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Andhra Pradesh Power Sector: A Roadmap Till 2040

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Executive Summary

Andhra Pradesh's (AP's) gross state domestic product stood at INR 1,201,736 crore (USD 157.36 billion) in FY 22. The power sector played a crucial role in supporting the state's economic growth. The state initiated power sector reforms as early as 1998 and was also the first state to sign the 'Power for All' agreement—the basis for power sector planning in AP—with the Government of India in September 2014.

Currently, the state's power sector is marked by surplus base power capacity and growing renewable capacity. Managing the grid with high renewable capacity, optimising power purchase costs, and ensuring reliable supply to consumers, pose several challenges. Therefore, a detailed roadmap is needed to address the power sector issues in the state. The Center for Study of Science, Technology and Policy (CSTEP) carried out a study to develop long-term pathways till 2040 for the AP power sector by covering demand, supply, and cost components. These pathways will help the state to make informed decisions on renewable energy (RE) transition and optimise power purchase costs.

Over the past 5 years, the demand for electrical energy in the state has steadily increased. On the basis of past trends and historical growth, this study forecasted AP's energy demand to reach 194,847 MU by FY 40 in a business-as-usual (BAU) scenario. This forecast was overlaid with the impact of various policy levers on the state's BAU demand. As per the results, by FY 40, the penetration of 14.4 million electric vehicles (EVs) will increase the demand by 9,874 MU. However, measures such as the adoption of energy-efficient technologies in residential and commercial sectors and solarisation and installation of energy-efficient irrigation pump sets can help reduce the demand by 25,102 MU. Lastly, the installation of 2,271 MW of solar rooftop photovoltaic (RTPV) systems by FY 40 can further impact the net demand. With the judicious implementation of policy levers, the energy and peak demand in AP can be optimised to 174,158 MU and 28,372 MW, respectively.

To cater to this demand, comprehensive supply planning is required. The demand–supply planning section in this report, thus, examines three supply scenarios—the state standard scenario, aggressive RE scenario, and economical scenario. In the state standard scenario, we have considered the existing capacity, additional capacity, and retirement plans (of power plants), as per the state. Any deficit thereof is catered by additional RE (solar, wind, hydro, and other sources) capacity proposed through the analysis. The aggressive RE scenario takes into account existing and proposed capacity, year-on-year RE capacity addition, and gradual reduction of energy from thermal power plants. A sensitivity analysis of plant load factors (PLFs) of thermal power plants was performed to understand the required RE capacity addition based on the operational performance of thermal plants. In the economical scenario, the objective was to look at the replacement of costly thermal plants with cheaper RE sources. Thus, thermal plants with tariffs higher than INR 5/unit were considered for replacement in this scenario. No additional thermal capacity was considered in any of the supply scenario analyses. The analysis further identified the need for utility-scale energy storage systems to balance the grid during periods of high energy demand.

Therefore, to cater to the projected demand and align with the national goals of the clean energy transition, the state would require RE capacity in the range of 32,887 MW to 40,637 MW under various supply scenarios. This capacity is inclusive of 7,000 MW of solar power, for which the state has signed a purchase agreement with the Solar Energy Corporation of India (SECI). The proposed RE capacity will lead to an increase in the RE share in the total energy supply mix from 24% in FY 22 to 47%–55% by FY 40. We also analysed the demand–supply balance for a peak day in the state. As per the results, in the aggressive RE scenario, the state will experience an energy deficit from 2 AM to10 AM (9 hours) and from 6 PM to 7 PM (1 hour) in FY 40. However, an excess supply situation will occur from11 AM to 6 PM (8 hours) and from 7 PM to 12 AM (6 hours) due to higher solar and wind generation during the respective periods. Thus, the state will need to manage this demand–supply situation by developing grid-scale storage systems with a capacity of 6,390 MW to 8,292 MW by FY 40. Further, the analysis of bulk storage systems using a technology assessment framework suggested that pumped hydro will be a more feasible choice for a bulk storage system than compressed air energy storage and hydrogen energy storage by FY 40.

The proposed RE capacity addition will also help the state to reduce its power purchase cost by 24%–27% (from INR 4.14/unit) in FY 23. Although the aggressive RE scenario with thermal plants operating at 40% PLF will be the most feasible supply scenario for the state, it will increase the storage requirement. Therefore, we suggest the state to consider the supply scenario with thermal plants operating at 60% PLF and an optimum storage and RE capacity requirement.

The above analysis indicated that the state will have to undertake the following measures to achieve a sustainable and reliable energy system by FY 40:

- Develop RE parks by conducting geographic-information-system-based assessment and identifying suitable/feasible land parcels for solar and wind.
- Expedite commissioning of the proposed Upper Sileru Pumped Storage Project (1,350 MW).
- Implement pollution control technologies to ensure that the thermal plants comply with environmental norms.
- Conduct techno-economic feasibility assessments to determine the retirement term of thermal plants.
- Expedite commissioning of the Kovvada nuclear plant (7,248 MW) and allocate at least 50% of the plant's capacity (3,624 MW) to the state by FY 31 and additional 3,264 MW capacity from upcoming nuclear plants by FY 36.
- Conduct 11-kV feeder-level load-flow analyses in major cities to understand the technical feasibility of EV integration into the distribution grid.
- Generate accurate RTPV system potential by using drone-based aerial photogrammetry and develop suitable business models for specific consumer categories to ensure zero negative impact on DISCOMs' finances.
- Mandate Energy Conservation Building Code compliance across commercial buildings and extend it to residential buildings.
- Promote the adoption of solar irrigation pump sets by incentivising farmers with favourable rates for the sale of solar power back to DISCOMs.

By implementing these measures and following the recommended pathways, AP can achieve a sustainable and reliable power sector, support a clean energy transition, and provide an affordable and quality power supply to its consumers.

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1. Introduction

Andhra Pradesh (AP) is the eighth largest state in India, with a well-developed power, airport, and port infrastructure. The state's gross state domestic product (GSDP) was INR 1,201,736 crore (USD 157.36 billion) for the financial year (FY) 22, which was an increase at a compounded annual growth rate (CAGR) of 12.14% from 2015–16 (IBEF, 2023). The state's power sector has played a vital role in securing this growth, with AP being one of the pioneer states in the country to initiate power sector reforms as early as 1998. Moreover, it was the first state to sign the 'Power for All' agreement with the Government of India in September 2014. This agreement provided a 5-year plan, which formed the basis for power sector planning in AP. From a situation of power shortage in FY 15 (4.9% energy and 5% peak power), the state moved to a situation of zero megawatt (MW) of peak and only 726 million unit (MU) of energy deficit in FY 22 (CEA 2023). As of FY 22, there has been a significant increase in solar, wind, and state-owned thermal capacity by 1,763 MW, 1,131 MW, and 1,302 MW, respectively. The state also has a promising renewable energy (RE) potential, with a solar and wind capacity of 38 gigawatt (GW) and 44 GW, respectively (APEDB, 2022).

1.1 Study Objective

The AP power sector is facing some challenges in this context of surplus base power capacity and increasing renewable capacity, which makes grid management a difficult task. Optimising power purchase costs and ensuring reliable supply to consumers are also challenging. There is, therefore, an urgent need to construct a detailed roadmap to address these challenges. Long-term planning is required for augmenting the renewable capacity commensurate with the increase in demand by having a common integrated planning framework. Therefore, the objective of this study was to develop long-term pathways for the AP power sector till 2040, covering demand, supply, and cost components of the power sector. The Center for Study of Science, Technology and Policy's (CSTEP's) pathways till 2040 will help AP to take informed decisions on its RE transition and cost optimisation, thereby ensuring reliable, affordable, and quality supply to its consumers.

Such long-term planning studies are critical for the power sector to achieve its goals by ensuring a robust and enabling policy, regulatory, and technical environment. This CSTEP study is, therefore, relevant for all power sector stakeholders, including policymakers, project developers, utilities, and consumer groups.

2. Current Power Situation in AP

2.1 Generation

2.1.1. Installed Capacity

The state's installed capacity increased from 15,876 MW in FY 17 to 23,953 MW in FY 22, with a CAGR of 8.6% (APTRANSCO, 2023) .

Table 1 provides the breakdown of the installed capacity in FY 22 by different resource types. Thermal plants account for the largest share of installed capacity, contributing approximately 58% or 13,882 MW. Thermal plants are followed by RE, comprising solar, wind, large hydro, and other non-conventional sources (NCESs, including cogeneration, biomass, small hydro, and waste-to-energy], which altogether contribute 41% or 9,939 MW of installed capacity. Nuclear plants contribute 1% or 132 MW of installed capacity.

Table 1: Resource-wise installed capacity in FY 22

Resource	Installed capacity (MW)
Solar	3,609
Wind	4,191
Large hydro	1,848
Other NCESs	290
Sub-total RE (A)	***9,939***
Thermal + gas	13,882
Nuclear	132
Sub-total (B)	***14,015***
Total (A + B)	**23,953**

Source: Data shared by APTRANSCO

2.1.2. Development of RE

Over the last 5 years, AP has harnessed its RE potential sustainably, with a 6.6% CAGR from FY 17 to FY 22. Within the RE sector, solar capacity increased significantly at a CAGR of 14.3%, followed by that of wind (6.5%) and large hydro (1.4%). However, the capacity of small hydro and other RE sources (including cogeneration, biomass, and mini plants) declined at a CAGR of −19.7% and −12.6%, respectively, during the same period. Table 2 lists the RE capacity expansion in the state for FY 17 and FY 22.

Table 2: RE capacity expansion for FY 17 and FY 22 (in MW)

FY	Solar	Wind	Large hydro	Small hydro	Other RE sources	Total
FY 17	1,846	3,060	1,721	87	512	**7,226**
FY 22[1]	3,609	4,191	1,848	29	261	**9,939**

Source: FY 17 data as per Power Development in Andhra Pradesh (Statistics), FY 22, from APTRANSCO

[1] Data shared by APTRANSCO to CSTEP

The state has come up with various policies for promoting RE capacity, such as Andhra Pradesh Solar Power Policy-2018 in 2019, Andhra Pradesh Wind Power Policy-2018 in 2019, Andhra Pradesh Renewable Energy Export Policy, 2020, in 2020, and Andhra Pradesh Pumped Storage Power Promotion Policy-2022, to harness its vast RE potential (solar: 38.4 GW, wind: 44.3 GW [100-m height], and pumped storage project [PSP]: 33.2 GW) (GoAP, 2019a; GoAP, 2019b; Energy Department, GoAP, 2020; GoAP, 2022).

2.1.3. Current Status of Demand, Supply, and Shortage

From FY 17 to FY 21, the state has been able to cater to the demand. There were negligible shortfalls in energy supply mainly due to the high plant load factors (PLFs) of thermal plants, increased RE penetration, and reduced energy requirement in FY 21 than in FY 20, owing to the pandemic-induced restrictions and lockdowns. However, in FY 22, AP faced a deficit of 726 MU, which accounted for approximately 1.1% of the energy requirement. This deficit is attributable to an increased energy requirement within the state (Figure 1).

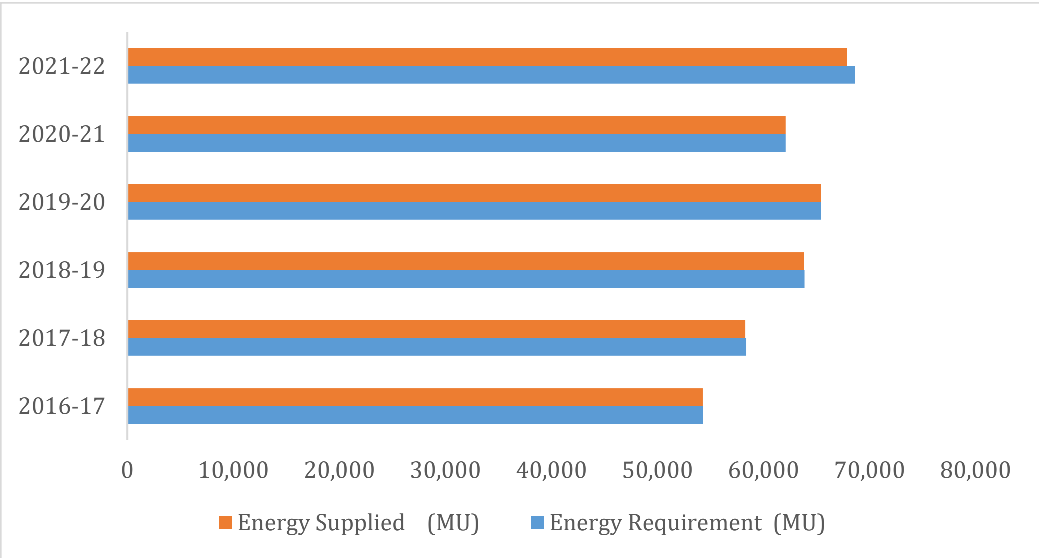

Figure 1: Year-on-year energy surplus/deficit

Source: Load Generation Balance Reports (LGBRs) by Central Electricity Authority (CEA, 2023)

Furthermore, from FY 17 to FY 22, the state's installed generation capacity was well adequate to meet the peak demand with minimal deficit, as depicted in Figure 2. This achievement is attributable to the substantial RE capacity developed within the state, which plays a crucial role in fulfilling the energy requirements during peak periods.

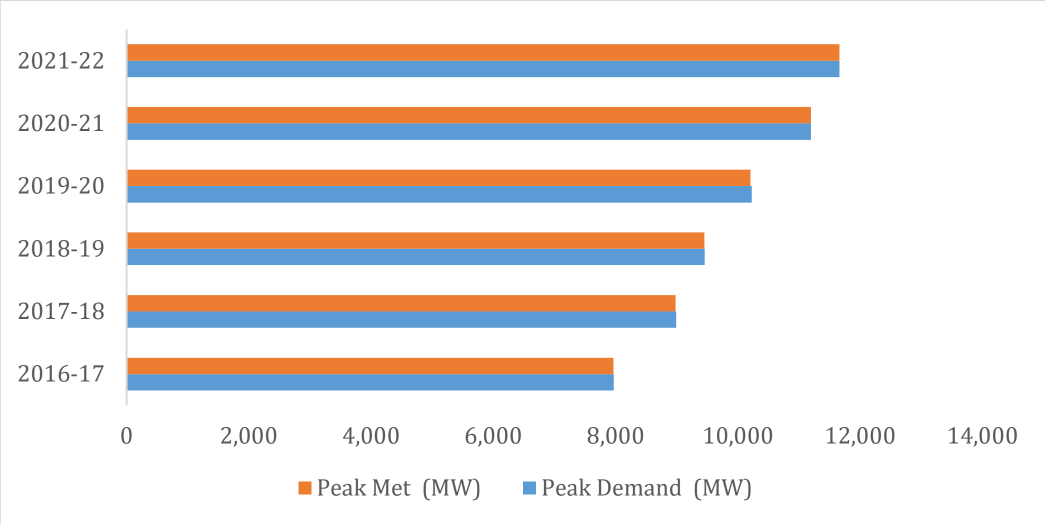

Figure 2: Year-on-year peak demand/met

Source: CEA LGBR reports

2.2 Transmission

Transmission Corporation of Andhra Pradesh Limited (APTRANSCO) is a state-owned entity that plays a crucial role in the power sector by managing the transmission infrastructure. Along with APTRANSCO, Power Grid Corporation of India (PGCIL) owns and operates the transmission grid from 765 kV to 220 kV voltage in AP. As of FY 21, the state's transmission grid consisted of 357 transmission substations to transmit power from the generation point to the load centre. These substations have a combined transformation capacity of 79,916 megavolt-ampere (MVA) and a transmission line length of 36,993 circuit kilometre (Ckt Km). The transmission losses in the state reduced significantly from 3.13% in FY 18 to 2.76% in FY 22 (Table 3).

Table 3: Historical transmission losses

FY	Transmission loss (%)
FY 18	3.13
FY 19	3.10
FY 20	2.91
FY 21	2.60
FY 22	2.76

Source: Power Development in Andhra Pradesh (Statistics), 2021-22, by APTRANSCO

2.3 Distribution Sector

After the erstwhile AP state bifurcated in 2014, three distribution companies (DISCOMs)—Andhra Pradesh Southern Power Distribution Company Limited (APSPDCL), Andhra Pradesh Eastern Power Distribution Company Limited (APEPDCL), and Andhra Pradesh Central Power Distribution Company Limited (APCPDCL)—and Rural Electric Cooperative Society Limited (generally known as RESCO) distribute the electricity, with APCPDCL being recently formed in FY 20. The number of consumers in the state grew from 1,71,82,480 in FY 17 to 1,96,04,871 in FY 22 (14% CAGR), leading to huge growth in the connected load from 29,305 MW in FY 17 to 44,042 MW in FY 22 (50% CAGR).

2.3.1. Technical Operations

Energy sales in the state increased from 43,487 MU in FY 17 to 52,937 MU in FY 21 at a CAGR of 5%. Domestic energy consumption accounted for 32% of the total consumption in FY 21, followed by industrial (28%), agricultural (25%), institutional (8%), and commercial (7%) energy consumption. The growth in Y-o-Y category-wise consumption is shown in Table 4.

Table 4: Category-wise energy sales (in MU)

Category	FY 17	FY 18	FY 19	FY 20	FY 21
Domestic	12,077	13,278	14,110	16,117	17,194
Commercial	3,675	3,987	4,329	4,450	3,795
Industrial	14,565	16,346	18,089	15,522	14,601
Institutional and others	2,577	2,849	3,098	4,175	4,160
Agricultural	10,594	10,214	11,600	14,676	13,186
Total	**43,487**	**46,674**	**51,225**	**54,939**	**52,937**

Source: Data shared by respective DISCOMs with CSTEP

The state has significantly reduced its transmission and distribution (T&D) loss from 11.65% in FY 17 to 9.76% in FY 22, as shown in Table 5.

Table 5: Historical T&D loss

FY	T&D loss (%)
FY 17	11.65
FY 18	11.93
FY 19	13.04
FY 20	13.02
FY 21	9.49
FY 22	9.76

Source: Power Development in Andhra Pradesh (Statistics), 2021-22, by APTRANSCO

2.3.2. Financial Operations

The Y-o-Y net revenue collection and expenditure due to energy sales are listed in Table 6. The revenue deficit in FY 19 was very high at INR 11,864 crore, leading to a gap of INR 2.32/unit between the average cost of supply (ACS) and the average revenue realised (ARR). By FY 21, the revenue was surplus with INR 261 crore and a positive ACS–ARR gap of INR 0.05/unit. Therefore, the DISCOMs were stable with respect to revenue operations.

Table 6: Year-on-year revenue surplus/deficit details (INR in crore)

Details	FY 17	FY 18	FY 19	FY 20	FY 21
Revenue receipts	26,749	32,798	37,806	42,938	47,642
Revenue expenditure	28,987	32,765	49,669	42,975	47,381
Net surplus/deficit	**−2,238**	**33**	**−11,864**	**−36**	**261**

Source: Power Development in Andhra Pradesh (Statistics), 2021-22, by APTRANSCO

Above data indicate that the state power sector is functioning smoothly and catering to the consumers' demand with current supply availability. Going forward, with the integration of intermittent and variable RE on the supply side and penetration of evolving frontiers, such as electric vehicles (EVs) and rooftop photovoltaics (RTPVs) on the demand side, the state needs to balance the demand and supply efficiently to provide a reliable power supply, allocate resources efficiently, and make prudent investment decisions. Therefore, the subsequent sections conduct demand projections in the state by 2040, along with analysing various supply scenarios to cater to the futuristic demand.

3. Demand Forecast: FY 23 to FY 40

Any DISCOM must adopt accurate demand forecasting (DF) to effectively plan and manage its operations, such as energy procurement, peak demand, and revenue management. We forecasted the state's energy demand Y-o-Y between FY 23 and FY 40 by accounting for factors such as historical consumption trends, population growth, consumer demographics, and the effects of various other policy levers.

The DF involved a business-as-usual (BAU) scenario overlaid with the effects of several policy levers, such as EV adoption, RTPV penetration, energy efficiency (EE) in domestic, commercial, and agriculture sectors, and solarisation efforts in the agriculture sector. Demand projection was performed using CAGR-based and econometric methodologies. The methodology with the closest fit to the historical data and a better predictive accuracy was selected as the preferred approach for estimating future electricity demand.

3.1 Data and Methodology

3.1.1. Data Consideration

We collected the historical data on electricity consumption for each consumer category (domestic, commercial, industrial, agricultural, and institutional) from the respective DISCOMs to forecast electricity demand. In 2020, APSPDCL was bifurcated into two separate DISCOMs—APSPDCL and APCPDCL. Because of the bifurcation and the resulting lack of data, historical data from FY 17 to FY 21 was used for APSPDCL and APCPDCL, whereas we considered historical data from FY 16 to FY 21 for APEPDCL.

3.1.2. Methodology

A. Econometric Forecasting Model

In this method, separate linear regression models were developed for each consumer category of each DISCOM (Nardini, S. et al., 2009). This model was used for estimating electricity demand for different consumer segments on the basis of variables with a significant influence on consumer electricity demand (Table 7).

Table 7: Econometric forecasting model

Consumer category	Econometric model
Domestic	$Energy = \alpha + \beta 1 * Consumers_{year} + error$
Commercial	$Energy = \alpha + \beta 2 * CGVA_{year} + error$
Industrial	$Energy = \alpha + \beta 3 * GSDP_{year} + error$
Agricultural	$Energy = \alpha + \beta 4 * NNI_{year} + error$
Institutional	$Energy = \alpha + \beta 5 * IGVA_{year} + error$

Where,

- Energy is the electricity demand for the respective consumer category for a particular year.
- The term 'consumers' is the consumers of the domestic sector for a particular year.

- CGVA is the 'gross value added' (GVA) of the state's commercial sector for a particular year (Awasthy, A. & Spencer, T., 2019).
- GSDP is the 'GSDP' of the state's industrial sector for a particular year.
- NNI is the state's 'net irrigated area' for a particular year.
- IGVA is the 'GVA' of the state's institutional sector for a particular year.
- β1 is the coefficient of the domestic consumers[2].
- β2 is the coefficient of the commercial sector's 'GVA'[3].
- β3 is the coefficient of the industrial sector's 'GSDP'[4].
- β4 is the coefficient of 'NNI'[5].
- β5 is the coefficient of the institutional sector's 'GVA'[6].

Table 8 lists the Y-o-Y demand for the consumer categories of the whole state.

Table 8: Year-on-year DF (in MU) for consumer categories using the econometric forecasting model

Consumer category	FY 23	FY 24	FY 29	FY 34	FY 39	FY 40
Domestic	19,561	20,860	28,107	36,779	47,184	49,504
Commercial	6,249	6,808	10,161	14,439	19,642	20,793
Industrial	24,949	27,016	40,308	60,301	90,374	98,007
Agricultural	18,095	19,342	25,878	32,944	40,583	42,184
Institutional	3,949	4,179	5,330	6,481	7,632	7,862
Total	**72,802**	**78,206**	**1,09,784**	**1,50,944**	**2,05,414**	**2,18,350**

The analysis revealed a discrepancy between the actual electricity demand and the demand forecasted by the model. While the actual demand in FY 22 was reported as 62,334 MU, the model projected a higher demand of 67,663 MU for the same period. Further, the model failed to accurately forecast the industrial electricity demand for APEPDCL, leading to an abnormal increase in industrial electricity demand in FY 40. Considering the variations in the forecasted and actual demand, as well as the inability of the model to accurately predict industrial demand for APEPDCL, this model was concluded to be unsuitable for forecasting.

B. CAGR-Based DF Model

As the econometric model was found to be less accurate, we performed DF using CAGR trend analysis.

[2] This indicates the impact of domestic consumers on energy consumption/tells how much will energy consumption increase or decrease if domestic consumers change by 1 unit.

[3] This indicates the impact of the commercial sector's GVA on energy consumption/tells how much will energy consumption increase or decrease if the commercial sector's GVA changes by 1 unit.

[4] This indicates the impact of the industrial sector's GSDP on energy consumption/tells how much will energy consumption increase or decrease if the industrial sector's GSDP changes by 1 unit.

[5] This indicates the impact of NNI on the agriculture sector's energy consumption/tells how much will energy consumption increase or decrease if NNI changes by 1 unit.

[6] This indicates the impact of the institutional sector's GVA on energy consumption/tells how much will energy consumption increase or decrease if the institutional sector's GVA changes by 1 unit.

The model used a constant rate of Y-o-Y growth (based on past trends) to estimate the energy demand. Due to the pandemic's impact, a decrease in electricity demand was observed for various consumer categories in FY 21, including commercial, industrial, institutional, and agricultural consumer categories. Thus, we decided to use data until FY 20 for these consumer categories, while data until FY 21 was considered for the domestic consumer category.

Table 9 lists the growth rates for each consumer category obtained from the model.

Table 9: Category-wise and DISCOM-wise growth rates

DISCOM	Agricultural	Commercial	Domestic	Industrial	Institutional
APSPDCL	5%	5%	5%	6%	5%
APEPDCL	6%	8%	6%	5%	4%
APCPDCL	5%	9%	7%	6%	4%

On the basis of consultations with stakeholders, a 10% growth rate was concluded as too high and, therefore, a 5% growth rate was considered for APEPDCL's industrial consumer category.

The category-wise electricity demand was forecasted for each DISCOM on the basis of the selected annual growth rates. Table 10, Table 11, and Table 12 list the BAU demand without T&D loss.

Table 10: Consumer category-wise Y-o-Y electricity demand (in MU) for APSPDCL

APSPDCL						
Consumer category	**FY 23**	**FY 24**	**FY 29**	**FY 34**	**FY 39**	**FY 40**
Domestic	6,189	6,602	8,670	10,737	12,804	13,218
Commercial	1,540	1,618	2,076	2,662	3,414	3,589
Industrial	6,296	6,698	9,127	12,438	16,949	18,032
Agricultural	11,745	12,332	15,739	20,087	25,637	26,919
Institutional	1,766	1,868	2,376	2,884	3,392	3,494
Total	**27,535**	**29,118**	**37,987**	**48,808**	**62,197**	**65,251**

Table 10 illustrates consumer category-wise electricity demand projection till FY 40 for APSPDCL. As per the results, the agricultural consumer category has the largest share of 41% of DISCOM's overall electricity demand in FY 40. From FY 23 to FY 40, the DISCOM's overall electricity demand is estimated to grow at a CAGR of 5%.

Table 11: Consumer category-wise Y-o-Y DF (in MU) for APEPDCL

APEPDCL						
Consumer category	**FY 23**	**FY 24**	**FY 29**	**FY 34**	**FY 39**	**FY 40**
Domestic	7,247	7,727	10,322	13,243	16,491	17,180
Commercial	2,602	2,869	4,552	6,813	9,651	10,288
Industrial	9,636	10,225	13,754	17,740	21,790	22,662

Agricultural	5,282	5,599	7,493	10,027	13,419	14,224
Institutional	1,373	1,445	1,806	2,167	2,528	2,601
Total	**26,141**	**27,866**	**37,927**	**49,991**	**63,879**	**66,954**

Table 11 lists consumer category-wise electricity demand projection till FY 40 for APEPDCL. The values indicate that the industrial consumer category has the largest share of 34% of DISCOM's overall electricity demand in FY 40. Further, the DISCOM's overall electricity demand will grow at a CAGR of 6% between FY 23 and FY 40.

Table 12: Consumer category-wise Y-o-Y DF (in MU) for APCPDCL

APCPDCL						
Consumer category	**FY 23**	**FY 24**	**FY 29**	**FY 34**	**FY 39**	**FY 40**
Domestic	6,640	7,201	10,234	13,652	17,455	18,262
Commercial	1,956	2,129	3,247	4,953	7,555	8,221
Industrial	5,701	6,058	8,210	11,127	15,080	16,025
Agricultural	136	142	182	232	296	311
Institutional	873	946	1,310	1,674	2,038	2,111
Total	**15,306**	**16,475**	**23,182**	**31,637**	**42,424**	**44,929**

Table 12 illustrates the consumer category-wise electricity demand projection till FY 40 for APCPDCL. As per this data, the domestic consumer category has the largest share of 40% of DISCOM's overall electricity demand in FY 40. Further, the DISCOM's overall electricity demand is projected to grow at a CAGR of 7% from FY 23 to FY 40.

Table 13: Consumer category-wise Y-o-Y electricity demand (in MU) in AP

State-level						
Consumer category	**FY 23**	**FY 24**	**FY 29**	**FY 34**	**FY 39**	**FY 40**
Domestic	20,076	21,530	29,225	37,632	46,750	48,659
Commercial	6,098	6,617	9,875	14,428	20,620	22,097
Industrial	21,632	22,980	31,091	41,305	53,819	56,719
Agricultural	17,162	18,073	23,414	30,346	39,352	41,453
Institutional	4,012	4,259	5,492	6,725	7,958	8,205
Energy demand	**68,982**	**73,459**	**99,097**	**1,30,436**	**1,68,500**	**1,77,134**
T&D loss	8,899	9,355	11,791	14,408	17,147	17,713
Energy requirement	**77,881**	**82,815**	**1,10,888**	**1,44,844**	**1,85,646**	**1,94,847**

Table 13 lists the consumer category-wise electricity demand till FY 40 before and after considering T&D loss in AP. By FY 40, the share of APSPDCL, APEPDCL, and APCPDCL in the state's electricity demand will be 37%, 38%, and 25%, respectively. The state's overall electricity demand will grow at a CAGR of 5.7% between FY 23 and FY 40.

Further, the state is performing fairly well in reducing its annual T&D losses, and we expect the same trend to follow. The current T&D loss of 13.23% (transmission and distribution loss of 2.86% and 10.37%, respectively) in FY 21 is expected to gradually reduce to 10% (transmission and distribution loss of 2.0% and 10.0%, respectively) by FY 40, with an annual average reduction of 0.17%.

3.2 Policy Analysis

In this section, we examine the policy levers impacting the DF in a BAU scenario. The analysis considered the impact of various emerging developments, such as RTPV generation, EV penetration, solarisation (of irrigation pump [IP] sets), and EE (in commercial buildings, household appliances, and IP sets), on the energy demand.

3.2.1. Demand Projection Considering EV Penetration

Penetration of EVs in the transportation sector is one of the most anticipated clean energy moves in the country. The Government of Andhra Pradesh (GoAP) is also emphasising electric mobility as a significant growth driver. By supporting the electric mobility ecosystem, AP seeks to lead the way in developing sustainable transportation infrastructure. Hence, GoAP has set an ambitious target of achieving 1 million EVs across all segments by FY 24 under Electric Mobility Policy 2018-23, with an aim of becoming one of the top three EV hub states by 2022 and the best state by 2029 (Industries & Commerce Department, GoAP, 2018).

The state witnessed an increase in the total number of vehicles registered, from 80.6 lakhs in FY 09 to 1.46 crore in FY 21 (5.1% CAGR) (Ministry of Road Transport & Highways, GoI, 2021; Rao, U., 2022). At this growth rate, the state's total vehicle registrations will reach 3.74 crore by FY 40. Further, the number of new EVs increased from 5,743 in FY 17 to 21,565 in FY 21, with a CAGR of 39% (Table 14).

Table 14: Historical EV data (in numbers)

Vehicle type	EVs in FY 17	EVs in FY 21
2-Wheelers	3,195	14,441
3-Wheelers	96	2,587
4-Wheelers	2,452	4,537
Goods/commercial	-	52
Buses	-	55
Total	**5,743**	**21,565**

Source: Vahan Dashboard (MORTH, 2022)

Even with a 39% CAGR, the state will be able to achieve its EV target of 1 million only by FY 33, as against achieving it by FY 24. Thus, we normalised the growth rates to help the state achieve its EV target by FY 28. We assumed category-wise penetration of newly registered electric 2-wheelers (E2-Ws), E3-Ws, E4-Ws, goods/commercial vehicles, and buses to be 80%, 80%, 50%, 5%, and 40%, respectively, from FY 22 to FY 30. Further, from FY 31 to FY 40, the penetration is assumed as 100% for E2-Ws, E3-Ws, and E4-Ws and 12% for buses and goods/commercial vehicles. Accordingly, Table 15 shows the category-wise projected CAGR.

Table 15: Vehicle category-wise CAGR projection

Vehicle type	CAGR for FY 22–FY 30	CAGR for FY 31–FY 40
2-Ws	53.60%	7.45%
3-Ws	39.02%	7.45%
4-Ws	27.11%	12.62%
Goods/commercial	66.52%	14.70%
Buses	33.91%	15.17%

On the basis of the above CAGRs, the Y-o-Y category-wise EV numbers are projected (Table 16), with the total number reaching up to 1.44 crore and accounting for 38.5% of total vehicles by FY 40.

Table 16: Vehicle category-wise Y-o-Y EV projection (in numbers)

Vehicle type	FY 24	FY 29	FY 34	FY 39	FY 40
2-Ws	1,23,028	12,55,331	52,43,880	1,09,57,721	1,23,68,257
3-Ws	18,135	1,21,972	4,13,191	8,30,380	9,33,368
4-Ws	26,953	1,28,242	3,81,071	8,39,212	9,68,278
Goods/commercial	519	7,568	41,653	1,09,315	1,29,354
Buses	362	2,096	7,278	17,776	20,921
Total	**1,68,996**	**15,15,208**	**60,87,073**	**1,27,54,404**	**1,44,20,178**

On the basis of each vehicle's energy consumption and the average daily kilometres travelled by the vehicle (Table 17), the energy demand (for charging) from each EV type was estimated (Tiwari, G. et al., 2015).

Table 17: Vehicle category-wise daily energy needs

Vehicle type	Average daily travel (km)	Energy consumption (kWh/km)	Daily individual energy needs (kWh)
2-Ws	10	0.03	0.33
3-Ws	8.4	0.07	0.56
4-Ws	13.2	0.14	1.89
Goods/commercial	150	0.80	120.00
Bus	90	1.25	112.50

Table 18 lists the annual Y-o-Y energy demand for EVs. Due to EV adoption, the state would experience an increased energy demand of 9,874 MU by FY 40.

Table 18: Annual EV energy demand projection (in MU)

Vehicle type	EV energy demand				
	FY 24	**FY 29**	**FY 34**	**FY 39**	**FY 40**
2-Ws	17	170	709	1,481	1,672
3-Ws	4	28	94	189	212
4-Ws	21	98	291	642	741
Goods/commercial	25	368	2,027	5,320	6,295
Buses	16	96	332	811	955
Total	**83**	**759**	**3,453**	**8,443**	**9,874**

3.2.2. Generation from RTPVs

To promote the integration of solar RTPV systems into the distribution grid, the GoAP has set a target of installing 2,000 MW of solar rooftop systems in the state by FY 22 through net metering and gross metering facilities for grid-connected systems (APERC, 2019). However, the state could achieve only 115 MW by FY 21.

We anticipate that the state would be able to achieve its RTPV target by FY 40 at a nominal CAGR of 17%, reaching 2,271 MW by FY 40 (Table 19). This would, therefore, result in a net 3,581 MU reduction in the state's overall energy demand in FY 40, assuming a minimum capacity utilisation factor of 18%.

Table 19: Year-on-year RTPV capacity additions and energy generations

FY	Installed capacity (MW)	Energy generation (MU)
FY 24	184	290
FY 29	404	637
FY 34	885	1,396
FY 39	1,941	3,061
FY 40	2,271	3,581

3.2.3. Energy Efficiency in Buildings and Household Appliances

Buildings and household appliances account for a significant portion of electricity consumption in both residential and commercial sectors. Improving the EE of buildings and household appliances can have a substantial impact on reducing overall electricity demand and promoting sustainability. Hence, to promote EE, various states have notified the Energy Conservation Building Code (ECBC), with AP mandating it for the commercial sector (Kumar, S. et al., 2017). According to the Andhra Pradesh State Energy Conservation Mission (APSECM), the adoption of ECBC in commercial buildings is expected to save 30% of direct energy.

To forecast the demand in the residential and commercial sectors with the implementation of energy-efficient measures, the following assumptions were made:

- State population to grow at 1% CAGR.
- Domestic consumers to grow at 4% CAGR.
- In the residential sector (lighting),
  - 60-W incandescent bulbs to be replaced by 40-W fluorescent tubes or 8-W LED bulbs.
  - Penetration of LEDs to reach around 100% in FY 40 from 75% in FY 25.
  - Penetration of fluorescent lights to reduce from 17% in FY 25 to 0% in FY 40.
  - Penetration of incandescent bulbs to reduce from 33% in FY 25 to 0% in FY 40.
- In the residential sector (appliances),
  - Penetration of high-efficiency appliances (television, ceiling fans, refrigerators, and room air conditioners) to increase from 19% in FY 25 to 35% in FY 40.
  - Penetration of low-efficiency appliances to reduce from 59% in FY 25 to 35% in FY 40.
- In the commercial sector,
  - The Energy Performance Index (EPI) of conventional buildings to increase from 92 KWh/m^2/year in FY 23 to 122 KWh/m^2/year in FY 40.
  - Buildings complaint with ECBC to have 30% less EPI than conventional buildings.
  - Commercial floor area (m^2) per capita to grow from 1.63 in FY 23 to 4.39 in FY 40.

The increased EE in lightings and appliances will reduce the overall energy consumption by 13.4% (Table 20) in the residential sector and 8.3% in the commercial sector by FY 40 (Table 21).

Table 20: Policy impact of EE on the residential sector (in MU)

Policy impact	FY 23	FY 24	FY 29	FY 34	FY 39	FY 40
Total demand_BAU	20,076	21,530	29,225	37,632	46,750	48,659
Policy impact (in %)	4.9	5.3	10.1	15.8	14.1	13.4
Total demand_EE scenario	19,102	20,383	26,285	31,679	40,137	42,151
Energy savings	**974**	**1,147**	**2,940**	**5,953**	**6,614**	**6,508**

Table 21: Policy impact of EE on the commercial sector (in MU)

Policy impact	FY 23	FY 24	FY 29	FY 34	FY 39	FY 40
Total demand_BAU	6,098	6,617	9,875	14,428	20,620	22,097
Policy impact (in %)	3.6	4.0	6.3	7.7	8.2	8.3
Total demand_EE scenario	5,880	6,350	9,253	13,320	18,938	20,269
Energy savings	**218**	**266**	**622**	**1,107**	**1,682**	**1,828**

3.2.4. Solarisation and Energy-Efficient IP Sets in the Agriculture Sector

In AP, IP sets account for significant energy consumption subject to varying monsoons and increased agricultural activities. Therefore, the agriculture sector provides vast scope for adopting emerging technologies to conserve energy consumption and provide reliable supply, thereby making these consumers self-reliant. The solarisation of IP sets and adoption of energy-efficient IP sets are two financially and environmentally viable solutions for a sustainable agriculture sector.

As of FY 21, AP had 1,835,329 IP sets, including electric, solar off-grid, and diesel sets. Our analyses project the total number of IP sets to reach 3,352,450 by FY 40 (3.2% CAGR).

Furthermore, the number of energy-efficient IP sets increased from 69,300 in FY 19 to 81,273 in FY 22 in the state (5.5% CAGR). Considering this growth rate, we projected energy-efficient IP sets to reach 211,458 by FY 40, accounting for 2.6% of the total IP sets.

The share of diesel-run IP sets in overall IP sets in the state was around 17.1% in FY 99, reducing to 13.7% in FY 02. We assume complete phasing out of diesel IP sets by FY 31, which will increase the overall energy demand in the agriculture sector.

As of FY 21, there were 34,045 solarised IP sets in the state (Goel, S. et al., 2022). We project solarised IP sets to reach 484,521 by FY 40 (about 14% of the total IP sets) at a CAGR of 15% due to the state's conducive policies for IP set solarisation.

The adoption of such policies is expected to have a significant impact on energy demand, resulting in a reduction by 16,765 MU or 40% in the baseline energy demand from the agriculture sector by FY 40 (Table 22).

Table 22: Year-on-year energy demand in the agriculture sector

Year	Total demand_BAU (MU)	Policy impact (%)	Total demand_policy scenario (MU)
FY 23	17,162	9	15,680
FY 24	18,073	11	16,154
FY 29	23,414	21	18,458
FY 34	30,346	30	21,102
FY 39	39,352	39	24,064
FY 40	41,453	40	24,688

3.3 Demand Projections Considering the Policy Levers (FY 23–FY 40)

The impact of the aforementioned policy levers (Table 23) was overlaid on the 'BAU demand forecast' to obtain Y-o-Y demand forecasts in the policy scenarios (Table 24).

Table 23: Year-on-year impact of policy levers

Policy lever	FY 23	FY 24	FY 29	FY 34	FY 39	FY 40
EV demand (+) in MU	50	83	759	3,453	8,443	9,874
RTPV generation (−) in MU	248	290	637	1,396	3,061	3,581
EE-domestic (−) in %	4.9%	5.3%	10.1%	15.8%	14.1%	13.4%
EE-commercial (−) in %	3.6%	4.0%	6.3%	7.7%	8.2%	8.3%
Agriculture (−) in MU	1,483	1,919	4,955	9,244	15,288	16,766

The demand in the 'policy scenario' is projected as 66,108 MU by FY 23 and 1,58,325 MU by FY 40, with a Y-o-Y CAGR of 5.3% (Table 24). This demand forecast is at the consumer end, without the inclusion of T&D losses.

Table 24: Year-on-year policy scenario energy DF (in MU)

Particulars	FY 23	FY 24	FY 29	FY 34	FY 39	FY 40
Domestic	19,102	20,383	26,285	31,679	40,137	42,151
Commercial	5,880	6,350	9,253	13,320	18,938	20,269
Agricultural	15,680	16,154	18,458	21,102	24,064	24,688
Industrial	21,632	22,980	31,091	41,305	53,819	56,719
Institutional	4,012	4,259	5,492	6,725	7,958	8,205
EV demand (+)	50	83	759	3,453	8,443	9,874
RTPV generation (–)	248	290	637	1,396	3,061	3,581
Energy demand	**66,108**	**69,920**	**90,702**	**1,16,189**	**1,50,299**	**1,58,325**
T&D loss (MU)	8,529	8,905	10,792	12,834	15,294	15,833
Energy requirement	**74,637**	**78,825**	**1,01,494**	**1,29,023**	**1,65,593**	**1,74,158**

The DISCOM-wise and category-wise demand projections are provided in the Appendix. We projected demand growth for APSPDCL, APEPDCL, and APCPDCL at a CAGR of 4.5%, 5.3%, and 6.4%, respectively. The T&D loss trajectory was overlaid on the energy demand, thereby obtaining the Y-o-Y total energy requirement of the state (Table 24).

The overall energy requirement, including T&D losses, is presented in Table 24. As per the results, the energy requirement increases from 74,637 MU by FY 23 to 1,74,158 MU by FY 40, and the share of APSPDCL, APEPDCL, and APCPDCL in total energy requirement is 35%, 38%, and 27%, respectively. Table 25 shows each DISCOMs' Y-o-Y energy requirement.

Table 25: Energy requirement (in MU) for each DISCOM

DISCOM	FY 23	FY 24	FY 29	FY 34	FY 39	FY 40
APSPDCL	29,449	30,786	37,741	46,369	58,038	60,785
APEPDCL	28,419	30,072	39,272	50,199	63,715	66,794
APCPDCL	16,769	17,967	24,481	32,454	43,840	46,579
Total	**74,637**	**78,825**	**1,01,494**	**1,29,023**	**1,65,593**	**1,74,158**

Traditionally, the state's energy demand has been characterised by the occurrence of an annual peak power demand, particularly during morning hours. We analysed the 8,760 hourly load curve of the state for FY 22 (Figure 3). The results revealed that the peak demand of 11,883 MW occurred on 28 March 2022 at 12 PM.

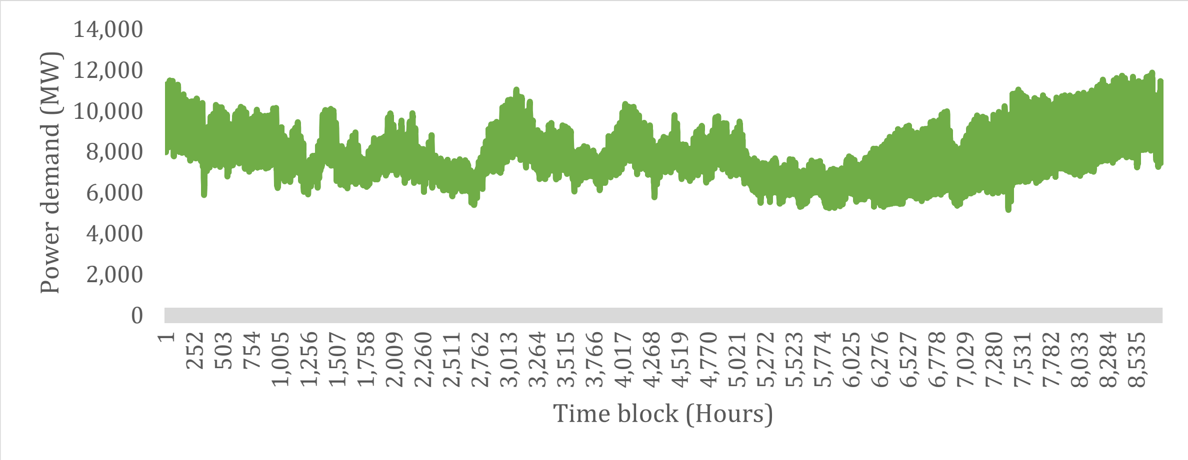

Figure 3: 8760 hourly load curve of FY 22

Assuming a similar pattern, we extrapolated the 8,760 hourly load curve till FY 40 and consolidated the Y-o-Y peak demand (Table 26). The anticipated peak demand of 12,159 MW in FY 23 increased significantly to 28,372 MW by FY 40, with a CAGR of 5.1%.

Table 26: Year-on-year peak demand

FY	FY 23	FY 24	FY 29	FY 34	FY 39	FY 40
Peak demand (MW)	12,159	12,841	16,534	21,019	26,977	28,372

Over the past 5 years, the demand for electrical energy in the state has steadily increased. In a BAU scenario including T&D losses, the energy demand forecast for FY 40 is 1,94,847 MU. Although EV introduction may increase the demand overall, initiatives like RTPV adoption and energy-saving endeavours in the residential, commercial, and agriculture sectors would reduce demand. Considering the impact of several policy levers, we anticipate that by FY 40, the state demand will decrease to 1,74,158 MU in the policy scenario.

4. Demand–Supply Planning by 2040

A comprehensive supply planning that takes into consideration various combinations of the energy mix is necessary to meet the projected energy demand smoothly. Therefore, this section examines the RE supply from FY 23 to FY 40, taking into account different scenarios of RE development, the gradual reduction of thermal power plants, and the need for utility-scale energy storage systems to balance the grid during periods of high energy demand.

By evaluating these factors and considering potential scenarios, we identified the most favourable pathways for achieving a sustainable and reliable energy system in the state.

4.1 Methodology

The additional supply capacity requirement is derived by comparing the peak power demand in each year (FY 23–FY 40) with the FY 23 power supply availability (estimated on the basis of operational parameters of each available generation source).

Table 27: Demand–supply comparison for future supply planning

FY	Peak power demand (MW)	FY 23 supply in peak hour (MW)	Power deficit (MW)
FY 24	**12,841**	**13,085**	**−244**
FY 25	13,540	13,085	454
FY 26	14,242	13,085	1,156
FY 27	14,972	13,085	1,887
FY 28	15,789	13,085	2,703
FY 29	**16,534**	**13,085**	**3,449**
FY 30	17,384	13,085	4,298
FY 31	18,244	13,085	5,15
FY 32	19,135	13,085	6,049
FY 33	20,054	13,085	6,969
FY 34	**21,019**	**13,085**	**7,934**
FY 35	22,013	13,085	8,928
FY 36	23,165	13,085	10,080
FY 37	24,381	13,085	11,296
FY 38	25,648	13,085	12,562
FY 39	**26,977**	**13,085**	**13,891**
FY 40	28,372	13,085	15,287

Table 27 indicates that the supply availability in FY 23 is sufficient to meet the peak power demand till FY 24, without any power deficit. However, from FY 25, the state will begin observing a peak power deficit. The deficit is projected to be 15,287 MW by FY 40, with energy demand exceeding the available supply. The deficit and surplus power in this comparison, thus, forms the basis for the Y-o-Y development of energy generation and storage capacity from FY 23 to FY 40.

4.2 Supply Planning Scenarios (FY 23–FY 40)

The following supply scenarios (Table 28) were considered to plan the required generation and storage capacity.

Table 28: Details of the scenarios

SI. No.	Scenario		Details
1	**State standard scenario**		1. Analysis was performed on the basis of data sourced from the stakeholders and the proposed capacity to meet the deficit. 2. Capacity addition of 20,219 MW and retirement of 3,562 MW of thermal and other resources, as per the state report.
2	**Aggressive RE scenario**		1. Higher RE integration by reducing generation from thermal capacity. 2. Thermal plants will operate with different PLFs. 3. Retirement of 188 MW of other RE resources.
	2a	**40% PLF scenario**	Both state-owned and CGS thermal plants to operate at 40% PLF.
	2b	**50% PLF scenario**	Both state-owned and CGS thermal plants to operate at 50% PLF.
	2c	**60% PLF scenario**	Both state-owned and CGS thermal plants to operate at 60% PLF.
	2d	**40% state-owned scenario**	Only state-owned thermal plants to operate at 40% PLF.
3	**Economical scenario**		Plants with tariffs above INR 5/kWh were identified and considered for cost optimisation.

4.3 Scenario 1: State Standard Scenario

4.3.1. Operational Parameters

The installed capacity, PLFs, and plant availability factors for thermal, nuclear, and biomass plants were considered as 65%–85%, as suggested by the Andhra Pradesh Power Coordination Committee (APPCC). The auxiliary consumption of power plants was considered as per the CEA standards—9% for a unit capacity of below 500 MW and 6.5% for a unit capacity of above 500 MW (CERC, 2009). The Appendix provides the details of all thermal, nuclear, and hydro capacities considered under the scenarios. The hourly generation profiles for wind were derived from

National Renewable Energy Laboratory's (NREL's) resource availability data and for solar, the generation profiles were obtained using CSTEM PV[7] tool.

4.3.2. Capacity Addition Plans

In this scenario, the state has planned a new project line-up from FY 23 to FY 40, which includes capacity additions of 16,595 MW from both conventional and RE sources. The scenario considers the addition of two state-owned thermal plants (Dr Narla Tata Rao Thermal Power Station [NTTPS] Unit 8: 800 MW and Sri Damodaram Sanjeevaiah Thermal Power Plant [SDSTPS] Unit 3: 800 MW) and a 625-MW unit from Sembcorp in FY 23. The commissioning of the Kovvada nuclear power plant of 7,248 MW is expected by FY 31, with 50% of its capacity (3,624 MW) considered until FY 40. Additional nuclear capacity from the upcoming projects (Kaiga [2 × 700]/ Kudankulam [4 × 1000]/Jaitapur [6 × 1650]) of 3,624 MW is considered between FY 36 and FY 40 for the analysis (Press Information Bureau, Government of India and Department of Atomic Energy, 2019). For the RE capacity, the state has signed a power purchase agreement (PPA) with Solar Energy Corporation of India (SECI) to procure solar power of 7,000 MW for the next 25 years in three tranches, starting from FY 25 (APERC, 2021).

4.3.3. Capacity Retirement Plans

The retirement plans for thermal power plants in the state were analysed on the basis of the existing operational performance and PPA expiry. The following are the retirement plans:

1. **State thermal power plants**: Rayalaseema Thermal Power Station (RTPS) Unit 1–2 (210 MW *2) and NTTPS Unit 1–6 (210 MW* 6) are scheduled for phased retirement from FY 31 to FY 34.
2. **Central thermal power plants**: Simhadri Unit 1 (state share: 461 MW), Ramagundam Unit 3 (state share: 69 MW), and Talcher Unit 3 (state share: 176 MW) thermal power plants are also being considered for retirement.
3. **Private thermal power plants**: Sembcorp Unit 2 (625 MW) in FY 35 and Unit 1 (231 MW) in FY 39 are being considered for retirement.

These plants are scheduled for retirement according to the state's guidelines and standards. The retirement process is likely to be influenced by various factors, such as plant age, operational efficiency, environmental considerations, and capacity additions from new projects. Other than the aforementioned plants, a few other plants in other resource categories are being considered for retirement, as per the state's data. . The source-wise capacity addition and retirement plan is presented in the Appendix. Figure 4 shows the new capacity addition and retirement from FY 23 to FY 40.

[7]The CSTEM PV platform is a web-based tool designed to facilitate the prefeasibility analysis of utility-scale solar photovoltaic (PV) plants. It provides a techno-economic perspective, allowing users to evaluate the viability and profitability of solar PV projects.

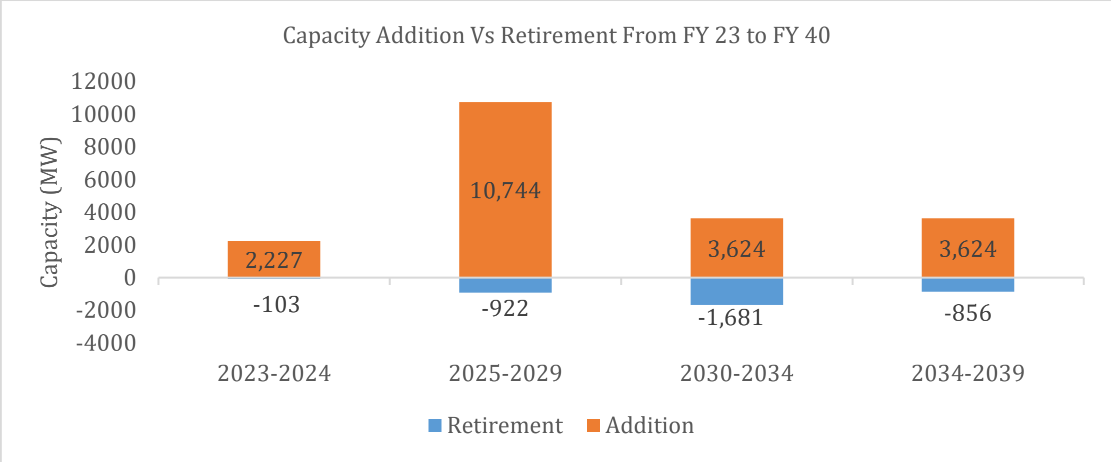

Figure 4: Capacity addition and retirement details

4.3.4 Demand Vs Supply Analysis

Installed Capacity and Energy Mix

Our analyses revealed that the state will experience an energy gap from FY 23 onwards, even after considering both state's and our proposed capacity additions. The state has planned for 9.3 GW of RE capacities, which include 7 GW of solar (PPA signed with SECI), 1.1 GW of wind, and 1.1 GW of hydro, with phased deployment between FY 25 and FY 27. However, due to the higher projected demand, the state will require additional capacities to cater the demand. CSTEP has suggested additional requirement of solar, wind, and hydro of 6,600 MW, 8,800 MW, and 2,100 MW, respectively, totalling to 17,500 MW by FY 40. The higher capacity of wind is proposed due to its higher potential in the state (44 GW). Table 29 and Table 30 list the installed capacity and energy mix of all resources from FY 22 to FY 40.

Table 29: Source-wise installed capacity (in MW)

Installed capacity (MW)	Existing capacity (FY 22)	FY 24	FY 29	FY 34	FY 39	FY 40
Solar	3,609	3,756	11,153	12,003	15,503	17,503
Wind	4,191	3,768	5,193	7,843	11,843	13,743
Large hydro	1,848	1,848	3,288	4,138	5,038	5,138
Other NCESs	290	208	155	153	153	153
Sub-total RE (A)	***9,939***	***9,580***	***19,788***	***24,137***	***32,537***	***36,537***
Thermal + gas	13,882	10,569	9,862	8,182	7,326	7,326
Nuclear	132	132	132	3,624	7,248	7,248
Sub-total (B)	***14,015***	***10,701***	***9,994***	***11,806***	***14,574***	***14,574***
Total (A + B)	**23,953**	**20,281**	**29,783**	**35,943**	**47,111**	**51,111**

Table 30: Source-wise energy mix (in MU)

Energy generation (MU)	Existing supply (FY 22)	FY 24	FY 29	FY 34	FY 39	FY 40
Solar	6,306	6,563	18,948	20,433	26,549	30,044
Wind	10,571	9,504	13,098	19,782	29,871	34,663
Large hydro	13,760	13,760	24,482	30,812	37,513	38,258
Other NCESs	1,730	1,240	921	913	913	913
Sub-total RE (A)	***32,368***	***31,068***	***57,449***	***71,940***	***94,846***	***1,03,878***
Thermal + gas	1,03,368	78,694	73,431	60,922	54,551	54,551
Nuclear	986	986	986	26,984	53,969	53,969
Sub-total (B)	***1,04,354***	***79,680***	***74,417***	***87,906***	***1,08,520***	***1,08,520***
Total (A + B)	***1,36,722***	***1,10,747***	***1,31,865***	***1,59,846***	***2,03,366***	***2,12,398***
Energy demand	**72,942**	**78,825**	**1,01,494**	**1,29,023**	**1,65,593**	**1,74,158**

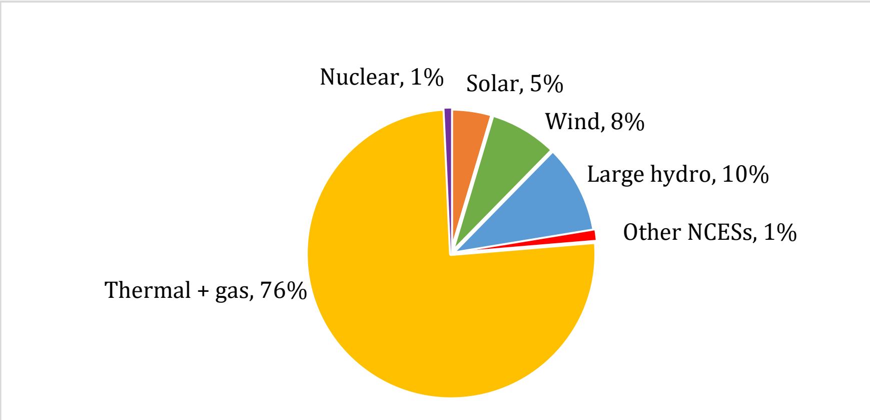

Figure 5: Source-wise percentage share in the energy mix in FY 22

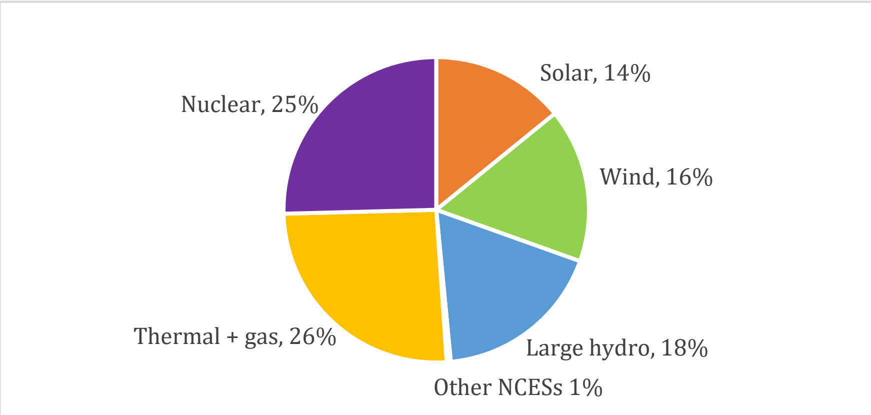

Figure 6: Source-wise percentage share in the energy mix in FY 40

The state is expected to significantly increase its RE share, with a 49% in the overall energy mix by FY 40 (Figure 6). This signals a substantial shift towards cleaner and more sustainable energy sources.

4.3.5. Storage Analysis

With the huge integration of intermittent RE share of about 49% in the supply mix, the storage requirement is inevitable. We analysed 8760 hours of all years along with the peak day and assessed the demand–supply gap and balance requirement. In a peak day, the energy demand exceeds the available supply from 2 AM to10 AM (9 hours). However, there is excess supply from 11 AM to 12 PM (15 hours) due to higher solar and wind generation during the respective periods. Figure 7 illustrates the peak demand and supply in FY 40.

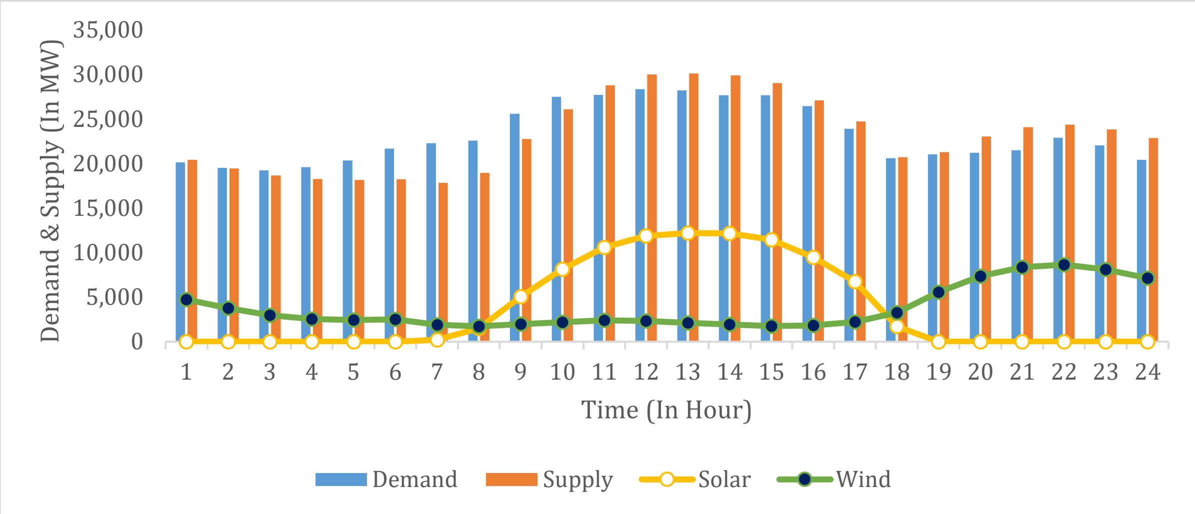

Figure 7: Peak demand and supply in FY 40 (in MW)

To cater to the deficit, we projected a storage capacity of 11 GWh (0.83 GW) by FY 23, with a gradual increase to a cumulative of 2,014 GWh (i.e. 7.3 GW of storage capacity) by FY 40. During FY 27, the state has proposed to operationalise the 1.35 GW of Upper Sileru PSP. The state would require additional storage capacity of 6 GW to cater the demand from FY 27 to FY 40.

4.4 Scenario 2: Aggressive RE Scenario

The nation's ambitious target of achieving 50% of electric installed capacity from non-fossil sources by FY 30 demonstrates a strong commitment to transitioning towards a sustainable and clean energy future. In this context, we considered an aggressive RE scenario, wherein all thermal plants, including IPPs and CGSs, will operate under 40% PLF. A sensitivity analysis was conducted with respect to the PLFs of thermal power plants. Lower PLF values may accelerate the retirement of thermal power plants and create space for more solar and wind plants. However, it is important to ensure that the grid infrastructure and RE technologies can meet the demand during low PLF periods to maintain a reliable power supply.

4.4.1. Considerations

The capacity addition was considered the same as in the state standard scenario. However, the retirement capacity will only apply to resources other than thermal plants. This means that while the capacity addition of 20,219 MW by FY 36 remains unchanged, the retirement was considered only for 188 MW of non-conventional sources. Table 31 shows the retiring capacity from FY 23 to FY 31.

Table 31: Retirement of plants from FY 23 to FY 31

SI. No	Plant name	Capacity (MW)	Date of decommission
1	Biomass and bagasse	79	2023
2	Biomass, municipal solid waste, small hydro, and industrial waste	25	2024
3	Bagasse and small hydro	36	2025
4	Industrial waste and biomass	10	2026
5	Biomass	2	2027
6	Biomass, industrial waste, and small hydro	15	2028
7	Bagasse	20	2029
8	Small hydro	1	2031

Installed Capacity and Energy Mix

The state's thermal installed capacity is reported to be 10,484 MW, including both CGSs and IPPs. This analysis assumed that all thermal power plants will operate under 40% PLF. The results revealed that the state will face a peak hour energy gap from FY 23 to FY 40, despite considering the capacity additions by both conventional and RE sources. To mitigate this energy gap, CSTEP has suggested additional requirement of solar, wind, and hydro installed capacity of 8,150 MW, 11,250 MW, and 2,200 MW, respectively, totalling to 21,600 MW by FY 40. The analysis indicated a higher integration of RE under this scenario. Table 32 lists the installed capacity, whereas Table 33 lists the energy mix of all resources from FY 22 to FY 40.

Table 32: Source-wise installed capacity (in MW)

Installed capacity (MW)	Existing capacity (FY 22)	FY 24	FY 29	FY 34	FY 39	FY 40
Solar	3,609	3,756	12,803	14,553	16,803	19,053
Wind	4,191	3,768	9,043	11,043	13,793	16,193
Large hydro	1,848	1,848	4,988	5,238	5,238	5,238
Other NCESs	290.46	208	155	153	153	153
Sub-total RE (A)	***9,938***	***9,580***	***26,988***	***30,987***	***35,987***	***40,637***
Thermal + gas	13,882	10,569	10,569	10,569	10,569	10,569
Nuclear	132	132	132	3,756	7,380	7,380
Sub-total (B)	***14,015***	***10,701***	***10,701***	***14,325***	***17,949***	***17,949***
Total (A + B)	**23,953**	**20,281**	**37,689**	**45,312**	**53,936**	**58,586**

Table 33: Source-wise energy mix (in MU)

Energy generation (MU)	Existing capacity (FY 22)	FY 24	FY 29	FY 34	FY 39	FY 40
Solar	6,306	6,563	21,831	24,889	28,821	32,753
Wind	10,571	9,504	22,809	27,853	34,789	40,842
Large hydro	13,760	13,760	37,141	39,002	39,002	39,002
Other NCESs	1,730	1,240	921	913	913	913
Sub-total RE (A)	***32,368***	***31,068***	***82,701***	***92,657***	***1,03,525***	***1,13,511***
Thermal + gas	1,03,368	37,032	37,032	37,032	37,032	37,032
Nuclear	986	986	986	27,970	54,954	54,954
Sub-total (B)	***1,04,354***	***38,018***	***38,018***	***65,003***	***91,987***	***91,987***
Total (A + B)	**1,36,722**	**69,086**	**1,20,719**	**1,57,660**	**1,95,512**	**2,05,497**

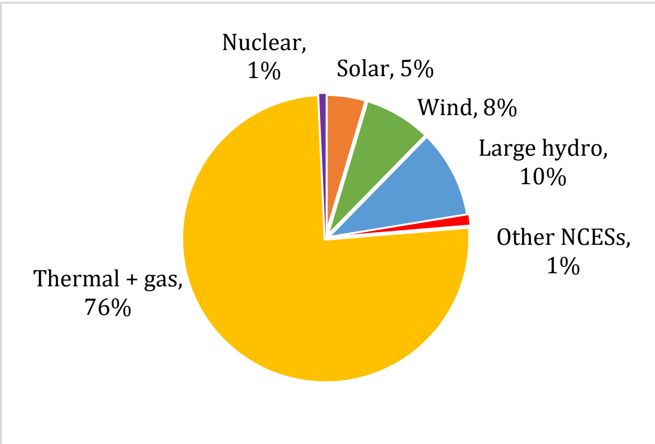

Figure 8: Source-wise percentage share in the energy mix in FY 22

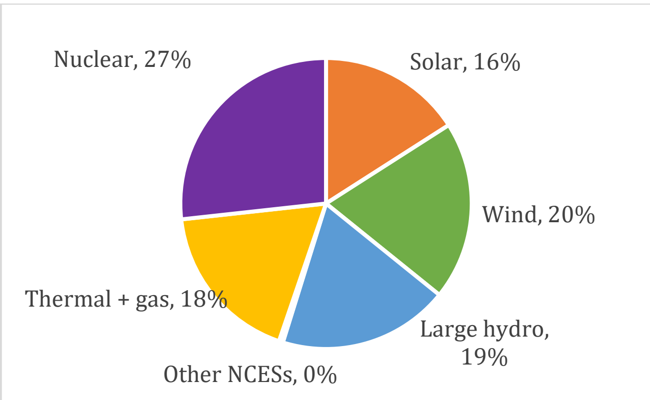

Figure 9: Source-wise percentage share in the energy mix in FY 40

When thermal power plants operate at 40% PLF, lower electricity is generated from fossil fuels and higher from RE sources, such as solar, wind, and hydro. This would help the nation fulfil its objective by FY 30. As per the analysis, the state can achieve a 55% share of RE in the overall energy mix by FY 40 (Figure 9). This indicates significant progress towards a more sustainable and clean energy system.

4.4.2. Storage Analysis

The peak-day analysis revealed that energy demand exceeded the available supply from 2 AM to10 AM (9 hours) and from 6 PM to 7 PM (1 hour). However, an excess supply occurred from 11 AM to 5 PM (7 hours) and 7 PM to 1 AM (7 hours) due to higher solar and wind generation during the respective periods. Figure 10 depicts the peak demand and supply in FY 40.

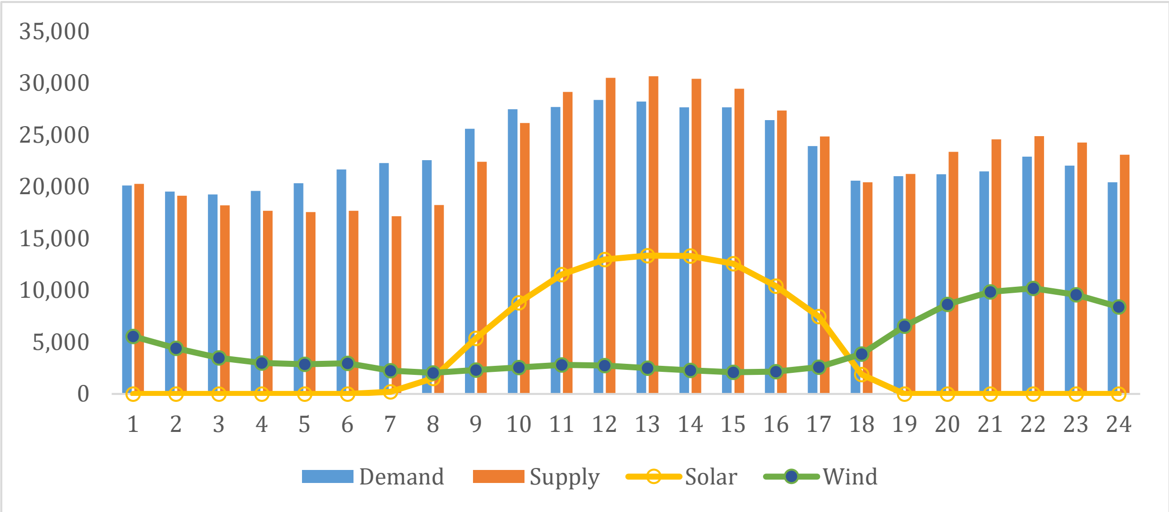

Figure 10: Peak demand and supply in FY 40 (in MW)

To address the demand–supply gap created due to suboptimal operation of thermal power plants, we projected a storage capacity of 6,751 GWh (4.7 GW) by FY 23 with a gradual increase to a cumulative of 9,703 GWh (i.e. 8.29 GW of storage capacity) by FY 40. This indicates the requirement for significant investments in energy storage technologies.

4.4.3. Sensitivity Analysis

The sensitivity analysis was performed to assess the impact of different PLF values of thermal power plants on the growth of RE. By varying the PLF value, the analysis can determine the optimal utilisation of thermal power plants while maximising the integration of RE into the grid.

We analysed scenarios with varying PLFs between 50% and 60% for the overall installed capacity of thermal plants, as well as a scenario considering only the state-owned thermal plants operating at 40% PLF. Table 34 illustrates the energy mix for all scenarios in FY 40.

Table 34: Sensitivity analysis for scenario-wise energy mix in FY 40 (in MU)

Energy (MU)	Scenario 2a: 40% PLF	Scenario 2b: 50% PLF	Scenario 2c: 60% PLF	Scenario 2d: 40% PLF (state-owned)
Solar	32,753	29,607	26,899	28,559
Wind	40,842	35,420	29,745	30,375
Large hydro	39,002	39,002	39,002	39,002
Other NCES	913	913	913	913

Total RE (A)	***1,13,511***	***1,04,942***	***96,559***	***98,849***
% of RE	55%	51%	47%	48%
Thermal	37,032	46,290	55,549	52,637
Nuclear	54,954	54,954	54,954	54,954
Total Non-RE (B)	***91,987***	***1,01,245***	***1,10,503***	***107,592***
% of Non-RE	45%	49%	53%	52%
Grand total (A + B)	**2,05,497**	**206,187**	**2,07,062**	**206,441**
Storage (GW)	**8.3**	**7.3**	**6.4**	**6.7**
Storage (MU)	**2,867**	**2,025**	**1,376**	**1,585**

The analysis revealed that operating all thermal plants at 40% PLF would result in the highest share of RE in the energy mix and could be a favourable option to meet the nation's target. However, it is important to consider the higher storage capacity requirements of 8.3 GW to address the deficit in the energy supply by FY 40.

The scenario where thermal plants operate at 60% PLF would require a lower storage capacity of 6.4 GW to address the deficit by FY 40. Further, it is more feasible to attain the storage capacity requirement. Considering the feasibility and practicality of implementing the required storage infrastructure, the 60% PLF scenario for thermal plants may be a more viable option.

4.5 Scenario 3: Economical Scenario

The objective of this scenario is to identify power plants with higher electricity generation costs (tariffs above INR 5/kWh) and replace them with lower-cost RE sources for cost optimisation.

4.5.1. Considerations

The capacity addition and retirement plans remain the same as incorporated in Scenario 2. Additionally, this scenario considered the replacement of plants with a tariff of above INR 5/kWh—1,947-MW capacity in total—from FY 23. Table 35 lists the details of plants with a higher generation cost.

Table 35: Details of plants with a higher generation cost

Si. No	Plant name	Capacity (MW)	Cost (INR/kWh)
1	RTPS Unit 1 & 2	420	5.34
2	RTPS Unit 3 & 4	420	5.19
3	RTPS Unit 5	210	5.52
4	RTPS Unit 6	600	6.13
5	Kudgi TPS	211	6.79
6	NTECL Vallur	86	5.41

Installed Capacity and Energy Mix

To understand the energy requirement, we assessed the generation on the peak day to determine the maximum energy demand and plan for adequate supply. Over and above the 9.5 GW from the state's RE plans, CSTEP has proposed 17.9 GW to meet the deficit by FY 40. Table 36 lists the installed capacity, while Table 37 lists the energy mix of all resources from FY 22 to FY 40.

Table 36: Source-wise installed capacity (in MW)

Installed capacity (MW)	Existing capacity (FY 22)	FY 24	FY 29	FY 34	FY 39	FY 40
Solar	3,609	3,756	12,653	13,853	15,853	17,703
Wind	4,191	3,768	8,393	9,593	12,093	13,893
Large hydro	1,848	1,848	4,188	4,288	5,088	5,238
Other NCESs	290	208	155	153	153	153
Sub-total RE (A)	***9,938***	***9,580***	***25,388***	***27887***	***33,187***	***36,987***
Thermal + gas	13,882	8,622	8,622	8,622	8,622	8,622
Nuclear	132	132	132	3,756	7,380	7,380
Sub-total (B)	***14,014***	***8,754***	***8,754***	***12,378***	***16,002***	***16,002***
Total supply (A + B)	**23,952**	**18,334**	**34,142**	**40,265**	**49,189**	**52,989**

Table 37: Source-wise energy mix (in MU)

Energy generation (MU)	Existing capacity (FY 22)	FY 24	FY 29	FY 34	FY 39	FY 40
Solar	6,306	6,563	21,569	23,666	27,161	30,394
Wind	10,571	9,504	21.169	24,196	30,501	35,041
Large hydro	13,760	13,760	31,184	31,928	37,885	39,002
Other NCESs	1,727	1,240	921	913	913	913
Sub-total RE (A)	***32,365***	***31,068***	***74,842***	***80,703***	***96,461***	***1,05,350***
Thermal + gas	1,03,365	64,196	64,196	64,196	64,196	64,196
Nuclear	986	986	986	27970	54,954	54,954
Sub-total (B)	***1,04,351***	***65,182***	***65,182***	***92,166***	***1,19,151***	***1,19,151***
Total supply (A + B)	**1,36,716**	**96,250**	**1,40,024**	**1,72,870**	**2,15,611**	**2,24,501**

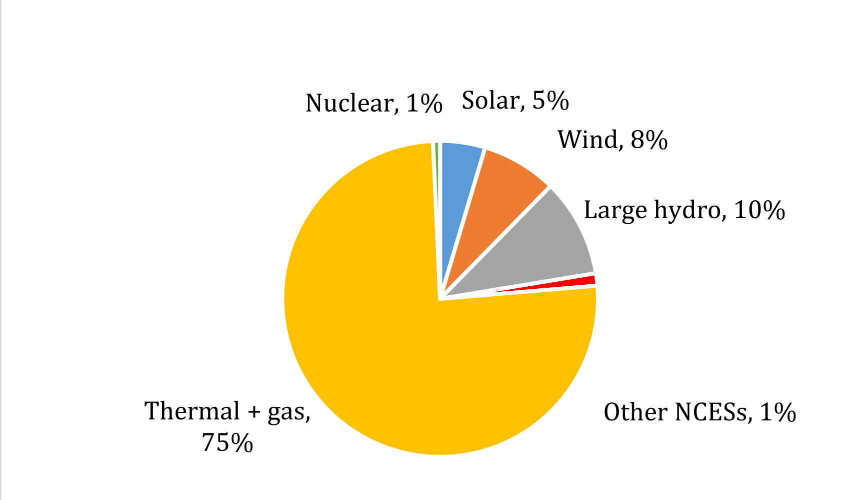

Figure 11: Source-wise percentage share in the energy mix in FY 22

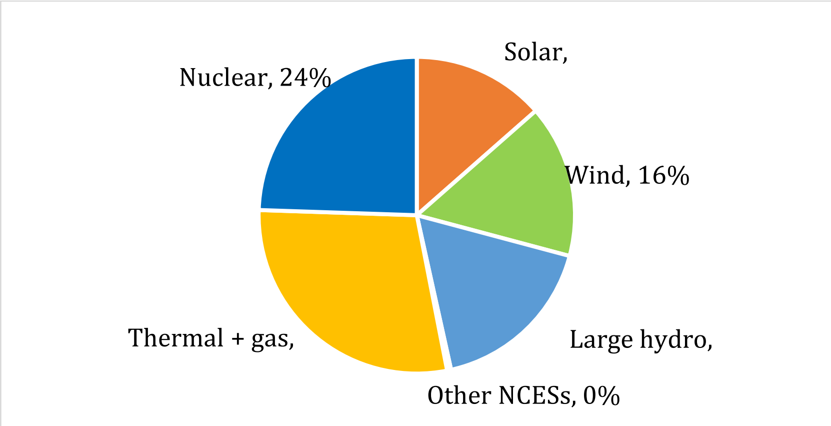

Figure 12: Source-wise percentage share in the energy mix in FY 40

The state is expected to gradually increase its RE share, with a 47% share in the overall energy mix by FY 40 (Figure 12). This is attributable to the less retirement of thermal plants, resulting in a lower integration of RE sources in the energy mix.

4.5.2. Storage Analysis

According to the storage analysis, the energy demand exceeded the available supply from 2 AM to 10 AM (8 hours). However, excess supply was observed from 11 AM to 1 AM (16 hours) due to higher solar and wind generation during the respective periods. Figure 13 depicts the peak demand and supply in FY 40.

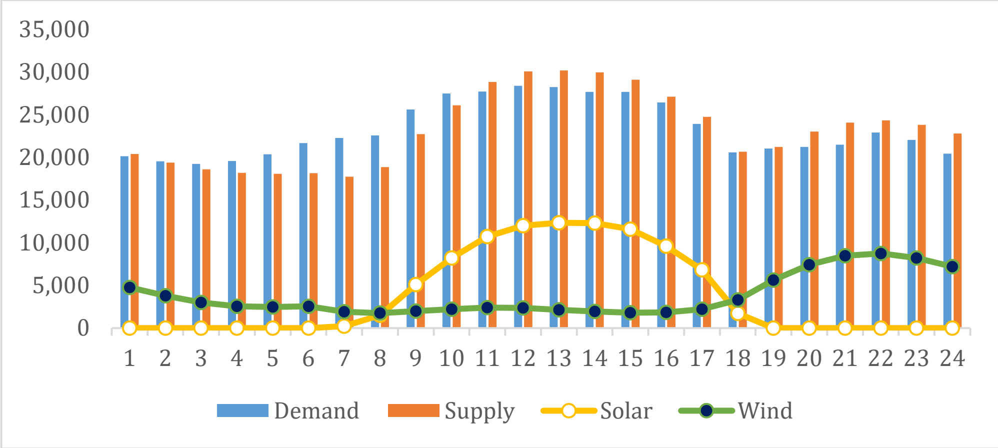

Figure 13: Peak demand and supply in FY 40

To cater to the energy demand–supply gap, we projected a storage capacity of 2,795 GWh (3.81 GW) by FY 23. This will gradually increase to cumulative of 4,723 GWh on a peak day (i.e. 7.40 GW of storage capacity) by FY 40, thereby lowering the investment requirement in energy storage compared with other scenarios.

5. Impact of RE Addition on DISCOMs' costs

For clean energy transition, the state power sector is required to integrate higher RE into the system. The cost of generating electricity from renewable sources has been declining in recent years. This can impact the overall cost of electricity procurement for DISCOMs and potentially lead to changes in tariff rates. In this study, we analysed the unit cost of power for different sources from FY 23 to FY 40.

5.1 Methodology

The approach considers the weighted average cost for all resources and maintains the same tariff for thermal, nuclear, and hydro resources until FY 40. However, resources such as solar, wind, and other NCESs have their existing average weighted tariff considered until FY 29, with a cost revision to INR 2.49/kWh (SECI tariff for AP from 2024 onwards) starting from FY 30. Table 38 shows the unit cost of power from FY 23 to FY 40.

Table 38: Unit cost of power (in INR) from FY 23 to FY 40

Source	FY 23 to FY 29	FY 30 to FY 40
Thermal + gas	4.48	4.48
Nuclear	3.38	3.38
Hydro	1.78	1.78
Solar	4.28	2.49
Wind	4.63	2.49
Other NCESs	4.58	2.49

5.2 Energy Cost and Storage Analysis

The analysis suggested that compared with other scenarios, the scenario with an increased RE penetration has economic advantages. In FY 40 where all thermal power plants operate at 40% PLF, the power purchase cost drops to 27% compared with the current tariff. However, supplying RE power throughout the year remains challenging, and excess generation during the peak season could be utilised through a storage system. Table 39 lists the unit cost of power to DISCOMs under different scenarios.

Table 39: Source-wise unit cost of power (in INR/kWh)

Source	Description	2023	State-specific	40% PLF	50% PLF	60% PLF	40% PLF (state-owned)	Economical
			2040	2040	2040	2040	2040	2040
Thermal + gas	Energy supplied (MU)	78,694	54,551	37,032	46,290	55,549	52,637	64,196
	Total cost (INR/kWh)	4.48	4.48	4.48	4.48	4.48	4.48	4.13
Nuclear	Energy supplied (MU)	986	53,969	54,954	54,954	54,954	54,954	54,954
	Total cost (INR/kWh)	3.38	3.38	3.38	3.38	3.38	3.38	3.38
Solar	Energy supplied (MU)	6,563	30,044	32,753	29,607	26,899	28,559	30,394
	Total cost (INR/kWh)	4.28	2.49	2.49	2.49	2.49	2.49	2.49
Wind	Energy supplied (MU)	9,504	34,663	40,842	35,420	29,745	30,375	35,041
	Total cost (INR/kWh)	4.63	2.49	2.49	2.49	2.49	2.49	2.49
Hydro	Energy supplied (MU)	13,760	38,258	39,002	39,002	39,002	39,002	39,002
	Total cost (INR/kWh)	1.67	1.67	1.67	1.67	1.67	1.67	1.67
Other NCESs	Energy supplied (MU)	1,730	913	913	913	913	913	913
	Total cost (INR/kWh)	4.58	2.49	2.49	2.49	2.49	2.49	2.49
Storage	Energy supplied (MU)	11	2,014	9,703	4,439	1,495	1,585	4,723
	Total cost (INR/kWh)	3.73	3.73	3.73	3.73	3.73	3.73	3.73
PPA cost	**Total energy supplied (MU)**	**1,11,237**	**2,12,398**	**2,05,497**	**2,06,187**	**2,07,062**	**2,06,441**	**2,24,501**
	(INR/kWh)	**4.14**	**3.11**	**3.01**	**3.07**	**3.13**	**3.11**	**3.08**

Regarding storage systems, the state has the significant advantage of having a potential of 33.2 GW of pumped storage plants (PSPs). We assume that the current levelised cost of PSPs will decrease from INR 6.75–7/kWh to INR 3.75–4/kWh by FY 40 due to the reduced cost of RE sources. The lower operational costs contribute to the feasibility of the PSP project. Further, pumped storage facilities have a long lifespan of 50 years and do not require fuel consumption for operation, resulting in reduced operating expenses.

The levelised cost of battery energy storage systems (BESSs) is INR 6–6.25/kWh, which is similar to levelised cost of PSPs. However, the cost reduction in lithium-ion batteries has been significant, leading to a more competitive landscape for BESS. Therefore, the levelised cost of BESS is estimated to be around INR 3–3.25/kWh in FY 40. These systems have a high round-trip efficiency and release energy with minimal losses. Other advantages include being more compact and flexible, thereby allowing for installation in various locations and providing decentralised energy storage solutions. However, the lifespan of lithium-ion batteries typically ranges from 10 to 20 years, and operational costs include maintenance and battery replacement expenses. Furthermore, the cycling of batteries, which involves charging and discharging, can lead to gradual degradation of their capacity and performance over time, affecting the operational efficiency of BESS.

In view of the above, we considered 75% of storage capacity to come from PSPs and remaining from BESS. The estimated overall cost to DISCOMs for providing continuous power while incorporating higher share of RE and storage is projected to be INR 3.01–3.13/kWh by FY 40. This cost is 24%–27% lower than the current PPA cost. This reduction in cost is a significant achievement and highlights the economic viability of transitioning to a cleaner and more sustainable energy mix.

5.3 Technology Assessment Framework for Bulk Energy Storage Technologies

To understand the feasibility of storage technologies for 2040, we developed a technology assessment framework (TAF) by applying the Technique for Order Preference by Similarity to Ideal Solution (TOPSIS) method on bulk storage technologies—PHS, compressed air energy storage (CAES), and hydrogen energy storage. A 100-MW 4-hour backup system was considered for PHS and CAES, while for hydrogen storage, a 100-MW and 10-hour backup system was considered.

To compare these technologies, we considered three scenarios with varying weightage assigned to the technical and economic impacts of these technologies. Of Scenario A (60:40, respectively), Scenario B (50:50, respectively), and Scenario C (75:25, respectively), a higher weightage was assigned to the technical impact of two scenarios (A and C). This is because we assumed that although the technical impact of emerging technologies (such as hydrogen) may be higher than that of mature technologies (such as PHS), the economic impact may be lower due to factors such as economies of scale, support of policies, project learnings with larger deployments at ground level, and a historic evolution in the market.

First, data on technical and economic characteristics (provided in the Appendix) of these technologies were collected through literature review. Ranks were generated from the collected data, which pertained to the years 2020 and 2030, by using TOPSIS. We then converted these ranks to points (0 to 100) by using suitable scales. Subsequently, scenario-wise strategic scores were generated by assigning weights to the rank-based points. Due to no or minor differences between the data sets (economic and technical characteristics) for 2020 and 2030, the overall ranks remained the same while applying TOPSIS for these two base years. Therefore, the ranks and strategic scores can be said to be representative of both years (Table 40).

Table 40: Scenario-wise ranks and strategic scores of bulk storage technologies (2020 and 2030)

Bulk storage technology	TOPSIS rank		Strategic score		
	Technical impact	Economic impact	Scenario A	Scenario B	Scenario C
PHS	1	3	73	66.5	83
CAES	3	1	60	66.5	50
Hydrogen	2	2	67	67	67

The strategic scores indicate that PHS clearly leads over CAES and hydrogen energy storage in two of the three scenarios, i.e. Scenario A and Scenario C. In Scenario A, PHS leads by 6 points over hydrogen energy storage and 13 points over CAES. In Scenario C, PHS leads by 16 points over hydrogen energy storage and 33 points over CAES. Only in scenario B, the three technologies are at a near-equal score. Thus, we can conclude that PHS is the most promising bulk storage technology, followed by hydrogen energy storage and CAES. On the basis of these results and considering that the strategic scores remain the same over the 10-year period (2020–2030), we can conclude that PHS would be the dominant bulk storage technology by 2030 and shall continue to be the most promising technology by 2040. Further, any alterations in ranks or strategic scores in the coming years will require significant growth of the emerging technologies (hydrogen energy storage and CAES) in the open market over the next 5 to 10 years.

6. Conclusions and Recommendations

This section discusses the foreseeable challenges in the state's power sector due to higher RE penetration and increased demand and suggests key measures in the generation and distribution sectors to address the same.

6.1 Generation Sector

By FY 24, the state will be able to adequately manage the electricity demand with the available generation capacity. However, the generation sector will start encountering challenges in meeting the peak and energy demand beyond FY 24. To bridge the demand–supply gap, additional capacity—mainly from RE to align with the energy transition and net-zero targets—is to be commissioned. However, the increased penetration of intermittent and variable RE will require certain measures to be put in place for seamless integration. These measures are discussed below.

6.1.1. Higher RE Integration

Our analysis indicated that the requirement of RE capacity in the state would be in the range of 32,887–40,637 MW under various supply scenarios. To commission the capacity of such magnitude, we recommend the state to adopt the following measures:

- Develop RE parks by conducting geographic-information-system (GIS)-based assessments and identifying suitable/feasible land parcels for setting up solar and wind plants.
- Conduct techno-economic feasibility of such RE parks by considering factors such as project costs, grid connectivity, and evacuation infrastructure requirements.

While the RE parks will help in catering to the demand within the state, it will also align with the Andhra Pradesh Renewable Energy Export Policy, 2020. The policy aims to facilitate the installation of 120 GW of RE capacity and provides a framework to export excess RE generation to other states. The proposed RE capacity, thus, aligns well with the state's objectives, emphasising the importance of RE integration.

6.1.2. Energy Storage

Further, for smooth RE integration into the state's grid, the development of grid-scale storage systems (PSPs and BESSs) is essential. Our analysis indicated that a storage capacity in the range of 6,390 MW to 8,292 MW will be needed by FY 40. To achieve this, suitable energy storage technologies should be selected by comprehensively evaluating project requirements, site suitability, construction period, grid integration capabilities, and long-term energy system planning. The GoAP has introduced the Andhra Pradesh Pumped Storage Power Promotion Policy-2022 to leverage the state's 33.2-GW pumped storage potential. While the state has already proposed the development of a 1,350-MW capacity of Upper Sileru PSP by FY 27, it is essential to consider a diversified approach to meet the remaining storage requirements (NREDCAP, 2022). We suggest expediting the commissioning of Upper Sileru PSP and planning for an additional (4800–6200 MW) PSP capacity in the state. The remaining capacity can be planned as battery storage due to its economic viability and decentralisation features. By diversifying storage technologies, including both PSPs and BESSs, the state can leverage the unique advantages offered by each technology, resulting in a more reliable, efficient, and sustainable energy system.

6.1.3. Optimisation of Coal Assets

As per our analysis, the availability of RE plants with a cheaper cost will make thermal power plants with a variable cost of INR 5 per unit or above unviable. With the advancement towards a more environmentally friendly energy mix, AP requires optimisation of its current thermal assets. For this, we recommend the following measures for the state:

- Opt for thermal–RE bundling and procure RE from either a co-located plant or plants at a new location to reduce the tariffs and increase the competitiveness of thermal plants (MoP, 2022).
- Consider selling power generated by thermal plants through an open access mechanism directly to the energy-intensive industrial consumers. This is in the context of the envisaged backing down of thermal power due to the availability of cheaper RE.
- Implement pollution control technologies, such as advanced Flue gas desulfurisation, for thermal plants for complying with environmental norms.
- Perform techno-economic feasibility of the plants to determine the retirement term.

6.1.4. Allocation from the Proposed Kovvada Nuclear Plant

Being a zero-emission clean energy source, the Kovvada nuclear plant (7,248 MW) can act as an optimum choice for thermal plant replacement in the state. Because of providing flexibility to higher RE penetration, the plant has helped in reducing the storage requirement (as per our analysis) considerably in the state. In this context and on the basis of our analysis, we suggest the state to implement the following measures:

- Expedite the commissioning of the Kovvada nuclear plant in the state by FY 31,
- Allocate at least 50% of the plant's capacity (3,624 MW) to the state by FY 31,
- Allocate an additional nuclear capacity of 3,264 MW from the upcoming units of projects, such as Kaiga, Kudankulam, and Jaitapur, by FY 36.

6.2 Distribution Sector

The state's distribution sector is experiencing shifts due to changes in consumer behaviour and evolution in the demand side (EV and RTPV adoption, energy-efficient initiatives in residential, commercial, and agriculture sectors, and IP set solarisation). In this situation, DISCOMs must focus on having stable operational procedures and be future-ready for consumer energy security.

6.2.1. Increased Demand Due to EV Penetration

According to our analysis, the state will have 14.4 million EVs by FY 40, leading to the additional energy demand of 9,874 MU and posing unique challenges for DISCOMs. These challenges can be mitigated through the measures discussed below.

Demand Management

- Due to the high EV penetration, DISCOMs may face difficulties in tracking and monitoring the energy demand. Therefore, DISCOMs should leverage the funds offered by the central government's Revamped Distribution Sector Scheme (RDSS) for smart and prepaid meters to monitor EV demand.
- The metering infrastructure would also aid DISCOMs in introducing time-of-day (ToD) tariffs, which will further help in effectively managing peak demand by encouraging

consumers to charge EVs during off-peak hours and facilitating demand response measures.

Charging Infrastructure Deployment

The availability of adequate charging infrastructure is crucial to support the increased EV adoption. To ensure a robust charging infrastructure and meet the energy needs of EV owners effectively, we suggest the following for DISCOMs:

- Collaborate with government agencies—transport and energy departments—and private players to facilitate the deployment of EV charging stations.
- Develop a comprehensive framework backed with technical feasibility for developing charging infrastructure.

Grid Strengthening and Upgrades

The state should carry out 11-kV feeder-level load flow analyses in major cities to understand the technical feasibility of EV integration into the distribution grid. The studies will help in understanding the requirement of any strengthening and upgradation of feeders, distribution transformers, or sub-stations and the addition of new lines. One such load flow study performed by CSTEP in a selected feeder in Bengaluru city identified bottlenecks in the network due to EV penetration. Thus, DISCOMs should conduct similar studies to assess the feasibility of EV integration in the state.

6.2.2 Enhanced RTPV Adoption in the Distribution Grid

The state had set a target of installing 2-GW RTPV systems by FY 22. With the existing 115-MW RTPV capacity in place, we estimated that the state's RTPV target will be met only by FY 40 with a 2,271-MW capacity. However, the following measures should be undertaken for enhanced RTPV adoption in the state:

- Potential sites for installing RTPV systems can be identified through drone-based aerial photogrammetry.
- The state should develop suitable business models for specific consumer categories to ensure zero negative impacts on DISCOMs' finances.
- Distribution companies should conduct demand aggregation in a scientific and structured manner to reduce capital costs and, hence, requisite tariffs.
- Multilateral financing institutions should be brought in to reduce the cost and increase tenure financing for all consumer categories.

Such measures on RTPV adoption can also help in promoting EV integration in the state. The RTPV–EV integration can be further enhanced by allowing consumers to trade RTPV energy (peer-to-peer trading), and DISCOMs can conduct pilot studies on such decentralised energy market mechanisms.

6.2.3. Energy-Efficient Initiatives in Residential and Commercial Sectors

Adoption of energy-efficient initiatives in residential and commercial sectors will help in curbing future energy demand and deliver significant cost energy savings. Our analysis suggested that the state, by FY 40, will have energy savings of 13.4% (equivalent to 6,508 MU) through increased penetration of energy-efficient appliances in the domestic sector. Further, energy savings of 8.3%

(equivalent to 1,828 MU) will occur due to increased adoption of ECBC compliance in the commercial sector.

To capitalise on the analysed energy savings, we recommend the following in the state:

- Accelerate the market transformation of super-efficient appliances by implementing a scheme similar to Super-Efficient Equipment Programme (SEEP) and increase the supply of energy-efficient appliances in the market.
- Expedite the distribution of energy-efficient houses to the economically weaker section under the Navaratnalu Pedalandariki Illus scheme by FY 23 (Tasleem, 2017; Chauhan, 2023). Such schemes should be extrapolated to the other housing schemes of the state, which will aid in reducing the overall residential energy consumption.
- Launch a home energy rating system index to measure the EE of a household. The rating could be initially based on the energy-efficient appliances used in the household and further extrapolated to other parameters, such as energy-efficient infrastructure. Such a rating will assist homebuyers and sellers in determining the energy performance of a house, thereby impacting its sale value. This will eventually motivate consumers to adopt more energy-efficient practices.
- Mandate ECBC compliance across the commercial buildings in the state and extend it to residential buildings for greater energy savings.
- Provide guidelines for retrofitting the existing buildings to achieve energy savings in addition to ECBC compliance for new commercial buildings.
- Carry out training and capacity-building programmes on the implementation of energy-efficient and ECBC measures for all concerned stakeholders (architects, developers, engineers, and government officials). This will bring in a systemic change in the awareness of energy-efficient measures, leading to improved energy savings.

6.2.4. Solarisation and Energy-Efficient IP Sets in the Agriculture Sector

Our analysis revealed that the agriculture sector can reduce 40% of its energy consumption through the implementation of 2,11,458 energy-efficient IP sets and solarisation of 4,84,521 IP sets (requiring around 1.8 GW of solar capacity) by FY 40. Solarisation of IP sets will provide a reliable power supply to farmers and increase earnings through selling excess power to DISCOMs. The DISCOMs and GoAP will benefit from reduced T&D losses and subsidy burden. The state should, thus, promote the adoption of solar IP sets by incentivising farmers with favourable rates for the sale of solar power back to DISCOMs. Thus, implementing solar IP sets across the state will empower farmers, improve the financial health of DISCOMs, and foster sustainable agricultural practices.

Further, although the state has made considerable progress in implementing energy-efficient IP sets, it should plan further execution in a phased manner for better results. For this, we recommend the following:

- DISCOMs should conduct surveys to identify the exact pump capacity across all divisions/sub-divisions.
- The existing inefficient IP sets with a capacity of up to 5 HP should be replaced with those rated 4 stars by the Bureau of Energy Efficiency (BEE), whereas IP sets with a capacity of above 5 HP should be replaced with 5-star BEE-rated ones.

- The IP set replacement should be prioritised on the basis of their age, with older IP sets being replaced first for higher energy savings.
- DISCOMs should also continuously monitor hours of usage by IP sets to regulate the supply and avoid any wastage.
- DISCOMs need to conduct awareness campaigns on agriculture–water nexus to educate farmers on the nuances of using energy-efficient IP sets, water-use optimisation, and suitable cropping patterns for the given region.

Thus, this study for the AP power sector outlines a roadmap through which the state can provide an optimised, reliable, and sustainable power supply in the face of high RE integration, as well as play a crucial role in fulfilling India's Nationally Determined Goals.

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8. Appendix

Demand Forecast (DF)

DISCOM-wise transmission and distribution (T&D) loss trajectory

DISCOM	FY 23	FY 24	FY 29	FY 34	FY 39	FY 40
APSPDCL	12.8%	12.5%	11.5%	10.6%	9.7%	9.5%
APEPDCL	13.0%	12.8%	12.0%	11.2%	10.3%	10.1%
APCPDCL	13.1%	12.9%	12.3%	11.5%	10.7%	10.5%
State-level	**12.9%**	**12.7%**	**11.9%**	**11.0%**	**10.2%**	**10.0%**

Business-as-usual (BAU) DF for Andhra Pradesh Southern Power Distribution Company Limited (APSPDCL)

Parameter (MU)	FY 23	FY 24	FY 29	FY 34	FY 39	FY 40
Energy demand	27,535	29,118	37,987	48,808	62,197	65,251
T&D loss	3,511	3,654	4,538	5,178	6,010	6,182
Energy requirement	**31,046**	**32,772**	**42,372**	**53,986**	**68,207**	**71,433**

BAU DF for Andhra Pradesh Eastern Power Distribution Company Limited (APEPDCL)

Parameter (MU)	FY 23	FY 24	FY 29	FY 34	FY 39	FY 40
Energy demand	26,141	27,866	37,927	49,991	63,879	66,954
T&D loss	3,389	3,569	4,563	5,606	6,597	6,794
Energy requirement	**29,529**	**31,435**	**42,490**	**55,596**	**70,477**	**73,748**

BAU DF for Andhra Pradesh Central Power Distribution Company Limited (APCPDCL)

Parameter (MU)	FY 23	FY 24	FY 29	FY 34	FY 39	FY 40
Energy demand	15,306	16,475	23,182	31,637	42,424	44,929
T&D loss	1,999	2,132	2,844	3,624	4,346	4,539
Energy requirement	**17,305**	**18,608**	**26,026**	**35,261**	**46,963**	**49,666**

BAU DF for AP

Parameter (MU)	FY 23	FY 24	FY 29	FY 34	FY 39	FY 40
Energy demand	68,982	73,459	99,097	1,30,436	1,68,500	1,77,134
T&D loss	8,899	9,356	11,791	14,408	17,147	17,713
Energy requirement	**77,881**	**82,815**	**1,10,888**	**1,44,844**	**1,85,646**	**1,94,847**

Policy impacts for APSPDCL

Policy lever	FY 23	FY 24	FY 29	FY 34	FY 39	FY 40
EV (+) in MU	22	37	342	1,554	3,799	4,443
RTPV (−) in MU	100	117	257	564	1,237	1,447
EE-domestic (−) in %	4.9%	5.3%	10.1%	15.8%	14.1%	13.4%
EE-commercial (−) in %	3.6%	4.0%	6.3%	7.7%	8.2%	8.3%
Agri (−) in MU	1,018	1,313	3,341	6,138	9,992	10,923

Policy impacts for APEPDCL

Policy lever	FY 23	FY 24	FY 29	FY 34	FY 39	FY 40
EV (+) in MU	20	33	304	1,381	3,377	3,950
RTPV (−) in MU	91	107	234	513	1,125	1,316
EE-domestic (−) in %	4.9%	5.3%	10.1%	15.8%	14.1%	13.4%
EE-commercial (−) in %	3.6%	4.0%	6.3%	7.7%	8.2%	8.3%
Agri (−) in MU	453	591	1,576	3,035	5,181	5,717

Policy impacts for APCPDCL

Policy lever	FY 23	FY 24	FY 29	FY 34	FY 39	FY 40
EV (+) in MU	7	12	114	518	1,266	1,481
RTPV (−) in MU	57	66	145	319	699	817
EE-domestic (−) in %	4.9%	5.3%	10.1%	15.8%	14.1%	13.4%
EE-commercial (−) in %	3.6%	4.0%	6.3%	7.7%	8.2%	8.3%
Agri (−) in MU	12	15	39	71	115	126

Policy scenario DF for APSPDCL

Category (MU)	FY 23	FY 24	FY 29	FY 34	FY 39	FY 40
Domestic	5,888	6,251	7,797	9,038	10,993	11,450
Commercial	1,485	1,553	1,945	2,458	3,136	3,292
Agricultural	10,727	11,019	12,398	13,949	15,645	15,996
Industrial	6,296	6,698	9,127	12,438	16,949	18,032
Institutional	1,766	1,868	2,376	2,884	3,392	3,494
EV demand (+)	22	37	342	1,554	3,799	4,443
RTPV generation (-)	100	117	257	564	1,237	1,447
Energy demand	***26,084***	***27,308***	***33,727***	***41,757***	***52,678***	***55,259***
T&D loss	3,365	3,478	4,013	4,612	5,360	5,526
Energy requirement	**29,449**	**30,786**	**37,741**	**46,369**	**58,038**	**60,785**

Policy scenario DF for APEPDCL

Category (MU)	FY 23	FY 24	FY 29	FY 34	FY 39	FY 40
Domestic	6,896	7,316	9,284	11,149	14,158	14,882
Commercial	2,509	2,754	4,265	6,290	8,864	9,437
Agricultural	4,829	5,009	5,917	6,992	8,238	8,507
Industrial	9,636	10,225	13,754	17,740	21,790	22,662
Institutional	1,373	1,445	1,806	2,167	2,528	2,601
EV demand (+)	20	33	304	1,381	3,377	3,950
RTPV generation (-)	91	107	234	513	1,125	1,316
Energy demand	***25,172***	***26,675***	***35,096***	***45,206***	***57,831***	***60,722***
T&D loss	3,247	3,397	4,176	4,993	5,885	6,072
Energy requirement	**28,419**	**30,072**	**39,272**	**50,199**	**63,715**	**66,794**

Policy scenario DF for APCPDCL

Category (MU)	FY 23	FY 24	FY 29	FY 34	FY 39	FY 40
Domestic	6,318	6,817	9,204	11,492	14,986	15,819
Commercial	1,886	2,043	3,042	4,573	6,939	7,541
Agricultural	124	127	143	161	181	185
Industrial	5,701	6,058	8,210	11,127	15,080	16,025
Institutional	873	946	1,310	1,674	2,038	2,111
EV demand (+)	7	12	114	518	1,266	1,481
RTPV generation (-)	57	66	145	319	699	817
Energy demand	***14,853***	***15,937***	***21,878***	***29,226***	***39,791***	***42,344***
T&D loss	1,916	2,030	2,603	3,228	4,049	4,234
Energy requirement	**16,769**	**17,967**	**24,481**	**32,454**	**43,840**	**46,579**

RTPV capacity addition trajectory

Year	Installed capacity (in MW)			Energy generation (in MU)		
	CAGR: 20%	CAGR: 17%	CAGR: 15%	Capacity utilisation factor: 18%		
	Optimistic	*Base*	*Pessimistic*	*Optimistic*	*Base*	*Pessimistic*
FY 21	115	115	115	181	181	181
FY 24	199	184	175	313	290	276
FY 29	494	404	352	780	637	555
FY 34	1,230	885	708	1,940	1,396	1,116
FY 39	3,062	1,941	1,423	4,828	3,061	2,244
FY 40	3,674	2,271	1,637	5,793	3,581	2,581

Year-on-year peak demand projections (in MW)

DISCOM	FY 23	FY 24	FY 29	FY 34	FY 39	FY 40
APSPDCL	5,400	5,645	6,921	8,503	10,643	11,146
APEPDCL	4,581	4,847	6,330	8,092	10,270	10,767
APCPDCL	2,780	2,978	4,058	5,380	7,268	7,722
State-level	12,159	12,841	16,534	21,019	26,977	28,372

Supply Planning

New capacity addition from FY 23 to FY 36

Si. No.	Resource	Plant name	State share (MW)	Date of decommission
1	Thermal	Dr Narla Tata Rao Station (Vijayawada) Unit 8	800	2023
2	Thermal	Sri Damodaram Sanjeevaiah TPS Unit 3 (stage 2)	800	2023
3	Thermal	Sembcorp	625	2023
4	Mini hydel station	Pinjarikonda Mini Hydel	1.2	2023
5	Mini hydel station	Metlapalem Mini Hydel	1.2	2024
6	Hydro	Polavaram Hydro Power Project	560	2025
7	Municipal solid waste	Jindal Guntur and Vizag	10	2025
8	Municipal solid waste	Rajahmundry	10	2025
9	Hydro	Lower Sileru	230	2025
10	Solar	SECI Phase 1	3000	2025
11	Hydro	Polavaram Hydro Power Project	400	2026
12	Wind	AXIS Unit 1 and Unit 2	1174.9	2026
13	Mini hydel station	Victory Power	9	2026
14	Solar	SECI Phase 2	3000	2026
15	PHES	Upper Sileru PHES	1350	2027
16	Solar	SECI Phase 3	1000	2027
17	Nuclear	Kovvada Nuclear Power Project	3624	2031
18	Nuclear	Jaitapur Nuclear Power Project	2345	2036
19	Nuclear	Kaiga Atomic Power Station	332	2036
20	Nuclear	Kudankulam Nuclear Power Plant	947	2036

Retirement of plants from FY 23 to FY 40

Si. No.	Resource	Plant name	State share (MW)	Date of decommission
1	Others	Biomass	39	2023
2	Others	Bagasse	40	2023
3	Others	Biomass	20	2024
4	Others	Municipal solid waste	0.15	2024
5	Others	Mini hydel station	1	2024
6	Others	Industrial waste	5	2024
7	Others	Bagasse	24	2025
8	Others	Mini hydel station	12	2025
9	Others	Industrial waste	6	2026
10	Others	Biomass	4	2026
11	Nuclear CGS	Kaiga Unit 3 and Unit 4	55	2026
12	Nuclear CGS	Kaiga Unit 1–Unit 2	59	2026
13	Nuclear CGS	Madras Atomic Power Station	18	2026
14	Thermal CGS	Simhadri Stage-I	461	2027
15	Others	Biomass	2	2027
16	Others	Biomass	8	2028
17	Others	Industrial waste	4	2028
18	Others	Mini hydel station	3	2028
19	Others	Bagasse	20	2029
20	Thermal CGS	Ramagundam Stage III	69	2029
21	Thermal CGS	Talcher Stage II	176	2029
22	Others	Mini hydel station	1	2031

23	Thermal	NTTPS Unit 1	210	2031
24	Thermal	NTTPS Unit 2	210	2031
25	Thermal	NTTPS Unit 3	210	2032
26	Thermal	NTTPS Unit 4	210	2032
27	Thermal	NTTPS Unit 5	210	2033
28	Thermal	NTTPS Unit 6	210	2033
29	Thermal	RTPS Unit 1	210	2034
30	Thermal	RTPS Unit 2	210	2034
31	Thermal	Sembcorp Unit 2	625	2035
32	Thermal	Sembcorp Unit 1	231	2039

Economic characteristics for bulk energy storage systems used in the technology assessment framework (TAF)

Energy storage technologies (ESTs)	Capital costs (USD/KW)	Cavern/Reservoir costs (USD/KW)	Total project cost (USD/KW)	Operations and maintenance fixed (USD/KW/Year)
PHS	1209	81	2046	30.4
CAES	1153	3.66	1168	16.12
Hydrogen	3080.09	3.66	3117	28.51

Technical characteristics for bulk energy storage systems used in the TAF

ESTs	Round trip efficiency (in %)	Response time (in seconds)	Cycle life (in numbers)	Calendar life (in years)
PHS	80	164	13870	40
CAES	52	390	10403	30
Hydrogen	35	1	10403	30

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