

Least-Cost Resource Adequacy Assessment for APEPDCL: FY 2039–40



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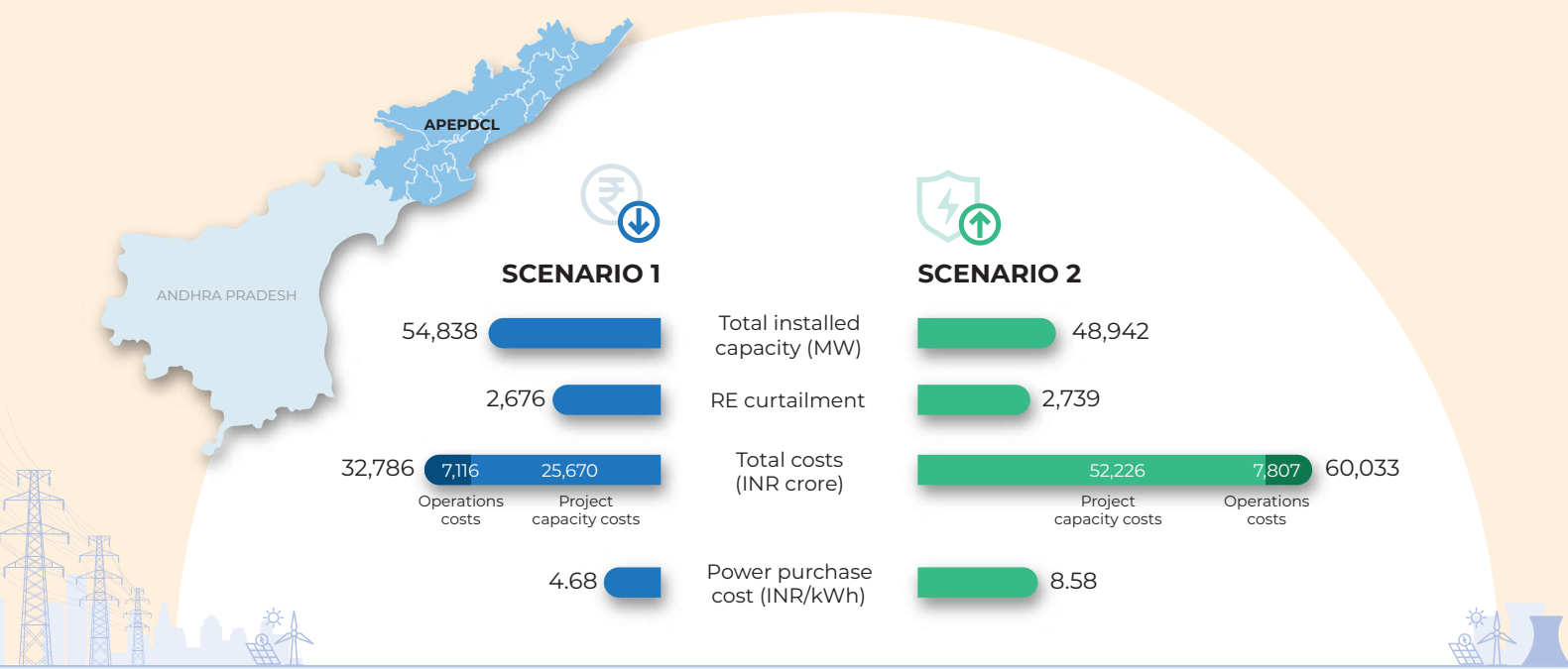
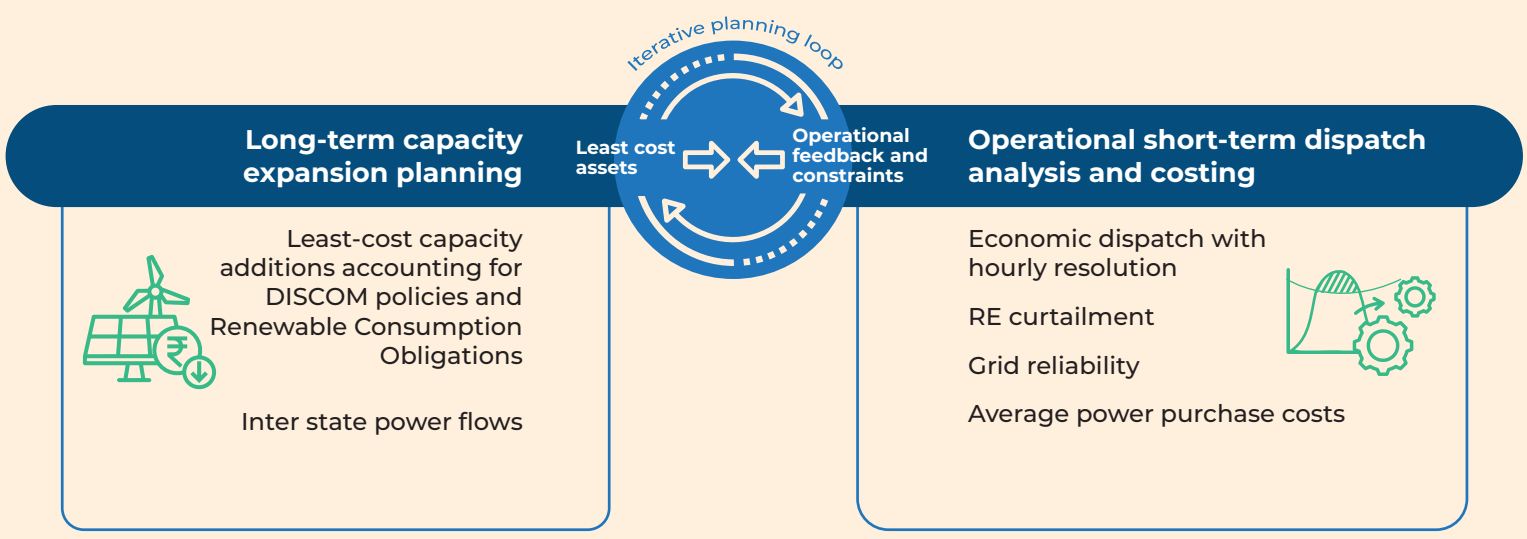
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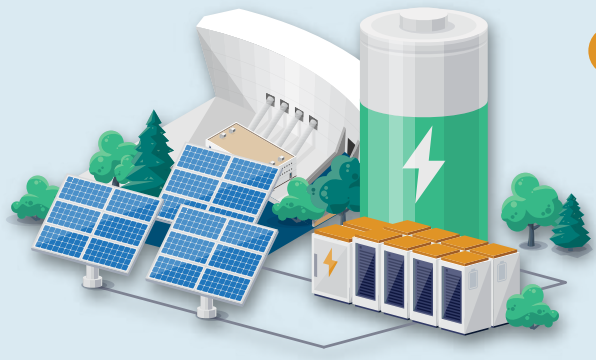
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INSIGHTS

1  Energy storage is critical for future planning in the power sector.



2  There is a reliability–cost trade-off for long-term procurement planning.

3  A combination of storage technologies is more effective than reliance on any single technology.

RECOMMENDATIONS



Develop a diversified storage portfolio.



Prioritise co-located and distribution-level BESS.



Use storage to support thermal fleet flexibility during the transition.

Executive Summary

India's national policy framework for the power sector requires distribution companies (DISCOMs) to undertake tailored long-term planning to ensure a reliable, cost-effective power supply and to integrate renewable energy (Ministry of Power, 2023). In line with the Ministry of Power's (2023) *Guidelines for Resource Adequacy Planning Framework for India*, Andhra Pradesh released the *APERC (Framework for Resource Adequacy) Regulation, 2026* in June, reinforcing the need for sub-national and DISCOM-level planning (Andhra Pradesh Electricity Regulatory Commission, 2026).

In this context, this study assesses the energy storage requirements of the Andhra Pradesh Eastern Power Distribution Company Limited (APEPDCL) over a planning horizon from FY 2023–24 to FY 2039–40. Using least-cost capacity expansion planning and hourly dispatch analysis, this study evaluates key system indicators, including average power purchase cost (APPC), unserved energy, renewable energy curtailment, total system cost, and thermal plant load factor (PLF), under high renewable energy penetration. The target year was FY 2039–40, and the intermediate planning years included FY 2027–28, FY 2031–32, and FY 2035–36.

The study compares two key scenarios for APEPDCL for FY 2039–40, assuming the same load growth.

In **Scenario 1 (S1)**, the long-term capacity expansion assessment for APEPDCL considers only the installed capacity available in the base year, with no additional committed capacity assumed.

In **Scenario 2 (S2)**, APEPDCL's long-term expansion planning considers the base-year installed capacity together with 36.2% of the capacity additions envisaged for Andhra Pradesh in the Central Electricity Authority's *Long-Term National Resource Adequacy Plan (2026–27 to 2035–36)*, reflecting APEPDCL's share of power procurement, and evaluates any additional capacity requirements.

Together, the two scenarios help compare two different planning choices for APEPDCL. S1 shows what the future capacity mix could look like if APEPDCL planned mainly from its existing capacity and added new resources based on least-cost optimisation. S2 shows what the future system could look like if APEPDCL also accounted for its share of the capacity additions already planned at the state level. This comparison helps assess whether the state-level planned additions are sufficient and cost-effective for APEPDCL's long-term needs.

Comparative analysis of S1 and S2

Parameter	S1		S2	
	Planned capacity addition (MW)	Projected new build (MW)	Planned capacity addition (MW)	Projected new build (MW)
Nuclear	0	400	0	0
Coal	0	168	893	0
Hydro	0	1,747	431	1,395
Biomass	0	0	0	200
Wind	0	4,800	143	4,800

Parameter	S1		S2	
Solar	0	19,635	2,843	18,807
DRE	0	8,176	0	4,915
Pumped hydro energy storage (PHES)	0	1,821	2,380	0
Battery energy storage systems (BESS) (4h)	0	10,887	0	8,301
Total installed capacity (MW)	54,838		48,942	
Unserved energy (MU)	216		184	
PLF (%) of coal plants	27		32	
Renewable energy curtailment	2,676		2,739	
Project capacity costs (INR crore)	25,670.45		52,225.60	
Project operations costs (INR crore)	7,116		7,807	
Total costs (INR crore)	32,786		60,033	
Power purchase cost (INR/kWh)	4.68		8.58	

Key insights for APEPDCL

- **Solar and energy storage procurement are critical for future power sector planning of DISCOMs.**

The scenario comparison shows solar, decentralised renewable energy, 4-hour BESS, and PHES as key resources for meeting APEPDCL's future demand across both scenarios.

- **There is a reliability–cost trade-off for long-term procurement planning.**

S1 results in a lower APPC of INR 4.68/kWh compared to the base year APPC of INR 5.77/kWh, while S2 results in a higher APPC of INR 8.58/kWh by FY 2039–40. However, S1 records approximately 32 MU higher unserved energy than S2, indicating a trade-off between cost and power supply reliability.

- **A combination of storage technologies is more effective than reliance on any single technology.**

The findings indicate that large-scale storage will be essential for APEPDCL by FY 2039–40. Under S1, the required storage additions include 10,887 MW of 4-hour BESS and 1,821 MW of PHES. Under S2, the requirement is limited to 8,301 MW of 4-hour BESS, with no additional PHES capacity required by the target year. BESS can provide fast response, intra-day balancing, and evening peak support, while PHES can provide bulk storage for sustained and overnight discharge. A combined portfolio of BESS and PHES is therefore better suited to APEPDCL's future system needs than dependence on a single storage technology.

Implications for APEPDCL

Overall, the study shows that energy storage should be treated as a core resource in APEPDCL's long-term procurement and resource adequacy planning rather than as a supporting technology for renewable energy deployment alone.

Under S1, the study projects an installed capacity of 54 GW by FY 2040, along with a notable decline in the APPC from the base year. This reduction in per-unit cost underscores the long-term economic benefits of scaling up renewables and storage capacity, showing how greater installed capacity can lower procurement costs and improve overall grid efficiency over time.

In contrast, APPC increases substantially by FY 2040 under S2 due to the incorporation of planned capacity additions, particularly coal-based generation, with higher costs.

Consequently, S1 and the associated capacity additions emerge as a least-cost alternative for APEPDCL to meet future demand through a portfolio dominated by solar and energy storage (BESS (4h) and PHES).

Recommendations

1. Develop a diversified storage portfolio.

Build a planned storage portfolio combining 4-hour BESS, PHES, co-located storage, distribution-level storage, and thermal fleet flexibility.

3. Use storage to support thermal fleet flexibility during the transition.

BESS near thermal plants can also support thermal fleet flexibility, especially as thermal PLF declines to 27% under S1 and 32% under S2 by FY 2039–40.

2. Prioritise co-located and distribution-level BESS.

Co-located BESS with renewable energy plants can improve renewable energy utilisation, reduce curtailment, and support evening and non-solar-hour demand. Distribution-level BESS can help manage the projected increase in distributed renewable energy capacity, which reaches 8,176 MW under S1 and 4,915 MW under S2 by FY 2039–40, by addressing reverse power flow, voltage variations, feeder congestion, and transformer overloading.

Taken together, these measures can help APEPDCL reliably meet future demand, manage peak load, reduce challenges associated with renewable energy integration, and support cost-effective clean power procurement.

Contents

1. Introduction.....	14
1.1. Overview of Andhra Pradesh's power system.....	14
1.2. APEPDCL.....	14
1.3. Study objectives and significance	15
2. Methodology	17
2.1. Approach	17
2.2. GridPath: Power system modelling software	18
2.3. Capacity expansion.....	18
2.4. Production costing	19
3. Model Setup, Scenarios, and Data Inputs	21
3.1. Model setup and temporal scope	21
3.2. Scenario definition.....	21
3.3. Planning assumptions	22
3.4. Data inputs.....	22
4. Capacity Expansion for APEPDCL for FY 2039–40	29
4.1. Modelling.....	29
4.2. Scenarios considered	29
4.3. Results	30
5. Production Costing	33
5.1. Results summary	33
5.2. Discussion on hourly dispatch for FY 2039–40.....	35
5.3. Yearly analysis for FY 2039–40	39
6. Use Cases of Energy Storage Systems for APEPDCL	42
6.1. Use cases of ESS at different levels of the power system.....	42
6.2. ESS use cases for APEPDCL.....	44

7. Conclusion.....	48
7.1. Key findings.....	48
7.2. Role of storage and recommended deployment pathways for APEPDCL.....	49
7.3. Final recommendations.....	49
8. References	50
9. Appendices	51
9.1. Appendix A.....	51
9.2. Appendix B.....	54
9.3. Appendix C.....	57

Figures

Figure 1: APEPDCL capacity mix, FY 2023–24.....	16
Figure 2: Methodological approach.	18
Figure 3: Capacity expansion analysis framework and representative generation capacity evolution across the planning horizon.	20
Figure 4: Production cost simulation framework and representative least-cost hourly dispatch output of the power system.....	21
Figure 5: Monthly peak day demand profile.....	24
Figure 6: Planned capacity additions for Andhra Pradesh as per the CEA's Long-Term National Resource Adequacy Plan (2026–27 to 2035–36).....	31
Figure 7: Capacity projections for APEPDCL under least-cost optimisation (S1) and least-cost optimisation with planned capacity additions (S2) across future years (2028, 2032, 2036, 2040).....	32
Figure 8: Month-wise Heat Map of Unserved Energy for Scenarios S1 and S2.	35
Figure 9: Dispatch plots for S1.	37
Figure 10: Dispatch plots for S2.	39
Figure 11: Energy delivered (MU) for S1 and S2 in FY 2039–40.....	41
Figure 12: Use cases of ESS at different levels of the grid.	43
Figure 13: Capacity additions for storage under S1.....	45
Figure 14: Capacity additions for storage under S2.....	46
Figure 15: PLF degradation under S1.	46
Figure 16: PLF degradation for S2.	47

Tables

Table 1: Planning assumptions.	23
Table 2: Peak demand and energy requirement projections for the target years.	24
Table 3: Common operational characteristics for different generation technologies.....	25
Table 4: Operational characteristics for different generation technologies.....	26
Table 5: Average CUF assumptions.....	27
Table 6: Year-wise RCO targets (%).	28
Table 7: Technology-wise cost assumptions for new generation plants in FY 2039–2040.	29
Table 8: Cost assumptions for new storage technologies.	29
Table 9: PCS results comparison for FY 2027–28, FY 2031–32, FY 2035–36, and FY 2039–40.	34
Table 10: Energy delivered (in MU) for selected representative seasonal days under S1.	37
Table 11: Energy delivered (MU) for a representative day for S2.....	39
Table 12: Energy delivered (MU) in FY 2039–40.	40
Table 13: Financial and operational details for FY 2039–40.	41
Table 14: Unit-wise generation and contracted capacity.	52
Table 15: Unit-wise average fixed costs and variable costs for FY 2023–24 and FY 2039–40....	55
Table 16: Unit-wise fuel prices for FY 2023–24 and FY 2039–40.	58

Abbreviations

Abbreviation	Definition
APCPDCL	Andhra Pradesh Central Power Distribution Corporation Limited
APEPDCL	Andhra Pradesh Eastern Power Distribution Corporation Limited
APERC	Andhra Pradesh Electricity Regulatory Commission
APGENCO	Andhra Pradesh Power Generation Corporation Limited
APPC	Average power purchase cost
APPGCL	Andhra Pradesh Power Generation Corporation Limited
APSPDCL	Southern Power Distribution Corporation Limited
APTRANSCO	Andhra Pradesh Transmission Corporation
AFC	Annualised fixed cost
BESS	Battery energy storage system
CAES	Compressed air energy storage
CAGR	Compound annual growth rate
CEA	Central Electricity Authority
CUF	Capacity utilisation factor
DISCOM	Distribution company
DRE	Distributed renewable energy
EPS	Electric Power Survey
EV	Electric vehicle
FC	Fixed cost
FY	Financial year
GW	Giga-watt
IPP	Independent power producers
ISTS	Inter-State Transmission System
LT-DRAP	Long-term distribution licensee resource adequacy plan
MW	Mega-watt
NREL	National Renewable Energy Laboratory
PCS	Production costing simulation
PHES	Pumped-hydro energy storage
PLF	Plant load factor
PRM	Planning reserve margin
PV	Photovoltaic
RCO	Renewable Consumption Obligation
RE	Renewable energy
VC	Variable cost

1. Introduction

India remains steadfast in its commitment to achieving net-zero emissions by 2070. Towards this goal, the Government of India has set a target for non-fossil sources to account for 60% of installed power capacity by 2035 (PIB, 2026).

As of March 2026, the country's total installed capacity stood at 524 GW (Ministry of New and Renewable Energy, n.d.). In 2025, India surpassed the 250 GW non-fossil installed capacity milestone, five years ahead of the 2030 target.

As the clean energy transition progresses, distribution companies (DISCOMs) will play a key role in integrating renewable energy while ensuring a reliable, affordable, and round-the-clock power supply. To manage rising renewable energy penetration and meet peak demand, DISCOMs will need to adopt robust long-term planning approaches.

Recognising this need, the Ministry of Power in India has established a structured framework for long-term resource adequacy planning to ensure sufficient electricity generation and transmission capacity to meet demand over a 10-year horizon (Central Electricity Authority [CEA], 2026). Under the *Electricity (Amendment) Rules, 2022*, the framework requires the CEA to prepare a National Electricity Plan and DISCOMs to prepare tailored, 10-year long-term demand and resource adequacy plans (LT-DRAP) to ensure consistent and reliable power availability.

In this context, power system planning studies that evaluate least-cost capacity additions, storage requirements, and dispatch operations are essential tools for distribution utilities. Such analyses, conducted at the national and subnational levels, can help DISCOMs plan ahead and manage power procurement costs effectively.

1.1. Overview of Andhra Pradesh's power system

Andhra Pradesh ranks among India's top electricity-consuming states. The 20th Electric Power Survey (EPS) estimated the state's energy consumption at around 80,515 MU in FY 2026, with demand projected to increase to 1,21,978 MU by FY 2032 (CEA, 2022).

This substantial rise in Andhra Pradesh's electricity demand is largely driven by industrial expansion, data centre proliferation, electric vehicle (EV) adoption, and the continued push for reliable, 24×7 power supply across all consumer categories.

Andhra Pradesh's power sector is structured around four functions: regulation, generation, transmission, and distribution. The Andhra Pradesh Electricity Regulatory Commission (APERC) serves as the regulatory authority. Generation is handled by the Andhra Pradesh Power Generation Corporation Limited (APPGCL), while transmission is managed by the Andhra Pradesh Transmission Corporation (APTRANSCO). Distribution is managed by three utilities: Andhra Pradesh Eastern Power Distribution Corporation Limited (APEPDCL), Andhra Pradesh Central Power Distribution Corporation Limited (APCPDCL), and Andhra Pradesh Southern Power Distribution Corporation Limited (APSPDCL).

1.2. APEPDCL

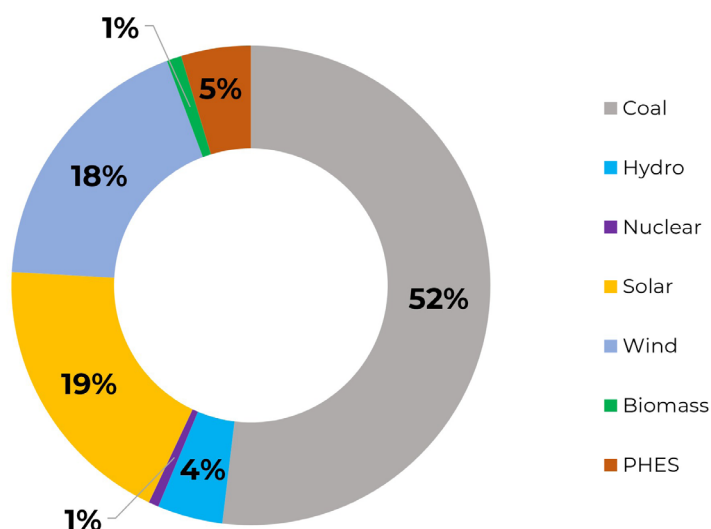
This study focuses on APEPDCL, which serves the northern and eastern coastal districts of Andhra Pradesh. APEPDCL was incorporated as a public limited company under the Companies Act in 2000. It is a fully state-owned DISCOM headquartered in Visakhapatnam and distributes power across 11 districts: Srikakulam, Alluri Sitharama Raju, Vizianagaram, Parvathipuram Manyam, Visakhapatnam, Anakapalli, Kakinada, East Godavari, Dr B R Ambedkar Konaseema, Eluru, and West Godavari.

APEPDCL's license area includes some of the state's most economically significant regions, with growing electricity load additions from industrial, commercial, and technological infrastructure. Visakhapatnam has emerged as a leading industrial centre, with major public- and private-sector establishments producing large-scale industrial goods and supporting shipbuilding, port operations, and fisheries. Further, Google is set to invest USD 15 billion (approximately INR 1.43 lakh crore) in an AI Hub, along with corresponding data centre capacity (PIB, 2025). The combination of a strong industrial base, rapid growth in electricity demand, and expanding energy transition infrastructure makes APEPDCL the most policy-relevant distribution zone for this study.

For FY 2023–24, APEPDCL procured power from a total installed capacity of 7,205 MW allocated by Andhra Pradesh, accounting for approximately 36.2% of the state's total installed capacity (APERC, 2025).

As shown in Figure 1, coal accounts for 52% of APEPDCL's procured capacity mix, followed by solar at 19% and wind at 18%. Hydro and pumped hydro energy storage (PHES) contribute 4% and 5%, respectively, while biomass and nuclear each account for 1%. Renewable energy sources, including solar, wind, and biomass, together constitute approximately 38% of the total procured capacity.

Figure 1: APEPDCL capacity mix, FY 2023–24.



As renewable energy capacity additions accelerate across the state, APEPDCL must plan its future capacity mix strategically to ensure a reliable supply at the lowest possible procurement cost.

1.3. Study objectives and significance

Distribution utilities have a fundamental obligation to supply reliable and uninterrupted power to consumers.

In line with the Ministry of Power's *Guidelines for Resource Adequacy Planning Framework for India*, issued in June 2023, APERC released the *APERC (Framework for Resource Adequacy) Regulation, 2026* in June (APERC, 2026). This regulation applies directly to DISCOMs in Andhra Pradesh and mandates demand forecasting, generation resource planning, storage procurement, and compliance monitoring as part of an annual planning cycle.

Least-cost generation planning is a core analytical tool within this framework. It helps determine the optimal combination of resources, including thermal, renewables, imports, and storage, required to meet demand over the long term at the lowest total system cost. It also helps states and utilities assess whether sufficient capacity is available to reliably meet electricity demand under various operating conditions, including extreme weather events, generator outages, and peak-demand periods.

Given the variable nature of renewable energy sources, which are expected to constitute an increasing share of the generation mix in line with national and state-level clean energy targets, the integration of large-scale energy storage systems is equally critical.

Against this backdrop, this study extends the planning horizon to FY 2039–40 to capture not only near-term requirements but also the longer-term trajectory of technology deployment across the power sector. This DISCOM-specific approach enables a more granular understanding of electricity demand growth, existing contracted capacity, procurement gaps, and storage requirements unique to APEPDCL's service territory. It can also facilitate targeted and operationally actionable recommendations for capacity addition and resource procurement.

The study objectives are as follows:

- 


Determine the least-cost optimal capacity addition pathway for APEPDCL through FY 2039–40
- 


Conduct a yearly dispatch study at a resolution of one hour for FY 2039–40
- 


Estimate the change in average power purchase cost (APPC) under the optimal capacity mix.

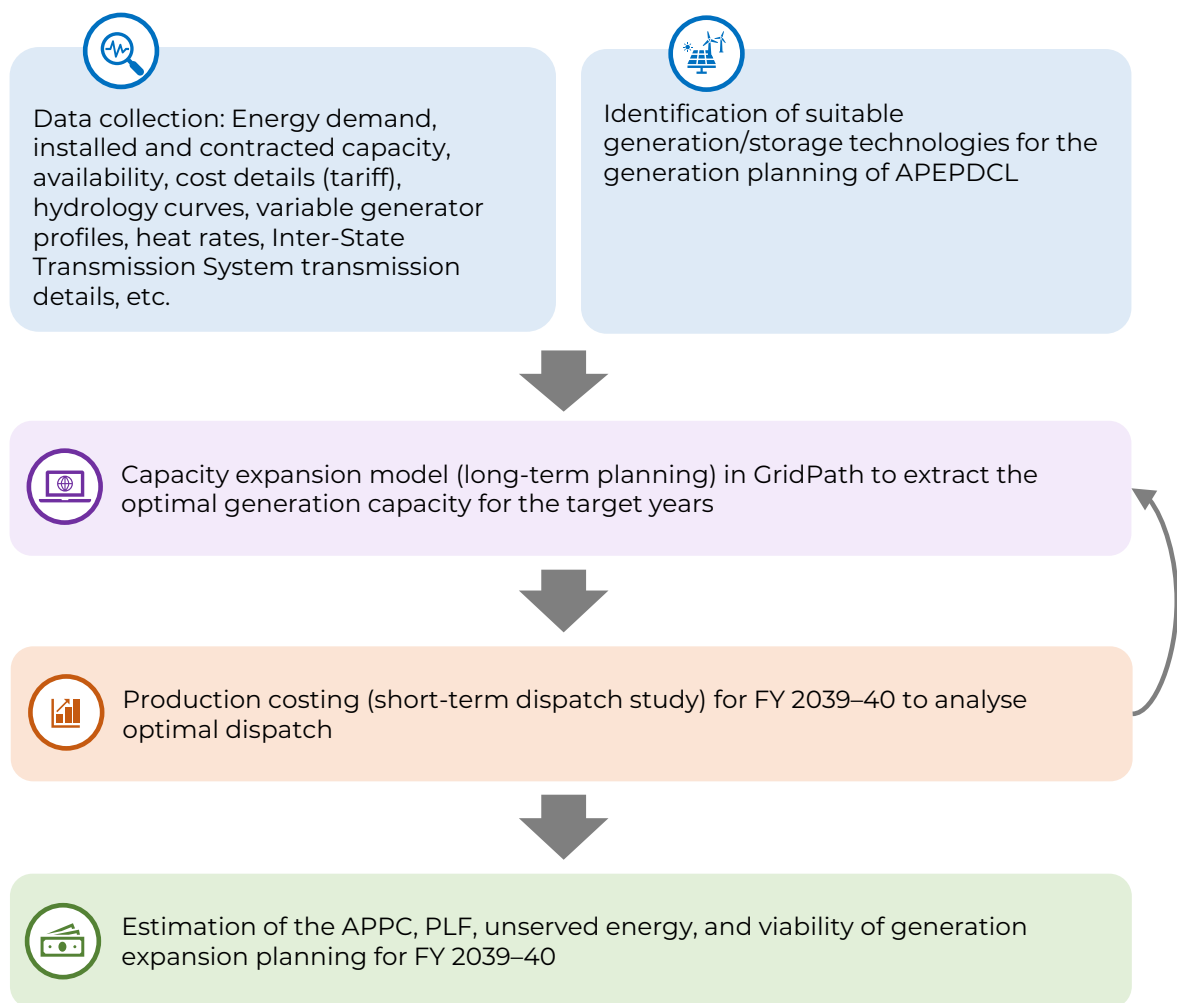
2. Methodology

This section outlines the analytical framework used to assess APEPDCL's optimal long-term generation and storage capacity requirements through FY 2039–40. The study combines capacity expansion modelling with production cost simulation.

2.1. Approach

The study adopts a two-stage modelling framework to assess the least-cost evolution of APEPDCL's power procurement portfolio, as presented in Figure 2.

Figure 2: Methodological approach.



The process begins by collecting data on energy demand, existing capacity, costs, hydrology, and transmission parameters, followed by identifying suitable generation and storage technologies.

GridPath, an open-source software for power system modelling, is then used to determine the optimal generation mix through capacity expansion modelling, while production costing simulations are conducted to analyse dispatch operations. Finally, key performance indicators, including APPC, plant load factor (PLF), unserved energy, and the overall feasibility of the expansion plan, are assessed. The following section provides an overview of GridPath and its application in this study.

2.2. GridPath: Power system modelling software

GridPath supports a range of planning and analytical approaches, including production cost simulation, capacity expansion, asset valuation, and reliability analysis. These approaches are often used complementarily in power system planning. Integrating them within a single modelling platform reduces complex data translation requirements and improves system planning efficiency. GridPath provides insights into power system operations, system reliability, transmission congestion, locational marginal prices, and the impacts of capacity additions and retirement of older power plants as they become too expensive to run, lose efficiency over time, and fail to meet environmental safety rules. These insights support the development of our long-term grid planning strategies.

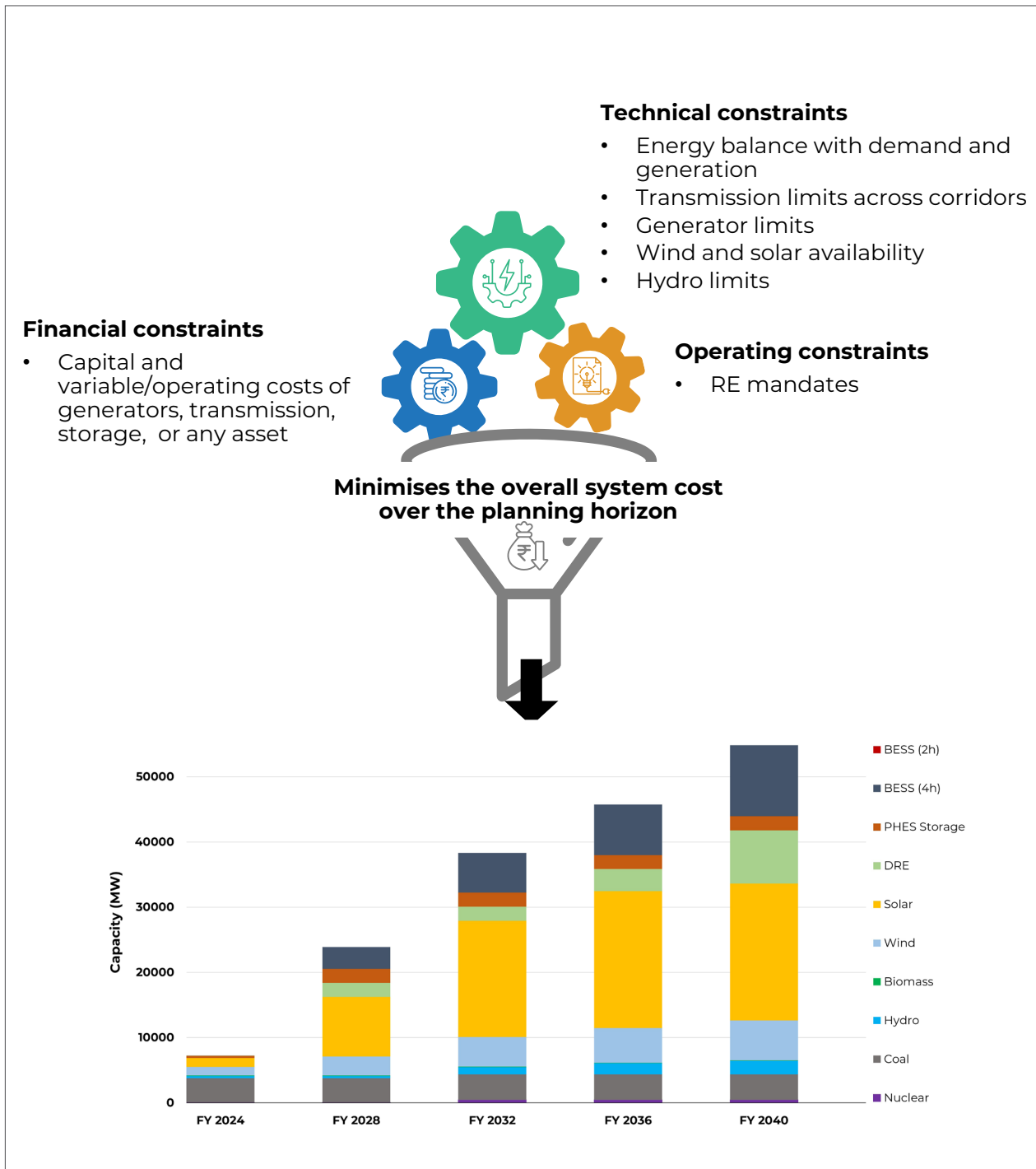
2.3. Capacity expansion

Capacity expansion analysis is a long-term planning exercise used to identify the cost-optimal installed capacity mix of available energy resources to meet future electricity demand. GridPath's capacity expansion model optimises the power system by minimising overall system costs while determining the most effective investment and retirement decisions for generation assets. This optimisation accounts for several important factors, including projected demand, available generation technologies, renewable energy targets, and policy constraints. The analysis also incorporates key inputs, such as capital costs of candidate power plants and resource availability, as constraints. GridPath allows users to define the model's spatial and temporal resolution based on the study's complexity and computational limitations.

To maintain reasonable runtimes, capacity expansion models are often executed with simplifications in both spatial and temporal parameters while processing various generation-related input data. The system is typically represented at an aggregated level, such as balancing areas or states, with generating units within each region grouped together. Similarly, instead of modelling every hour of the year, representative days and time periods are selected and assigned appropriate weights to accurately reflect annual operating conditions.

Figure 3 outlines the overall framework of the capacity expansion study. It highlights the key input parameters used in the preliminary phase and presents representative outputs for the base year (2023–24) and future study years (2027–28, 2031–32, 2035–36, and 2039–40).

Figure 3: Capacity expansion analysis framework and representative generation capacity evolution across the planning horizon.



Notes: DRE: distributed renewable energy; PHES: pumped hydro energy storage.

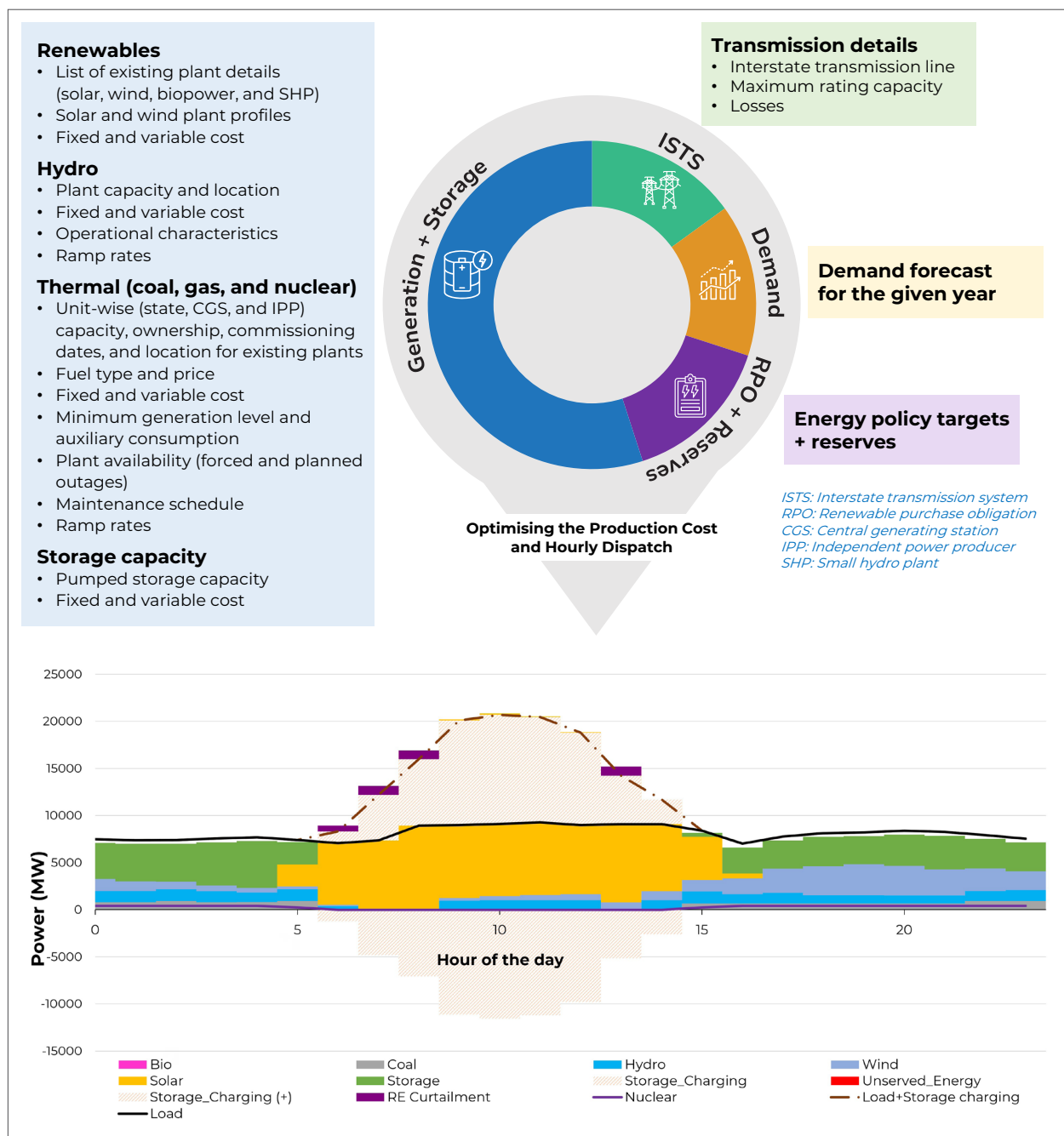
2.4. Production costing

The objective of a production costing simulation (PCS) model is to optimise the dispatch and day-to-day operation of available generation resources to reliably meet electricity demand. Unit commitment and dispatch decisions are determined based on multiple factors, including the least cost per unit; renewable energy targets; and relevant policy, technical, and operational constraints.

The PCS model in GridPath operates at a higher temporal resolution—typically hourly—enabling a detailed assessment of each generating unit's performance at every time interval throughout the study period. In GridPath, the balancing horizon for the PCS model is generally set to 1 day, ensuring daily energy balance throughout the year.

Key inputs to the PCS model include hourly demand profiles, available generation resources, and the technical and operational characteristics of generating units. Figure 4 illustrates the overall methodology and representative outputs of a typical PCS model.

Figure 4: Production cost simulation framework and representative least-cost hourly dispatch output of the power system.



Note: Negative values represent charging demand from storage resources.

3. Model Setup, Scenarios, and Data Inputs

The capacity expansion and PCS models developed for APEPDCL were built within the GridPath framework, with both models drawing on a common, consistently structured database. This section outlines the model structure, temporal scope, and scenario definitions. Detailed input assumptions covering demand, plant characteristics, and operational parameters are presented in the subsections that follow.

3.1. Model setup and temporal scope

The capacity expansion model covers the planning horizon from FY 2023–24 (the base year) to FY 2039–40 (the target year), with intermediate milestone years of FY 2027–28, FY 2031–32, and FY 2035–36. Twelve representative days were selected to characterise the full year, each simulated at hourly resolution, with 24 time points per representative day. The day corresponding to peak demand in each calendar month of the base year was selected as that month's representative day.

The PCS model operates at a higher temporal resolution, with all days in the simulation years, FY 2027–28, FY 2031–32, FY 2035–36, and FY 2039–40, modelled at hourly resolution. This results in 8,784 time points per year, as each simulation year is a leap year. This full-year chronological simulation was adopted to capture renewable energy variability, hydrological seasonality, and reserve compliance requirements for each milestone year.

3.2. Scenario definition

The study presents findings from two primary scenarios:

- **Scenario 1 (S1):** Long-term least-cost capacity expansion assessment for APEPDCL based on base-year installed capacity, with no additional committed capacity assumed.
- **Scenario 2 (S2):** Long-term least-cost capacity expansion assessment for APEPDCL using base-year installed capacity together with 36.2% of the capacity additions envisaged for Andhra Pradesh in the CEA's *Long-Term National Resource Adequacy Plan (2026–27 to 2035–36)*, reflecting APEPDCL's share of power procurement; the scenario evaluates additional capacity requirements.

Throughout this report, the two scenarios are referred to as **S1** and **S2**.

Together, these scenarios allow the study to distinguish between a least-cost expansion pathway developed from APEPDCL's existing capacity base and one that incorporates the utility's proportional share of state-level planned capacity additions. S1, therefore, indicates the capacity mix that would emerge if APEPDCL were to meet future demand primarily through fresh least-cost additions. S2, by contrast, tests whether the planned capacity additions identified at the state level remain cost-effective and sufficient when allocated to APEPDCL's demand and procurement share.

3.3. Planning assumptions

The key planning assumptions underlying the study are summarised in Table 1.

Table 1: Planning assumptions.

Category	Assumptions
Capacity expansion	Planning horizon: FY 2023–24 to FY 2039–40
	Twelve representative days were used at hourly resolution to reduce computational time.
	Endogenous investment optimisation was employed to determine the least-cost capacity additions.
Production costing	All days of FY 2027–28, FY 2031–32, FY 2035–36, and FY 2039–40 were simulated at hourly resolution.
Demand and supply profiles	Renewable energy generation profiles were assumed to be constant between FY 2023–24 and FY 2039–40.
	Energy requirement was scaled to FY 2039–40 based on 20th EPS data.
	Load shape from FY 2023–24 was retained for the target years.
Plant characteristics	Availability and operational parameters for thermal and renewable energy plants were assumed to be unchanged from the base year across all target years.
	Hydro generation was represented using a three-year average generation profile across all target years.
Transmission and market	The state was modelled as a single node under the copper plate assumption, with ISTS transmission considered.
	Short-term open access and market transactions were excluded from the simulation

3.4. Data inputs

This section details the data inputs underlying the study, including demand projections, the existing and candidate generation and energy storage portfolio, and the technical and operational parameters used in capacity planning and dispatch modelling. These inputs were sourced from data shared by APEPDCL, publicly available regulatory filings, and standard industry references and form the basis for all subsequent analysis.

3.4.1. Demand

Hourly demand profiles for each modelled zone constitute the primary demand-side input to the analysis. The demand profile for APEPDCL was obtained directly from DISCOM stakeholders. The load shape from the FY 2023–24 base-year profile was retained across all target years to preserve the observed diurnal and seasonal characteristics of electricity consumption.

Absolute energy requirements were subsequently scaled to reflect projected growth, with energy scaling factors derived from the CEA's 20th EPS. Based on these projections, APEPDCL's energy demand is estimated to increase by approximately 7% every four years. Table 2 presents the projected peak demand and annual energy requirement for the target years.

Table 2: Peak demand and energy requirement projections for the target years.

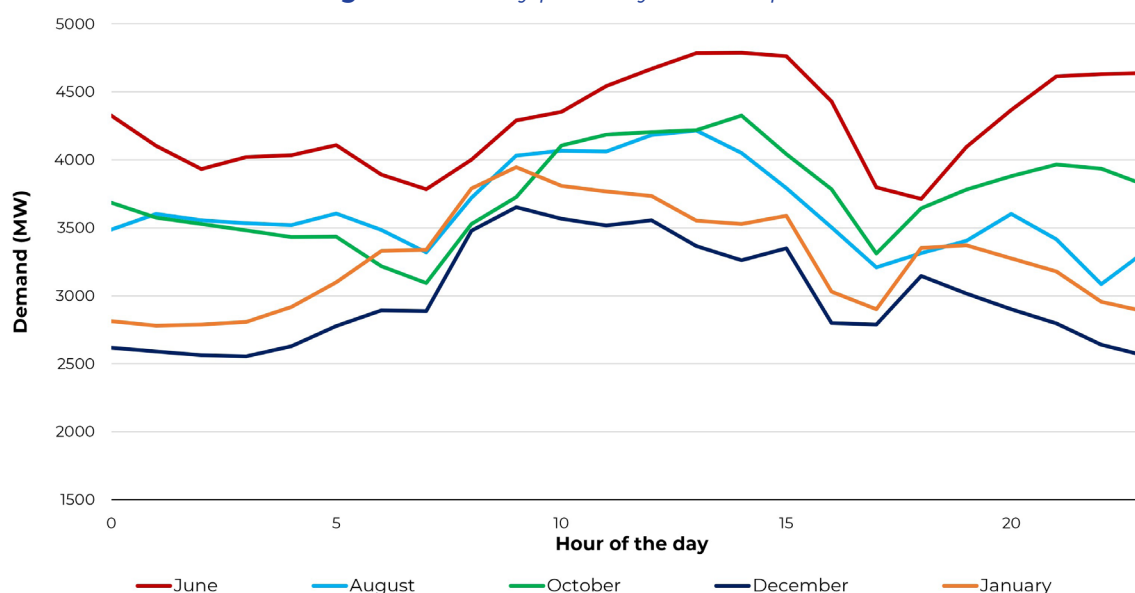
FY	Energy requirement (MU)	Peak demand (MW)
2023–24	30,629	4,788
2027–28	40,261	6,294
2031–32	55,174	8,625
2035–36	61,631	9,634
2039–40	69,982	10,939

Figure 5 presents the demand profile for the monthly peak-demand days in the base year, FY 2023–24. The profiles indicate that APEPDCL has a predominantly daytime-peaking demand pattern, with demand peaking between 12 PM and 3 PM in most months. However, several months also display a sharp evening ramp after 5 PM, particularly April, May, June, July, September, and October.

The demand profile shows clear seasonal variation throughout the year. Summer months, particularly April to July, record the highest electricity demand, with peaks occurring during the afternoon and evening, likely due to increased cooling and air-conditioning loads. June records the maximum demand among all months.

In contrast, winter months such as December and January show the lowest overall demand, despite slight increases in the morning and evening due to heating and lighting needs. Spring and autumn months show moderate, stable demand due to milder weather. Overall, demand follows a daily cycle, rising during active daytime hours and declining late at night.

Figure 5: Monthly peak day demand profile.



Load zones: Each load zone, defined as the level at which load-balance constraints are enforced, was assigned a set of penalty parameters governing how the optimiser handles energy-imbalance conditions. The load zones considered in the model are Andhra Pradesh, Telangana, Odisha, Tamil Nadu, and Karnataka. Both overgeneration and unserved energy are permitted across all zones but are assigned extremely high penalty costs to discourage their occurrence.

3.4.2. Reserves

The model incorporates system-level reliability requirements through three constraints. Non-spinning reserves are set at 4% of the total load, comprising reserve up, reserve down, regulation up, and regulation down, each at 1% of the load. Spinning reserves are set at 5% of load. These reserve requirements are particularly important in systems with increasing renewable energy penetration, where short-term variability and ramping requirements are expected to increase.

In addition, a planning reserve margin of 5% above peak load is applied to ensure that the optimised portfolio maintains sufficient capacity above the expected peak demand (CEA, 2026). The planning reserve margin represents the available firm capacity above expected peak demand and helps ensure reliability amid uncertainties. Together, these constraints enable the model to identify a resource mix that is not only least-cost but also capable of maintaining reliability under operational variability and planning uncertainty.

3.4.3. Operational and technical characteristics

The operational and technical characteristics of generation technologies were defined based on two reference sources: CEA technology sheet values and practical characteristics observed in the field.

Certain parameters were kept consistent across both scenarios, including ramp-up and ramp-down rates and auxiliary consumption, as shown in Table 3.

Table 3: Common operational characteristics for different generation technologies.

Technology	Ramp-up and ramp-down rates (%/min)	Auxiliary consumption (%)
Coal	1	7
Gas	12	3
Nuclear	1	8
Large and small hydro	30	3
Biomass	1	7
BESS	100	Negligible
PHES	50	4

The two scenarios differ in their assumptions regarding minimum stable load, minimum uptime, and minimum downtime, as presented in Table 4.

Table 4: Operational characteristics for different generation technologies.

Technology	CEA characteristics			Practical characteristics		
	Minimum stable limit (%)	Minimum uptime (h)	Minimum downtime (h)	Minimum stable limit (%)	Minimum uptime (h)	Minimum downtime (h)
Coal	55	6	4	55–70 (for plants commissioned after 2015); 80 (for plants commissioned during 2010–2015); 85 (for plants commissioned before 2010)	12	6
Gas	20–50	4	2–3	20–50	6	3
Nuclear	90	6	4	90	96	96
Large and small hydro	7.5	0.25	0.25	7.5	0.25	0.25
Biomass	40	4	2	70	12	6
BESS	Negligible	0	0	Negligible	0	0
PHES	7.5	0.25	0.25	7.5	0.25	0.25

The practical characteristics assume higher minimum uptime and downtime values because power plants are generally operated more conservatively in real-world conditions than their technical minimum capabilities suggest. Factors such as equipment wear and tear, operational constraints, maintenance requirements, and economic considerations make frequent start-ups and shutdowns less desirable. In particular, nuclear plants are designed to operate continuously for long periods and are not intended to be turned on and off frequently like gas plants. Once shut down, they take several days to restart safely and efficiently, which is why the practical characteristics assume higher minimum uptime and downtime values than the CEA characteristics.

3.4.4. Thermal power plant inputs

Each thermal generating unit, including coal-based stations, gas plants, and nuclear units, is characterised by a set of technical and financial parameters. These include state utilities, central generating stations, and independent power producers (IPP). Plant-level data for Andhra Pradesh, including contracted capacity, fixed costs, and variable costs, were provided by APEPDCL. The share of APEPDCL in Andhra Pradesh's total contracted capacity is assumed to be 36.2%, based on the APERC Tariff Order for FY 2025–26 (APERC, 2025).

3.4.5. Renewable energy and hydro plant inputs

Renewable energy plants considered in the study include solar, DRE, wind, biopower, industrial waste, and small hydro plants.

For solar, wind, bio, and small hydro plants modelled as variable generators, a generation profile is specified for each time point, representing power output as a fraction of installed capacity. Solar and wind generation profiles were developed using location-specific data from Renewables.ninja for existing renewable energy plants, accounting for spatial variation in generation profiles across sites (Stefan & Jain, 2016). Individual plant-level profiles were averaged separately for solar and wind to create representative profiles for the modelling analysis. Hydro operational characteristics were assigned using a three-year average generation profile. Table 5 presents the average capacity utilisation factors (CUFs) assumed for these technologies.

Table 5: Average CUF assumptions.

Types of generation	CUF (%)
Biomass	23
DRE	17
Hydro	49
Industrial waste	23
Solar	17
Offshore wind	26

Solar and wind plants are modelled as must-run plants. Biomass and small hydro plants are modelled with power output equal to a pre-specified fraction of available capacity at each time point. Hydro plants are also modelled as must-run plants, with generation constrained between minimum and maximum output levels for each time horizon. They are required to meet a predefined energy target within each horizon when available.

3.4.6. Existing storage plant inputs

All existing storage plants in Andhra Pradesh are modelled as PHES units with a 6-hour discharge duration. Similar to renewable energy plants, the variable operating cost of these assets is assumed to be zero. Costs are instead represented through a fixed cost per MWh, based on the specified energy capacity of the storage component in each operational period.

3.4.7. Unit costs

Fixed costs (FC) and variable costs (VC) were estimated using average compound annual growth rate (CAGR) trends derived from tariff orders spanning FY 2019 to FY 2026. The average CAGR assumptions applied over each four-year interval are as follows:

- **FC:** –6% to +6%
- **VC:** –2% to +2%

Coal plants are modelled with fractional commitment decisions, allowing commitment values between 0 and 1 to represent partial commitment of generating units. For example, a commitment value of 0.5 for a 1,000 MW coal plant represents 500 MW of committed capacity, while a value of 1 represents full commitment of the plant's capacity. Nuclear plants are modelled as must-run resources, generating power continuously whenever available.

Fuel costs vary across the planning horizon and are projected based on escalations in variable costs over the years and unit-specific heat rates, sourced from the *First Indian Technology Catalogue* for power generation (CEA & DEA, 2022). Availability and operational characteristics are assumed to remain unchanged between the base year and the target years. For all renewable energy plants, variable operation and maintenance costs were assumed to be zero, with these costs fully reflected in FC components.

3.4.8. Renewable Consumption Obligations

The Renewable Consumption Obligations (RCO) targets—previously referred to as Renewable Purchase Obligations (RPO) targets—form the primary policy constraint in both models (Bureau of Energy Efficiency, 2026).

RCO targets up to FY 2029–30 are taken directly from the Ministry of Power’s gazette notification dated 20 October 2023, which specifies minimum renewable energy consumption shares. Beyond FY 2029–30, targets are extrapolated assuming a continued linear increase consistent with the trajectory implied by the notification. Table 6 presents the resulting year-wise RCO targets used in this study. Zone 1 includes wind, hydro, and other renewable energy sources such as solar and biomass, while Zone 2 includes DRE targets.

These targets are enforced as minimum energy fraction constraints within the optimisation. In cases of non-compliance, an RCO penalty cost is imposed, creating a financial incentive for the model to meet the mandated targets.

Table 6: Year-wise RCO targets (%).

Year	Zone 1 – RCO	Zone 2 – DRE
2024	28.69	1
2028	35.51	3
2032	41.50	6
2036	46.80	8
2040	52.84	10

3.4.9. New generation and storage plants

This section presents the candidate technologies available to the capacity expansion model as new build options over the planning horizon. Capital cost assumptions for each technology were compiled from the National Renewable Energy Laboratory’s (NREL, 2024) *Annual Technology Baseline*, Lawrence Berkeley National Laboratory (n.d.) reports, and the *Indian Technology Catalogue* (CEA & DEA, 2022), and are expressed in INR crore/MW/year for generation technologies and for storage technologies. The cost assumptions are summarised in Tables 7 and 8.

Given that the study horizon extends to FY 2039–40, the analysis includes advanced energy storage technologies that are projected to achieve commercial viability within this timeframe. These include sodium-ion batteries, flow batteries, and compressed air energy storage (CAES). Although large-scale deployment of these technologies remains limited at present, anticipated cost reductions and performance improvements over the coming years make them relevant candidates for long-term planning analysis.

Table 7: Technology-wise cost assumptions for new generation plants in FY 2039–2040.

Technology type	Lifetime (years)	Cost (INR crore/MW)
DRE	25	2.7
Solar PV	25	2.7
Onshore wind	25	4.9
Offshore wind	25	13
Biomass	20	4.9
Small hydro	40	7.8
Large hydro	40	9.8
Nuclear	30	15
Coal – supercritical	25	10
Coal – ultra-supercritical	25	10.5

Table 8: Cost assumptions for new storage technologies.

Storage type	Lifetime (years)	Discharge duration (h)	Cost (INR crore/MW)
BESS (2 h)	15	2	1.328
BESS (4 h)	15	4	1.992
BESS (6 h)	15	6	4.98
PHES – Class 1	40	6	4.5
PHES – Class 2	40	8	8.9
PHES – Class 3	40	12	12
Sodium-ion battery	15	5	6.5
Flow battery	15	8	10
CAES	50	12	15

Note: PHES – Class 1: PHES with 6h discharge duration; PHES – Class 2: PHES with 8h discharge duration; PHES – Class 3: PHES with 12h discharge duration.

The cost assumptions for new generation technologies were derived from current-year cost estimates and technology-specific cost projection curves. For selected technologies, gradual cost reductions were assumed over the modelling horizon, allowing the model to reflect projected cost evolution by 2040 for future capacity additions.

The availability of new investments for each technology is determined based on construction lead times and expected commercial readiness. Utility-scale solar photovoltaics (PV) and BESS are assumed to be available from FY 2027–28, the first planning period. Technologies with longer gestation timelines, such as nuclear, large hydro, PHES, and new coal capacity, are introduced only in later planning periods. Sodium-ion batteries, flow batteries, and CAES are assumed to become commercially available starting in FY 2039–40, consistent with their expected technological maturity.

4. Capacity Expansion for APEPDCL for FY 2039–40

This section presents the optimal procurement decisions recommended for APEPDCL across the simulation years. The analysis is structured so that APEPDCL's procurement requirements are assessed as a subset of the overall state-level capacity additions required in Andhra Pradesh for the corresponding years.

4.1. Modelling

The capacity expansion model was developed to determine the least-cost generation expansion pathway for APEPDCL. Long-term capacity expansion models with endogenous investment decisions are computationally intensive because they simultaneously optimise investment and operating costs over multiple years. To reduce the computational burden while preserving key temporal variations, the analysis uses 12 representative days rather than modelling all 8,784 hours in each year. These representative days are selected to capture seasonal and daily variations in demand and renewable generation, enabling the model to assess long-term capacity and storage requirements efficiently. The results are presented across two scenarios, selected after reviewing key indicators, including unserved energy, coal plant PLF, and APPC.

As discussed earlier, S1 reflects procurement decisions for APEPDCL that are derived solely from the least-cost optimisation model based on base-year installed capacity, with no additional committed capacity assumed. S2 uses base-year installed capacity together with 36.2% of planned capacity additions for Andhra Pradesh as specified in the CEA's *Long-Term National Resource Adequacy Plan (2026–27 to 2035–36)*, reflecting APEPDCL's share of power procurement. The following sections discuss the details of each scenario.

4.2. Scenarios considered

The scenarios are evaluated across four planning years—FY 2027–28, FY 2031–32, FY 2035–36, and FY 2039–40. They are assessed using two planning approaches: independent-day and cyclic-day capacity expansion.

In the independent-day (linear boundary) approach, each representative day is treated as a standalone operating horizon. Constraints that depend on a previous time point, such as generator ramping limits and storage state-of-charge transitions, are not enforced for the first hour of the day. Consequently, there is no linkage between the final hour and the first hour of the representative day. This approach is computationally efficient and provides broad insights into long-term capacity expansion.

In the cyclic-day (circular boundary) approach, each representative day is modelled as a closed operating horizon in which the last hour of the day is considered the previous time point for the first hour. As a result, storage state-of-charge and other time-coupled operational constraints are tracked continuously across the day boundary, ensuring internally consistent and balanced operation within each representative day.

Both approaches were used to assess the robustness of capacity expansion and energy storage investment outcomes. Comparing the two helps determine whether the estimated storage requirement is sensitive to temporal modelling assumptions. The inclusion of intermediate simulation years alongside the target year, FY 2039–40, enables the analysis to capture the broader capacity expansion trajectory over the planning horizon.

The broader scenario framework considered two alternative sets of key modelling choices for generation assets: CEA-specified technical characteristics and practical operating characteristics. However, for both Andhra Pradesh and APEPDCL, results under these two modelling choices were found to be identical, effectively reducing the meaningful scenario space. Accordingly, the primary analysis focuses on the cyclic-day model using CEA technical characteristics, evaluated for S1 and S2. These scenarios form the basis of the results discussed in Section 4.3.

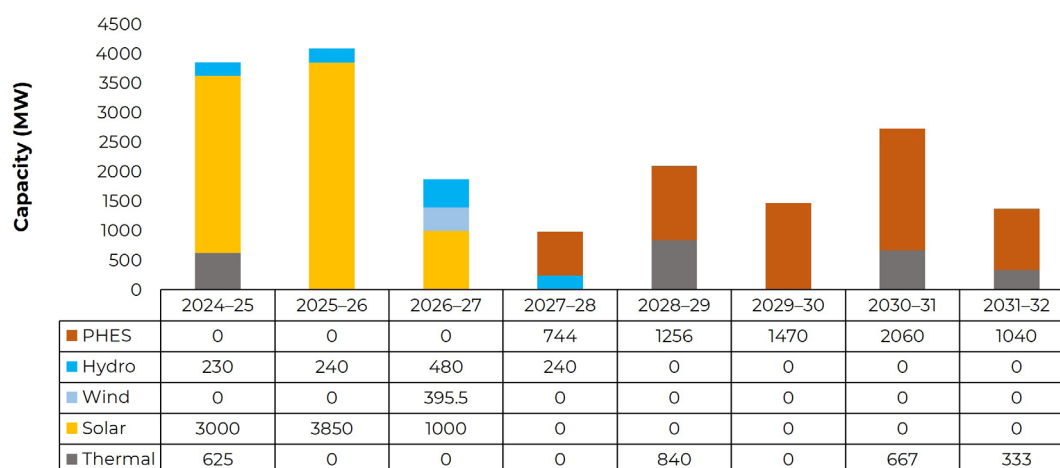
4.3. Results

This section presents capacity procurement recommendations for APEPDCL across the target simulation years, under both S1 and S2. For each milestone year, the model identifies the least-cost combination of generation and storage technologies to meet projected demand while satisfying RCO targets and supply adequacy constraints.

4.3.1. Planned capacity additions proposed by CEA

Scenario S2 incorporates the planned capacity additions prescribed by the CEA for Andhra Pradesh, as illustrated in Figure 6. The APEPDCL's share of these additions is estimated by proportionately scaling state-level additions based on its 36.2% share of Andhra Pradesh's demand.

Figure 6: Planned capacity additions for Andhra Pradesh as per the CEA's Long-Term National Resource Adequacy Plan (2026–27 to 2035–36).



4.3.2. Capacity procurement for S1

Under S1, APEPDCL's least-cost procurement portfolio expands from 7,205 MW in FY 2024 to 54,838 MW by FY 2040, as shown in Figure 7.

Solar forms the dominant share of new additions, increasing from 1,361 MW in FY 2023–24 to 20,996 MW by FY 2039–40, driven by its strong cost competitiveness within the least-cost optimisation framework. Wind capacity also expands substantially, reaching 6,126 MW by FY 2039–40. DRE enters the portfolio in FY 2027–28 at 2,161 MW and steadily grows to 8,176 MW by FY 2039–40, becoming a consistent component of APEPDCL's supply mix throughout the period.

Compared with these renewable energy additions, conventional capacity procurement, including coal, nuclear, hydro, and biomass, occurs at a relatively lower scale. This does not indicate a reduction in existing contracted volumes; rather, it reflects the significantly large scale of renewable energy and storage additions being brought in to meet demand as the least-cost solution.

On the storage side, PHES procurement reaches 2,159 MW by FY 2027–28 and remains at this level through FY 2039–40. Further, 4-hour BESS enters the portfolio in FY 2028 at 3,358 MW and expands steadily across each milestone year, reaching 10,887 MW by FY 2039–40. In the absence of significant new firm conventional capacity, storage plays a critical role in ensuring dispatchable supply during evening peak-demand periods. Combined storage capacity under S1 reaches approximately 13 GW by FY 2039–40.

Figure 7: Capacity projections for APEPDCL under least-cost optimisation (S1) and least-cost optimisation with planned capacity additions (S2) across future years (2028, 2032, 2036, 2040).



4.3.3. Capacity procurement under S2

Under S2 (Figure 7), APEPDCL's procurement portfolio includes the CEA's planned capacity additions for Andhra Pradesh, proportionately scaled to APEPDCL's 36.2% share of demand. The resulting portfolio grows from 7,205 MW in FY 2023–24 to 48,942 MW by FY 2039–40. While broadly comparable to S1 in overall scale, S2 results in a notably different technology mix.

The CEA's planned additions are introduced progressively over the intermediate years, FY 2027–28 and FY 2031–32, increasing the share of conventional capacity in the portfolio. Coal procurement rises from 3,740 MW in FY 2024 to 3,966 MW by FY 2028, then reaches 4,632 MW by FY 2032, and remains at that level through FY 2040. Hydro procurement more than doubles from 319 MW to 750 MW by FY 2028, while biomass capacity grows from 72 MW to 174 MW over the same period.

The availability of this additional firm capacity reduces near-term storage requirements relative to S1 by approximately 3 GW. PHES procurement in FY 2028 is 789 MW under S2, compared with 2,159 MW under S1. Similarly, 4-hour BESS capacity in FY 2039–40 is 7,857 MW under S2, compared with 10,887 MW under S1.

Solar follows a trajectory similar to S1 but on a somewhat larger scale in the intermediate years, reaching 14,914 MW by FY 2031–32 and 23,902 MW by FY 2039–40.

4.3.4. Conclusions from capacity expansion

Across all scenarios, solar generation and battery storage consistently emerge as the least-cost options for future capacity additions. This is the central finding of the capacity expansion analysis, indicating that solar and storage remain the least-cost and robust options across different capacity-addition assumptions, representative-day modelling approaches, and technical parameter assumptions.

The independent-day scenario, while yielding a lower total build than the cyclic-day approach, reinforces the same overall conclusion: solar paired with storage remains the preferred least-cost capacity combination, even when the modelling methodology changes.

The difference in storage procurement between S1 and S2 by FY 2039–40 reflects the contribution of CEA's planned conventional additions towards meeting peak demand, thereby reducing the requirement for battery storage even at high levels of solar penetration. However, the key takeaway from comparing the two scenarios is that the CEA's planned additions significantly alter both near-term procurement and the long-term capacity mix. A notable distinction lies in the pace and scale of renewable energy and storage procurement required, given the higher coal allocation carried through S2 and its associated long-term fuel cost and carbon risk exposure.

The impact of these compositional differences across scenarios on APEPDCL's overall procurement cost and APPC cannot be fully assessed through capacity figures alone. A meaningful cost comparison requires a detailed analysis of the PCSs, as presented in the following section.



5. Production Costing

This section presents the PCS framework and the operational results across the milestone years under two scenarios. S1 is based on base-year capacity and future load within the APEPDCL boundary, with no additional committed capacity assumed. S2 incorporates APEPDCL's proportional share of the CEA-planned additions for Andhra Pradesh, calculated based on its 36.2% share of the state's demand, along with base-year capacity and future load.

The PCS analysis was initially conducted for 64 scenarios, covering different temporal assumptions (independent-day and cyclic-day approaches) and technical parameter assumptions (CEA technical sheet data and practical operational characteristics) for both APEPDCL and Andhra Pradesh. Based on the simulation outcomes, the two most policy-relevant scenarios were selected for detailed analysis.

The generation portfolios obtained from the capacity expansion model, as discussed in Section 4, are used as inputs to the PCS for each milestone year to simulate the power system's operational behaviour. While capacity expansion modelling identifies the least-cost capacity additions required over the planning horizon, production cost modelling determines how the resulting system operates by optimising the hourly dispatch of available resources, subject to technical and grid constraints.

The production cost model yields several operational outputs for each simulation year, including technology-wise energy dispatch, unserved energy, renewable energy curtailment, and capacity and operational costs. Further, two key performance indicators: the PLF of thermal generating units and the APPC for the system were analysed for the scenarios considered. PLF reflects the extent to which thermal capacity is utilised under the prevailing generation mix, while APPC captures the overall cost of meeting demand across the planning horizon.

5.1. Results summary

The study has been carried out for the base year and all milestone years. Table 9 summarises the results.

Table 9: PCS results comparison for FY 2027–28, FY 2031–32, FY 2035–36, and FY 2039–40.

Parameter	FY 2023–24	FY 2027–28		FY 2031–32		FY 2035–36		FY 2039–40	
		S1	S2	S1	S2	S1	S2	S1	S2
Total installed capacity (MW)	7,205	23,899	16,797	38,313	30,921	45,743	42,455	54,838	48,942
Unserved energy (MU)	296	184	68	0	62	109	85	216	184
PLF (%) of coal plants	72	50	48	15	38	28	34	27	32
Power purchase cost (INR/kWh)	5.77	4.96	4.49	5.58	8.24	5.10	8.61	4.68	8.58
Renewable energy curtailment	0	0	20	3,654	1,467	2,254	2,518	2,676	2,739

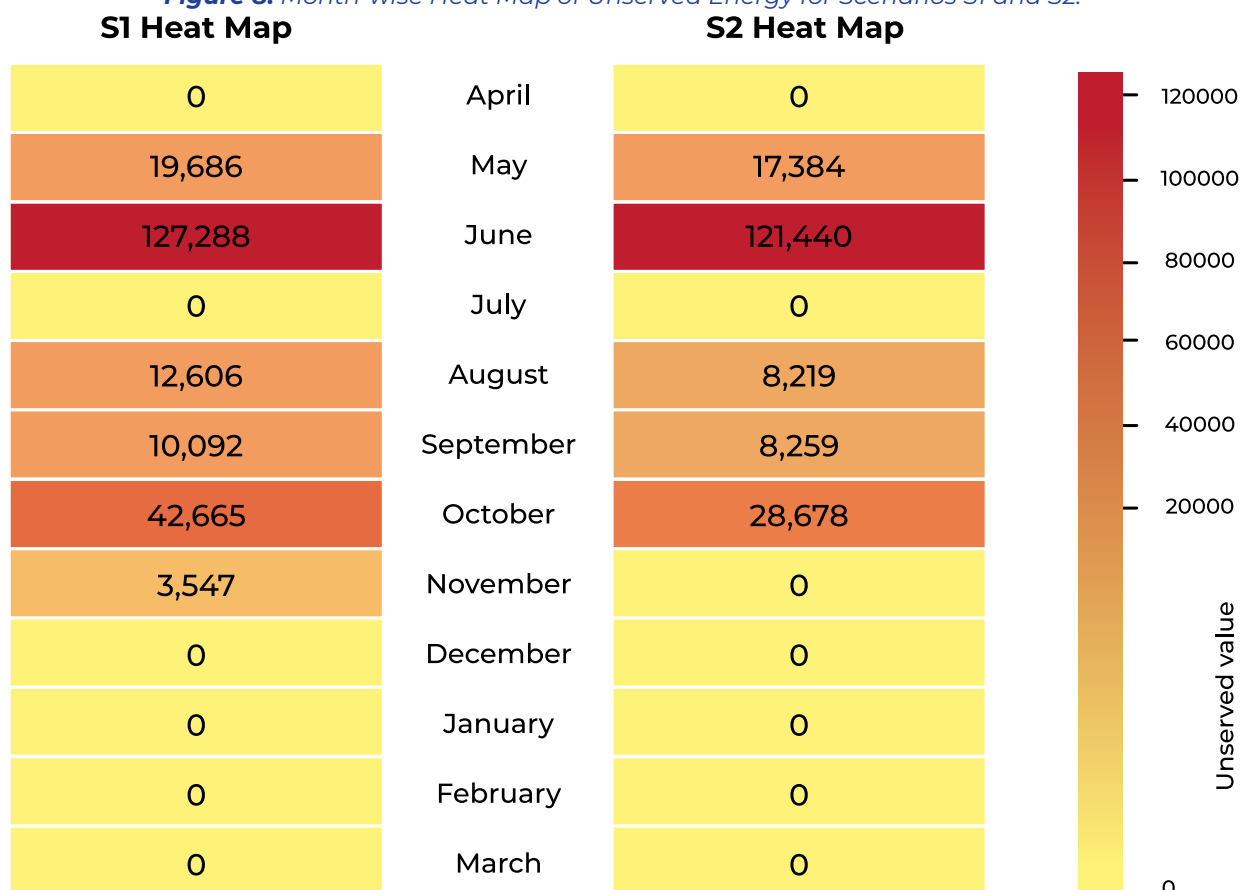
The PCS results provide insights into the power system’s operational performance, including renewable energy utilisation, system adequacy, reliability, and the cost implications of different procurement pathways.

The increase in installed capacity over the study period is driven by the growth in electricity demand. As discussed in Section 4, most new capacity additions comprise renewable energy resources, reflecting both the RCO targets and least-cost capacity expansion requirements. The rapid increase in generation during the initial years is primarily attributable to strong demand growth driven by industrial expansion, urbanisation, increasing electric vehicle adoption, and the development of new data centres, particularly as APEPDCL serves the Visakhapatnam Special Economic Zone (SEZ).

Renewable energy curtailment: It becomes significant from FY 2031–32 onwards, reflecting challenges in integrating large shares of renewable energy generation into the grid. Under S1, curtailment rises sharply to 3,654 MU in FY 2031–32. It declines in subsequent years but remains substantial through FY 2039–40. Under S2, curtailment is lower than S1 in FY 2031–32 but marginally higher in FY 2035–36 and FY 2039–40.

Unservd energy: It represents the system’s inability to fully meet demand. It is relatively high in the base year, FY 2023–24, at 296 MU. Under S1, unserved energy declines from 184 MU in FY 2027–28 to zero in FY 2031–32, indicating improved system adequacy during that period. However, it increases again to 109 MU in FY 2035–36 and further to 216 MU in FY 2039–40, suggesting that demand growth and system constraints begin to exceed available capacity in later years. Under S2, unserved energy is lower than S1 in most years, particularly in FY 2035–36 (85 MU) and FY 2039–40 (184 MU), demonstrating improved reliability due to planned capacity additions.

Figure 8: Month-wise Heat Map of Unserved Energy for Scenarios S1 and S2.



Unserved energy is lower under S2 than under S1; however, residual unserved energy persists in both scenarios. As shown in Figure 8, these deficits are concentrated in a limited number of months and occur primarily during non-solar hours on a few days. In S1, unserved energy is observed in May, June, August, September, October, and November, while under S2 it is concentrated mainly between May and October. Given the relatively short duration of these deficits, short-term power procurement through energy exchanges could be explored to meet these requirements.

PLF: Coal PLF declines significantly over the planning horizon, reflecting reduced dependence on conventional thermal generation as renewable energy penetration increases. Under S1, coal PLF decreases from 50% in FY 2027–28 to 15% in FY 2031–32, before increasing slightly to 28% in FY 2035–36 and 27% in FY 2039–40. Under S2, coal PLF remains consistently higher at 48%, 38%, 34%, and 32% across the respective years, indicating greater utilisation of coal plants to support system reliability and balancing requirements.

APPC: It varies significantly across the planning horizon. The base year (FY 2023–24) records an APPC of INR 5.77/kWh. Under S1, APPC increases from INR 4.96/kWh in FY 2027–28 to INR 5.58/kWh in FY 2031–32, before declining to INR 5.10/kWh in FY 2035–36 and further to INR 4.68/kWh in FY 2039–40. In contrast, S2 shows a sharp increase in APPC after FY 2027–28, rising from INR 4.49/kWh to INR 8.24/kWh in FY 2031–32 and INR 8.62/kWh in FY 2035–36, before declining marginally to INR 8.58/kWh in FY 2039–40. The significantly higher APPC values under S2 in the later years are primarily attributable to the additional investments in planned capacity additions, storage systems, and balancing resources required for reliable grid operation and renewable energy integration.

Overall, the PCS results highlight a clear trade-off between cost optimisation and system reliability as renewable energy penetration increases over the planning horizon. While S1 achieves lower APPC and reduced coal utilisation, it experiences higher levels of renewable energy curtailment and increasing unserved energy in later years, indicating emerging adequacy and integration challenges. In contrast, S2 demonstrates improved reliability and lower unserved energy through higher utilisation of thermal and balancing resources, albeit at substantially higher system costs driven by additional investments in capacity, storage, and grid flexibility.

These results highlight the need for improved grid flexibility, storage solutions, and better demand-side management to integrate renewable energy efficiently and minimise system losses.

5.2. Discussion on hourly dispatch for FY 2039–40

Given the scale of the PCS results, a detailed assessment is presented for FY 2039–40, a representative year that illustrates system behaviour at a mature stage of the energy transition. Hourly dispatch plots for selected representative periods are included in the following sections to provide an intuitive understanding of how different technologies interact to meet demand across seasons and times of day.

5.2.1. Dispatch plots for S1

To understand the operational behaviour of the power system under S1, energy delivery (in MU) is analysed across four representative periods: peak demand (June), summer (March), monsoon (August), and winter (November). The results are shown in Figure 9 and Table 10.

Figure 9: Dispatch plots for S1.

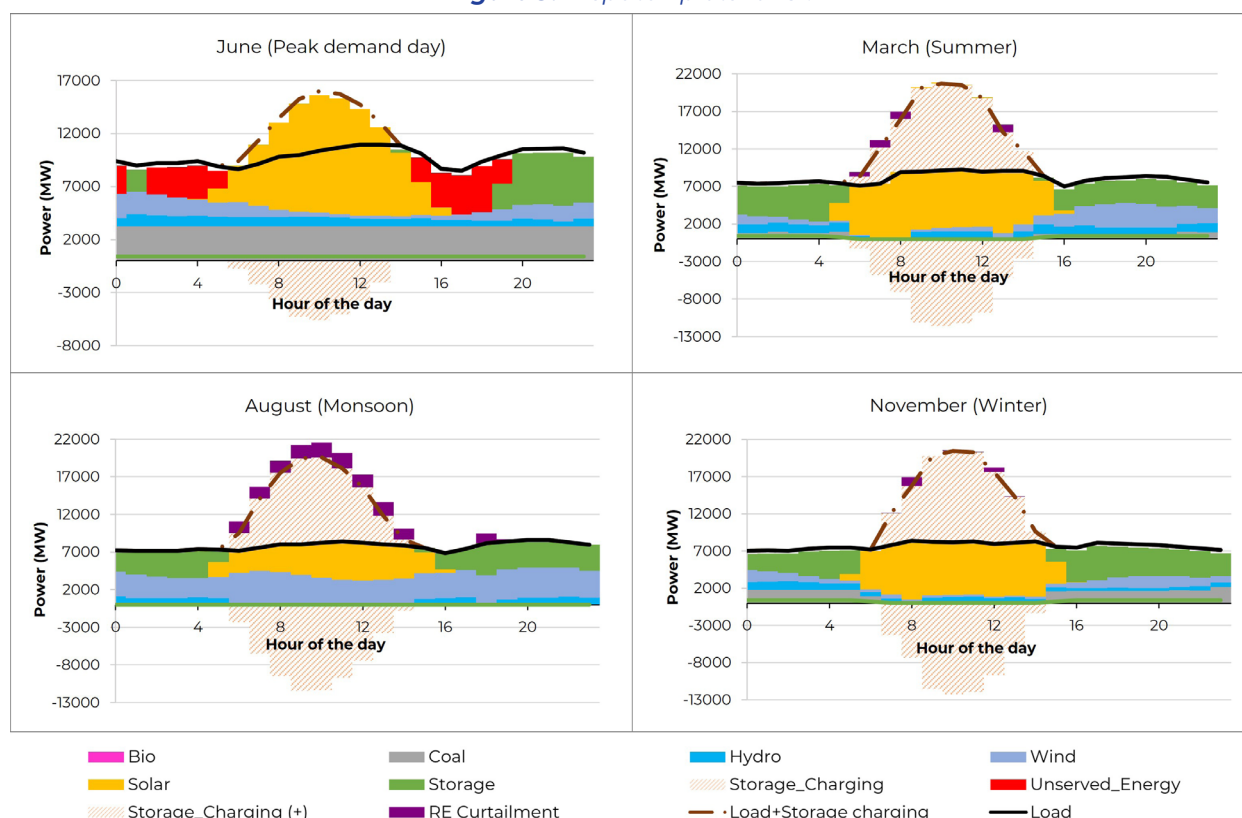


Table 10: Energy delivered (in MU) for selected representative seasonal days under S1.

Generation type	June (peak demand)	March (summer)	August (monsoon)	November (winter)
Biomass	0	1	0	1
Coal	78	11	0	27
Hydro	18	21	13	15
Nuclear	10	6	0	6
Solar	79	143	112	132
Storage (PHES + BESS)	24	49	47	50
Wind	25	31	85	19
Imports	0	0	0	1

June (peak demand)

During a representative peak-demand day in June in FY 2039–40, the system exhibits a balanced contribution from conventional and renewable sources (Figure 9, Table 10). Solar generation is one of the dominant contributors, delivering around 79 MU, closely followed by coal at 78 MU. This indicates continued dependence on both thermal and renewable generation to meet peak demand. Wind and storage provide additional flexibility, contributing 25 MU and 24 MU, respectively. Hydro and nuclear make moderate contributions, supporting system stability. The absence of imports indicates that internal generation resources are sufficient to meet demand throughout the timeframe.

March (summer)

During summer, energy requirements are relatively high due to increased cooling demand, as reflected in the overall generation mix. Solar generation emerges as the dominant contributor at 143 MU, driven by higher solar irradiance. Storage contributes approximately 49 MU, highlighting its role in shifting surplus daytime solar generation to meet peak demand during non-solar hours and balancing variability. Coal generation remains limited at 11 MU, indicating reduced utilisation of thermal power, while wind and hydro continue to contribute moderately to the overall energy mix.

August (monsoon)

During the monsoon period, the generation mix shifts significantly. Wind becomes a dominant contributor at 85 MU, reflecting higher seasonal wind availability. Solar generation declines to 112 MU, likely due to cloud cover and monsoon conditions. Storage contribution remains high at 47 MU, reflecting its role in maintaining grid stability amid renewable variability. Coal and nuclear contributions remain zero, indicating minimal dependence on conventional baseload generation during the selected monsoon period. Hydro generation continues to support the system, benefiting from seasonal water availability.

November (winter)

In November, the energy mix becomes more diversified. Solar generation remains the dominant contributor at 132 MU due to clearer skies, while coal generation contributes about 27 MU to meet demand during non-solar hours. Storage continues to play a critical role, contributing 50 MU and supporting reliability during peak demand periods. Wind contributes 19 MU, reflecting seasonal variability, while hydro and nuclear provide stable support. Minor imports of 1 MU indicate limited external dependency.

Overall, across seasons, renewable energy sources, particularly solar and wind, dominate the generation mix, with storage playing a critical role in balancing variability and maintaining system reliability. The reduced utilisation of coal during specific periods indicates a shift towards cleaner generation sources, while seasonal fluctuations in renewable energy output highlight the growing importance of storage and system flexibility to ensure grid stability.

5.2.2. Dispatch plots for S2

To understand the operational behaviour of the power system under S2, energy delivery (in MU) was analysed across four representative periods: June (peak demand), March (summer), August (monsoon), and November (winter) (Figure 10, Table 11).

Figure 10: Dispatch plots for S2

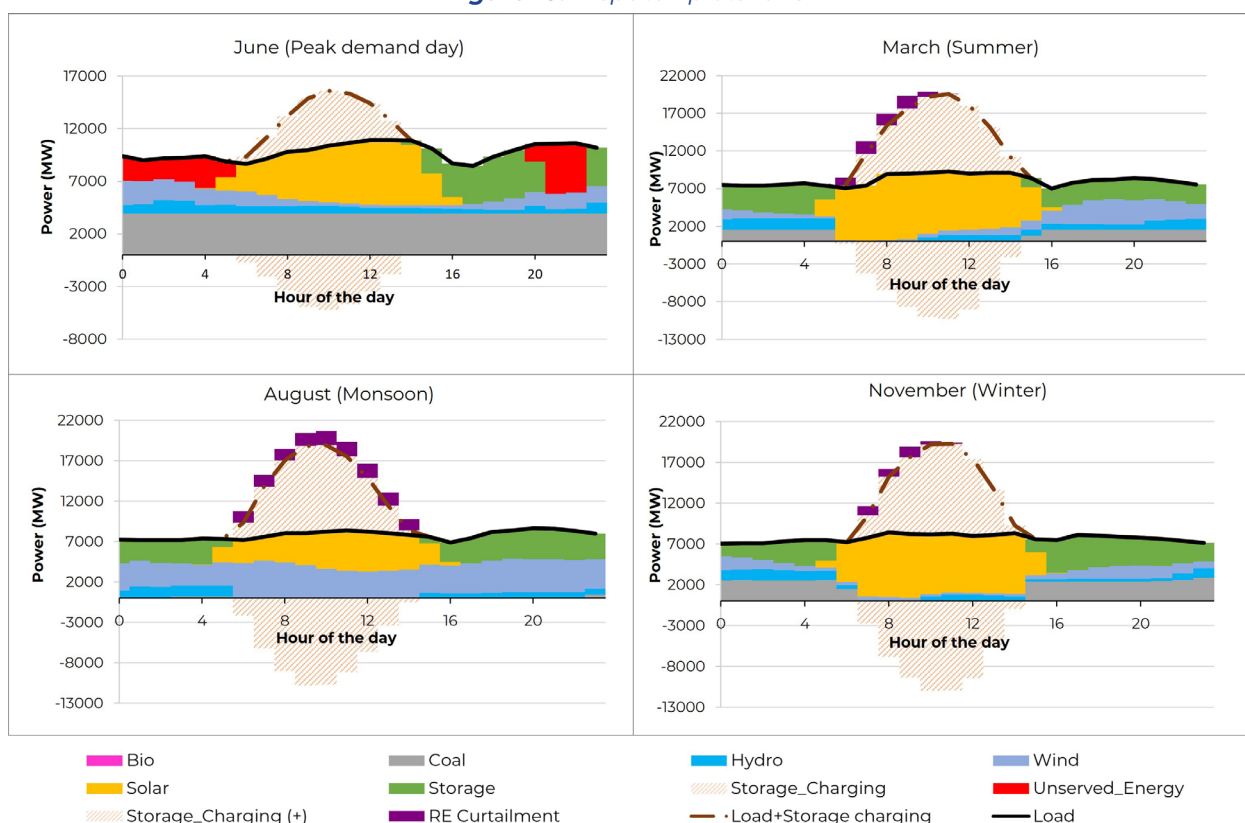


Table 11: Energy delivered (MU) for a representative day for S2.

Generation type	June (peak demand)	March (summer)	August (monsoon)	November (winter)
Biomass	0	2	0	2
Coal	94	21	1	37
Hydro	16	21	14	15
Solar	76	137	108	127
Storage	25	42	43	40
Wind	25	31	87	20
Imports	0	0	0	0

The energy delivered (MU) under S2 for FY 2039–40 reflects a diversified energy mix, with noticeable improvements in reliability, flexibility, and contribution from different generation sources across seasons.

June (peak demand)

During June, the system shows a stronger dependence on conventional and firm power generation sources, particularly coal, which contributes 94 MU to meet base demand. Solar power also contributes substantially at 76 MU, enabling a stable and continuous energy supply. Wind and storage systems each contribute 25 MU, supporting system flexibility and load balancing, while hydro generation contributes 16 MU.

March (summer)

During summer, the generation mix becomes more balanced. Solar energy emerges as the dominant source, contributing 137 MU, reflecting the high availability of solar irradiance. Wind generation contributes 31 MU, ensuring a consistent baseload supply, while storage delivers 42 MU, highlighting its role in managing peak demand. Coal generation remains limited at 21 MU, reflecting a partial shift towards cleaner energy sources during this period.

August (monsoon)

During monsoon, solar generation remains the backbone of the system at 108 MU, while wind generation becomes a major contributor at 87 MU due to favourable seasonal conditions. Storage contribution remains high at 43 MU, highlighting its role in balancing renewable variability and maintaining grid stability. Hydro contributes 14 MU, while coal generation falls to 1 MU, indicating minimal dependence on thermal generation during this period.

November (winter)

During winter, the system shows a diversified energy mix. Solar power remains dominant at 127 MU, while coal contributes 37 MU to meet demand during low-renewable-output periods. Storage provides 40 MU, supporting reliability and flexibility. Wind contributes 20 MU due to seasonal variability, while hydro contributes 15 MU. Bioenergy contributes minimally at 2 MU.

Overall, compared with S1, S2 demonstrates a more stable and reliable system, with higher contributions from firm generation sources such as solar generation, storage systems, and flexible resources, at the expense of higher costs than S1. The increased role of storage under both scenarios, particularly with surplus renewable energy generation, highlights improved system flexibility.

5.3. Yearly analysis for FY 2039–40

The yearly analysis for FY 2039–40 compares S1 and S2 in terms of generation mix, system reliability, and cost, as shown in Table 12 and Figure 11.

Table 12: Energy delivered (MU) in FY 2039–40.

Generation type	Energy delivered (MU)	
	S1	S2
Biomass	114	426
Coal	9,099	12,860
Hydro	6,750	6,595
Nuclear	2,359	0
Solar	44,748	42,837
Storage	16,471	14,300
Wind	14,334	14,669

Figure 11: Energy delivered (MU) for S1 and S2 in FY 2039–40.

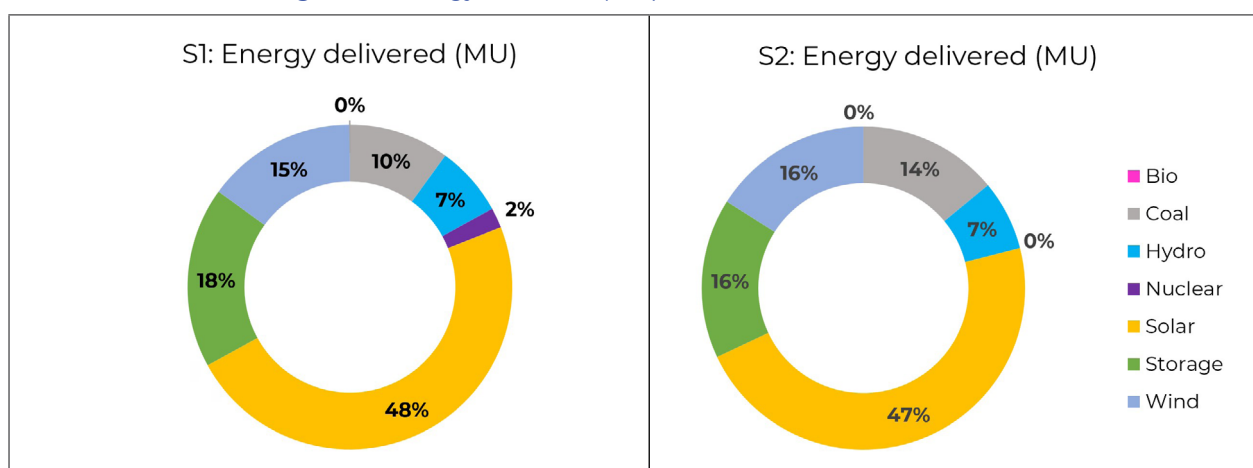


Table 13: Financial and operational details for FY 2039–40.

Parameter	S1	S2
Project capacity costs (INR crore)	25,670.45	52,225.60
Project operations costs (INR crore)	7,115.79	7,807.01
Total costs (INR crore)	32,786.24	60,032.60
Total energy generation as per energy requirement (MU)	69,981.82	69,981.82
Unserved energy	215.88	183.98
APPC (INR/kWh)	4.68	8.58

Tables 12 and 13 present a comparative assessment of energy generation mix, system performance, and overall cost under the two scenarios. The pie charts in Figure 10 indicate that renewable energy sources, primarily solar and wind, account for the largest share of energy delivered in both scenarios. Solar generation makes the highest contribution, followed by wind and storage, indicating the growing importance of renewable energy and flexibility resources in future power system operation.

A comparison between the two scenarios shows that solar generation is slightly higher in S1, at 44,748 MU, than in S2, at 42,837 MU. Wind generation remains broadly similar across both scenarios. Storage contribution is also higher in S1 (16,471 MU) than in S2 (14,300 MU), indicating greater reliance on storage systems to balance renewable intermittency. In contrast, coal generation is higher under S2 (12,860 MU) than under S1 (9,099 MU), reflecting the differences in the generation mix and dispatch across the two scenarios.

Unserved energy is 216 MU in S1 and 184 MU in S2, with S2 recording 32 MU less unserved energy and, therefore, better system reliability with the planned capacity additions. The higher unserved energy in S1 results from the model optimising for the least-cost solution. Lowering unserved energy in S1 would require additional firm generation or storage capacity. However, because such capacity would be utilised only during a few peak-demand hours each year, it would be a costly investment relative to its limited use. Therefore, to avoid investing in underutilised capacity, the model permits a small amount of unserved energy, as this is the more cost-effective solution.

This reflects the inherent cost–reliability trade-off in power system planning: although additional capacity investments could reduce unserved energy, they would also increase the total system

cost and the APPC. In practice, a small amount of unserved energy does not necessarily imply interruptions in consumer supply, as the shortfall may be met through short-term electricity markets or managed through other operational measures. These options can help maintain supply reliability while avoiding investment in capacity that would remain idle for most of the year.

The economic analysis in Table 13 shows that S2 involves substantially higher project capacity and operational costs, resulting in a total system cost of INR 60,032.60 crore, compared with INR 32,786.24 crore under S1. Consequently, APPC increases significantly from INR 4.68/kWh in S1 to INR 8.58/kWh in S2. Although both scenarios meet the same annual energy requirement of 69,981.82 MU, S1 emerges as the more cost-effective pathway, while S2 offers improved reliability with lower unserved energy.

Overall, the results demonstrate the significant contribution of solar generation and storage systems in meeting future electricity demand under both scenarios. The substantial contribution of solar energy, supported by storage, indicates that solar-storage integration is emerging as a cost-effective and flexible solution for the future power system, while helping manage renewable energy intermittency and enhance grid stability.



6. Use Cases of Energy Storage Systems for APEPDCL

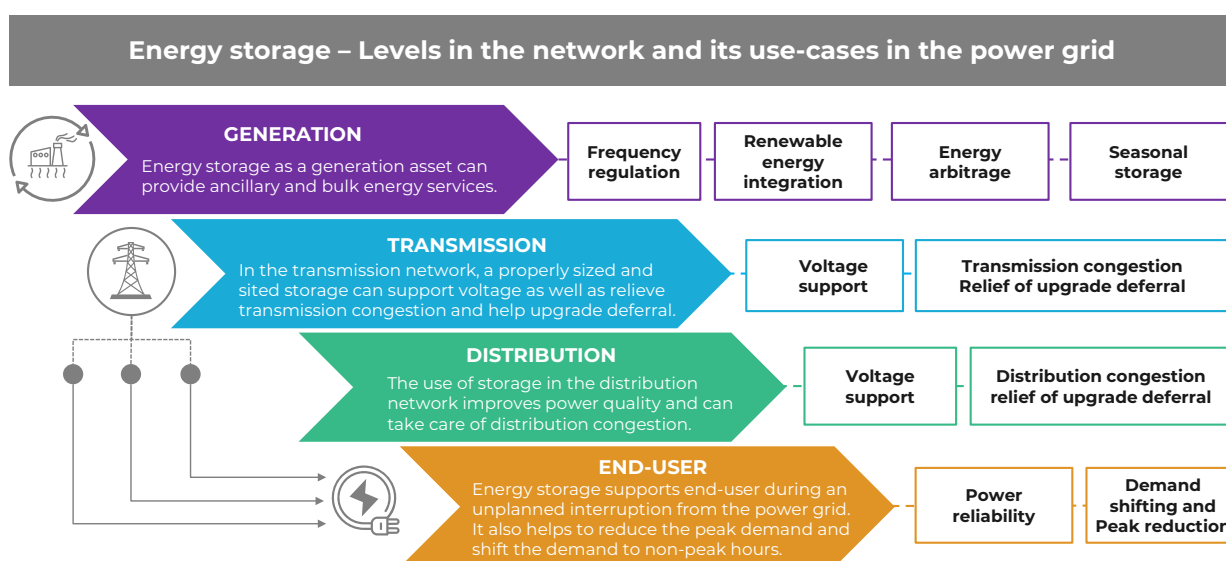
Energy storage systems (ESS) play a multifaceted role in modern power networks. Beyond simply storing energy, their value depends on where they are deployed and the specific grid functions they serve at that location. Unlike most conventional grid assets, ESS can be deployed at multiple points across the network, including generator terminals, transmission corridors, distribution substations, and behind the customer's meter.

ESS can deliver a wide range of ancillary and operational benefits that improve grid stability, reliability, power quality, and economic efficiency. However, their use cases are strongly shaped by their deployment location. Understanding this location dependence is, therefore, essential for optimal planning and investment decisions.

6.1. Use cases of ESS at different levels of the power system

The different use cases of ESS across various levels of the power system are summarised in Figure 11.

Figure 12: Use cases of ESS at different levels of the grid.



6.1.1. Generation level

When deployed as a generation-side asset, ESS can provide both ancillary and bulk energy services.

- Frequency regulation:** The Indian grid is required to maintain a frequency of 50 Hz within the permitted range of 49.900–50.050 Hz (CERC, 2023). Any imbalance between generation and load can cause frequency to deviate from this nominal value. Fast-responding ESS, particularly BESS, can rapidly inject or absorb power to correct these frequency deviations and help maintain system frequency within prescribed limits.

- **Renewable energy integration:** Wind and solar generation are inherently intermittent. ESS can absorb excess renewable generation during peak output periods and discharge when generation declines, thereby effectively providing firm power output like a conventional unit.
- **Energy arbitrage:** Electricity prices are generally low during periods of abundant supply and low demand and high during peak demand periods when more expensive generation is dispatched to meet the load. ESS can capture this price differential by charging (buying or storing energy) when prices are low and discharging (selling energy) when prices are high.
- **Seasonal storage:** Seasonal storage using ESS can help address extended mismatches between generation availability and demand over weeks or months, particularly during extreme weather events.

6.1.2. At the transmission level

Within the transmission network, appropriately sized and sited storage can support voltage regulation and relieve transmission congestion.

- **Voltage support:** Modern grid-scale ESS are interfaced through voltage-source converters (VSCs), which can independently control active and reactive power output and thus improve voltage stability.
- **Transmission congestion relief and upgrade deferral:** ESS can be strategically deployed at congested nodes in the transmission network as an alternative to transmission infrastructure expansion. During off-peak periods, when the transmission network is unconstrained, storage can charge by importing power through the network. During peak hours, it can discharge locally, reducing the power that needs to flow across the congested network. This peak shaving of transmission flows can defer or even permanently avoid costly network upgrades, particularly where long-term load growth remains uncertain.

6.1.3. Distribution level

ESS in the distribution network can improve power quality and alleviate distribution congestion.

- **Voltage support in distribution networks:** During solar hours, ESS can absorb excess generation locally, preventing reverse power flow and the associated voltage rise. During evening peak hours, storage can discharge to support voltage at the end of long feeders. Advanced inverter-based ESS can also provide continuous reactive power regulation, actively managing the voltage profile along the feeder in real time.
- **Distribution congestion relief and upgrade deferral:** ESS placed at distribution substations or individual feeders can charge during light load periods and discharge during peak hours, shaving the demand that upstream network infrastructure must accommodate. This can keep loading within the rated capacity of existing transformers and cables, deferring or avoiding the need for substation augmentation, new feeder cables, or transformer replacement.

6.1.4. End-user level (Behind-the-meter)

At the end-user level, energy storage can provide backup power during unplanned grid interruptions, reduce peak demand, and shift demand to non-peak hours.

- **Power reliability:** Behind-the-meter (BTM) ESS can provide seamless and near-instantaneous backup power during grid outages, responding within milliseconds.

- **Demand shifting and peak reduction:** BTM ESS can charge during off-peak hours when tariffs are lower and discharge during peak periods to reduce demand spikes. This can lower demand charges for consumers while also reducing stress on the grid during peak demand periods.

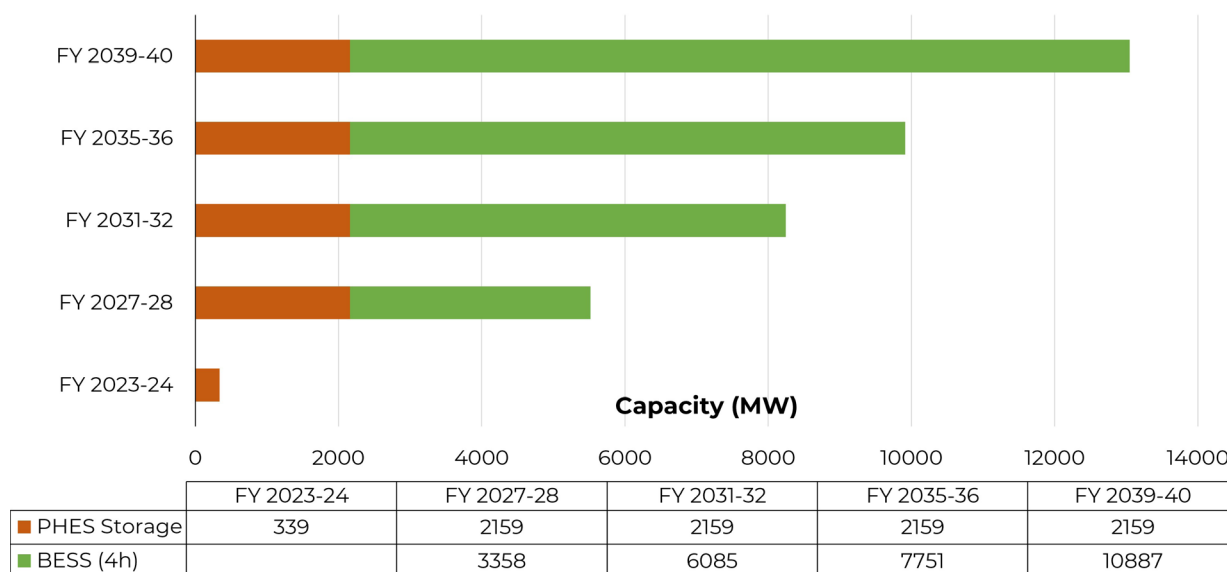
6.2. ESS use cases for APEPDCL

6.2.1. Solar energy shifting for evening peak support

The study's recommendation of 4-hour BESS and 6-hour PHES, rather than conventional 2-hour storage, provides an important planning signal for APEPDCL. APEPDCL's demand profile exhibits two distinct peaks: a midday peak between 12 PM and 2 PM, driven largely by industrial and commercial load coinciding with peak solar hours, and a more pronounced evening peak during non-solar hours. Bridging the gap between daytime solar availability and sustained evening peak demand requires storage that can absorb surplus solar generation during the solar window and sustain discharge during the evening peak, an operational requirement that conventional 2-hour storage may not adequately fulfil. As load grows over time, this peaking pattern reinforces the need for longer-duration storage as a core system resource.

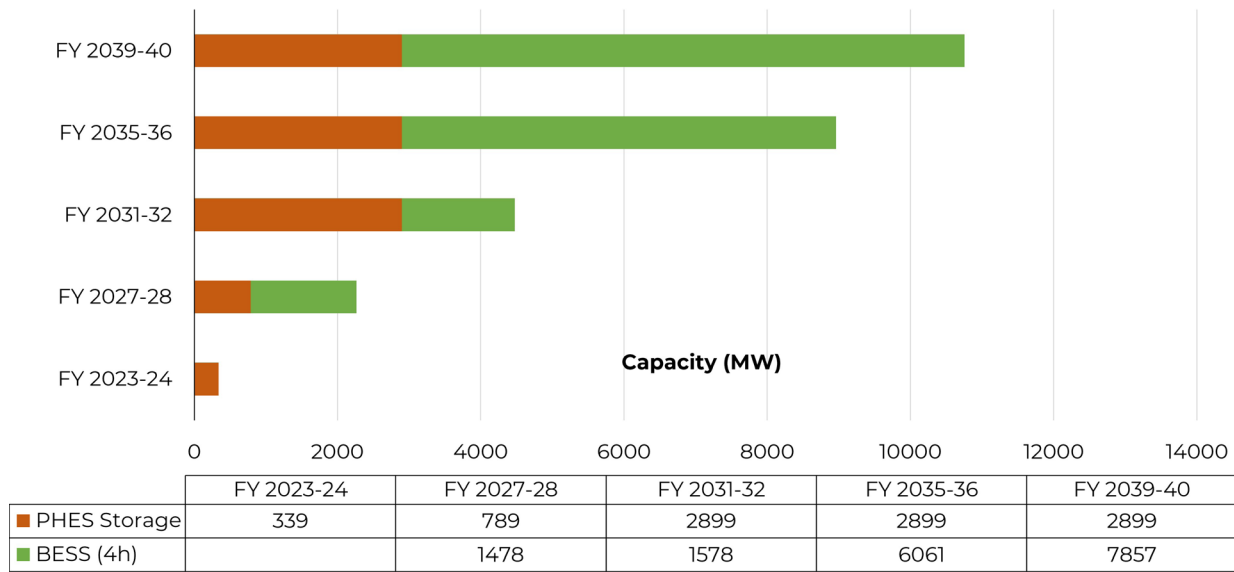
No BESS capacity exists in the grid in FY 2023–24, the base year (Figures 12 and 13). Under S1, where higher solar penetration necessitates greater storage to manage the transition from solar hours to the evening peak, BESS capacity grows from 3,358 MW in FY 2027–28 to 10,887 MW by FY 2039–40 (Figure 12).

Figure 13: Capacity additions for storage under S1.



Under S2, planned coal capacity additions contribute to meeting the same demand peaks, reducing the reliance on solar and consequently lowering storage requirements. As a result, BESS capacity under S2 starts at 1,478 MW in FY 2027–28 and reaches 7,857 MW by FY 2039–40 (Figure 13).

Figure 14: Capacity additions for storage under S2.

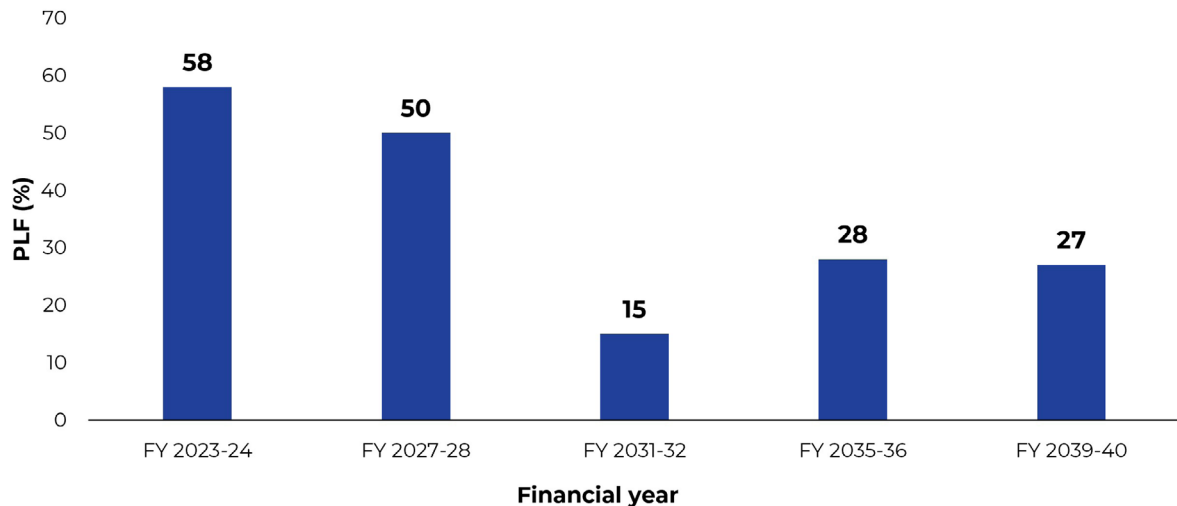


PHES, which is already present at 339 MW in FY 2024, scales to 2,159 MW under S1 and 2,899 MW under S2 by FY 2039–40. While BESS provides fast-response flexibility and short-duration balancing, PHES serves as a bulk energy reservoir capable of supporting sustained discharge, including overnight supply requirements. Together, these technologies serve complementary roles in APEPDCL’s system: 4-hour BESS supports intra-day balancing of generation and demand, peak demand reduction, demand shifting, and energy arbitrage, while PHES provides long-duration bulk storage. This combination strengthens APEPDCL’s ability to manage renewable energy variability and improve overall grid reliability.

6.2.2. BESS for thermal fleet flexibility and PLF support

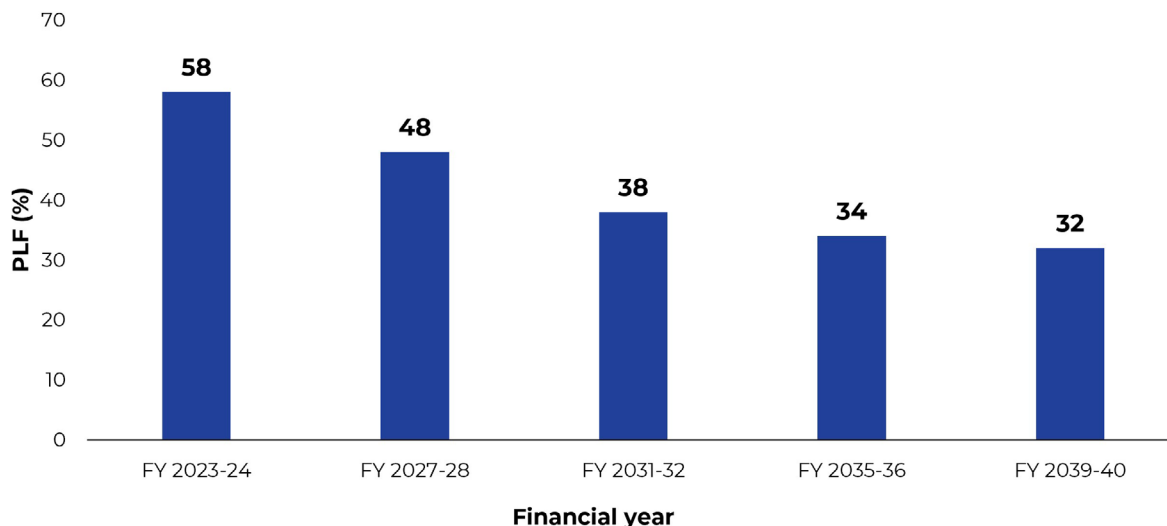
The declining PLF of thermal plants in Andhra Pradesh reflects the increasing penetration of renewable energy. Under S1, where renewable energy penetration is higher, thermal PLF declines sharply from 58% in FY 2023–24 to just 15% by FY 2031–32, before partially recovering to 27% by FY 2039–40 as storage and other flexibility resources are deployed to manage the system (Figure 14).

Figure 15: PLF degradation under S1.



Under S2, larger planned coal capacity additions result in comparatively lower renewable energy penetration. The larger thermal fleet distributes generation across more units, moderating the PLF decline from 58% in FY 2024 to 38% in FY 2032 and 32% by FY 2040 (Figure 15).

Figure 16: PLF degradation for S2.



Both scenarios show a clear decline in thermal PLF over time, although the extent of decline differs. This reflects the growing share of solar generation in meeting daytime demand, which reduces the need for thermal generation during solar-rich hours. When thermal plants operate at low load factors or cycle frequently, their heat rates can increase, leading to lower efficiency, higher fuel use, greater operational stress, and higher maintenance requirements. This can increase generation costs and, in turn, the cost of power procurement for DISCOMs.

Siting BESS near existing thermal plants can help manage this challenge. During periods of low demand or high renewable generation, BESS can charge using thermal power. This can reduce the need for deep backing down of thermal plants and help them operate more steadily. During evening peaks or non-solar hours, BESS can discharge to support supply, reducing the need for thermal plants to ramp up sharply.

In this context, BESS should be seen as a support resource for thermal plants, allowing them to operate in an optimal load factor. Thus, BESS can help improve thermal fleet flexibility while supporting a reliable and cost-effective power supply for APEPDCL.

6.2.3. Renewable energy integration through co-location of ESS

The projected scale of 4-hour BESS deployment in this study, growing from zero in FY 2023–24 to 10,887 MW under S1 and 7,857 MW under S2 by FY 2039–40, indicates that co-location of storage with solar will need to become a mainstream deployment strategy for APEPDCL. At the utility scale, co-located solar-plus-BESS projects can improve renewable energy utilisation, reduce curtailment, and support evening and non-solar-hour demand.

Co-located projects can share land, evacuation infrastructure, and grid connectivity, thereby reducing project costs and alleviating right-of-way constraints for new transmission corridors. This provides APEPDCL with a practical route for scaling renewable energy without the delays associated with new transmission infrastructure.

6.2.4. Distribution network support through BESS

The projected increase in decentralised renewable energy capacity highlights the need for distribution-level flexibility in APEPDCL's network. Under S1, DRE capacity increases from 0 MW in FY 2024 to 2,161 MW by FY 2028 and to 8,176 MW by FY 2040. Under S2, it increases from 0 MW in FY 2024 to 2,161 MW by FY 2028 and to 4,915 MW by FY 2040. As rooftop solar, agriPV, and other decentralised renewable energy systems expand, the distribution network may face operational challenges, including reverse power flow, voltage variations, feeder congestion, and transformer overloading.

BESS can help manage these challenges by absorbing excess local renewable generation during high-solar hours and discharging during evening hours or local peak-demand periods. Siting storage at distribution substations, feeders, distribution transformers, or near DRE clusters can improve renewable energy absorption, support voltage management, reduce network stress, and improve local reliability. In areas with high DRE penetration, BESS can also help defer distribution infrastructure upgrades by reducing peak loading on feeders and transformers.



7. Conclusion

The *Guidelines for Resource Adequacy Planning Framework for India*, issued by the Ministry of Power in consultation with the CEA, provide the national framework for ensuring reliable and cost-effective power supply. These guidelines require each DISCOM to prepare a LT-DRAP for a 10-year horizon. In line with this national framework, Andhra Pradesh released the *APERC (Framework for Resource Adequacy) Regulation, 2026* in June. Together, these frameworks emphasise the importance of conducting resource adequacy studies at the subnational and DISCOM levels (CEA, 2026). Such studies enable DISCOMs to plan sufficient capacity to meet projected energy and peak demand requirements while maintaining reliability and cost-effectiveness.

This study contributes to that objective by assessing APEPDCL's long-term resource adequacy and storage requirements. It uses FY 2023–24 as the base year and FY 2039–40 as the target year, representing a planning horizon of approximately 16 years. Intermediate planning years were analysed to track the timing and trajectory of capacity additions. The study carried out least-cost capacity expansion planning for APEPDCL, conducted hourly dispatch analysis, and assessed key indicators, including APPC, unserved energy, renewable energy curtailment, total system cost, and thermal plant PLF, under high renewable energy penetration. The objective was to identify the least-cost resources capable of supporting a reliable supply, managing peak demand, and enabling higher integration of renewable energy.

The study has been carried out in line with the *APERC (Framework for Resource Adequacy) Regulation, 2026* (APERC, 2026), based on available data and project scope, with a least-cost objective. Demand projections follow the framework recommendations using EPS data as the baseline. The hourly chronological generation expansion planning model incorporates the key technical parameters for different generation technologies, planning reserve margins, and RCO targets to identify the least-cost expansion plan.

7.1. Key findings

Under the cyclic-day approach, the least-cost capacity mix for APEPDCL by FY 2039–40 indicates a strong role for renewable energy and storage. Under S1, long-term capacity expansion assessment for APEPDCL considers only the installed capacity available in the base year, with no additional committed capacity assumed. The optimal mix under S1 comprises approximately 450 MW of nuclear, 4 GW of coal, 2 GW of hydro, 70 MW of biomass, 20 GW of solar, 8 GW of DRE, 11 GW of 4-hour BESS, 2 GW of PHES, and 6 GW of wind, resulting in an APPC of INR 4.68/kWh.

Under S2, long-term expansion assessment for APEPDCL considers the base-year installed capacity together with 36.2% of the capacity additions envisaged for Andhra Pradesh in the CEA's *Long-Term National Resource Adequacy Plan (2026–27 to 2035–36)*, reflecting its share of power procurement, and evaluates any additional capacity requirements. The capacity mix under S2 comprises approximately 50 MW of nuclear, 4.6 GW of coal, 750 MW of hydro, 174 MW of biomass, 23 GW of solar, 5 GW of DRE, 8 GW of 4-hour BESS, 3 GW of PHES, and 3.7 GW of wind. While S2 achieves lower unserved energy, it does so at a significantly higher APPC of INR 8.58/kWh, indicating a reliability–cost trade-off.

The planned capacity additions under S2 include additional coal-based generation, resulting in a lower share of renewable energy in the generation mix. In contrast, under S1, the required firm power is supplied through increased deployment of renewable energy coupled with energy storage systems. This renewable energy- and storage-based approach proves to be a lower-cost alternative, resulting in a lower APPC under S1 compared to S2.

The independent-day analysis shows a similar broad trend to the cyclic-day results. Across S1 and S2, solar, DRE, wind, BESS, and PHES consistently emerge as important resources to meet APEPDCL's future demand, indicating their importance in meeting future demand, supporting reliability, and integrating higher shares of renewable energy. While S2 reduces unserved energy, it does so at a higher procurement cost, highlighting the need to balance reliability and affordability in long-term planning. However, this unserved energy can be met through targeted short-duration flexible resources or market purchases.

Overall, the findings indicate that APEPDCL will require substantial additions of solar and storage by FY 2039–40.

7.2. Role of storage and recommended deployment pathways for APEPDCL

Based on the study findings, the following storage deployment pathways are recommended for APEPDCL:

- **Develop a diversified storage portfolio of 4-hour BESS and 6-hour PHES.**

APEPDCL will require a combination of 4-hour BESS and 6-hour PHES to manage its future demand profile. While BESS can provide fast response, intra-day balancing, and evening peak support, PHES can provide longer-duration bulk storage for sustained and overnight discharge. Together, these technologies offer complementary flexibility to manage renewable variability, reduce peak stress, and improve grid reliability.

- **Site BESS near thermal plants to support fleet flexibility.**

By FY 2039–40, thermal PLF declines to 27% under S1 and 32% under S2, indicating that thermal plants may increasingly operate at lower load factors as renewable energy penetration rises. This can increase cycling stress and reduce operational efficiency. Siting BESS near existing thermal plants can reduce deep backing down and sharp ramping, while supporting evening and non-solar-hour demand. This can improve thermal fleet flexibility while supporting a reliable power supply for APEPDCL.

- **Promote co-located BESS with renewable energy plants.**

The projected growth of 4-hour BESS from 0 MW in FY 2024 to 10,887 MW under S1 and 7,857 MW under S2 by FY 2039–40 indicates that co-location with renewable energy plants could become an important deployment pathway for APEPDCL. Co-located solar-plus-BESS projects can improve renewable energy utilisation, reduce curtailment, and support evening and non-solar-hour demand. Shared land, evacuation infrastructure, and grid connectivity can also reduce project costs and ease right-of-way challenges for new transmission infrastructure.

- **Deploy distribution-level BESS for DRE integration.**

The projected growth of DRE capacity, reaching 8,176 MW under S1 and 4,915 MW under S2 by FY 2039–40, highlights the need for distribution-level flexibility in APEPDCL's network. As rooftop solar, agriPV, and other DRE systems expand, BESS can help manage reverse power flow, voltage variations, feeder congestion, and transformer overloading. Siting BESS at substations, feeders, distribution transformers, or near DRE clusters can improve local renewable energy absorption, reduce network stress, support reliability, and defer distribution upgrades where feasible.

7.3. Final recommendations

Overall, APEPDCL should treat energy storage as a core resource in long-term procurement and resource adequacy planning, rather than as a supporting component of renewable energy deployment. A planned portfolio of BESS and PHES, deployed across generation, distribution, and thermal-flexibility applications, can help APEPDCL reliably meet future demand while supporting greater integration of renewable energy.

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9. Appendices

9.1. Appendix A

Table 14 provides a comprehensive overview of all operational generation units in APEPDCL. It includes each unit's name, technology type, and contracted capacity.

Table 14: Unit-wise generation and contracted capacity.

S. No	Generation unit (operator's name and name of unit)	Technology	Contracted capacity (MW)
1	Andhra Pradesh Power Generation Corporation Limited (APGENCO), Rayalaseema Thermal Power Project (RTPP) Unit No 1	Coal	76.06
2	APGENCO, RTPP Unit No 2	Coal	76.06
3	APGENCO, RTPP Unit No 3	Coal	76.06
4	APGENCO, RTPP Unit No 4	Coal	76.06
5	APGENCO, RTPP Unit No 5	Coal	76.06
6	APGENCO, RTPP Unit No 6	Coal	217.32
7	APGENCO, Dr Narla Tata Rao Unit Thermal Power Station (Dr NTPPS) No 1	Coal	76.06
8	APGENCO, Dr NTPPS Unit No 2	Coal	76.06
9	APGENCO, Dr NTPPS Unit No 3	Coal	76.06
10	APGENCO, Dr NTPPS Unit No 4	Coal	76.06
11	APGENCO, Dr NTPPS Unit No 5	Coal	76.06
12	APGENCO, Dr NTPPS Unit No 6	Coal	76.06
13	APGENCO, Dr NTPPS Unit No 7	Coal	181.10
14	APGENCO, Dr NTPPS Unit No 8	Coal	289.76
15	APGENCO, Sri Damodaram Sanjeevaiah Thermal Power Station (SDSTPS) Stage 1 Unit No 1	Coal	289.76
16	APGENCO, SDSTPS Stage 1 Unit No 2	Coal	289.76
17	APGENCO, SDSTPS Stage 2 Unit No 1	Coal	289.76
18	Independent power producer (IPP), Muthukur Mandal Power Station (Painampuram) Thermal Power Station (TPS) Unit No 1	Coal	83.51
19	IPP, Vizag TPS Unit No 1	Coal	376.69
20	IPP, Sembcorp Energy India Ltd	Coal	226.38
21	National Thermal Power Corporation Limited (NTPC Ltd), Ramagundam STPS Stage 1- and 2-Unit No 1–6	Coal	99.91

S. No	Generation unit (operator's name and name of unit)	Technology	Contracted capacity (MW)
22	NTPC Ltd, Ramagundam STPS Stage 3 Unit No 7	Coal	25.13
23	NTPC Ltd, Talcher STPS Unit No 1-4	Coal	63.76
24	NTPC Ltd, Simhadri STPS Stage 1 Unit No 1-2	Coal	167.01
25	NTPC Ltd, Simhadri STPS Stage 2 Unit No 3-4	Coal	77.51
26	NTPC Ltd, Kudgi STPS Stage 1 Unit No 1-3	Coal	76.42
27	NLC India Limited (NLCIL), Neyveli TPS Stage 2 Unit No 1-3	Coal	16.92
28	NLCIL, Neyveli TPS Stage 2 Unit No 4-7	Coal	31.01
29	NLCIL, Neyveli New TPS Unit No 1-2	Coal	19.09
30	NTPC Tamil Nadu Energy Company Limited, Vallur TPS Unit No 1-3	Coal	31.20
31	Tamil Nadu Power Generation Corporation Limited, Tuticorin TPS Unit No 1-5	Coal	43.95
32	Nuclear Power Corporation of India Limited (NPCIL), Madras Atomic Power Station (APS) Unit No 1-2	Nuclear	6.57
33	NPCIL, Kaiga APS Unit No 1-2	Nuclear	20.00
34	NPCIL, Kaiga APS Unit No 3-4	Nuclear	21.33
35	NTPC Ltd, Telangana STPS Unit No 1-2	Coal	5.80
36	NLCIL, Neyveli Stage 1 Expansion Unit No 1-2	Coal	0.72
37	NLCIL, Neyveli Stage 2 Expansion Unit No 1-2	Coal	1.09
38	NPCIL, Kudankulam Nuclear Power Plant Unit No 1-2	Nuclear	0.72
39	APGENCO, Upper Sileru Hydro Power Station (HPS) Unit No 1	Hydro	21.73
40	APGENCO, Upper Sileru HPS Unit No 2	Hydro	21.73
41	APGENCO, Upper Sileru HPS Unit No 3	Hydro	21.73
42	APGENCO, Upper Sileru HPS Unit No 4	Hydro	21.73
43	APGENCO, Lower Sileru HPS Unit No 1	Hydro	41.65
44	APGENCO, Lower Sileru HPS Unit No 2	Hydro	41.65
45	APGENCO, Lower Sileru HPS Unit No 3	Hydro	41.65
46	APGENCO, Lower Sileru HPS Unit No 4	Hydro	41.65
47	APGENCO, Penna Ahobilam Balancing Reservoir (PABR) HPS Unit No 1	Hydro	3.62
48	APGENCO, PABR HPS Unit No 2	Hydro	3.62

S. No	Generation unit (operator's name and name of unit)	Technology	Contracted capacity (MW)
49	APGENCO and Odisha Hydro Power Corporation (OHPC), Machkund HPS	Hydro	21.73
50	Tungabhadra Board, Tungabhadra HPS	Hydro	20.86

Pump storage plants

1	APGENCO, Nagarjunasagar Right Canal Power House (PH) Unit No 1	Storage	10.87
2	APGENCO, Nagarjunasagar Right Canal PH Unit No 2	Storage	10.87
3	APGENCO, Nagarjunasagar Right Canal PH Unit No 3	Storage	10.87
4	APGENCO, Srisailem Right Bank PH Unit No 1	Storage	39.84
5	APGENCO, Srisailem Right Bank PH Unit No 2	Storage	39.84
6	APGENCO, Srisailem Right Bank PH Unit No 3	Storage	39.84
7	APGENCO, Srisailem Right Bank PH Unit No 4	Storage	39.84
8	APGENCO, Srisailem Right Bank PH Unit No 5	Storage	39.84
9	APGENCO, Srisailem Right Bank PH Unit No 6	Storage	39.84
10	APGENCO, Srisailem Right Bank PH Unit No 7	Storage	39.84
11	APGENCO, Nagarjuna Sagar Tail Pond PH Unit No 1	Storage	9.06
12	APGENCO, Nagarjuna Sagar Tail Pond PH Unit No 2	Storage	9.06
13	APGENCO, Donkarayi Canal PH	Storage	9.06

Renewable energy plants

1	Small hydro	Hydro	15.16
2	Industrial waste		18.71
3	Wind	Wind	1325.89
4	Bio	Bio	53.24
5	Solar	Solar	1361.01

9.2. Appendix B

Table 15 outlines the annual fixed costs (AFCs; in INR crore) and variable costs (VCs; in INR per unit) associated with various power generation units for FY 2023–24 and FY 2039–40.

Table 15: Unit-wise average fixed costs and variable costs for FY 2023–24 and FY 2039–40.

S. No	Generation unit (operator's name and name of unit)	FY 2023–24		FY 2039–40	
		AFC (in INR crore)	VC (in INR/unit)	AFC (in INR crore)	VC (in INR/unit)
1	APGENCO, RTPP Unit No 1	17.19	4.42	8.57	6.56
2	APGENCO, RTPP Unit No 2	17.19	4.42	8.57	6.56
3	APGENCO, RTPP Unit No 3	18.40	4.41	28.12	6.54
4	APGENCO, RTPP Unit No 4	18.40	4.41	28.12	6.54
5	APGENCO, RTPP Unit No 5	22.61	4.40	9.95	6.53
6	APGENCO, RTPP Unit No 6	84.29	4.15	61.01	6.17
7	APGENCO, Dr NTPPS Unit No 1	46.54	4.31	28.59	6.39
8	APGENCO, Dr NTPPS Unit No 2	46.54	4.31	28.59	6.39
9	APGENCO, Dr NTPPS Unit No 3	46.54	4.31	28.59	6.39
10	APGENCO, Dr NTPPS Unit No 4	46.54	4.31	28.59	6.39
11	APGENCO, Dr NTPPS Unit No 5	46.54	4.31	28.59	6.39
12	APGENCO, Dr NTPPS Unit No 6	46.54	4.31	28.59	6.39
13	APGENCO, Dr NTPPS Unit No 7	39.38	4.01	24.19	5.95
14	APGENCO, Dr NTPPS Unit No 8	11.24	4.11	24.53	6.11
15	APGENCO, SDSTPS Stage 1 Unit No 1	98.59	3.65	135.34	5.42
16	APGENCO, SDSTPS Stage 1 Unit No 2	62.00	3.14	85.11	4.66
17	APGENCO, SDSTPS Stage 2 Unit No 1	98.59	0	135.34	5.42
18	IPP, Muthukur Mandal power station (Painampuram) Thermal Power Station (TPS) Unit No 1	36.65	2.82	93.11	3.88
19	IPP, Vizag TPS Unit No 1	105.86	0	268.91	3.88
20	IPP, Sembcorp Energy India Ltd	26.21	0	66.58	4.01
21	NTPC Ltd, Simhadri STPS Stage 1 Unit No 1–2	19.94	3.72	24.48	5.53
22	NTPC Ltd, Simhadri STPS Stage 2 Unit No 3–4	5.67	3.68	7.85	5.47

S. No	Generation unit (operator's name and name of unit)	FY 2023-24		FY 2039-40	
		AFC (in INR crore)	VC (in INR/unit)	AFC (in INR crore)	VC (in INR/unit)
23	NTPC Ltd, Kudgi STPS Stage 1 Unit no 1-3	14.13	1.76	21.41	2.62
24	NTPC Ltd, Neyveli TPS Stage 2 Unit no 1-3	45.99	4.14	48.55	6.15
25	NTPC Ltd, Neyveli TPS Stage 2 Unit no 4-7	29.12	4.04	27.81	6.00
26	NTPC Ltd, Neyveli New TPS Unit No 1-2	32.98	5.13	20.29	6.07
27	NTPC Tamil Nadu Energy Company Limited, Vallur TPS Unit No 1-3	2.09	3.21	8.97	4.72
28	Tamil Nadu Power Generation Corporation Limited, Tuticorin TPS Unit No 1-5	3.19	3.21	4.86	4.67
29	NPCIL, Madras APS Unit No 1-2	8.99	2.59	18.36	1.67
30	NPCIL, Kaiga APS Unit No 1-2	10.12	2.59	8.43	5.74
31	NPCIL, Kaiga APS Unit No 3-4	14.70	3.53	10.94	5.24
32	NTPC Ltd, Telangana STPS Unit No 1-2	0	2.84	0	4.25
33	NLCIL, Neyveli Stage 1 Expansion Unit No 1-2	0	3.78	0	4.91
34	NLCIL, Neyveli Stage 2 Expansion Unit No 1-2	0	0	0	4.91
35	NPCIL, Kudankulam Nuclear Power Plant Unit No 1-2	0.52	3.75	1.31	5.15
36	NTPC Ltd, Simhadri STPS Stage 1 Unit No 1-2	0.19	2.85	0.49	3.91
37	NTPC Ltd, Simhadri STPS Stage 2 Unit No 3-4	0.29	3.04	0.74	4.17
38	NTPC Ltd, Kudgi STPS Stage 1 Unit no 1-3	0	4.30	0	5.90
39	APGENCO, Upper Sileru HPS Unit No 1	2.84	0	7.22	0
40	APGENCO, Upper Sileru HPS Unit No 2	2.84	0	7.22	0

S. No	Generation unit (operator's name and name of unit)	FY 2023-24		FY 2039-40	
		AFC (in INR crore)	VC (in INR/unit)	AFC (in INR crore)	VC (in INR/unit)
41	APGENCO, Upper Sileru HPS Unit No 3	2.84	0	7.22	0
42	APGENCO, Upper Sileru HPS Unit No 4	2.84	0	7.22	0
43	APGENCO, Lower Sileru HPS Unit No 1	5.45	0	13.83	0
44	APGENCO, Lower Sileru HPS Unit No 2	5.45	0	13.83	0
45	APGENCO, Lower Sileru HPS Unit No 3	5.45	0	13.83	0
46	APGENCO, Lower Sileru HPS Unit No 4	5.45	0	13.83	0
47	APGENCO, Penna Ahobilam Balancing Reservoir (PABR) HPS Unit No 1	0.94	0	1.63	0
48	APGENCO, PABR HPS Unit No 2	0.94	0	1.63	0
49	APGENCO and OHPC, Machkund HPS	5.49	0	20.40	0
50	Tungabhadra Board, Tungabhadra HPS	3.76	0	9.56	0

Pump storage plants

1	APGENCO, Nagarjunasagar Right Canal Power House (PH) Unit No.1	43.55	0	84.38	0
2	APGENCO, Nagarjunasagar Right Canal PH Unit No.2	43.55	0	84.38	0
3	APGENCO, Nagarjunasagar Right Canal PH Unit No.3	43.55	0	84.38	0
4	APGENCO, Srisailem Right Bank PH Unit No 1	162.45	0	212.60	0
5	APGENCO, Srisailem Right Bank PH Unit No 2	162.45	0	212.60	0
6	APGENCO, Srisailem Right Bank PH Unit No 3	162.45	0	212.60	0
7	APGENCO, Srisailem Right Bank PH Unit No 4	162.45	0	212.60	0
8	APGENCO, Srisailem Right Bank PH Unit No 5	162.45	0	212.60	0

S. No	Generation unit (operator's name and name of unit)	FY 2023–24		FY 2039–40	
		AFC (in INR crore)	VC (in INR/unit)	AFC (in INR crore)	VC (in INR/unit)
9	APGENCO, Srisailam Right Bank PH Unit No 6	162.45	0	212.60	0
10	APGENCO, Srisailam Right Bank PH Unit No 7	162.45	0	212.60	0
11	APGENCO, Nagarjuna Sagar Tail Pond PH Unit No 1	121.41	0	337.48	0
12	APGENCO, Nagarjuna Sagar Tail Pond PH Unit No 2	121.41	0	337.48	0
13	APGENCO, Donkarayi Canal PH	42.62	0	108.27	0
Renewable energy plants					
1	Small Hydro	24.22	4.55	35.96	0
2	Industrial Waste	71.62	6.23	75.58	0
3	Wind	825.87	3.94	1226.01	0
4	Bio Power	142.37	4.35	138.87	0
5	Solar	1703.50	7.12	1136.10	0

9.3. Appendix C

Table 16 provides fuel prices for various generation units in INR per million metric British thermal unit (MMBtu) for FY 2023–24 and FY 2039–40.

Table 16: Unit-wise fuel prices for FY 2023–24 and FY 2039–40.

S. No	Generation unit	Fuel price (INR/MMBtu)	
		FY 2023–24	FY 2039–40
1	APGENCO, RTPP Unit No.1	466.22	692.10
2	APGENCO, RTPP Unit No.2	466.22	692.10
3	APGENCO, RTPP Unit No.3	465.00	690.29
4	APGENCO, RTPP Unit No.4	465.00	690.29
5	APGENCO, RTPP Unit No.5	464.47	689.51
6	APGENCO, RTPP Unit No.6	438.41	650.83
7	APGENCO, Dr NTPPS Unit No.1	454.67	674.96
8	APGENCO, Dr NTPPS Unit No.2	454.67	674.96
9	APGENCO, Dr NTPPS Unit No.3	454.67	674.96

S. No	Generation unit	Fuel price (INR/MMBtu)	
		FY 2023-24	FY 2039-40
10	APGENCO, Dr NTPPS Unit No.4	454.67	674.96
11	APGENCO, Dr NTPPS Unit No.5	454.67	674.96
12	APGENCO, Dr NTPPS Unit No.6	454.67	674.96
13	APGENCO, Dr NTPPS Unit No.7	423.11	628.11
14	APGENCO, Dr NTPPS Unit No.8	482.50	716.27
15	APGENCO, SDSTPS Stage 1 Unit No.1	428.21	635.68
16	APGENCO, SDSTPS Stage 1 Unit No.2	368.28	546.71
17	APGENCO, SDSTPS Stage 2 Unit No.1	428.21	635.68
18	IPP, Muthukur Mandal power station (Painampuram) TPS Unit No.1	298.55	409.85
19	IPP, Vizag TPS Unit No.1	331.27	454.77
20	IPP, Sembcorp Energy India Ltd	308.63	423.68
21	NTPC Ltd, NTPC Ramagundam STPS Stage 1- and 2-Unit No 1 to 6	393.14	583.62
22	NTPC Ltd, NTPC Ramagundam STPS Stage 3 Unit No 7	388.65	576.96
23	NTPC Ltd, Talcher STPS Unit No 1 to 4	186.09	276.26
24	NTPC Ltd, Simhadri STPS Stage 1 Unit No 1 to 2	437.51	649.49
25	NTPC Ltd, Simhadri STPS Stage 2 Unit No 3 to 4	426.95	633.81
26	NTPC Ltd, Kudgi STPS Stage 1 Unit no 1 to 3	542.00	640.92
27	NLCIL, Neyveli TPS Stage 2 Unit no 1 to 3	338.72	497.78
28	NLCIL, Neyveli TPS Stage 2 Unit no 4 to 7	338.80	493.40
29	NLCIL, Neyveli New TPS Unit No 1 to 2	273.28	176.69
30	NTPC Tamil Nadu Energy Company Limited, Vallur TPS Unit No 1 to 3	407.95	605.60
31	Tamil Nadu Power Generation Corporation Limited, Tuticorin TPS Unit No 1 to 5	372.34	552.74
32	NTPC Ltd, Telangana STPS Unit No 1 to 2	395.92	543.51
33	NLCIL, Neyveli Stage 1 Expansion Unit No 1 to 2	300.81	412.95
34	NLCIL, Neyveli Stage 2 Expansion Unit No 1 to 2	320.71	440.26

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