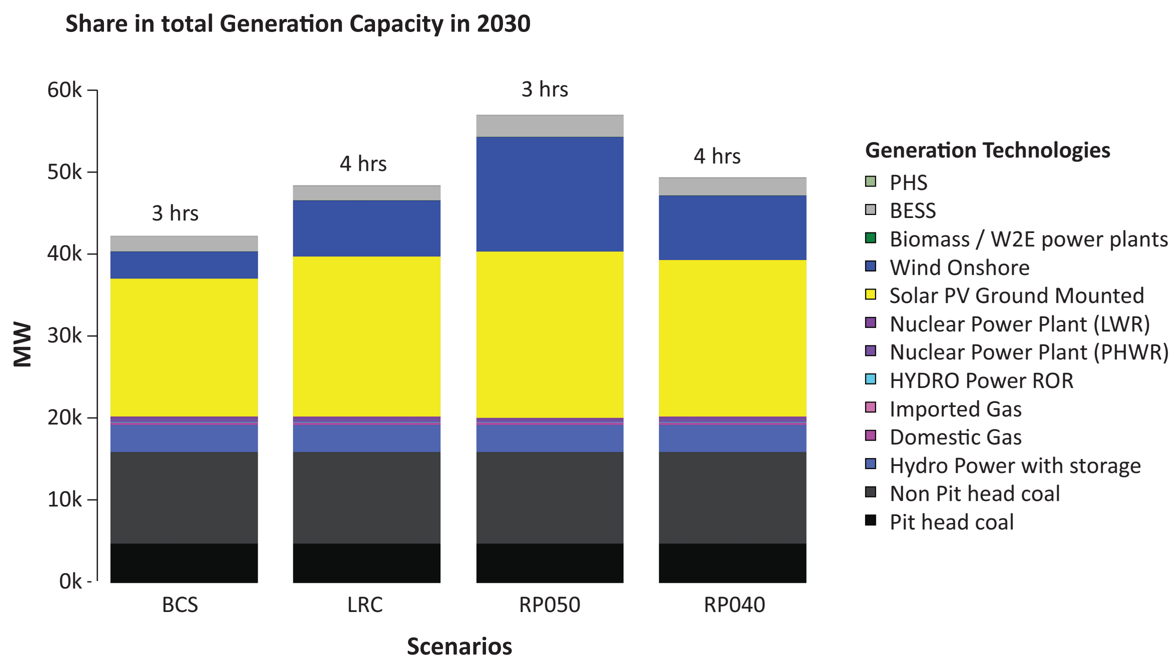


Figure 25: Installed capacity in RPO40 in comparison with other scenarios in 2030

7.6 Increase in solar and wind generation by 2030 beyond one-third of the total generation is not cost optimal unless BESS cost reduces significantly below the USD 104/kWh considered in the baseline scenario

The percentage share of all generation technologies in the total generation of 2030 is presented in Figure 26. It is evident that the maximum RE generation witnessed is ~38% under the low RE cost (LRC) scenario and the least share of RE generation of 21% can be observed under the high discount rate (HDR) scenario. However, in the baseline scenario, the RE share is of the order of 29%. Thus, until the BESS cost reduces below the costs assumed in this study, higher RE integration is going to be a challenge. This is because, of higher solar and wind curtailment with increasing RE penetration as observed across the scenarios. The BESS cost reduction aspect has been discussed in greater detail in Section 7.12.

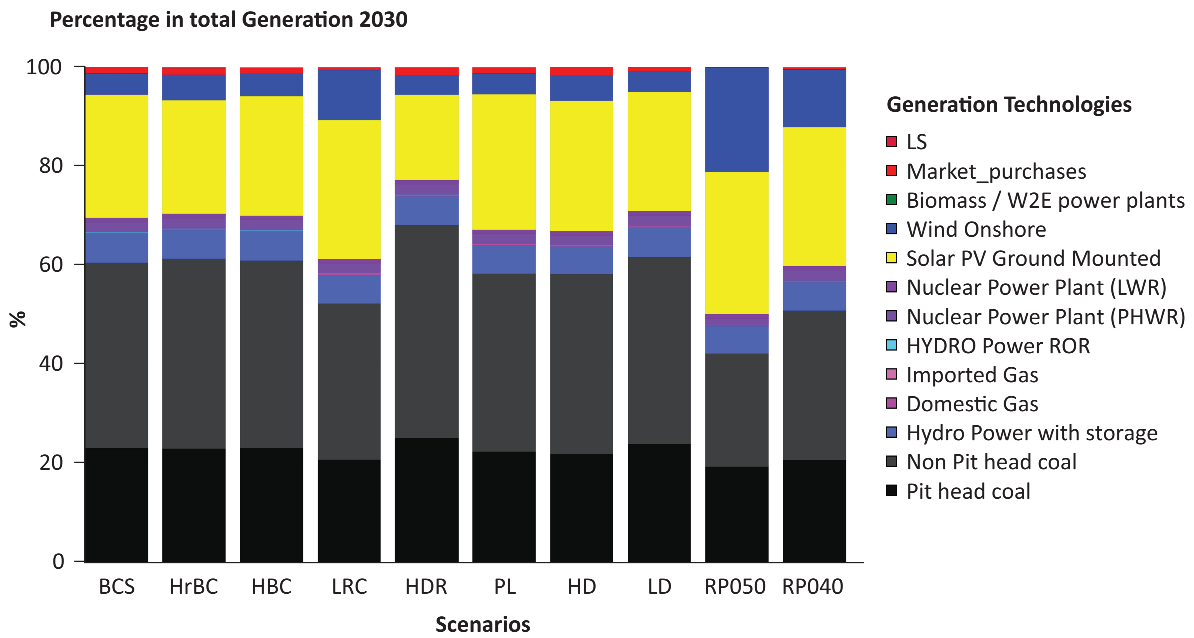
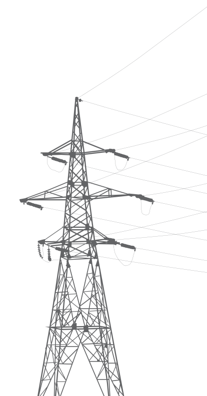


Figure 26: Share of generation in 2030

7.7 The inherent shape of the state load curve and solar PV generation profile would require a relatively lower addition of storage capacity, at least in the medium term

The shape of Madhya Pradesh load curve slightly lags the peak solar generation profile. Thus, it will be safe to say that solar PV-based generation is relatively complementary to the load curve. Wind, alternatively is less complimentary with the load curve hence its build-up is limited. The complimentary relationship between solar and load curve limits the addition of battery storage. Further, in the medium term when solar capacity addition is low the battery storage addition shall continue to be subdued.



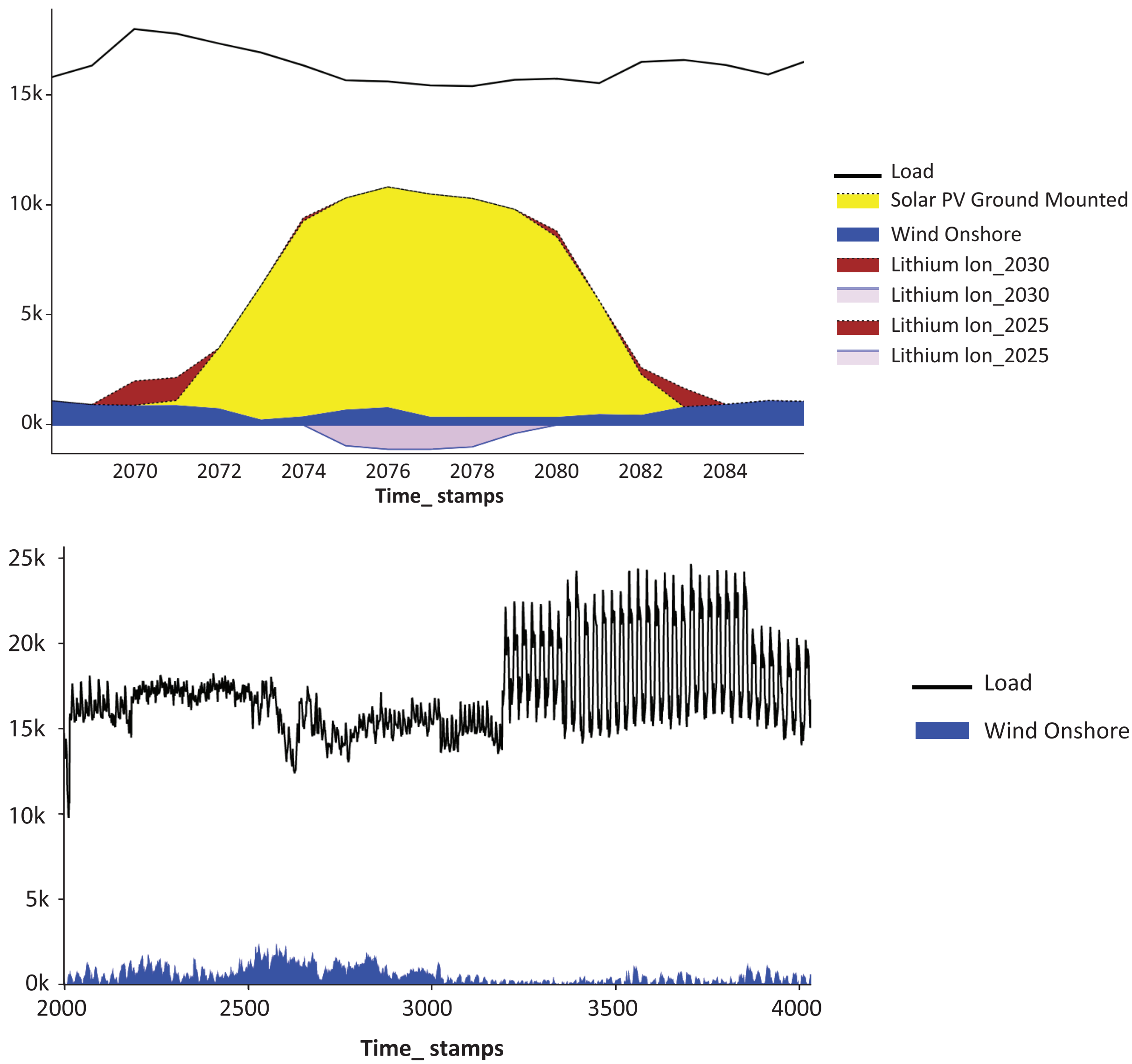


Figure 27: Correlation between solar and wind generation with electricity load curve in 2030

7.8 The period from 2025-30 could see a start in the capacity build-up of BESS but further cost decline in subsequent years would foster higher degree of VRE deployment

The installed capacity of various generation technologies in 2025 and 2030 is presented in Table 13. It is observed that buildup of BESS in the system starts after 2025. In 2030, the BESS capacity accounts for 4.37% of the total installed capacity. The decline in BESS cost post 2030 would give impetus to the integration of BESS into the system.

Table 13: Installed capacity in 2025 and 2030

Source	Capacity (MW)		
	Existing	2025	2030
Coal	12,600	12,544	15,971
Hydro	3,358	3,358	3,358
Gas	294	294	294
Nuclear	308	708	708
Solar PV	5,877	6,629	16,817
Wind	2,978	2,978	3,254
BESS (~3hrs)	0	0	1,846

7.9 The onus of grid flexibility would significantly depend on the variable cost of generation resources

In this section, we delve into the operation of non-pithead coal fleet beyond 2025. We first look into the correlation of overall unit starts with the marginal costs and the nature of flexibility across the months. As can be seen from Figure 28, the high marginal cost non-pithead generating units will witness higher number of starts and stops post 2025 due to increased RE share. The number of starts and stops are depicted in the heat map (Figure 29). During the winter months, the non-pithead coal plants operate at a fairly constant generation, given the high demand and low RE generation during this period; during the summer and monsoon months, high solar penetration makes these power plants operation cyclic in nature. Hence, non-pithead plants will need to perform flexibility duty beyond 2025.

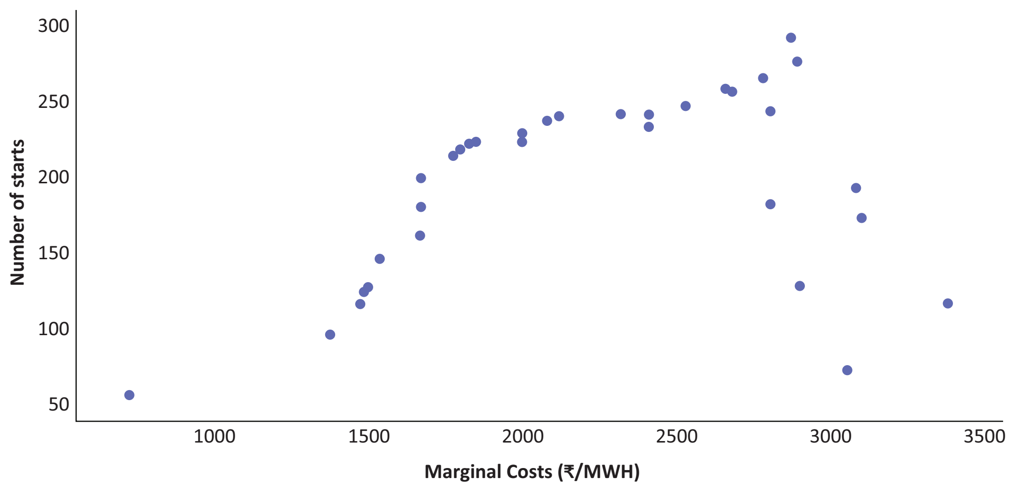


Figure 28: Correlation between number of starts in coal units and marginal costs

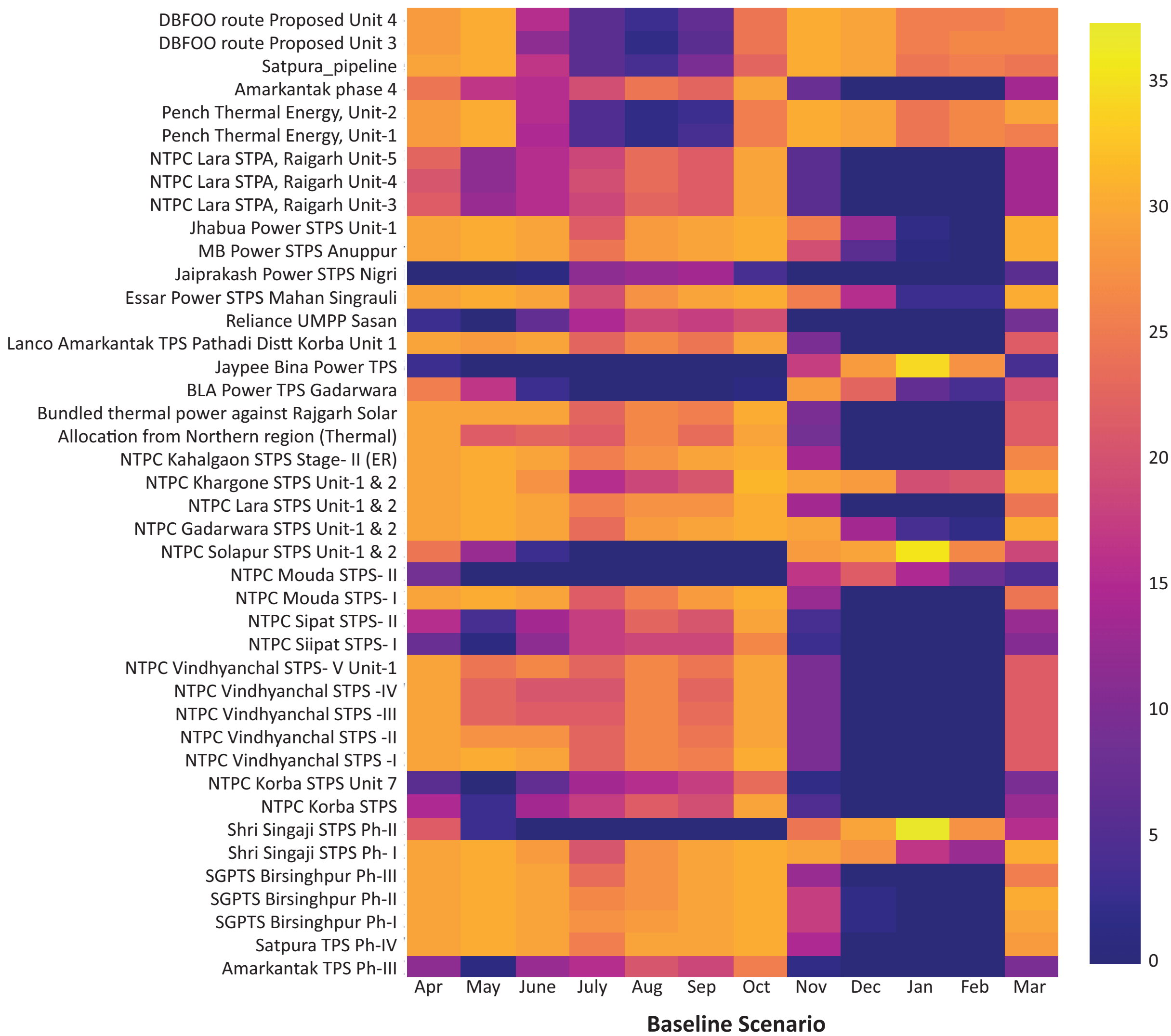


Figure 29: Number of starts in coal units across the year

7.10 The existing coal generators are the most cost-effective source of grid flexibility and play an important role in RE integration at least in the medium term

Figure 30 represents the average non-pithead coal plant generation for the three seasons. The generation from non-pithead plants and the flexibility with which they operate under different seasons and associated time of the day vary significantly. These units run at a higher plant load factor during early morning hours and late evening to support the peak demand; as the solar penetration increases during midday, the units ramp down their generation. Further, these units run at a higher plant load factor for shorter duration in winters in comparison to summer and monsoon period hence catering to the seasonal variations as well.

Having observed the seasonal variation in generation, it is important to understand the level of ramping required during this period as well. Table 14 shows the maximum ramp-up and ramp-down of generation and its time period in 2030. Although the state witnesses a peak both during morning and evening hours, the maximum ramp-up requirement during evening could be as high as from 5.1 to 5.8 GW. The maximum ramp-down requirement occurs during morning hours as the solar generation increases.

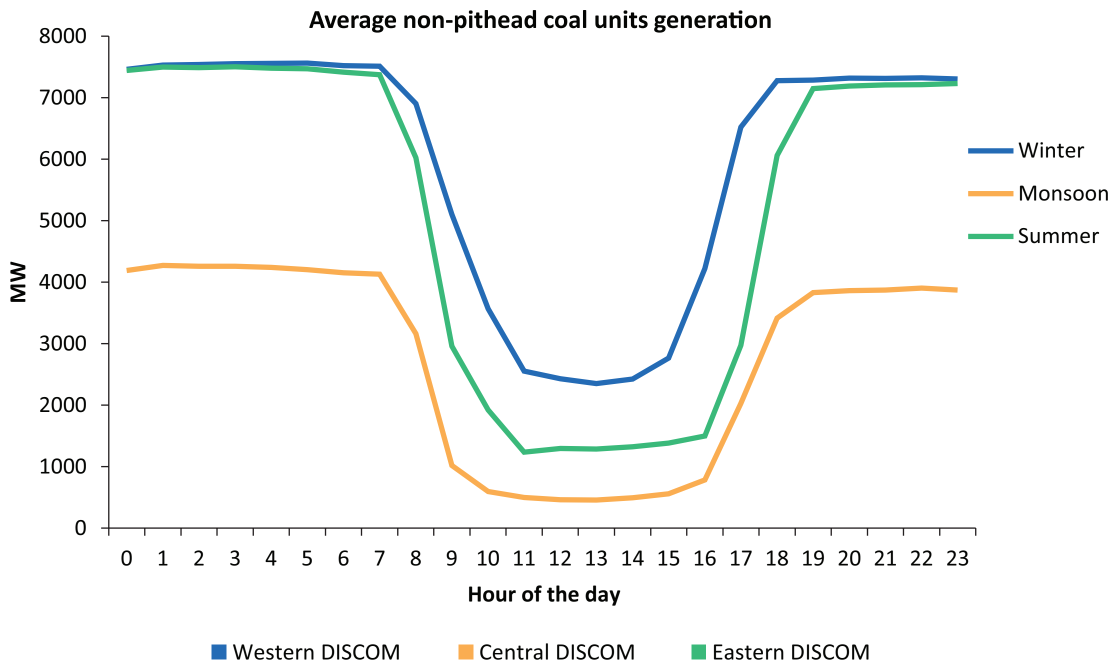


Figure 30: Average non-pithead coal generation across the seasons

Table 14: Coal plants ramping requirement at a glance

Coal plants ramping	Winter	Monsoon	Summer
Ramp up (GW)	5.1	5.8	5.2
Ramp up (hrs)	17:00-18:00	18:00-19:00	18:00-19:00
Ramp down (GW)	5.3	4.7	5.3
Ramp down (hrs)	09:00-10:00	10:00-11:00	09:00-10:00

7.11 Techno-economic assessment of coal-based flexibility is critical

The pithead coal plants due to their low marginal costs continue to get despatched to their full capacity for almost 85% of the time. The non-pithead coal plants get full despatch for ~22% of the time and no despatch for almost 15% of the time. Figure 31 show the load duration curve for the coal fleet in BCS in 2030. This coupled with the results under Section 7.9 and 7.10 reflects that these plants will be subject to frequent two shift operations while pithead plants will not be subjected to such operations. The additional operational costs of non-pithead plants at part load on account of heat rate degradation, increase in oil consumption and O&M costs may add ~20-45p/kWh to power generation costs[9]. Hence, it becomes pertinent to mention that the techno-economic assessment of non-pithead plants is important for flexible operations.

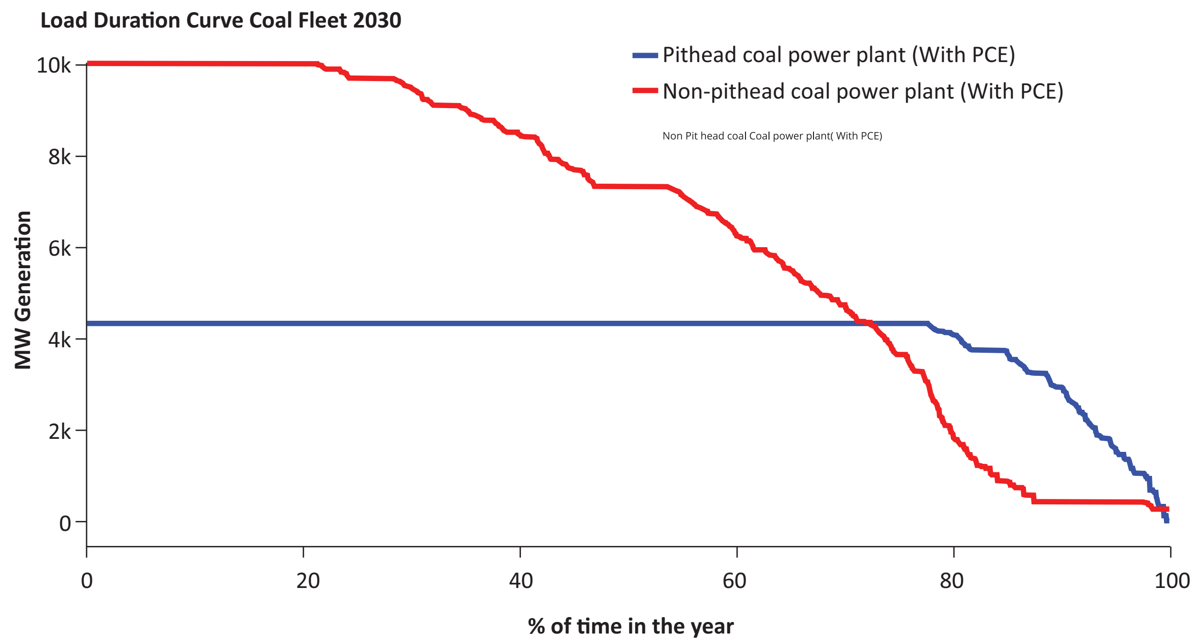


Figure 31: Coal generation duration curve in BCS in 2030

7.12 Coal flexibility, storage and RE curtailment could add a premium on the system cost

Figure 32 shows the comparison of system costs across the scenarios. As per the MPERC tariff order for FY 2021-22, the state's average cost of power purchase is ₹3.49 /kWh. This is expected to increase with the integration of RE up to a level of 9–13 GW by 2025 to ~₹3.75/kWh (minimum) in baseline scenario and ~ ₹3.82/kWh (maximum) under low RE cost. Beyond 2025, the system cost is estimated to increase by ₹0.42/kWh under the low RE cost scenario and ₹0.71/kWh in RPO50 scenario. This premium on system cost can be attributed to factors like expensive BESS capacity build-up, high RE-curtailment of the order of 10% and start-up costs due to flexibility provided by coal plants. Comparing the RPO50 with baseline scenario that is based on existing costs, it is found that RPO50 system costs increases by ~₹0.30/kWh. This premium results from high BESS costs constraining BESS capacity build-up leading to increased curtailments and dependency on coal fleet for meeting flexibility. This results in RPO50 scenario witnessing highest system cost of ₹4.20/kWh amongst all the scenarios considered representing a CAGR of 19%. Figure 33 shows the split of system costs in BCS and RPO50 scenarios.

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9 https://cea.nic.in/old/reports/others/thermal/trm/flexible_operation.pdf

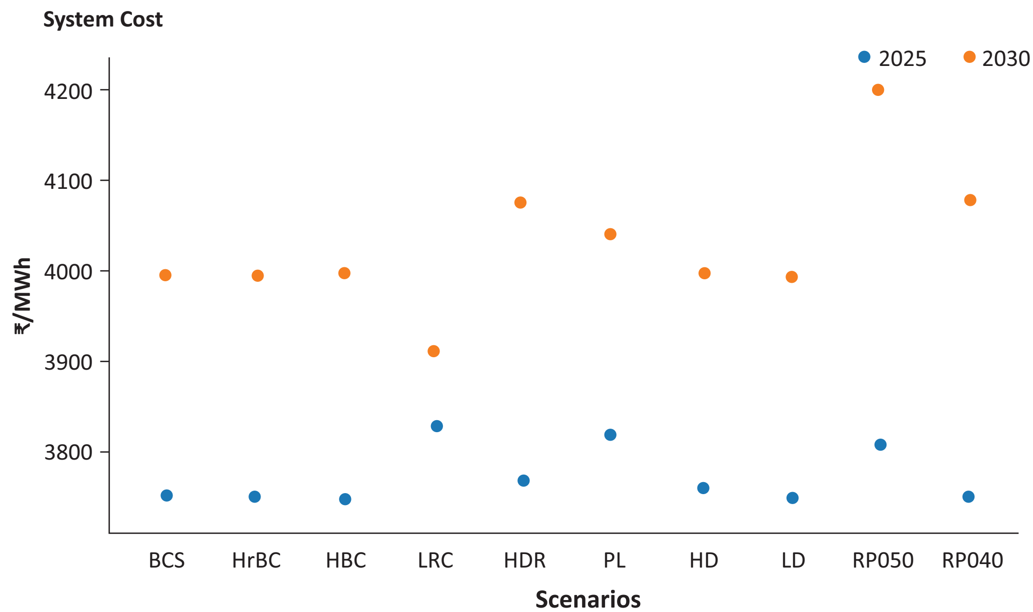

Figure 32: System costs comparison till 2030

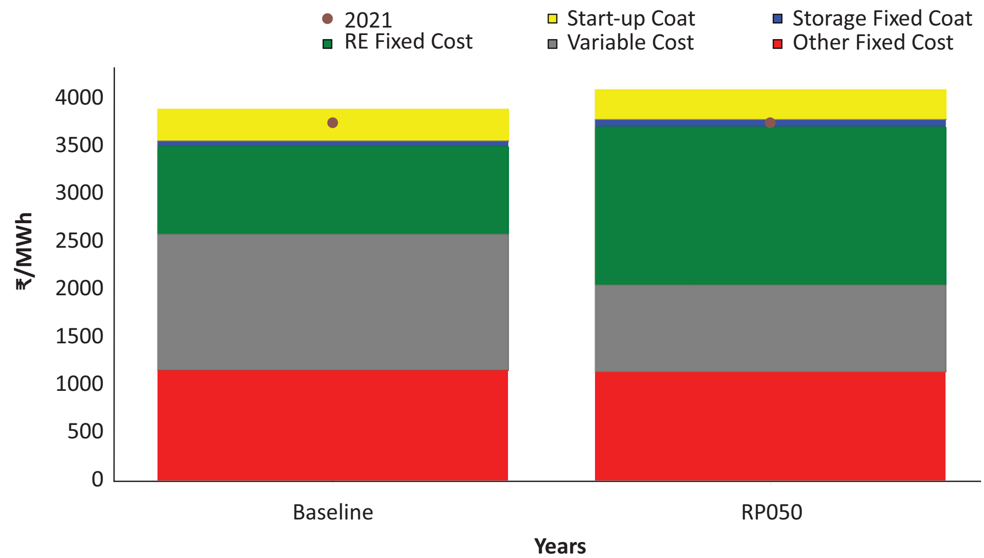

Figure 33: System costs split in BCS and RPO50

7.13 RPO50 witnesses highest curtailment

As mentioned in the previous section, system cost will be highest in RPO50 amongst all the scenarios due to curtailment of RE and lowest in low RE cost scenario. In this section, the curtailment for all the scenarios is shown in Figure 34, RPO50 witnesses the highest curtailment of ~10% followed by ~5% in RPO40 and ~4% in low RE cost scenario. The high curtailment in RPO50 is due to overbuilding of capacity (with limited storage) to meet the high RPO obligations. Considering the high curtailment observed in RPO50 scenario, it can be inferred that high RPO can adversely impact the system cost. The management of surplus by MP DISCOMs, which is not a part of this study, may reduce the premium on system cost due to curtailment.

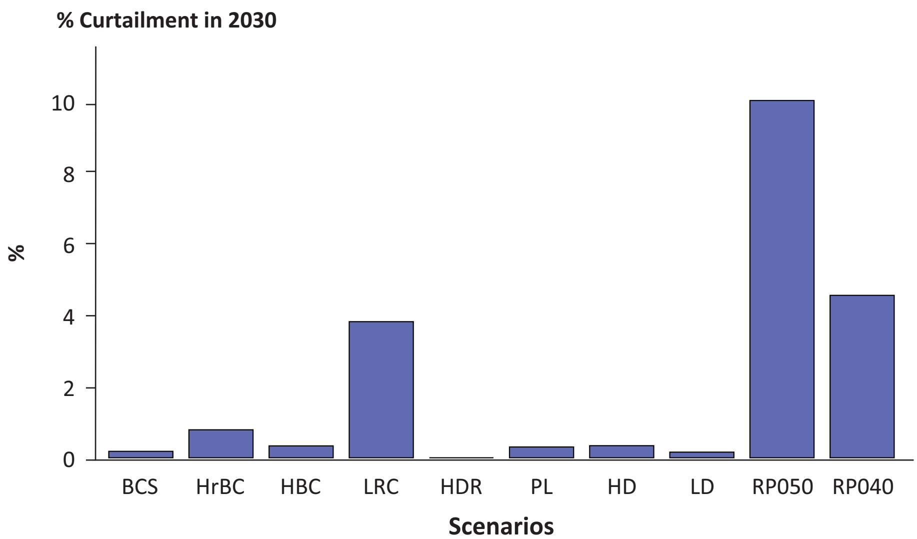

Figure 34: Curtailment across the scenarios in 2030

7.14 Market purchases could help defer investment (Long-term PPAs) in generation capacity, but higher market purchase costs could be a major deterrent

Amongst all the scenarios considered, high discount rate (HDR) scenario has the least amount of installed capacity ~35 GW. In order to meet the demand under this scenario it was observed that model prefers to meet the demand by procuring power to the tune ~2500 MW from the market instead of building new generation capacities . The market purchases are consequent to low storage build up which comes in the way of meeting the peak demand. However, it is not advisable to plan capacity addition based on the short-term market purchases as the prices in market are dynamic.

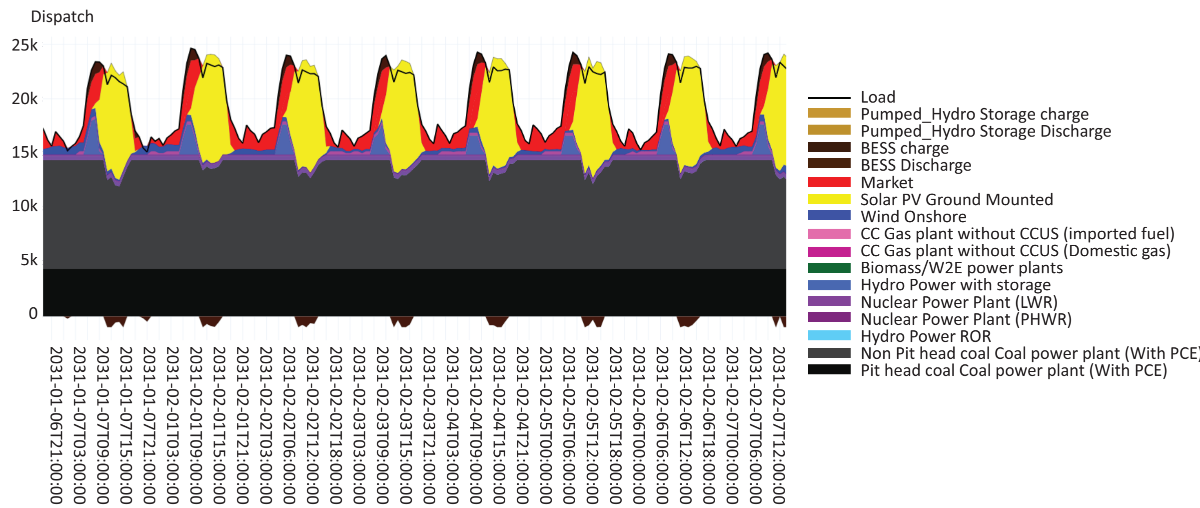

Figure 35: Dispatch stack showing higher market purchase in HDR 2030

7.15 Agricultural demand shift from non-sunny to sunny hours has the potential of meeting the high RPO cost-effectively

The agricultural demand shift exercise is based on the assumptions in regard to capital cost of BESS, solar and wind power resources forming a part of this study. Any significant deviation in regard to these with reference to the assumptions may change the financial viability of shifting demand. It was seen in Section 7.10 that RPO50 is the scenario with highest system cost of ₹4.20/kWh. The reason for this was RE curtailment ~ 10%. Thus, if high RPO is to be met effectively by the state, it calls for exploring the ways to meet RPO in a cost-effective manner. To this end agricultural demand shift was explored with 25%, 35% and 50% load shift scenarios from non-sunny hours to sunny hours. This shift results in increased capacity build-up of low-cost solar PV to meet the increased demand from ~20 GW in RPO50 scenario to 27GW in RPO50 + 50% load shift scenario. The increase in solar PV, however, replaces relatively high-cost wind and wind capacity reduces from ~14 GW in RPO50 scenario to ~7 GW in RPO + 50% load shift scenario. The overall capacity, however, remains same. Table 15 presents the results for the three agricultural demand shift scenarios in terms of capacity and generation mix. Figure 36 presents the overall system costs for 2025 and 2030 for all load shift scenarios.

Table 15: Evolution of capacity and generation under demand shift scenarios vs RPO50 scenario (without any demand shift)

Scenario	RPO50	RPO + 25% demand shift	RPO + 35% demand shift	RPO + 50% demand shift
Total capacity (GW)	54	54	54	54
Solar capacity (GW)	20	23	25	27
Wind capacity (GW)	14	11	9	7
Total generation (GWh)	150	150	149	149
Solar generation (GWh)	43	50	55	59
Wind generation (GWh)	31	25	20	15

As solar PV generation replaces the relatively expensive wind generation and BESS requirement consequently gets reduced, an impact is also observed on the system cost. The system cost declines with increasing load shift reaching a minimum of ₹3.96/kWh in comparison to ₹4.20/kWh in RPO50 scenario. Thus, the state can meet the high RPO up to 50% in a cost-effective manner in the 50% load shift scenario.

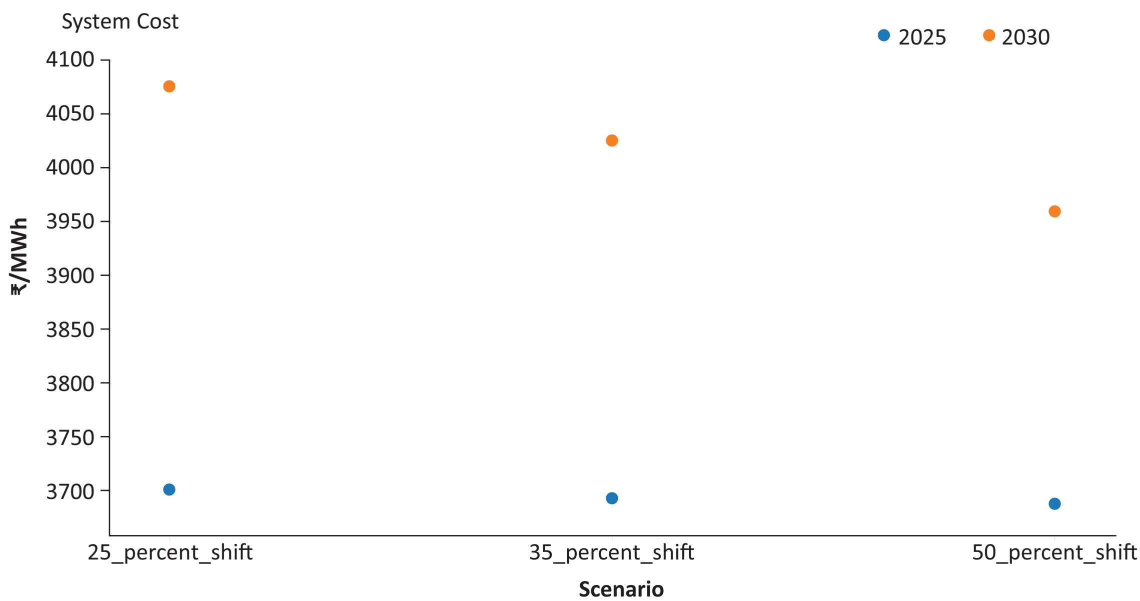

Figure 36: System costs for 2025 and 2030 for different load shift scenarios

7.16 Viability Gap Funding (VGF) to increase deployment of BESS

The study informs build-up of BESS to cater to evening peak load hours during 2025-2030. The system costs (in various scenarios) in 2030 is found to be ranging from ₹3.91/kWh to ₹4.20/kWh which happens to be 12%–20% higher than APPC of ₹3.49/kWh for FY 2021-22. The Viability Gap Funding (VGF) for BESS would help to off-set the increase depending on degree of VGF support. VGF would benefit the MP DISCOMs and in turn their consumers. This would foster deployment of solar-PV systems in the state and help the State Government in achieving the target of green power set by them pro-actively.

8. Summary of Findings and Key Recommendations

8.1 Demand and Capacity Mix

The electricity demand in Madhya Pradesh is estimated to witness 35–40% and 90–110 % increase by 2025 and 2030, respectively as compared to the demand during FY 2019-20. While there is marginal increase in the installed generation capacity in 2025, this would require the capacity to be 1.4 X and 1.7 X in the respective years as compared to the capacity at the end of FY 2019-20.

With 830 MW of planned retirements of coal capacity by 2025, the model found 724 MW of additional coal capacity build-up. With 3,427 MW of additional coal-based capacity and 4,839 MW of RE (4,399 MW: Solar ; 500 MW: Wind) capacity already planned to be added in the state or state's share in the new ISGS, model found proportion of non-fossil to fossil fuel capacity to be of the order of 1.3:1 and 2.3:1 in 2025 and 2030 respectively.

The type of new generation resources to be built is a function of (a) capital cost of various generation technologies and (b) peak demand (rather than energy requirement). The cost of capital can, however, significantly influence uptake of clean energy sources. As financing cost is the major cost component in the capital cost of a RE plant; the state may consider the measures/steps required to de-risk the PPA that will lead to low finance costs. The facilitation and support provided by the Government of Madhya Pradesh yielded lowest RE tariff for solar park in the state in the year 2021 achieved till then. Measures such as (a) timely payment to RE generators, (b) ensuring that the payment security mechanism remains truly functional, (c) transparently being able to demonstrate that the curtailment of RE generation, if any, is only on account of grid security considerations, and (d) energy shifting from evening to daytime hours, can help in achieving this goal.

The high share of agriculture in the state's aggregate demand has the potential for reducing the evening peak load through shifting of consumption from evening hours to daytime, reduction in the RE curtailment as well as the reduction in power procurement costs of the distribution utilities in the state. The state may thus expedite the solarisation of agricultural feeders and gradually shift agricultural load from the evening hours to day time.

8.2 Energy Mix and RPO

The Madhya Pradesh Electricity Regulatory Commission (MPERC) has mandated the RRPO of 21.5% and 24.5% for the year 2024-25 and 2026-27, respectively. The model suggests that the share of renewable energy in the generation mix is expected to witness an increase from 10% in 2020 to 15–24% in 2025. The RPO target for the year 2024-25 (21.5%) can almost be met in the RPO50 scenario with compliance being of the order of 20%. RPO target for the year can however be met if the cost of solar PV and wind technology declines by 30% and 20%, respectively. There is a potential for increasing uptake of RE up to ~38% with a system cost of ~ ₹3.91/kWh, representing a CAGR of 1.4% in 2030. For further increase in the share of RE upto 48% and 50%, the system cost touches ~₹4.08/kWh and ₹4.20/kWh, representing a CAGR of 2.0% and 2.3%, respectively. The shifting of agricultural load from the non-sunny to sunny hours and low-cost financing would be helpful in reduction of system cost.

The study suggests that RPO40 and LRC scenarios have almost equal generation capacity. From the system cost perspective, however, LRC scenario has the least system cost (₹3.91/kWh) in comparison to RPO40 scenario (₹4.10/kWh) The higher system cost in the RPO40 scenario as compared to the LRC scenario is on the account of flexibility of coal fired stations, high BESS cost and curtailment of RE. The purchase of Renewable Energy Certificates (RECs), provides an option to meet RPO beyond this level. Shifting of agricultural load, however, provides opportunities for achieving RPO up to 50%.

8.3 Supply Side Solutions

Energy storage is expected to be a part of supply portfolio of Madhya Pradesh only beyond 2025 in view of increasing demand, and cost-effective RE generation garnering an increasing share in the supply mix during the second half of the decade.

While the daily flexibility can be met by BESS, non-pithead coal power stations will be better suited for seasonal flexibility instead of building new generation resources, though they would get subjected to more starts/stops post 2025.

By 2030, pithead and non-pithead plants are seen to be operating at full capacity for ~85% of the time and ~20% of the time. The non-pithead plants are noted to operate at lower capacities for a significant amount of time; even being under shutdown for about 15% of the year.

The part-load-operation of non-pithead plants could entail additional investments on account of retrofitting, operation & maintenance costs due to heat rate degradation, etc. In this regard, the state can identify coal units for retrofitting to perform two-shift operations. In case, such units are supplying power based on competitive bidding, an appropriate regulatory mechanism could be put in place to allow pass-through of such costs. Some of these plants can be the ones that are due for retirement, as the fixed cost is already recovered, overall system costs could still be lower than other options.

8.4 System Cost

The RE capacity of the order of 9–13 GW by 2025 is likely to increase the system (generation plus storage) costs ranging from ~ ₹0.27/kWh to ₹0.34 /kWh in the low RE cost (LRC) scenario as compared to APPC of ₹3.49/kWh in 2021-22,representing a CAGR of 2.5%–3.1%..

By 2030, the system cost is noted to increase by ₹0.41 to 0.71/ kWh in the LRC scenario and RPO50 scenario, representing a CAGR of 1.9% to 2.3%, respectively. It is recommended that the energy efficiency and demand side management (DSM) measures including widening the ambit of time-of-the-day tariff be taken to shift the agricultural pumping operation from evening hours to daytime.

It is apparent from the findings that high peak load leads to high solar build-up and consequently higher BESS build-up. This leads to a higher system cost (~50 paisa/kWh) in comparison to the baseline scenario. As the increase in system cost is due to high BESS build-up and curtailment of RE power. However, announcements at COP26 are expected to increase the RPOs of states and hence it is imperative to explore solutions to lower these costs.

One solution that emerges, is agriculture demand-side management. To achieve this, agriculture demand can be shifted to the sunny hours so that it reduces the BESS support requirement but also has the potential of avoiding curtailment of solar generation. As seen in Section 7.14, as the agricultural load shift increases, the load factor reduces. It is recommended that the state may plan load shift exercise in a gradual manner starting with a 25% agriculture load shift, and based on the experience, degree of load shifting could be increased in phases.

Appendices

Appendix – 1

Baseline (BCS) assumptions		
Parameters	**2025**	**2030**
Demand (Twh)	101	142
Peak Demand (GW)	18.18	24.64
Capital Cost – Solar (₹Cr / MW)	4.8	4.7
Capital Cost – Wind (₹Cr / MW)	6.8	6.6
Capital Cost – BESS (₹Cr / MW)	149	113
Discount Factor (%)	10%	10%

Appendix – 2

S.no	Plant name	Configuration	State share	Units based on state share
1	Amarkantak TPS Ph-III	1x210	210	1
2	Satpura TPS Ph-II	1x200+1x210	410	2
3	Satpura TPS Ph-III	2x210	420	2
4	Satpura TPS Ph-IV	2x250	500	2
5	SGTPS Birsinghpur Ph-I	2x210	420	2
6	SGTPS Birsinghpur Ph-II	2x210	420	2
7	SGTPS Birsinghpur Ph-III	1x500	500	1
8	Shri Singaji STPS Ph-I	2x600	1200	2
9	Shri Singaji STPS Ph-II	2x660	1320	2
10	NTPC Korba STPS	3x200+3x500	472.95	1
11	NTPC Vindhyanchal STPS - I	6x210	434.87	2
12	NTPC Vindhyanchal STPS - II	2x500	312	1
13	NTPC Vindhyanchal STPS - III	2x500	239	1
14	NTPC Vindhyanchal STPS - IV	2x500	275.19	1
15	NTPC Vindhyanchal STPS - V Unit-1	1x500	137.25	1
16	NTPC Sipat STPS - I	3x660	320.19	1
17	NTPC Sipat STPS - II	2x500	181.35	1
18	NTPC Mouda STPS - I	2x500	19.19	1
19	NTPC Mouda STPS - II	2x660	24.39	1

Contd...

S.no	Plant name	Configuration	State share	Units based on state share
20	NTPC Solapur STPS Unit-1&2	2x660	320.66	1
21	NTPC Gadarwara STPS Unit-1&2	2x800	830.05	1
22	NTPC Lara STPS Unit-1&2	2x800	177.34	1
23	NTPC Khargone STPS Unit-1 & 2	2x660	684.79	1
24	NTPC Kahalgaon STPS Stage - II (ER)	3x500	74	1
25	BLA Power TPS Gadarwara	2x45	31.5	1
26	Jaypee Bina Power TPS	2x250	350	2
27	Lanco Amarkantak TPS Pathadi Distt Korba Unit 1	1x300	300	1
28	Reliance UMPP Sasan	6x660	1485	2
29	Essar Power STPS Mahan Singrauli	2x600	60	1
30	Jaiprakash Power STPS Nigri	2x660	495	1
31	MB Power STPS Anuppur	2x600	420	1
32	Jhabua Power STPS Unit-1	1x600	210	1
Total				**42**

Appendix – 3

Scenario	2025					2030				
	Capacity (GW)	RE share (%)	Generation (TWh)	RE share (%)	System cost (Rs/kWh)	Capacity (GW)	RE share (%)	Generation (TWh)	RE share (%)	System cost (Rs/kWh)
Baseline	26.5	36%	106.6	17%	3.748	40.4	50%	149.6	29%	3.992
B + Low demand	26.2	35%	105.4	16%	3.745	39.3	48%	145.3	28%	3.994
B + High demand	27.0	37%	108.9	17%	3.756	42.7	52%	156.7	31%	3.995
B+RPO40	26.3	36%	105.9	16%	3.745	47.3	57%	149.4	40%	4.077
B+ High Discount	25.8	34%	105.6	15%	3.763	35.4	43%	147.3	21%	4.072
B + Peak Load	27.5	39%	106.5	19%	3.817	42.3	52%	150.4	32%	4.039
B + LRC	30.0	44%	106.2	24%	3.825	46.7	56%	149.0	38%	3.909
B + RPO50	28.0	40%	106.0	20%	3.805	54.4	63%	149.8	50%	4.200
B + High BESS cost	26.3	36%	105.8	16%	3.745	40.1	49%	147.8	29%	3.994
B + Higher BESS cost	26.4	36%	105.8	16%	3.747	39.8	49%	147.5	29%	3.994
A Shift - 25%	29.4	43%	106.8	23%	3.701	54.2	63%	150.0	50%	4.076
A Shift -35%	30.4	46%	106.7	25%	3.693	53.9	63%	149.0	50%	4.025
A shift - 50%	32.1	48%	106.6	29%	3.688	54.1	63%	149.0	50%	3.959

For dispatch stacks in various scenarios, visit: https://www.teriin.org/mp2030/

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