

Report on Resource Adequacy Plan (Generation) for Chandigarh (2025-26 to 2035-36) (Version 2.0)

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Government of India
Ministry of Power
Central Electricity Authority

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Disclaimer

This Resource Adequacy study for the Union Territory of Chandigarh has been conducted based on data and inputs provided by Chandigarh Power Distribution Limited (CPDL). The findings, analysis and conclusions presented in this report are contingent upon the accuracy, completeness and timeliness of the information furnished by CPDL. Any discrepancies or limitations in the data may affect the outcomes of the study accordingly.

In accordance with the Resource Adequacy Guidelines dated 28th June 2023, each Distribution Licensee is mandated to prepare a Resource Adequacy Plan (RAP) for a 10-year horizon, referred to as the Long-Term Distribution Licensee Resource Adequacy Plan (LT-DRAP), which shall be vetted and validated by the Central Electricity Authority (CEA). CEA has facilitated this study and prepared the report solely to assist CPDL in fulfilling this requirement.

It is expressly stated that the responsibility for the implementation of the study's recommendations, ensuring the adequacy of electricity resources, and undertaking any related actions rests entirely with CPDL.

Executive Summary

Ministry of Power had notified the Electricity (Amendment) Rules in December 2022. As per Rule 16 of the Electricity (Amendment) Rules, Ministry of Power has notified Resource Adequacy (RA) Guidelines. According to these Guidelines, Central Electricity Authority (CEA) is entrusted with the responsibility of preparing the Long-Term National Resource Adequacy Plan (LT-NRAP). Further, each Distribution Utility is required to carry out a Long-Term Distribution Licensee Resource Adequacy Plan (LT-DRAP) to reliably meet its peak and energy requirements.

As per the Resource Adequacy Guidelines dated 28th June 2023, each Distribution Licensee shall undertake a Resource Adequacy Plan (RAP) with a 10-year planning horizon, LT-DRAP to meet its own peak electricity demand and electrical energy requirement. This plan shall be vetted/validated by CEA to leverage the benefits of national-level optimization for the Distribution Licensees. The LT-DRAP shall be prepared by the Distribution Licensees on an annual rolling basis, factoring in the already contracted capacity and optimizing the requirement for additional capacity.

Government of India has also recently gazette notified the Renewable Purchase Obligation (RPO) trajectory up to 2029-30 vide gazette notification dated 20th October 2023, which mandates that a specified portion of energy consumption must be met from renewable energy sources.

To support the utility in fulfilling this requirement, CEA, in collaboration with the State/UTs, initially conducted a Resource Adequacy (RA) study with a planning horizon up to FY 2034-35, based on the data received from the Discom and in compliance with the then prevailing RPO trajectory specified in the Ministry of Power's Office Memorandum dated 22nd July 2022 and its subsequent corrigendum dated 19th September 2022. This study has now been updated and extended to cover the period up to FY 2035-36, incorporating the latest data furnished by the State and planning assumptions. The RPO requirement for the utility has also been assessed in accordance with the recent gazette notified trajectory.

The electrical energy requirement and peak electricity demand for Chandigarh is increasing with a CAGR of 3.5% and 3.2% respectively from 2025-26 to 2035-36 as forecasted by Chandigarh Power Distribution Limited (CPDL). For satisfying resource adequacy i.e., meeting the electricity demand reliably and at affordable cost, the UT needs to methodically plan its capacity expansion either by investing or by procuring power. In view of the reduction in cost of solar panels and newer technology options like storage systems, planning for long term optimal generation capacity mix gains tremendous importance so as the future generation capacity mix is cost effective as well as environment friendly.

A study has been carried out for Chandigarh considering the existing contract capacity and planned capacity addition. It was found that the UT's likely contracted capacity may not be sufficient to meet the projected demand. Further, the total unserved energy in the year 2035-36

is expected to be about 243 MU which is about 8% of the annual projected electrical energy demand in the year 2035-36.

To find out the least cost option for generation capacity expansion for the period 2025-26 to 2035-36, long-term study has been carried out with the objective to minimize the total system cost of generation including the cost of anticipated future investments while fulfilling all the technical constraints associated with various power generation technologies. Additionally, reliability study has been carried out to determine the probability of unmet demand and hours by implementing the variation in demand, RE and forced outage of thermal generators (Coal/ Lignite) etc.

Generation capacity expansion pathways have been considered for the long-term study based on the yearly capacity addition plan of Chandigarh along with RPO constraints for solar and wind technologies. The Renewable capacities have been assessed in view of adherence to RPO notified by Ministry of Power considering the fungibility among different sources.

The Resource adequacy studies have projected likely optimal capacity mix for future years till 2035-36 which is able to meet anticipated demand reliably at every instance. Based on the study, the likely total projected contracted capacity for the year 2035-36 is around 814 MW which consists of 117 MW from coal, 49 MW from gas, 48 MW from nuclear, 357 MW from hydro, 40 MW from wind, 100 MW from solar, 101 MW from Distributed Renewable Energy (DRE) sources. Further, in addition to this, 213 MW of MTOA/STOA arrangement will be required. This capacity shall be able to meet the projected demand with prescribed reliability criteria.

1.0 Introduction

Ministry of Power has notified Electricity (Amendment) Rules, 2022 in December 2022. Rule 16 (I) of the said rules stipulates that "A guideline for assessment of resource adequacy during the generation planning stage (one year or beyond) as well as during the operational planning stage (up to one year) shall be issued by the Central Government in consultation with the Authority". Accordingly, the Resource Adequacy Guidelines have been notified in June, 2023 by Ministry of Power in consultation with Central Electricity Authority.

Resource Adequacy is generally defined as a mechanism to ensure that there is an adequate supply of generation resources to serve expected demand reliably at least cost. A key aspect of resource adequacy planning is to ensure that adequate generation capacities are available, round-the-clock, to reliably serve demand under various scenarios. This naturally translates into the need for ensuring adequate reserve margin, which could cater to varying levels of demand and supply conditions in the grid. In the wake of high RE generation, it is important to understand demand-supply situation in the grid precisely due to high seasonality and intermittency in RE generation. Resource Adequacy exercise may also help in assessment of capacity requirement to be tied up or contracted on long term, medium term, and short-term basis.

Further, Ministry of Power vide notification dated 20th October, 2023 had notified the RPO trajectory for the states/Discoms. Based on the trajectory specified, hydro, wind and other (solar, biomass etc.) RPO quantum in million units (MUs) has been calculated to find additional quantum of renewable capacity that the states/Discoms have to contract in addition to its existing/planned capacity to meet their RPO targets.

To support the utility in fulfilling the Resource Adequacy Guidelines and complying with the Renewable Purchase Obligation (RPO) notification, CEA has carried out the RA study for the UT of Chandigarh based on inputs furnished by CPDL. The study recommends an optimal resource mix up to FY 2035-36, taking into account technical and financial parameters associated with various capacities. It aims to optimize long-term power procurement while ensuring resource adequacy to meet demand on a 24×7 basis, considering variations in demand, RE generation, and forced outage of thermal capacities. The study assesses the Planning Reserve Margin (PRM) required by the UT to account for the aforementioned uncertainties, ensuring that demand can be reliably met throughout the year.

Prior to this, CEA had conducted the RA study for the UT up to FY 2034-35, based on inputs from Chandigarh Administration and in accordance with Ministry of Power's Gazette notification dated 20th October, 2023.

2.0 Highlights of the Previous RA Study (Up to FY 2034-35)

1. In the earlier Resource Adequacy (RA) study, the financial year 2023-24 had been considered as the base year, and the study covered the period from 2024-25 to 2034-35. The fuel-wise contracted capacity by CPDL as on 31st March, 2024 is given in Fig 1.

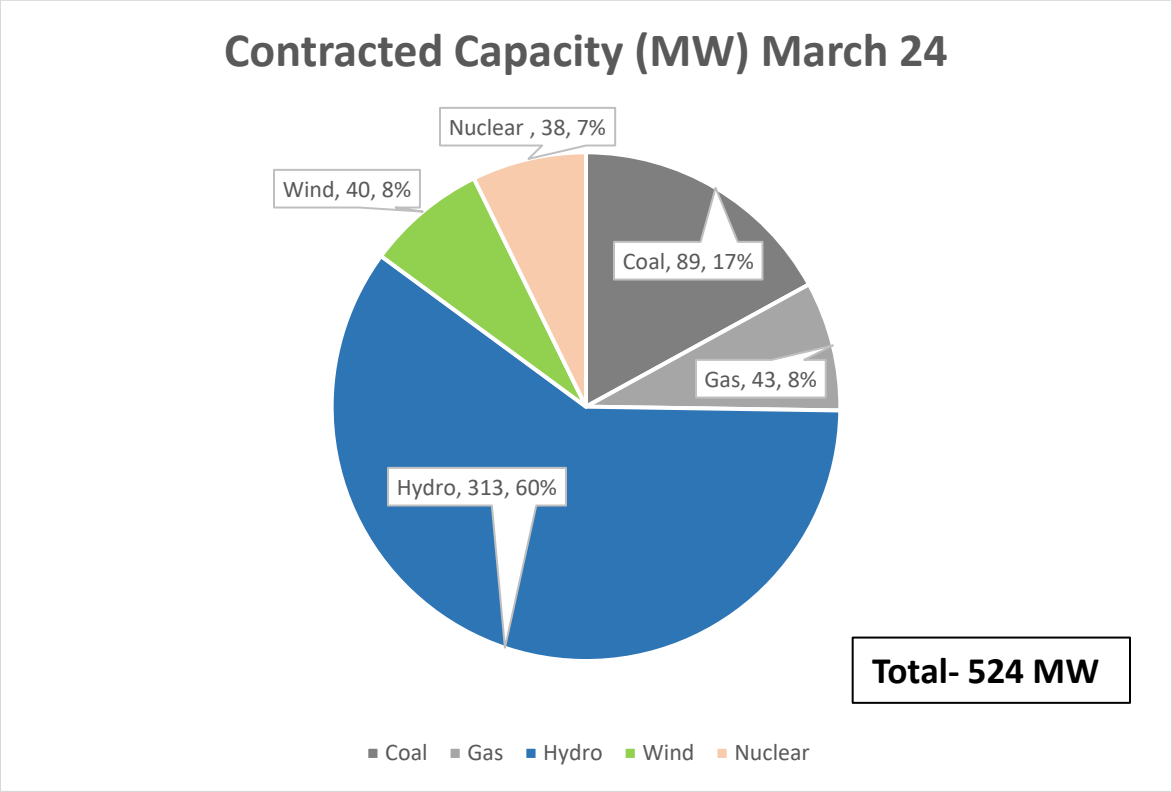


Figure 1: Contract Capacity 2023-24

2. The hourly demand pattern for 2023-24 was analysed and had been considered as base profile to interpolate the demand for future years.

3. The peak electricity demand and electrical energy projections as per 20th EPS had been considered in the study is given below:

Table 1: Peak demand and Energy Projections as per 20th EPS

	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
Energy Projections (MU)	1827	1869	1911	1953	1997	2047	2107	2157	2209	2262	2316
Year on Year Growth (%)		2.30%	2.25%	2.20%	2.25%	2.50%	2.93%	2.37%	2.41%	2.40%	2.39%
Peak Demand Projections (MW)	464	478	492	505	519	533	549	563	579	595	612
Year on Year Growth (%)		3.02%	2.93%	2.64%	2.77%	2.70%	3.00%	2.55%	2.84%	2.76%	2.86%

4. The actual peak electricity demand and electrical energy requirement of the UT observed during 2023-24 and 2024-25 is tabulated below based on the Power Supply Position (PSP) report of CEA:

Table 2: Actual Peak Demand and Energy requirement

Year	Actual Energy Requirement (in MU)	Actual Peak Demand (in MW)
2023-24	1789	411
2024-25	1952	449

To meet the above projected peak electricity demand and electrical energy requirement reliably, the source-wise projected capacity (in MW) as outlined in the previous report is tabulated below:

Table 3: Projected capacity

Year	Coal	Gas	Hydro	Wind	Solar	Nuclear	DRE	STOA	Total
2024/25	89	43	313	40	0	38	22	108	**655**
2025/26	89	43	353	45	5	43	32	82	**693**
2026/27	89	43	353	45	45	43	42	85	**746**
2027/28	89	43	353	45	45	43	53	96	**768**
2028/29	89	43	353	45	45	43	64	108	**791**
2029/30	89	43	353	45	45	43	75	121	**815**
2030/31	89	43	353	45	45	43	86	135	**840**
2031/32	89	43	353	45	45	43	97	147	**863**
2032/33	89	43	353	45	45	43	108	159	**886**
2033/34	89	43	353	45	45	43	120	173	**912**
2034/35	89	43	353	45	45	43	132	191	**942**

*****The STOA/MTOA value represents the peak power requirement in MW and it was recommended that this requirement may be met through power procurement from the market or through bilateral agreements.

5. The year-wise planned and additional capacity contract addition (in MW) for the above tabulated cumulative capacity is detailed below:

Table 4: Year wise planned and additional capacity addition

FY	Coal	Hydro	SOLAR		Wind		Nuclear	DRE	Total		STOA/MTOA
	Additional	Planned	Planned	Additional	Planned	Additional	Planned	Additional	Planned	Additional	Additional*
2024/25	0	0	0	0	0	0	0	22	**0**	**22**	108
2025/26	0	40	5	0	5	0	5	10	**55**	**10**	82
2026/27	0	0	40	0	0	0	0	10	**40**	**10**	85
2027/28	0	0	0	0	0	0	0	11	**0**	**11**	96
2028/29	0	0	0	0	0	0	0	11	**0**	**11**	108
2029/30	0	0	0	0	0	0	0	11	**0**	**11**	121
2030/31	0	0	0	0	0	0	0	11	**0**	**11**	135
2031/32	0	0	0	0	0	0	0	11	**0**	**11**	147
2032/33	0	0	0	0	0	0	0	11	**0**	**11**	159
2033/34	0	0	0	0	0	0	0	12	**0**	**12**	173
2034/35	0	0	0	0	0	0	0	12	**0**	**12**	191
Total	**0**	**40**	**45**	**0**	**5**	**0**	**5**	**132**	**95**	**132**	

3.0 Chandigarh RA Study (from 2025-26 to 2035-36)

3.1 Present Power Scenario in Chandigarh

The power supply position for Chandigarh for 2021-22 to 2024-25 is given in the Table 5.

Table 5: Power Supply Position of Chandigarh

Power Supply Position						
Year	**Energy required (MU)**	**Energy supplied (MU)**	**Gap (MU)**	**Peak Demand (MW)**	**Peak Met (MW)**	**Demand not met (MW)**
2021-22	1606	1606	0	426	426	0
2022-23	1788	1788	0	407	407	0
2023-24	1789	1789	0	411	411	0
2024-25	1952	1952	0	449	449	0

As of March 2025, the total contracted capacity for Chandigarh is 668 MW. Out of the total contracted capacity (CC), the share of non-fossil fuel-based Contracted Capacity is 75%.

The fuel-wise contracted capacity as on 31st March, 2025, is given in Table 6 and Figure 2.

Table 6: Fuel-wise Contracted Capacity as on March 2025

Source	Contracted Capacity (MW)	Percentage (%)
Coal	117	18%
Gas	49	7%
Nuclear	48	7%
Hydro	332	50%
Wind	40	6%
DRE	82	12%
Total	**668**	**100%**

Note- The above capacity is based on power allocation by MoP as on 01.04.2025 as provided by the Discom which consists of power from Firm as well as Unallocated quota. The unallocated quota varies from 12 to 14% in summers whereas in winter the quota gets reduced to 9%.

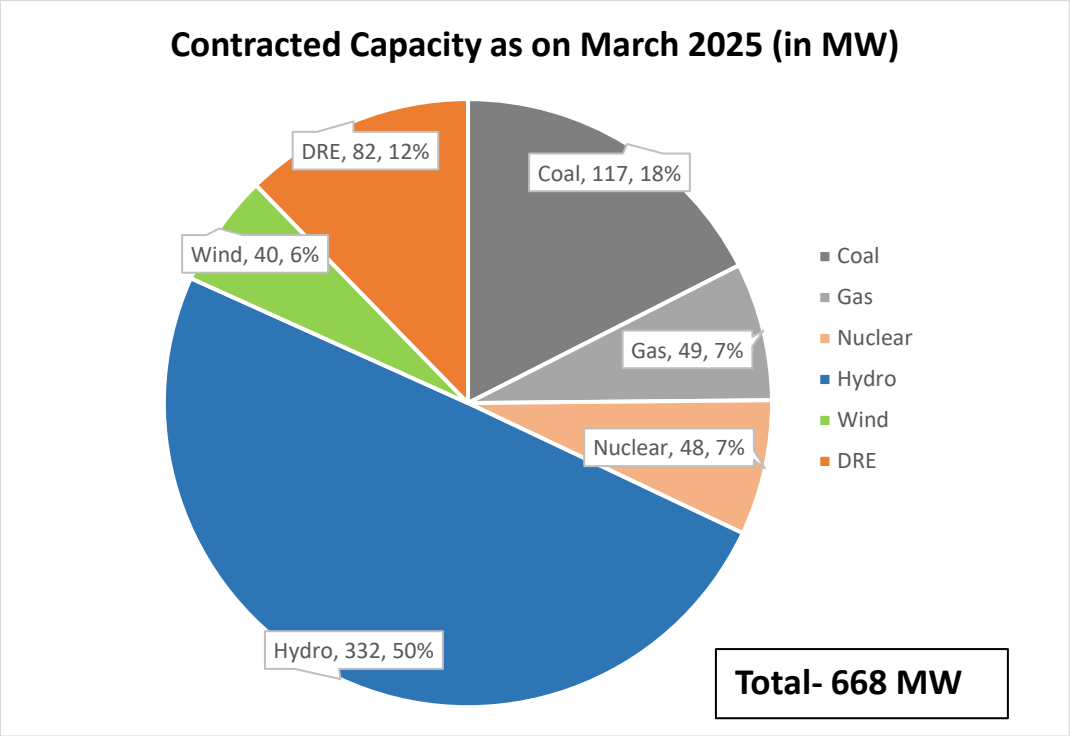


Figure 2 Fuel-wise Contracted Capacity (in MW) as on 31st March, 2025

3.2 Demand Analysis of the FY 2024-25

Hourly demand pattern of 2024-25 was analyzed and it was observed that peak electricity demand in Chandigarh occurs during June and July months. Notably, the Union Territory experiences peak electricity demand during the solar hours in July. However, the average hourly electricity demand is highest in the month of June. Overall, the demand during the solar hours in these months is significantly higher than in the rest of the year.

The month wise variation in average hourly electricity demand observed for the year 2024-25 is shown in Figure 3.

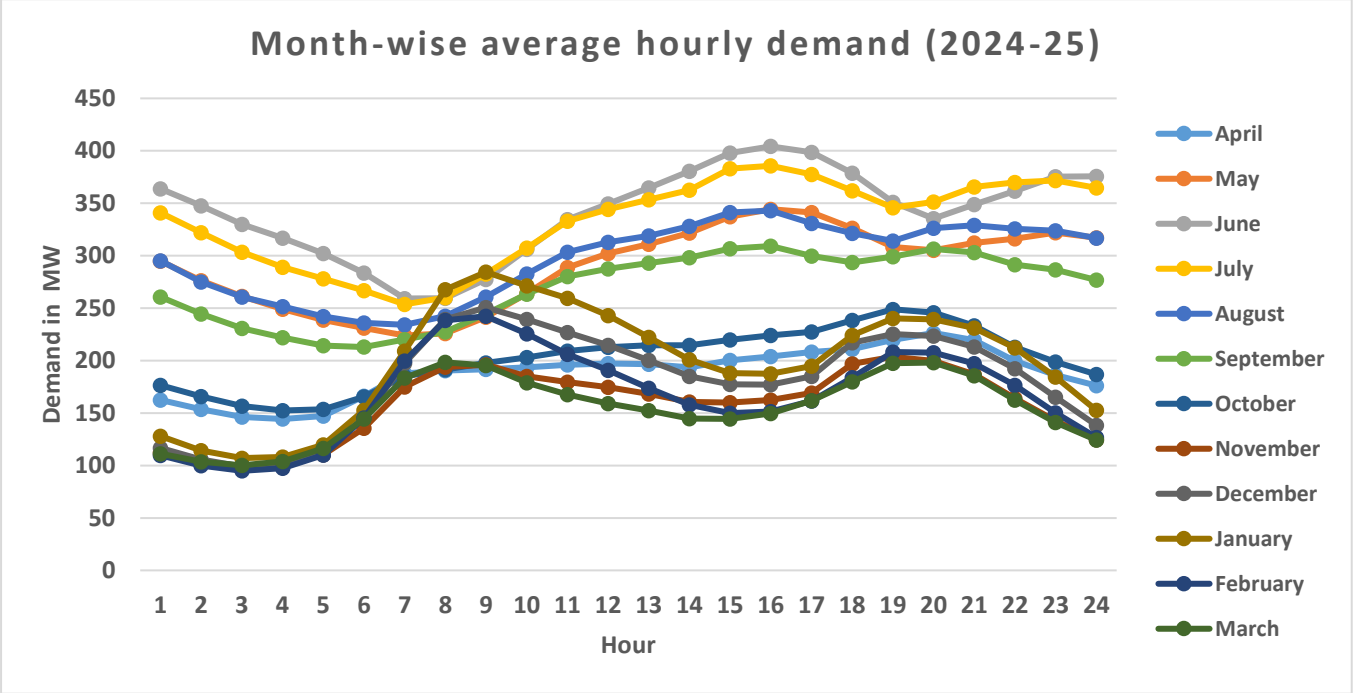


Figure 3: Average Hourly Demand Variation (Month-wise) for 2024-25

From the hourly demand data of 2024-25, the daily peak during solar hours (06:00 to 18:00 hrs) and non-solar hours are plotted in Figure 4.

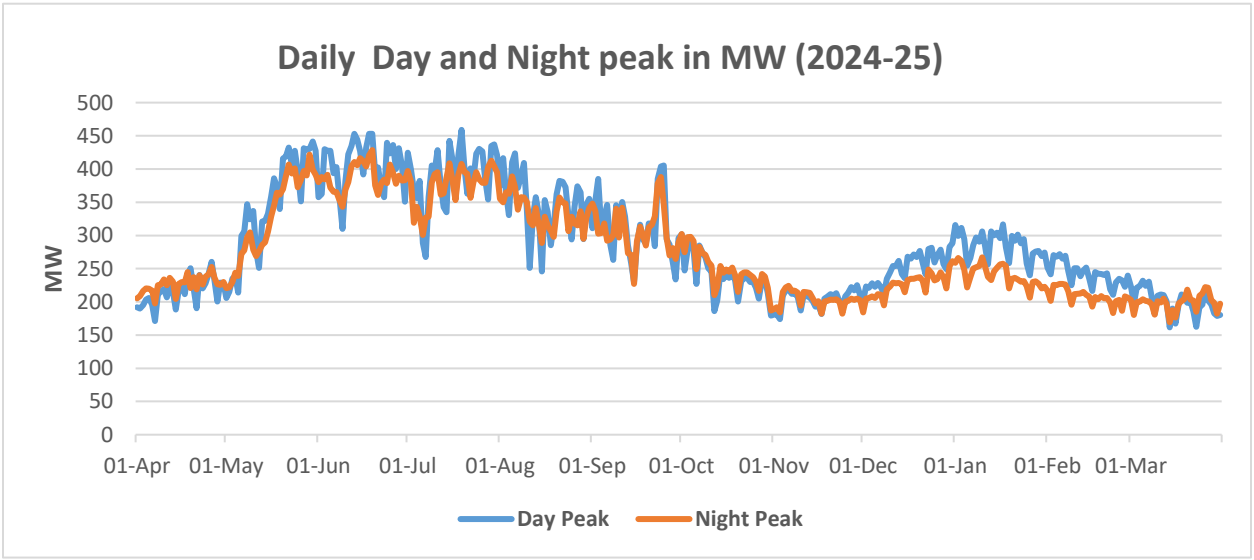


Figure 4: Day and Night Peak in MW for the year 2024-25

As seen from figure 4, the daily peak demand occurs during solar hours.

The hourly demand pattern of 2024-25 was analysed for finding out the number of occurrences of the peak and near peak demand. Such instances are critical for study purpose as it is necessary to ensure resource adequacy during such instances with an optimal mix of long-term, medium-term and short-term contracts.

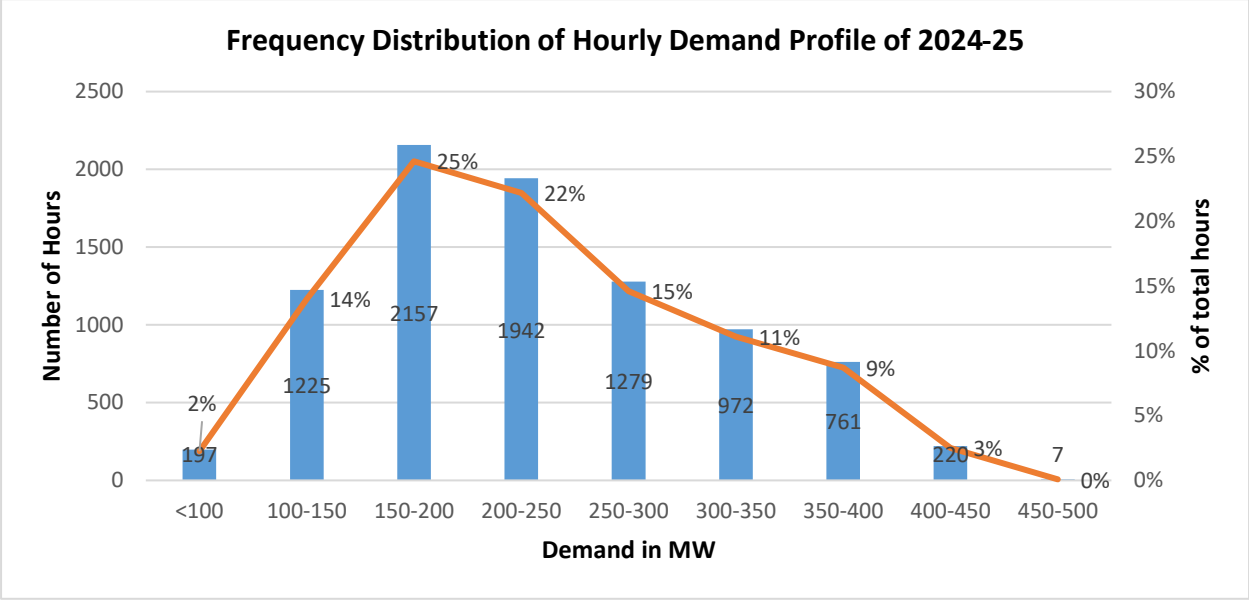


Figure 5 Frequency Distribution of Hourly Demand Profile of 2024-25

4.0 Principles of Generation Planning

The objective of the Generation Planning process is to obtain an optimal generation capacity mix in the least cost manner to meet the demand at every instance of time while ensuring the most efficient use of resources. Planning is therefore an activity encompassing balancing demand and supply at all instances of time and at all locations, which makes it a regular ongoing process.

The major aspects considered in the planning process are:

i) To Supply 24x7 reliable power to consumers
ii) To achieve objectives of all policies of the Government of India such as RPO trajectory, RE capacity addition etc.
iii) To achieve sustainable development.
iv) To fulfil desired operational characteristics of the system such as reliability and flexibility.
v) Most efficient use of resources.
vi) Fuel availability

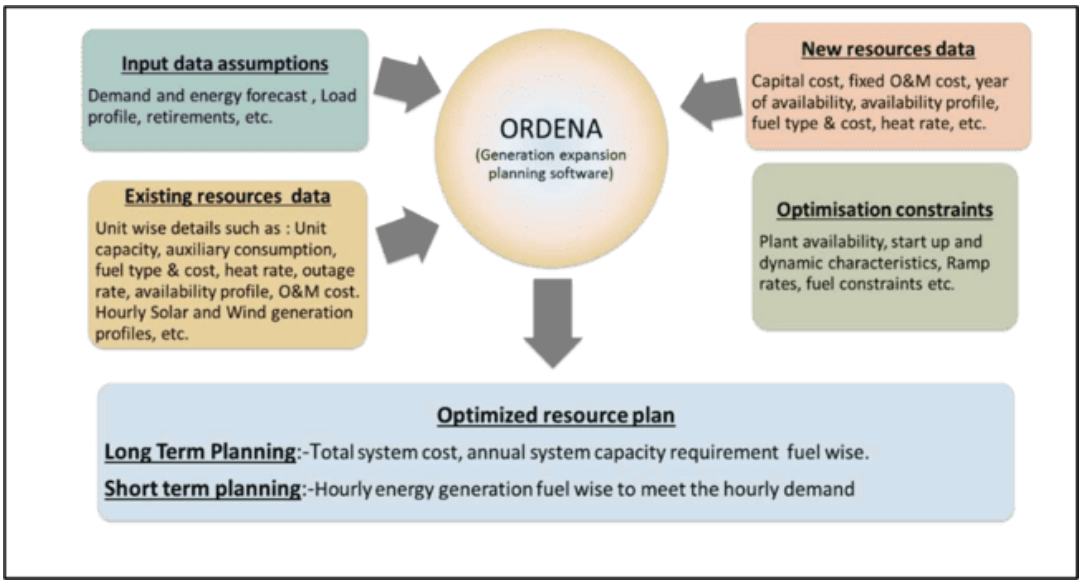
4.1 Generation Expansion Planning Tool -ORDENA

The studies were carried out using a generation expansion planning model namely ORDENA. ORDENA is a mixed integer linear optimization program that minimizes the Net Present Value (NPV) of investment and operating costs subject to several constraints. The major constraints include balancing electricity supply and demand, resource supply limits, planning and operating reserve limits, and policy targets. These constraints are met considering a broad portfolio of conventional generation, renewable generation, and storage.

ORDENA has a reliability module to determine the trustworthiness of the system using Monte Carlo simulations. The software is also capable of carrying out hourly/sub-hourly economic

generation dispatch, considering all the technical constraints associated with various generation technologies.

The schematic diagram of the software is given in Exhibit.



5.0 Reliability Analysis

One of the main criteria of resource adequacy studies is to determine the reliability of the system to meet the demand adequately at every instant of time. This reliability is measured via two indices (i.e.) LOLP (Loss of Load Probability) and EENS (Expected Energy Not Served). These indices have been defined in resource adequacy guidelines as below:

- **Loss of Load Probability (LOLP)**: Measure of the probability that a system's load may exceed the generation and firm power contracts available to meet that load in a year. E.g., 0.0274 % probability of load being lost.
- **Expected Energy Not Served (EENS):** Expected amount of energy (MWh) that may not be served for each year within the planning period under study. It is a summation of the expected number of megawatt hours of demand that may not be served for the year. This is an energy-centric metric that considers the magnitude and duration of energy being not served, calculated in Mega Watt hours (MWh). The metric can be normalized (i.e., divided by total system energy requirement) to create a Normalized Energy Not Served (NENS) metric.

Monte Carlo /Stochastic simulation has been used to factor-in the uncertainty associated with various generation resources and demand. It is an approach which is used to predict the probability of a variety of outcomes when the potential for random variables is present as compared to deterministic modelling of economic dispatch model. Monte Carlo simulation helps in analysing the randomness associated with RE energy resource, demand pattern changes and

forced outages of plant. A large number of random samples of these variables are simultaneously simulated to ascertain system reliability indices [i.e. Loss of load probability LOLP & Energy Not Served (ENS)] and the system robustness in case of above variation of system parameters.

Planning Reserve Margin (PRM): To meet the prescribed standard of LOLP / NENS conditions, sufficient reserve margins need to be maintained in the system for adequately addressing the demand and supply variations. Planning Reserve Margin (PRM) is the predominant metric used to ensure adequacy of generation resources in the system. PRM in a power system is expressed as a certain percent of projected peak load of the system.

5.1 Demand variation

The variation in demand pattern for the past two years has been analyzed. The hourly demand variation for consecutive years (i.e., 2023-24 and 2024-25) has been analyzed. The Demand pattern variation of 2023-24 and 2024-25 is shown below.

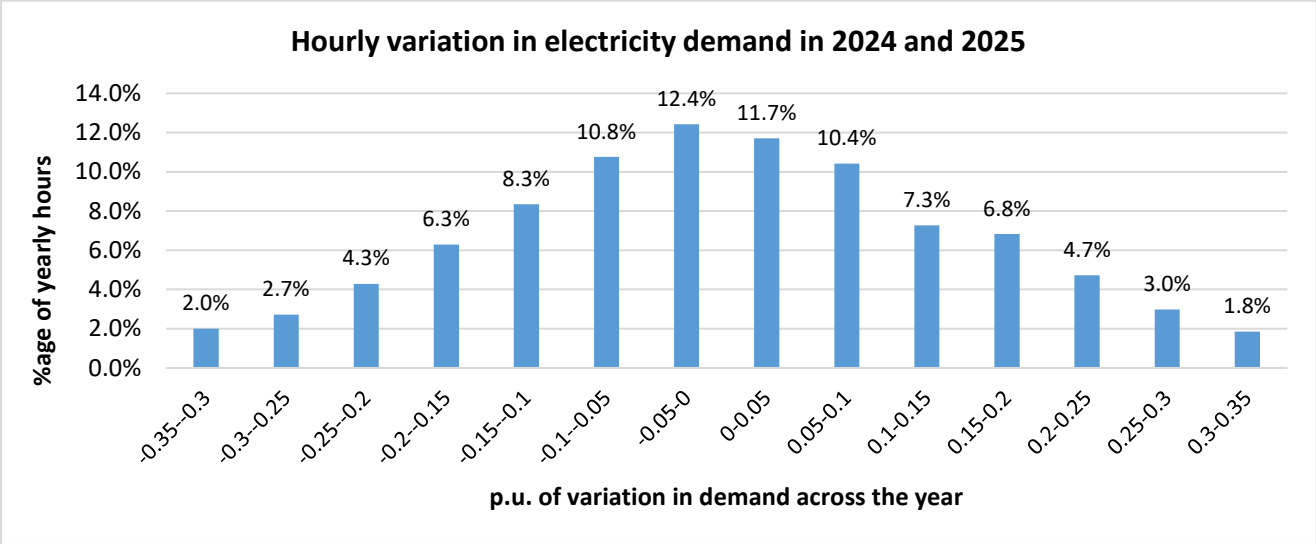


Figure 6 Hourly Variation in Demand across years

It can be observed that the hourly demand typically varies ±15% for 61% of instances. This variation is primarily due to temperature, weather parameter or any random outages of transmission line and generating units etc. This variation has been captured in the reliability study by varying the projected hourly demand for the future years by varying ±15% by introducing a random variable (with normal distribution) for demand as per observed behavior over the years.

5.2 RE variation

In the Long-term capacity expansion planning studies, a particular profile for Solar is considered based on the observed solar generation data to determine the optimal capacity mix. However, due to intermittent nature of these sources, the generation from these non-dispatchable sources may vary across years. As per the analyses carried out based on historical generation data, solar and hydro based generation has been varied by ± 10 % and wind generation has been varied by

± 50% to incorporate the variation in these generation sources and plan for requisite measures to mitigate such behavior.

5.3 Forced Outage of Thermal Generators

The average forced outage rate of thermal generators is typically 10% with ±5% variation. The same has been incorporated in the model.

Based on these variations, reliability studies have been carried out to ascertain robustness of the system.

6.0 Inputs/Assumptions for the Study

i) The electrical energy requirement of Chandigarh, furnished by CPDL and projections available in the 20th EPS (Electric Power Survey) mid-term review is tabulated below. The utility's electrical energy requirement and peak electricity demand projections is found to be on the higher side.

Table 7 Future Demand Projection as provided by CPDL and as per mid –term review of 20th EPS

	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
Peak Demand (in MW)											
CPDL Peak Demand Projections (in MW)	491	511	531	547	564	580	598	616	634	653	673
Year on Year Growth		4.0%	4.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
20th EPS Mid-term review Peak Demand Projections (MW)	472	488	498	511	524	530	534	542	550	558	570
Year on Year Growth		3.4%	2.1%	2.7%	2.5%	1.1%	0.9%	1.4%	1.4%	1.5%	2.1%
Energy Requirement (in MU)											
CPDL Energy Projections (in MU)	2056	2128	2202	2279	2359	2441	2527	2615	2707	2802	2900
Year on Year Growth		3.5%	3.5%	3.5%	3.5%	3.5%	3.5%	3.5%	3.5%	3.5%	3.5%
20th EPS Mid-term review Energy Projections (in MU)	1838	1900	1972	2059	2145	2203	2258	2326	2395	2467	2520
Year on Year Growth		3.3%	3.8%	4.4%	4.2%	2.7%	2.5%	3.0%	3.0%	3.0%	2.1%

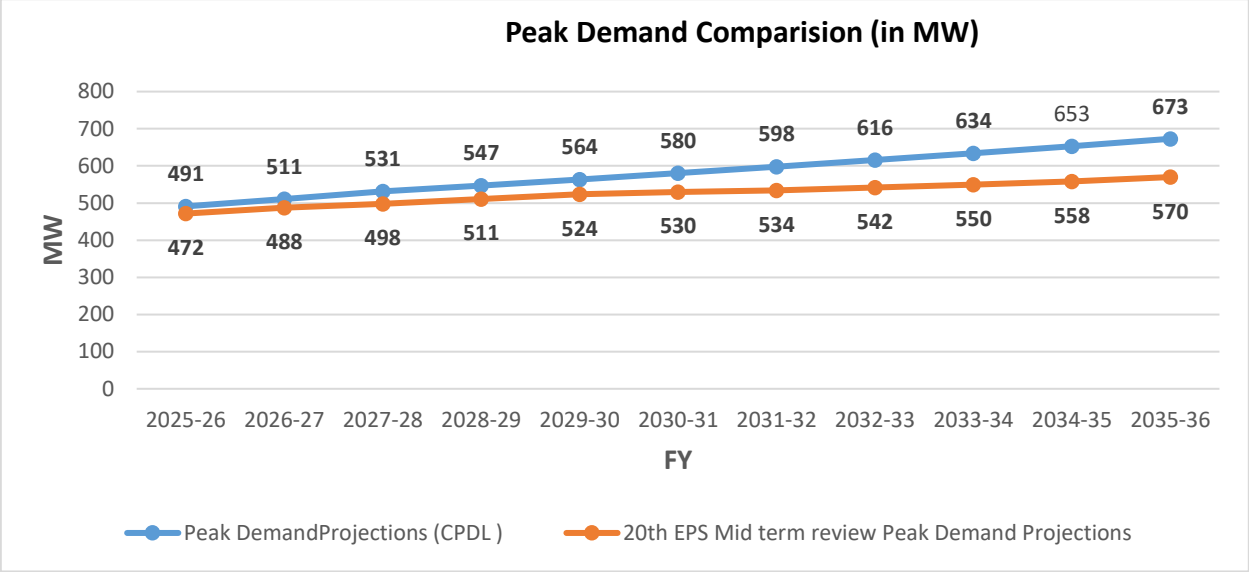


Figure 7 Comparison of Peak Demand Projections of 20th EPS mid-term vs CPDL

The actual peak load for 2024-25 as per the power supply position (April 2024 to March 2025) report, stands at 449 MW, which is slightly lower than the 20th EPS mid-term review peak load estimate of 455 MW.

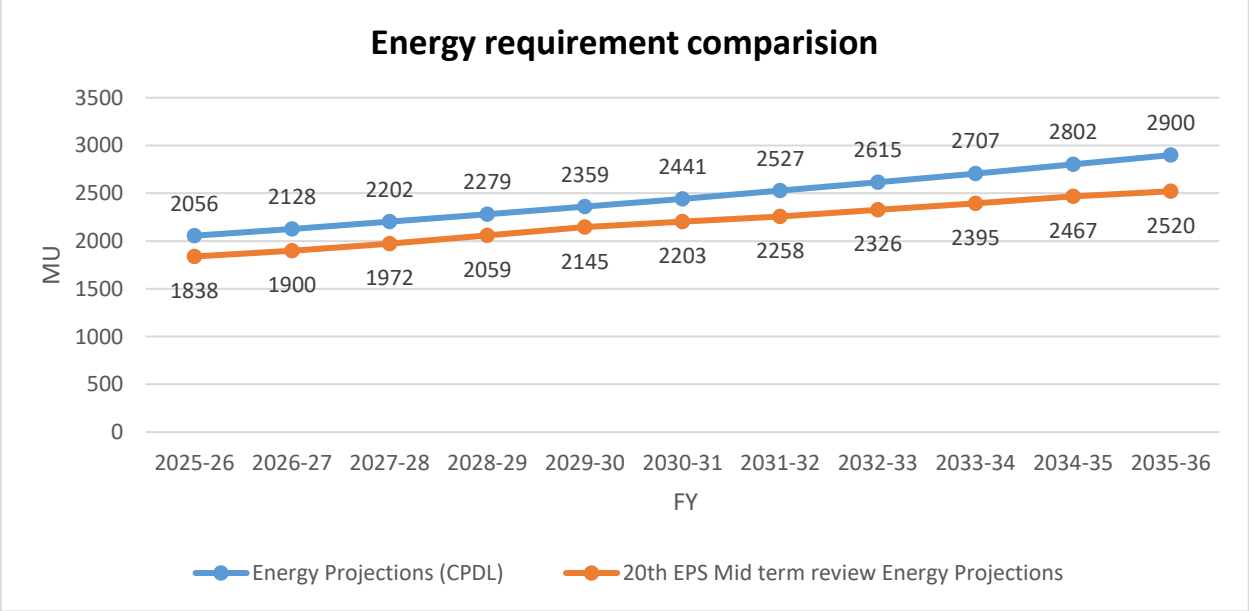


Figure 8 Comparison of Energy Requirement Projections of 20th EPS mid-term vs CPDL

The energy requirement projections of CPDL is higher compared to 20th EPS mid-term review. However, the actual energy requirement in FY 2024-25 is 1952 MUs which is significantly higher compared to 20th EPS mid-term review. Therefore, the peak demand and energy requirement projections from CPDL have been considered.

ii) Future demand profile till the year 2035-36 has been projected using the demand profile for the year 2024-25 as the base profile.

iii) The actual solar, wind and hydro generation profiles and CUFs have been considered from actual generation (as provided by CPDL) and National Electricity Plan 2023 (Vol I Generation).

iv) The capital costs of candidate plants for coal, wind, solar, and storage technologies is detailed in the Annexure and are aligned with current market trends and recent price discovery.

v) The planned capacity has been considered based on the tie-up information available with CEA and as furnished by CPDL.

Table 8 Source wise planned capacity addition (MW)

FY	COAL	HYDRO	WIND	SOLAR
2025/26	0	0	0	0
2026/27	0	25	0	0
2027/28	0	0	0	50
2028/29	0	0	0	0
2029/30	0	0	0	50
2030/31	0	0	0	0
2031/32	0	0	0	0
2032/33	0	0	0	0
2033/34	0	0	0	0
2034/35	0	0	0	0
2035/36	0	0	0	0
Total	**0**	**25**	0	**100**

vi) **Renewable Purchase Obligation (RPO) trajectory**: Ministry of Power vide gazette notification dated 20th October, 2023 had notified the source wise minimum share of consumption of non-fossil sources (renewable energy) by designated consumers till the year 2029-30.

Table 9 Renewable Purchase Obligation (RPO) trajectory as per MoP order

Sl. No.	Year	Wind renewable energy	Hydro renewable energy	Other renewable energy	Distributed renewable energy	Total renewable energy
1.	2024-25	0.67 %	0.38 %	27.35 %	1.5 %	29.91 %
2.	2025-26	1.45 %	1.22 %	28.24 %	2.1 %	33.01 %
3.	2026-27	1.97 %	1.34 %	29.94 %	2.7 %	35.95 %
4.	2027-28	2.45 %	1.42 %	31.64 %	3.3 %	38.81 %
5.	2028-29	2.95 %	1.42 %	33.1 %	3.9 %	41.36 %
6.	2029-30	3.48 %	1.33 %	34.02 %	4.5 %	43.33 %

Further, in view of the country's energy transition goals as well as the long-term net zero target of 2070, it is estimated that the share of RE generation in the generation mix will continue to proportionally increase beyond 2029-30. Therefore, the RPO trajectory is

assumed to rise steadily beyond 2029-30. Hence, the suggested trajectory of Renewable Purchase Requirement up to FY 2035-36 is presented in the table below:

Table 10 Renewable Purchase Obligation (RPO) trajectory considered for the study

Sl. No.	Year	Wind renewable energy	Hydro renewable energy	Other renewable energy	Distributed renewable energy	Total renewable energy
1.	2024-25	0.67 %	0.38 %	27.35 %	1.5 %	29.91 %
2.	2025-26	1.45 %	1.22 %	28.24 %	2.1 %	33.01 %
3.	2026-27	1.97 %	1.34 %	29.94 %	2.7 %	35.95 %
4.	2027-28	2.45 %	1.42 %	31.64 %	3.3 %	38.81 %
5.	2028-29	2.95 %	1.42 %	33.1 %	3.9 %	41.36 %
6.	2029-30	3.48 %	1.33 %	34.02 %	4.5 %	43.33 %
7.	2030-31	40.5 %			4.5 %	45.00 %
8.	2031-32	41.5 %			4.5 %	46.00 %
9.	2032-33	42.3 %			4.5 %	47.00 %
10.	2033-34	43.0 %			4.5 %	47.50 %
11.	2034-35	43.5 %			4.5 %	48.00 %
12.	2035-36	44.0 %			4.5 %	48.50 %

Based on the trajectory specified, RPO quantum in million units (MUs) from hydro, wind, other (Solar, biomass etc.) and distributed renewable energy (DRE) is calculated and tabulated below:

Table 11 Total Energy required to meet RPO (MU)

Sl. No.	Year	Wind renewable energy (MU)	Hydro renewable energy	Other renewable energy	Distributed renewable energy	Total renewable energy
1.	**2025-26**	13.1	7.4	533.9	43.2	678.5
2.	**2026-27**	29.8	25.1	580.5	57.4	764.8
3.	**2027-28**	41.9	28.5	637.0	72.7	854.6
4.	**2028-29**	53.9	31.3	696.7	88.9	942.6
5.	**2029-30**	67.2	32.4	754.4	106.1	1022.1
6.	**2030-31**	988.8			109.9	1098.6
7.	**2031-32**	1048.6			113.7	1162.3
8.	**2032-33**	1106.3			117.7	1223.9
9.	**2033-34**	1163.9			121.8	1285.7
10.	**2034-35**	1218.7			126.1	1344.7
11.	**2035-36**	1275.8			130.5	1406.3

Table 12 Renewable Energy Deficit/Surplus

FY	RE Generation required to meet RPO	RE Generation required to meet RPO	RE Generation available/met (From existing/ planned contracts)	RPO met (%)	RPO Surplus (+)/ Deficit (-)
	(MU)	(%)	(MU)	(%)	(%)
2025/26	678.5	33.01%	1450	70.54%	37.53%
2026/27	764.8	35.95%	1540	72.40%	36.45%
2027/28	854.6	38.81%	1626	73.83%	35.02%
2028/29	942.6	41.36%	1635	71.74%	30.38%
2029/30	1022.1	43.33%	1729	73.29%	29.96%
2030/31	1098.6	45.00%	1742	71.34%	26.34%
2031/32	1162.3	46.00%	1753	69.39%	23.39%
2032/33	1223.9	47.00%	1763	67.41%	20.41%
2033/34	1285.7	47.50%	1767	65.29%	17.79%
2034/35	1344.7	48.00%	1772	63.23%	15.23%
2035/36	1406.3	48.50%	1776	61.25%	12.75%

As indicated in the tables above, the UT will be able to meet its RPO requirements till 2035-36 based on the existing and planned contracts envisaged.

7.0 Outcome of the model

7.1 Unserved Energy Projections

Initially, the study has been carried out considering only the existing and planned capacity contracts. The total unserved energy for the year 2035-36 has been estimated as 243 MU. The year-wise likely unserved energy with the planned capacities is given in the figure.

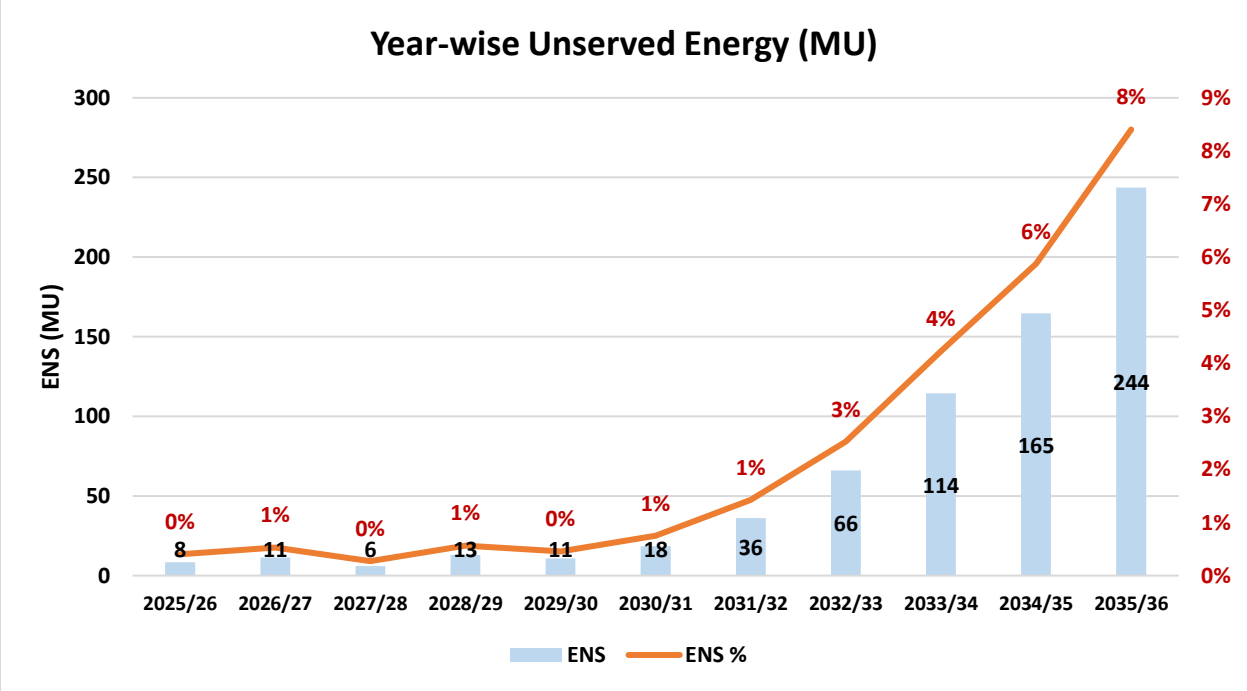


Figure 9 Yearly likely unserved energy (in MU) with the existing and planned capacities

The study has also analyzed the daily and monthly pattern of unserved energy in the year 2035-36, it can be seen that contracted capacity (present and planned) is unable to meet the projected electricity demand.

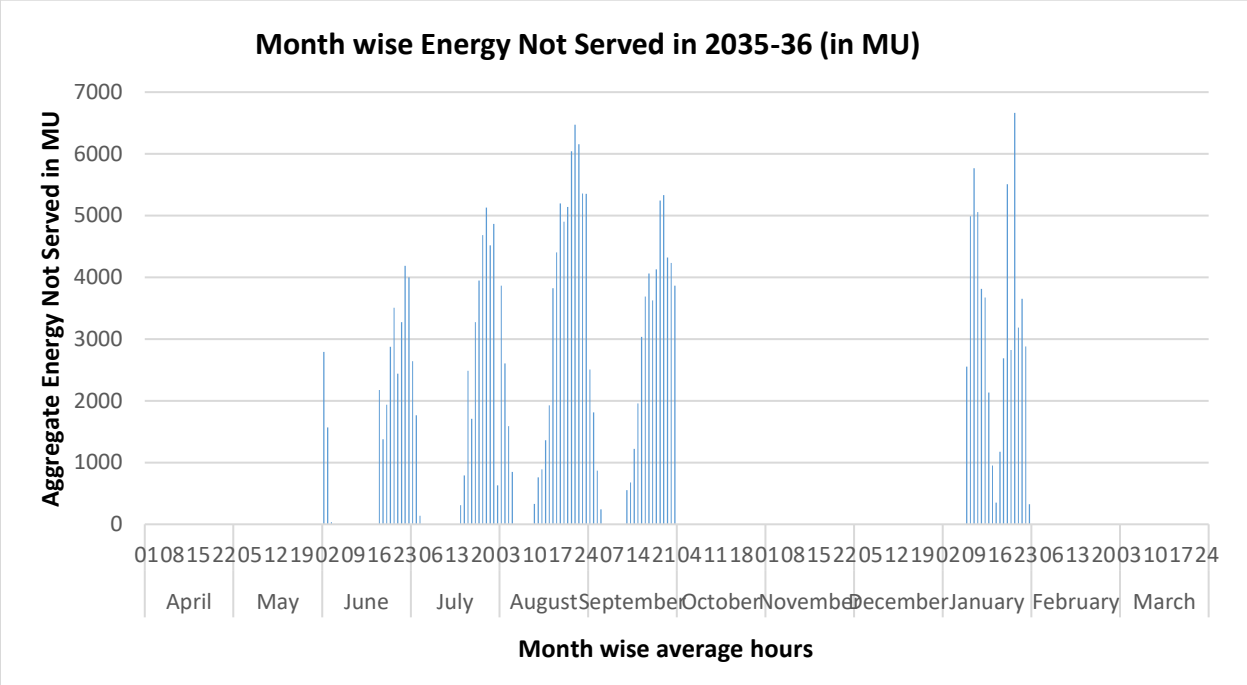


Figure 10 Block-wise Unserved Energy Pattern GWh (2035-36)

The unmet demand occurs during both solar and non-solar hours in peak demand months. Additionally, the UT is expected to face unmet demand during non-solar hours from January to March.

7.2 Options to meet the unserved energy

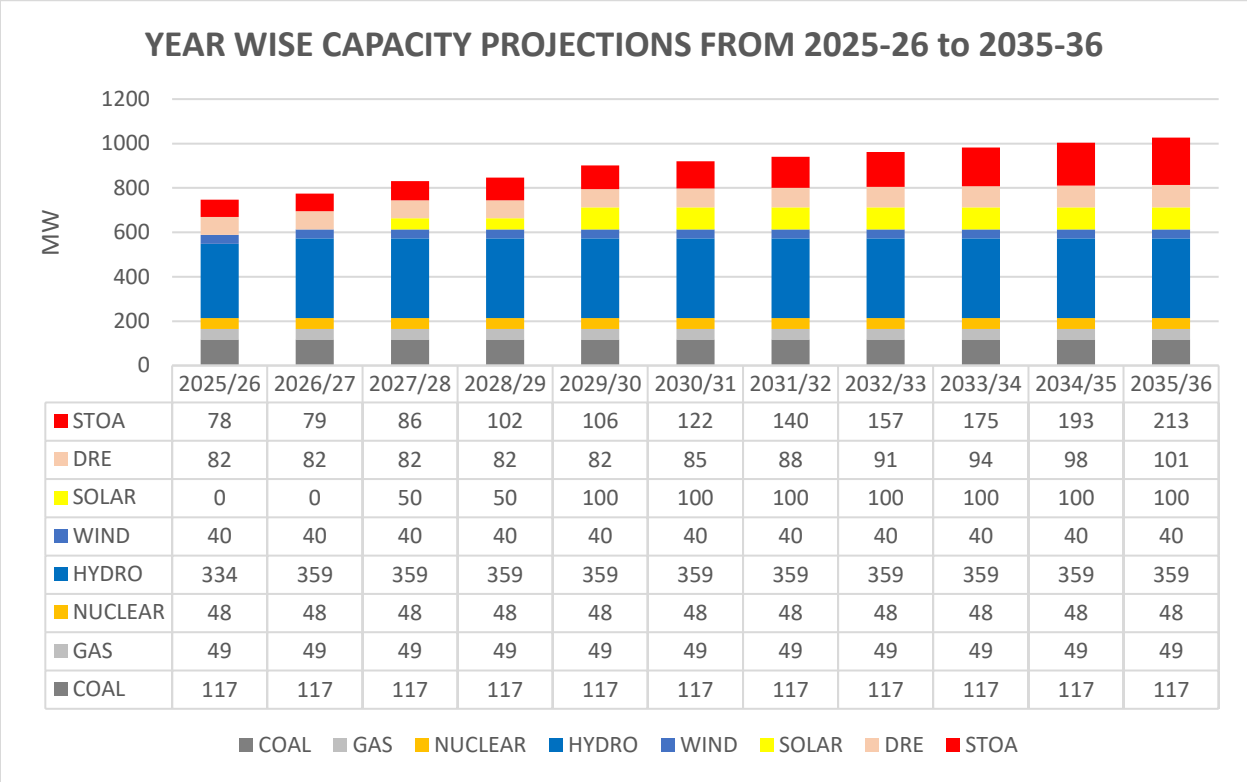
To meet this unserved energy, candidate capacities are given to the model to find the least cost optimal capacity mix required to meet the demand with RPO obligations. The capacity projections for Chandigarh are given below:

Table 13: Year-wise contracted capacity projections (in MW)

Year	COAL	GAS	NUCLEAR	HYDRO	WIND	SOLAR	DRE	STOA
2025/26	117	49	48	334	40	0	82	78
2026/27	117	49	48	359	40	0	82	79
2027/28	117	49	48	359	40	50	82	86
2028/29	117	49	48	359	40	50	82	102
2029/30	117	49	48	359	40	100	82	106
2030/31	117	49	48	359	40	100	85	122
2031/32	117	49	48	359	40	100	88	140
2032/33	117	49	48	359	40	100	91	157
2033/34	117	49	48	359	40	100	94	175

Year	COAL	GAS	NUCLEAR	HYDRO	WIND	SOLAR	DRE	STOA
2034/35	117	49	48	359	40	100	98	193
2035/36	117	49	48	359	40	100	101	213

The projected year-wise contracted capacity mix is given in the figure below:



	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36
STOA	78	79	86	102	106	122	140	157	175	193	213
DRE	82	82	82	82	82	85	88	91	94	98	101
SOLAR	0	0	50	50	100	100	100	100	100	100	100
WIND	40	40	40	40	40	40	40	40	40	40	40
HYDRO	334	359	359	359	359	359	359	359	359	359	359
NUCLEAR	48	48	48	48	48	48	48	48	48	48	48
GAS	49	49	49	49	49	49	49	49	49	49	49
COAL	117	117	117	117	117	117	117	117	117	117	117

Figure 11 Projected Contracted Capacity Mix Year-wise (MW)

The STOA/MTOA requirement can be fulfilled through power procurement from market or bilateral agreements. The STOA/MTOA value reflects the peak value requirement and seasonal banking requirements in terms of MW.

Reliability studies have been conducted based on the projected capacity for the year 2035-36. The analysis confirms that the projected capacity meets the reliability criteria specified in the National Electricity Plan (NEP), with the Loss of Load Probability (LoLP) and Normalised Energy Not Served (NENS) remaining within the permissible limits of 0.2% and 0.05%, respectively [as specified in the National Electricity Plan (NEP)].

As per the Resource Adequacy studies, the likely total projected contracted capacity for the year 2035-36 is around 814 MW which consists of 117 MW from coal, 49 MW from gas, 48 MW from nuclear, 359 MW from hydro, 40 MW from wind, 100 MW from solar, 101 MW from Distributed Renewable Energy (DRE) sources. Further, in addition to this, 213 MW of MTOA/STOA arrangement will be required. This capacity shall be able to meet the projected demand with prescribed reliability criteria.

It is important to note that any deviations in the commissioning schedule of the planned capacity could result in a situation where the UT is unable to meet the projected peak demand and energy requirements identified in this study with the available resources. Such changes may also lead to an increase in the cost of reliably meeting the UT's power demand.

The Planning Reserve Margin (PRM) for Chandigarh has been assessed at 1% during Solar hours and 3% during non-solar hours. Furthermore, the projected/contracted capacity is in compliance with the stipulated Renewable Purchase Obligation (RPO) targets.

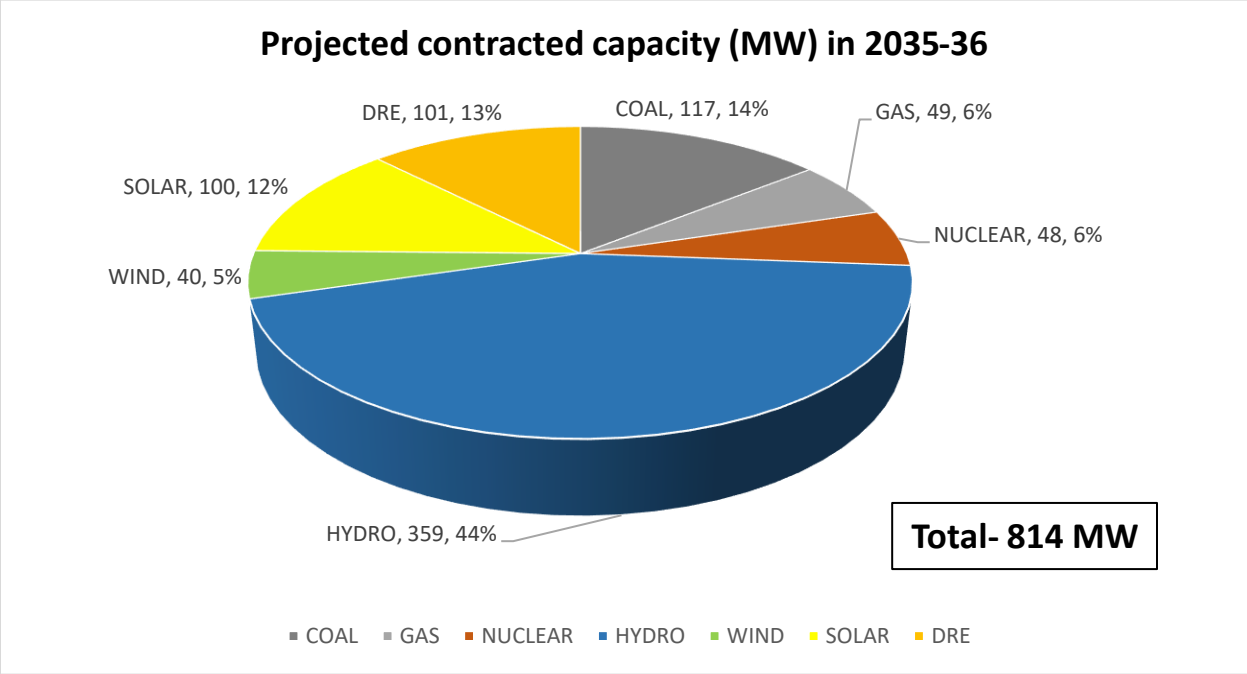


Figure 12 Contracted Capacity Mix in 2035-36

As per the study, the utility needs to contract following capacities (planned and additional) till 2035-36 to reliably meet its demand.

Table 15 Year wise Capacity Addition (in MW)

	Hydro	SOLAR	DRE
Year	**Planned Contracts**	**Planned Contracts**	**Additional Requirement**
2025/26	0	0	0
2026/27	25	0	0
2027/28	0	50	0
2028/29	0	0	0
2029/30	0	50	0
2030/31	0	0	3
2031/32	0	0	3
2032/33	0	0	3
2033/34	0	0	3
2034/35	0	0	4
2035/36	0	0	3
Total	**25**	**100**	**19**

The share of non-fossil fuel-based capacity in the generation mix is projected to remain between 70-86% from 2025-26 to 2035-36. The projected gross generation mix for the UT is shown in figure:

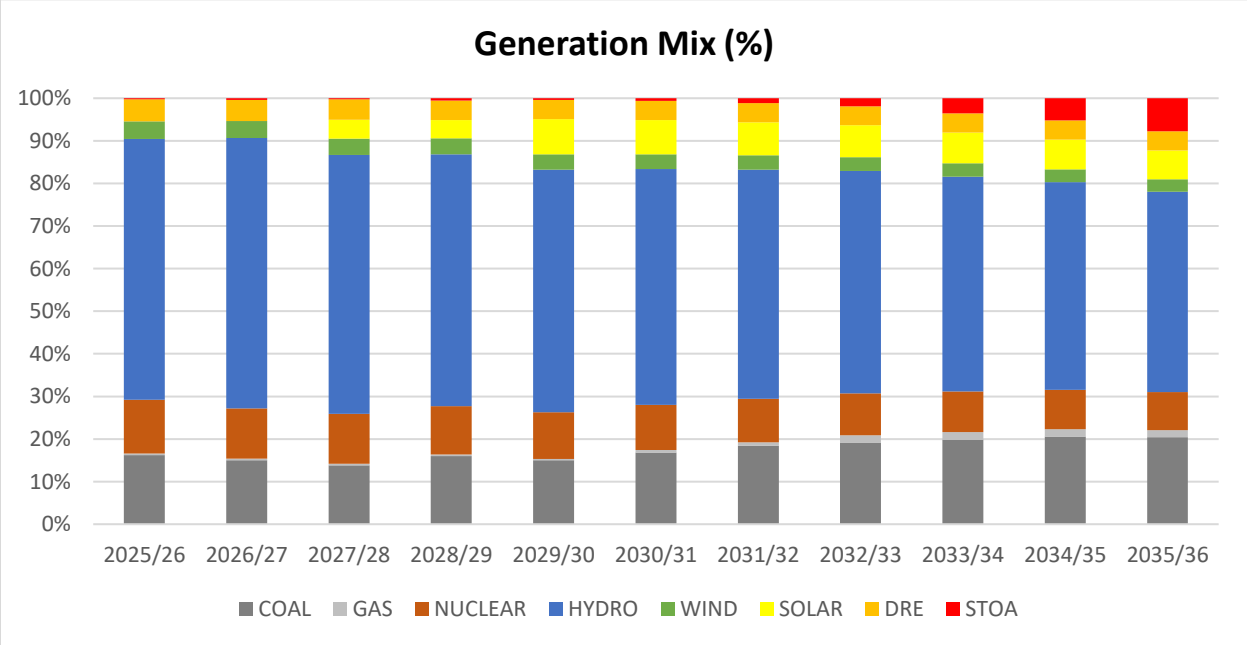
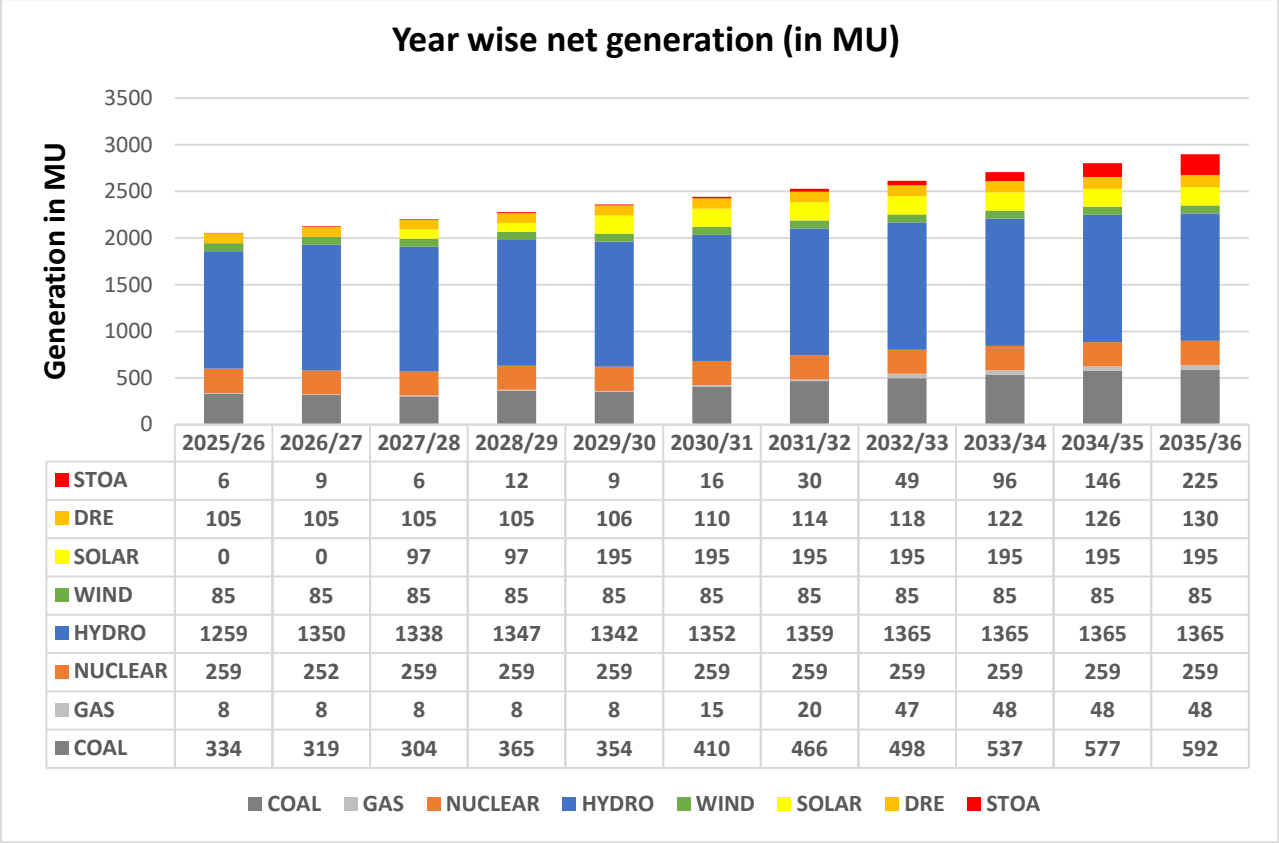


Figure 13 Year-wise projected gross generation mix (in %)



	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36
STOA	6	9	6	12	9	16	30	49	96	146	225
DRE	105	105	105	105	106	110	114	118	122	126	130
SOLAR	0	0	97	97	195	195	195	195	195	195	195
WIND	85	85	85	85	85	85	85	85	85	85	85
HYDRO	1259	1350	1338	1347	1342	1352	1359	1365	1365	1365	1365
NUCLEAR	259	252	259	259	259	259	259	259	259	259	259
GAS	8	8	8	8	8	15	20	47	48	48	48
COAL	334	319	304	365	354	410	466	498	537	577	592

Figure 14 Year-wise projected gross generation (in GWh)

7.3 Day-wise Surplus Coal Capacity (in MW)

Surplus capacity is available with the UT due to RE availability, Demand variation etc. The pattern of surplus capacities is given in Figure 15. This capacity can be shared with other states/ Discoms and reduce the fixed cost burden on the utility resulting in reduction in the cost to consumer. The UT has likely surplus capacity of around 40 MW during February to May months and 60-90 MW from October to December in 2028-29 as shown below which can be shared with other states/ Discoms.

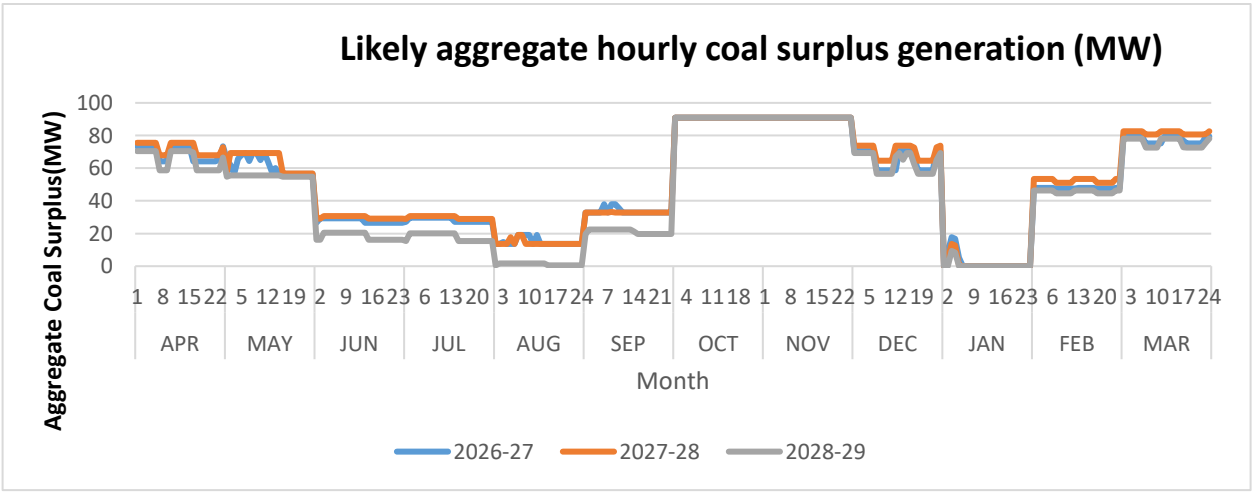


Figure 15 Surplus Coal Capacity Year-wise (MW)

8.0 Conclusions

Based on the Resource Adequacy studies of Chandigarh up to the year 2035-36, the following conclusions may be drawn:

1. The study has been done based on the hourly demand pattern of the year 2024-25. Based on the demand pattern, it is seen that the peak demand season is typically from June to August with peak demand occurring during solar hours.
2. The study has considered energy requirement projections as per the projections of CPDL, which envisages that the annual energy requirement of the UT is likely to grow at a CAGR of 3.5 % while the peak demand for the utility is likely to grow at a CAGR of 3.2% for the period of 2025-26 to 2035-36.
3. Chandigarh is likely to witness energy deficit ranging from 18 to 243 MUs in different years from 2025-26 to 2035-36 with the existing and planned capacity addition only.
4. The UT is likely to have unserved energy in coming years and need to contract STOA/MTOA around 78 MW to 213 MW in different years as outlined in the report. The STOA/MTOA requirement can be fulfilled through power procurement from market or bilateral agreements. The STOA/MTOA value reflects the peak value requirement and seasonal banking requirements in terms of MW.
5. The projected capacity and generation mix outlined in the report, meets the utility's RPO requirements for the years 2025-26 to 2035-36.
6. The Planning Reserve Margin (PRM) for Chandigarh has been assessed at 1% during Solar hours and 3% during non-solar hours. Further, the study indicates year-wise short-term/medium-term/bilateral requirements to meet the demand optimally.
7. The current capacity mix of the utility has 25% of contracted capacity from fossil fuel sources. The share of fossil fuel based capacity is likely to reduce to 20% in 2035-36. In 2035-36, the RE based (that includes hydro, solar, wind, biomass and DRE) capacity are likely to constitute around 74 % of the total installed capacity.
8. It is likely that Chandigarh may have surplus capacity available during the months from February to May and October to December which can be shared with other utilities/states through banking / bilateral arrangements including Pushp portal.
9. Accurate demand assessment is fundamental to capacity expansion modelling and directly impacts the Resource Adequacy (RA) study outcomes. To achieve realistic and data-driven results, States/UTs are strongly encouraged to adopt scientific tools and robust methodologies for demand forecasting.
10. Timely commissioning of planned capacities is critical to ensuring that the UT can meet the projected peak demand and energy requirements identified in this study. Any deviation from

the planned schedule may lead to resource shortfalls and could significantly increase the cost of reliably meeting the UT's power demand.

11. For the purpose of Peak load management and Renewable Energy Integration, the UT of Chandigarh can explore the tie up with storage capacity or BESS installation in the license area. This may offset the STOA requirement for the UT of Chandigarh.

Annexure

Planned Future Contracted (MW) considered in the study

Sr. No.	Tied capacity name	Type of generation	Expected COD	Tentative CPDL share (in MW)
1.	Ratle HEP	Hydro	2026-27	20
2.	Subansiri HEP	Hydro	2026-27	5

Assumption for Resource Adequacy Studies

1. Electricity Demand & peak requirement: As per projections made by CPDL.
2. Demand Profile: Based on hourly demand profile of 2024-25.
3. Existing & Planned Capacity: As per the information shared by the utility.
4. Cost parameters: based on information in National Electricity Plan.

RE CUF considered

Hydro	Wind	Solar	DRE
43 %	24%	20-22%	15%

Technical Parameters

Technology	Type	Availability (%)	Ramping (%/min)	Min. Technical . (%)	Start -up time (hr)		
					Hot	Warm	Cold
Coal/ Lignite	Existing/Planned	85	1	55	2	5	10
	Candidate	88	1	55	2	5	10
Gas	Existing	90	5	40	1.5	2	3
Nuclear	Existing/Planned	68	Const. Load	-	-	-	-
Biomass	Existing/Planned	60	2	50	2	4	8
Hydro	Existing/Planned/ Candidate	As per available hourly generation profile	100	-	-	-	-
Solar	Existing/Planned		-	-	-	-	-
	Candidate		-	-	-	-	-
Wind	Existing/Planned		-	-	-	-	-
	Candidate		-	-	-	-	-
Pumped storage	Existing/Planned	95	50	-	-	-	-
	Candidate		50	-	-	-	-
Storage Energy Storage	Candidate	98	NA	-	-	-	-

Technology	Type	Heat Rate (MCal/MWh)	Aux. Consum. (%)	Min. online	Min. offline	Start-up fuel consumption (MCal/MW)

		At max loading	At min loading		time (hr)	time (hr)	Hot	Warm	Cold
Coal	Existing/ Planned	2300 to 2879	2438 to 3052	7.0	6	4	600	1000	1800
	Candidate (SC & USC)	2060 to 2125	2183 to 2253	6.5	6	4	600	1000	1800
Gas	Existing	2000 to 2900	2260 to 3277	2.5	4	3	30	50	90
Nuclear	Existing/ Planned	2777	2777	10	6	4	-	-	-
	Candidate	2777	2777	10	-	-	-	-	-
Biomass	Existing/ Planned	4200	4450	8	6	4	600	1000	1800
	Candidate	4200	4450	8	6	4	600	1000	1800
Hydro	Existing/ Planned	-	-	0.7	-	-	-	-	-
	Candidate	-	-	0.7	-	-	-	-	-
Pumped Storage	Existing/ Planned	-	-	pump efficiency 80 %	-	-	-	-	-
	Candidate	-	-		-	-	-	-	-
Storage Energy Storage	Candidate	-	-	Round trip losses 12%	-	-	-	-	-

Transmission Parameters

A single node has been considered for the purpose of study with all generating units and demand connected to the node. No transmission bottleneck has been considered for the study. Interstate ATC limit has not been considered in the study.

Financial Parameters

Following cost parameters have been assumed:

Resource	Capex* (in ₹/MW)	O&M Fixed Cost (in ₹/MW)	Construction Time (in years)	Amortization /Life time (in years)
Coal	11.5 Cr	19.54 Lakh	4	25
Solar	5 Cr	1 % of Capex	0.5	25
Wind (Onshore)	8 Cr	1% of Capex	1.5	25

Storage (2-Hour)	5.13 Cr to 3.13 Cr	1 % of Capex	0.5	14
Storage (4-Hour)	8.22 Cr to 4.72 Cr	1 % of Capex	0.5	14
Storage (5-Hour)	9.77Cr to 5.51 Cr	1 % of Capex	0.5	14
Storage (6-Hour)	11.31 Cr to 6.30 Cr	1 % of Capex	0.5	14