Roadmap and Policy Interventions and Key Drivers to Accelerate Development of Mid-Size (up to 200-500 MW) Hydro Power Projects in India by 2050

WORLD ENERGY COUNCIL
INDIA

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ABBREVIATIONS

APGCL	Assam Power Generation Corporation
BOOT	Build, own, operate, transfer
BU	Billion Units
BVPCL	Beas Valley Power Corporation Limited
CCS	Carbon capture and storage
CCUS	Carbon capture, utilisation, and storage
CEA	Central Electricity Authority of India
CERC	Central Electricity Regulatory Commission
CoP	Conference of the Parties
CPSE	Central Public Sector Enterprises
CSR	Corporate Social Responsibility
CUF	Capacity Utilisation Factor
CVPPL	Chenab Valley Power Projects
DAM	Day-ahead Market
DBFOO	Design build, finance, own, operate
DPR	Detailed Project Report
DSRA	Debt Service Reserve Account
EPC	Engineering, Procurement and Construction
ESG	Environmental, Social, and Governance
EV	Electric Vehicles
FAME	Faster Adoption and Manufacturing of Electric Vehicles
FOO	Finance owns operate
FRA	Forest Rights Act
GHG	Green House Gases
GoI	Government of India
GST	Goods and Service Tax
GTAM	Green Term-Ahead Market
GW	Gigawatt
GWh	Gigawatt hour
HPP	Hydro Power Projects
IBN	Investment Board of Nepal
IC	Installed Capacity
IDC	Interest during construction
IPP	Independent power producer
JKSPDC	Jammu & Kashmir State Power Development Corporation
KPI	Key Performance Indicators
KSEB	Kerala State Electricity Board Limited
kWh	Kilowatt hour
LADF	Local Area Development Fund
MIT	Massachusetts Institute of Technology
MOA	Memorandum of Association
MoU	Memorandum of understanding
MU	Million Units
MW	Megawatt
NECP	National Energy and Climate Plan

NEEPCO	North-eastern Electric Power Corporation Limited
NHPC	National Hydro Electric Power Corporation Ltd.
NITI	National Institution for Transforming India
NREL	National Renewable Energy Laboratory
NTPC	National Thermal Power Corporation
PCF	Pan-Canadian Framework
PLF	Plant load factor
PLR	Prime Lending Rate
PPA	Power Purchase Agreements
PSU	Public Sector Undertaking
PV	Photovoltaic
R&R	Resettlement & Rehabilitation
RE	Renewable Energy
S&I	Survey and Investigation
SJVN	Satluj Jal Vidyut Nigam Limited
SMR	Small modular reactors
SPV	Special purpose vehicle
T&D	Transmission and Distribution Losses
THDC	Tehri Hydro Development Corporation Limited
TPCL	Tata Power Company, Ltd.
TWh	Terawatt hour
UJVNL	Uttarakhand Jal Vidyut Nigam Ltd
WEF	World Economic Forum

CONTEXT

The India Member Committee of the World Energy Council aims to be the foremost energy think-tank of the country and the voice of the sector. The organization is truly representative of the Indian energy sector and contributes to advancing the energy goals of India. Its mission is to facilitate review, research, and advocacy of energy technology, policy, and strategy; to provide a platform for dialogue within the Indian energy sector; and to collaborate with member committees worldwide towards long term sustainable supply and use of energy. The India Member Committee brings together high-level players in the energy sector together to forge a better understanding of energy issues towards identifying and implementing sustainable, effective solutions.

Following are the two objectives of the Study:

1. **Road Map and Policy Interventions & Key Drivers to accelerate development of mid-size (Up to 200-500 MW) Hydro Power Projects in India by 2050**
2. **Pumped Storage Development as a National Strategy for Long Term Energy Storage to meet net Zero Emissions Target for India**

For each of these study, stakeholder consultation has been conducted with developers (public/private), operators, lenders, states, CEA, regulators etc. in detailed manner, Indian energy scenarios including generation mix of 2030, 2040,2050 has been projected via developing a model along with projected share of hydropower in overall Indian energy scenarios and thorough secondary research has been done as per the scope of work as stipulated.

This is the detailed report on the first objective of the study i.e., "**Road Map and Policy Interventions & Key Drivers to accelerate development of mid-size (Up to 200-500 MW) Hydro Power Projects in India by 2050**".

The Overview of strategic areas of the projects scope are:

FOREWORD

The report is prepared by Ernst and Young LLP for World Energy Council India on the topic "Roadmap and Policy interventions and key drivers to accelerate development of mid-size (up to 200-500 MW) Hydro Power Projects in India by 2050". The period between 2022 and 2050 is quite critical for Indian energy sector owing to two reasons. First, Indian energy sector is preparing a trajectory to achieve net zero in 2070. Second, India will also witness a high electricity demand owing to its promising economic growth. For striking a balance between the two, role of hydro power sector is quite important. Though, India has a hydro power potential of ~145 GW, however, not even 1/3rd of the total potential is tapped. For India, most of the hydro power potential is in Himalayan region and on perennial rivers. Therefore, development of hydro power projects will not only ease the RE intermittency issue but also be helpful in flood control, water management, irrigation planning etc.

Owing to strategic nature of the subject, views of multiple stakeholders have been collected. These include various wings of CEA, CERC, CWC, Grid controller of India (formerly POSOCO), NHPC, SJVN, THDC, NTPC hydro units, IPPs, banks and financial institutions, equity funds, discoms etc. Therefore, we are expressing our thanks to officials and management of these organizations. We also want to express our thanks to the experts – Shri Anil Kumar Jha and Shri Janardan Choudhary for critically examining and providing valuable insights. Last but not the least, we want to thank World Energy Council India for giving an opportunity to work on the project. Working with such diversified stakeholder pool has enabled us to capture most of the impending issues and proposed workable solutions.

EXECUTIVE SUMMARY

With the shared vision of world and India of moving towards net zero vision in which Hydro Power projects will play a crucial role in meeting the aspirations. Therefore, it is imperative for the country to develop hydro power projects. For the said purpose, two scenarios have been created. One is high hydro scenario and other is high renewable scenario where hydro power projects will be developed at current pace. In high hydro scenario, India can develop 106 GW of hydro power by 2050. However, in high RE scenario, India can develop a maximum of only 73 GW of hydro power by 2050. It may be noted, for achieving high hydro scenarios, sectoral landscape needs to be changed. Some of the key changes which has been discussed in the report are as follows:

- **Revamping project allotment process:** The state should clearly define the project allotment process to CPSU, state sector PSU and IPPs. State government ideally follows the competitive bidding route for allocating the project. For conducting competitive bidding, a standard bidding document may be developed which may be adopted by different states. The principle of competitive bidding is mentioned in subsequent section. However, state shall have the option to allot project on MOU basis. The SOP, application format and allocation criteria for allotting the project on MOU basis should be notified by various states. The MOA/allotment agreement may need to homogenize and concessions to state government shouldn't have a bearing on tariff. Moreover, the MOA/allotment agreement should clearly define the milestones and the outcomes of not meeting the milestones.

- **Competitive bidding process:** Though, the experience with the IPPs pertaining to development of hydro power projects were not very good in the past, they should not be ruled out, any allocation to private developer may be done via competitive bidding. However, before conducting competitive bidding, balanced risk segregation framework may be finalized. For the said purpose, DBFOO (Design Build Finance Own Operate) framework is proposed. Also, for monetization of commissioned projects FOO (Finance Own Operate) framework is proposed. CEA may also conduct basin wise study and all the projects in a basin may be allocated/awarded via auction to one developer.

- **Market design:** 70% of the capacity may be under long term PPA. The tariff may be determined via cost plus or governed under price quote. The term of PPA may be 25/30 years beyond which developers shall have the freedom to sell power in market/ blending with renewable/ new hydro power stations. Developers may be allowed to sell 30% of power in market/ blending with renewable/ other hydro stations. The above market design will help in striking a balance between missing money and injecting liquidity in market.

- **Expediting clearances:** There are also scope of introducing means which will crash the time schedule. Such means include submission of online form based DPR, defining maximum turnaround time for every process and sub process, and introducing one stop window for getting clearances.

- **Increasing the involvement of state government:** Participation of state government in entire process needs to be increased. State government should play an active role in organizing public hearings, conducting awareness outreach program, acquiring land, preparing, and executing a SOP based law and order maintaining program etc.

- **Active monitoring framework:** An active monitoring mechanism may be introduced at state and central level. Appropriate escalation matrix at both centre and state level shall keep developers on toes.

- **Concessions for reducing tariff:** Required concessions from state and central government may also be given to reduce the tariff. This will improve the saleability of power and increases the viability of the plant. Some of these concessions include CGST and SGST waiver, including the dedicated transmission line under enabling infrastructure, waiver of upfront premium, reducing free power which is given as royalty to states and LADF and collecting in form of monetary consideration, waiver of GST on royalty free power, if any. State should also consider waiver of water cess and state specific tax. Waiver of ISTS charges, similar to renewable, may also make hydro power lucrative.

- **Increasing the availability of capital**: Lenders may get tax concessions on the interest charged (up to certain rate say MCLR plus 50 bps) against the loan disbursed for the development of hydro power projects. This will act as an incentive for funding hydro power projects. The sector cap may also be relaxed for funding hydro power projects.

- **Resolution of stalled projects:** In cases, where event of default has been triggered, state government should terminate the current allocation, even if project is deemed revert to state, and reallocate to different developer (PSU) by issuing fresh allotment agreement/MOA. In cases, where allotment agreement/ MOA is valid but event of default about to trigger, state government may observe the progress and discuss with developer. Post discussion, state government may examine if there is a case of termination or deemed revert. If there is no significant progress and current developer is not in position to develop, MOA need not to be extended. GoAP may also identify CPSUs and ask them to take over the project. If CPSU agrees to take over the project, the project may be transferred to CPSU, and adequate compensation may be paid to IPP (case to case bases). The framework for determining the compensation is mentioned in subsequent sections. This will expedite the project development and reduces the litigations in such transfers.

Chapter 1

Key Role of Hydropower in the transition to clean energy: Global & Indian Scenario

1.1. CURRENT POWER SCENARIO OF INDIA

Installed capacity has reached 400 GW with highest share (59%) of thermal capacity.

Below table and graph represent the Current Power Scenario (IC) of India (31.03.22) -

Table 1: Current Power Scenario of India (31.03.22)

Sector	Installed capacity (GW)
Thermal	**236.11**
Coal	204.08
Lignite	6.62
Gas	24.9
Diesel	0.51
Nuclear	**6.78**
Renewable	**156.602**
Hydro	46.722
SHP	4.848
Wind	40.36
Biomass	10.2
WtE	0.476
Solar	53.996
Total	**399.4**

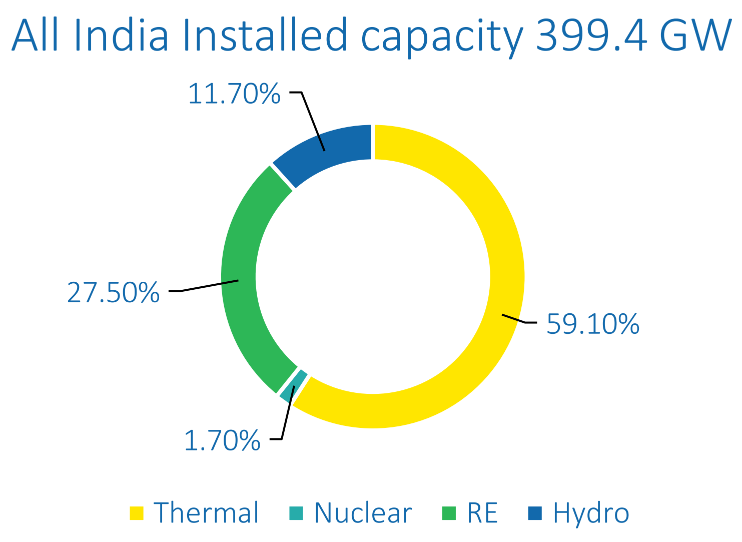


Figure 1: All India IC (GW)

- India is a coal dominated power system with largest installed capacity of 204 GW.

- India's generation mix consists of 59.1% of thermal; 11.7% of hydro; 1.7% of nuclear and 27.5% of renewable energy (RE). It shows the domination of thermal in India's generation mix.
- In the case of Renewable energy, solar constitutes the maximum share, followed by wind.

Demand is increasing in the year FY 22 and is expected to increase in FY 23

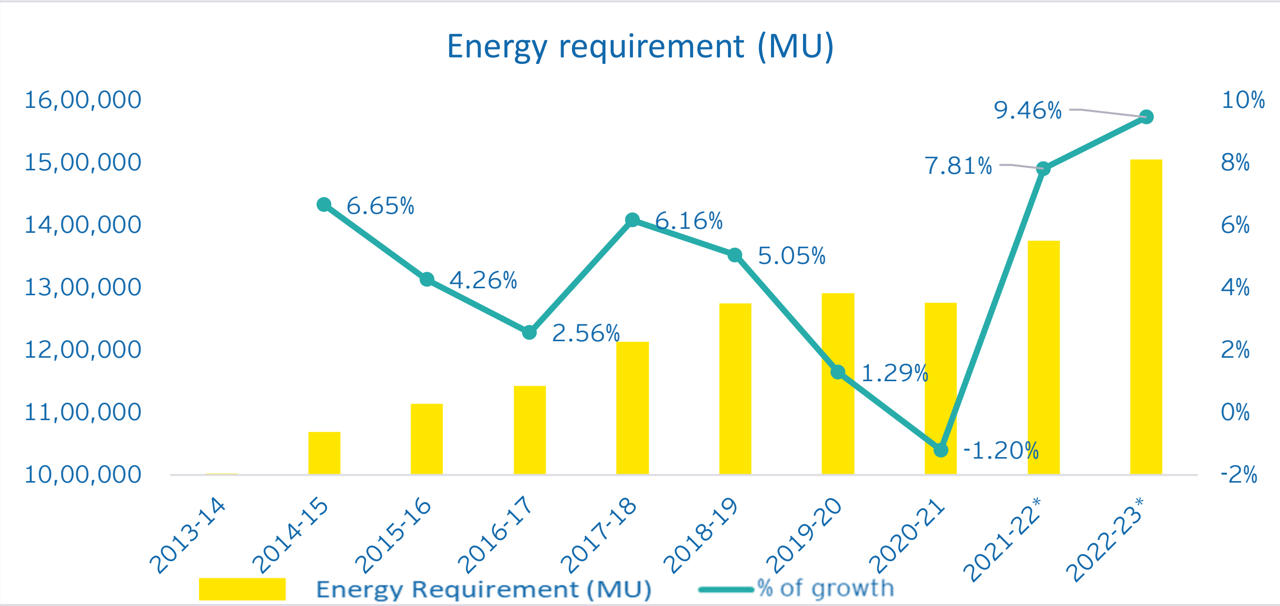


Figure 2: Demand increase in FY 22

- After a fall in FY 21 due to COVID-19 pandemic, there is an increasing trend in the energy requirement in the last year (FY 22) and is expected to keep the increasing momentum in FY 23 also.

All India peak demand trend (MW)

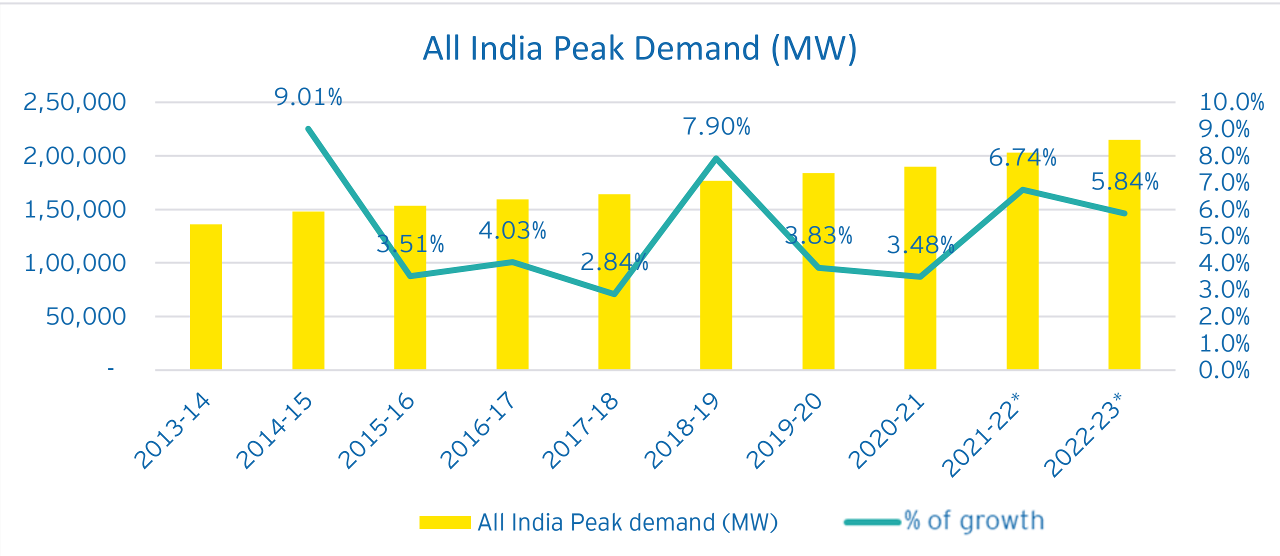


Figure 3: All India peak demand (MW)

- In the peak demand, there was a fall in FY 20 and FY 21, but it is again bouncing back in FY 22 and is expected to keep high momentum in FY 23 also.

Total generation in India including renewable sources (BU) and % growth

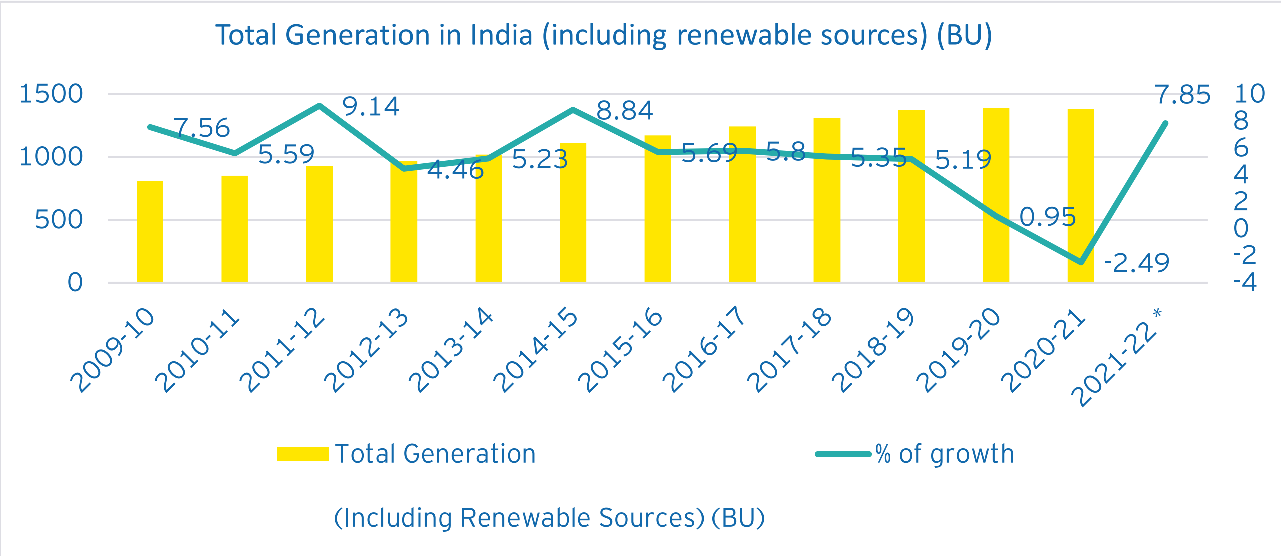


Figure 4: Total Generation in India (BU)

- The electricity generation target of thermal, hydro, nuclear & Bhutan import for the year FY 22 has been fixed as 1356 BU. (+9.83% over actual generation of 1234.6 BU in FY 21
- There was a negative growth in FY 21 (1234.g BU) as compared to FY 20 (1250.8 BU) representing a negative growth of about 1.29%.

1.2. CLEAN ENERGY TRANSITION ROADMAP FOR INDIA

India in CoP – 26

India's updated Nationally Determined Contribution (NDC) has been communicated to the United Nations Framework Convention on Climate Change (UNFCCC) -

1. India now stands committed to reduce Emissions Intensity of its GDP by 45 percent by 2030, from 2005 level.
2. Achieve about 50 percent cumulative electric power installed capacity from non-fossil fuel-based energy resources by 2030.

Win-win for the nation and the world

- As per WEF, India's transition to a net zero economy can save lives, catalyse new industries, create over 50 million jobs, add $1 trillion to GDP by 2030 and contribute more than $15 trillion in economic impact by 2070.
- India's path to rapid decarbonization can be a net-positive journey, with a net economic impact of over $1 trillion by 2030 and ~$15 trillion by 2070.
- India has an opportunity to take bold action to enable economic prosperity and avert the worst impacts of a changing climate. Supported by the right economic framework, these actions can put India – and the world – on a path to realizing strong, equitable and shared growth.

> WEF defines an effective energy transition as
> ***"A timely transition towards a more inclusive, sustainable, affordable and secure energy system that provides solutions to global energy-related challenges while creating value for business and society, without compromising the balance of the energy triangle."***

Shift towards renewable energy, CAGR (2011-19) for various energy sources

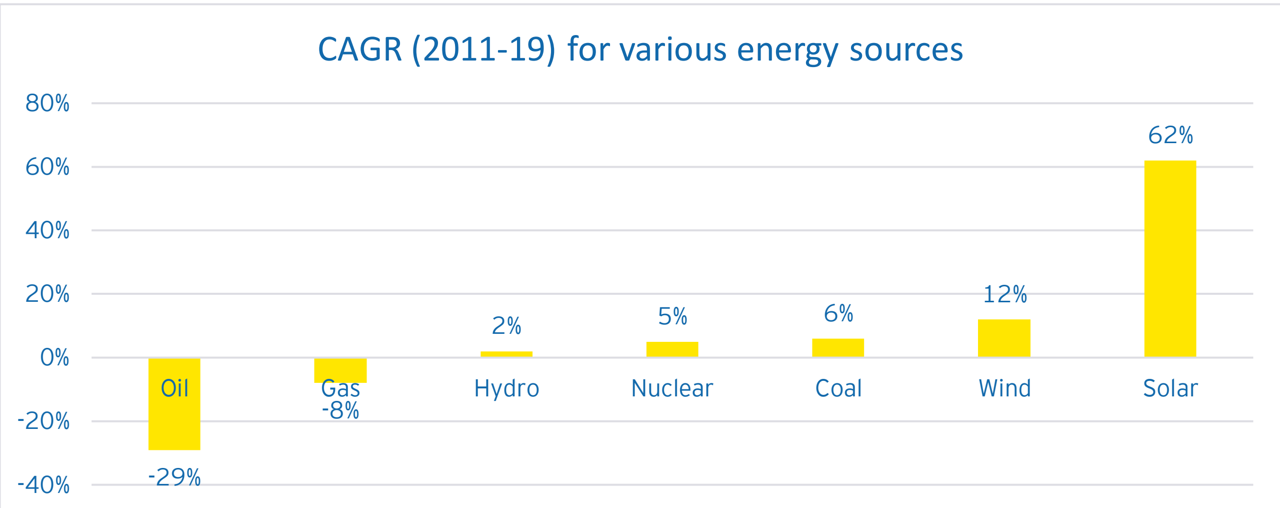


Figure 5: CAGR (11-19) from various energy sources[1]

- Electricity accounts for largest GHG emission (~34%) in India (2016-2017). Even though the share of coal is highest but the growth in renewable capacity has seen rapid growth.

1 - India_Green_Stimulus_Report_NITI_VF_June_29.pdf

Mission 2070: A Green New Deal for Net Zero India

Need to focus on the below 5 pillars

1. Low-carbon Energy	2. Green Mobility	3. Decarbonization of Energy-Intensive Industries	4. Green Buildings, Infrastructure and Cities	5. Sustainable Agriculture
Accelerated adoption of renewable/green energy/H2 across India	Adoption of electric, hydrogen, LPG/LNG, and other alternative green technology-based mobility platforms	Modernizing and decarbonizing energy-intensive industries through the adoption of green technologies and standards	Promoting green cities, energy efficient buildings, and green construction technologies in future infrastructure projects	Transitioning to sustainable methods of farming

Enablers

1. **Green Technology Innovation -** R&D and investments in technologies that can accelerate the carbon transition .
2. **Green Finance -** Adopt a clear and consistent taxonomy for green finance, Explore a formal carbon pricing framework for India, Mobilize domestic savings and institutional capital, Proactively attract global capital.
3. **Carbon Sequestration - CCUS and Carbon Sinks** Catalysing carbon capture as well as carbon offsets (natural sinks and Direct air carbon capture and storage).
4. **Climate Adaptation -** India cooling plan, knowledge and capability building, indoor work transitions.

Indian Energy Scenario- In all scenarios coal fired capacities first increases and then decreases

Power capacity in India by source, Sustainable Development Scenario, 2000-40 (GW)

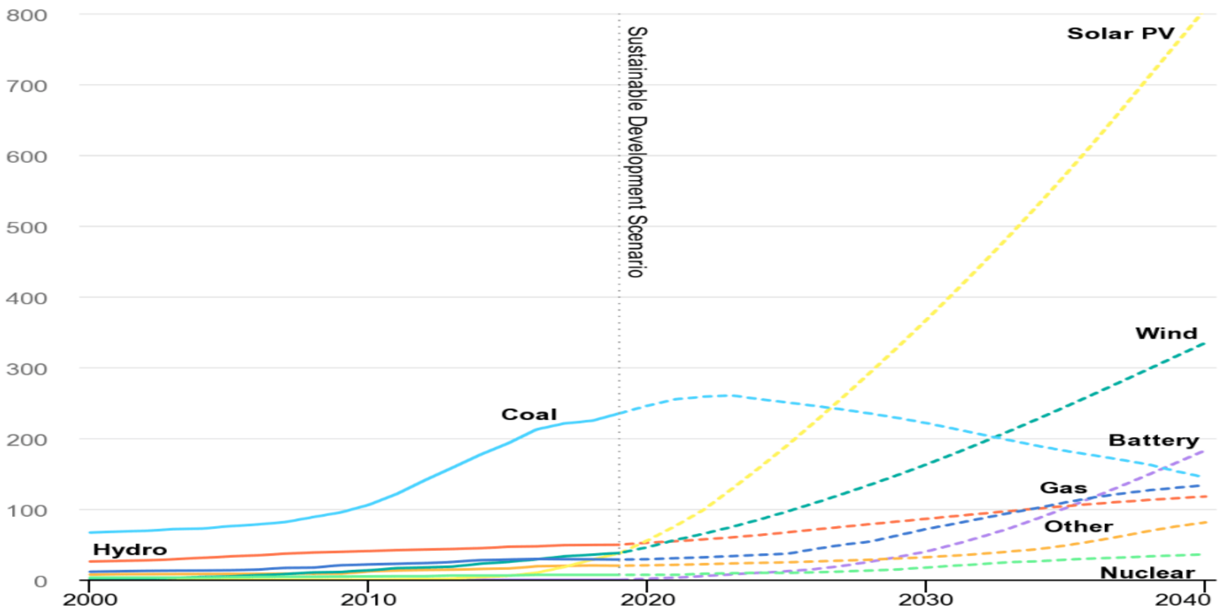


Figure 6: Power capacity in India by source[2]

Note: The above graph has been taken from the report "*Fuels and electricity in India – India Energy Outlook 2021 – Analysis - IEA*". It is a part of literature review but it is unlikely case that generation from gas will increase in coming future

2-Fuels and electricity in India – India Energy Outlook 2021 – Analysis - IEA

Power capacity in India by source in the India Vision Case, 2000-2040 (GW)

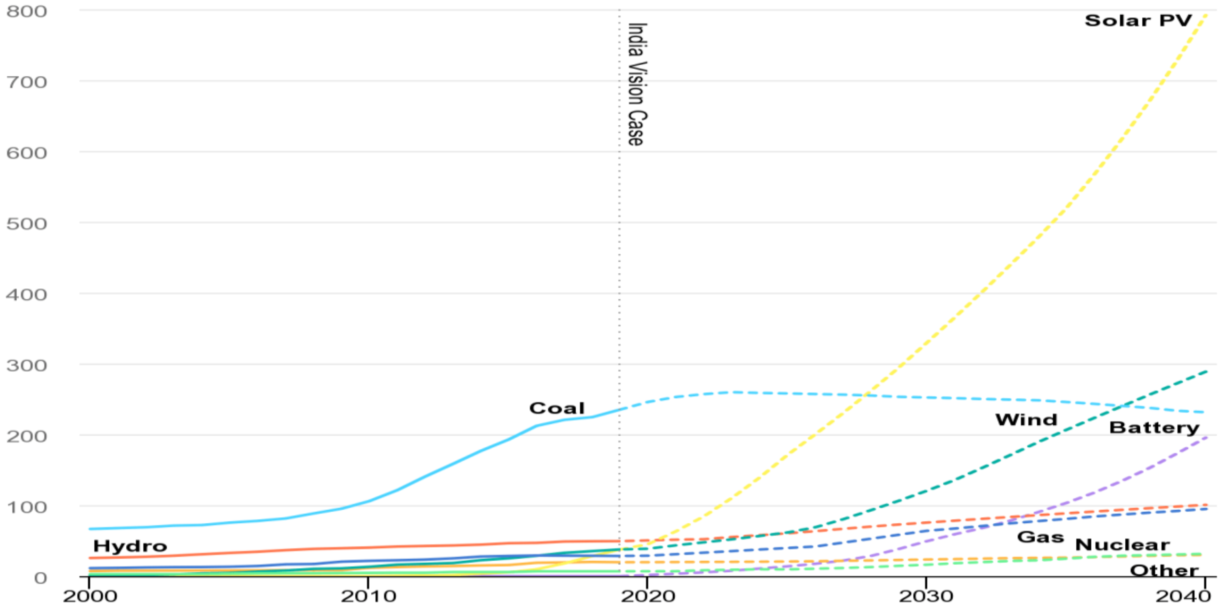


Figure 7: Power capacity in India by source in India Vison Case, 2000-40 (GW)

- In the above graph, solar and wind reach 344 GW and overtake coal capacity of 269 GW in 2030. The World Energy Outlook (2021) shows over 620 GW of solar and 219 GW of wind capacity in the Stated Policies Scenario (STEPS), and over 720 GW of solar and 309 GW of wind in the SDS, by 2040.
- In both scenarios, coal capacity increases up to 2030 and then declines. In the STEPS, coal is at 260 GW by 2040, while in the Sustainable Development Scenario (SDS) it is only at 144 GW.

GoI is working on stringent targets, coming up with clean energy focused schemes & policies and ranking to bring state-wise participation in the direction of clean energy

Renewable energy target

The government has established a national renewable energy target of 175 GW of solar and wind by 2022 and 500 GW by 2030.

Battery storage

National Mission on Transformative Mobility and Battery Storage, announced in March 2019, plans to establish a few gigawatt-scale, export-competitive integrated batteries, and cell-manufacturing plants in India.

FAME scheme for clean mobility

Faster Adoption and Manufacturing of Electric Vehicles (FAME) II scheme to support the adoption of 7,000 electric buses, 5 lakh electric three-wheelers, 55,000 electric passenger cars, and 10 lakhs electric two wheelers.

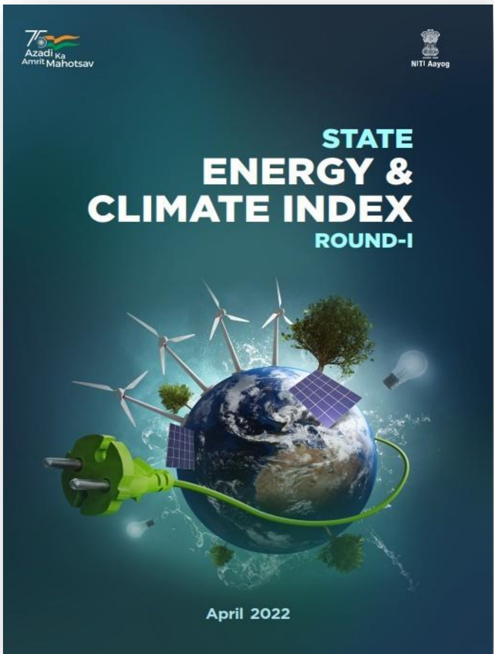
It is supplemented with announcement of state EV policies, and guidelines on EV charging and charging infrastructure from various ministries.

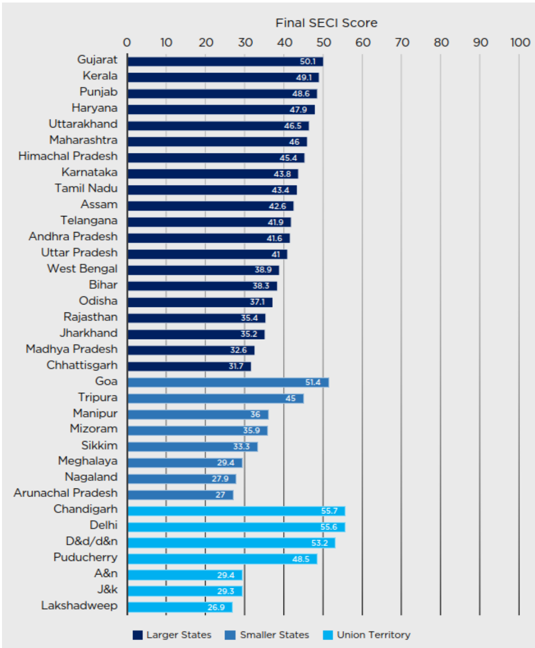
State Energy and Climate Index

Based on the criticality of role of governance and peer-to-peer learning among various states of India, NITI Aayog has come up with this index. It is based on the premise that state governments can play a key role in implementation of central policies and thereby administering the energy transition.

It creates a national benchmark for states. The state performance is done on 27 KPIs under following 6 parameters –

1. DISCOM's performance
2. Access, Affordability & Reliability
3. Clean energy initiatives
4. Energy efficiency
5. Environmental sustainability
6. New initiatives





Action plan for stakeholders – govt, corporates, investors, civil society & citizens[3]

1 Government

- Clear targets and roadmaps for each sector.
- Framework of regulations and incentives to catalyse change and innovation.
- Balanced approach to carbon pricing and a collaborative process for stakeholder engagement.

2 Corporates

- India's corporates will need to step up and set ambitious decarbonization targets.
- Measure and publish their carbon footprint.
- Review every aspect of their business to reduce carbon intensity.
- Engage in cutting-edge decarbonization R&D.
- Innovate business models,
- Invest significantly in the climate change agenda.

3 Investors

- Investors can push for greater carbon transparency from their investees.
- Catalyse climate-positive corporate action.
- Commit capital to green finance efforts.
- Expand investment time horizons to enable the adoption of longer payback capital investments in sustainability.

4 Civil society and citizens

- Civil society organizations, along with the media, will need to inform and educate the public and continue informing the national discourse on climate change.
- Individual citizens will need to be willing to switch to greener products, adopt more sustainable diets, reduce their mobility footprint.
- Vote for and support a green national agenda.

3 –WEF white paper titled "Mission 2070: Green new deal for a Net Zero India" published on Nov 2021,

1.3. INTERNATIONAL CASE STUDY IN RESPECT TO CLEAN ENERGY TRANSITION

Case of Sweden – 1

In Sweden, Renewable energy has the major share in the installed capacity and generation. Within which hydro power occupies the majority share with a 38% contribution.
Below graph represent renewable energy capacity (MW) in 2020

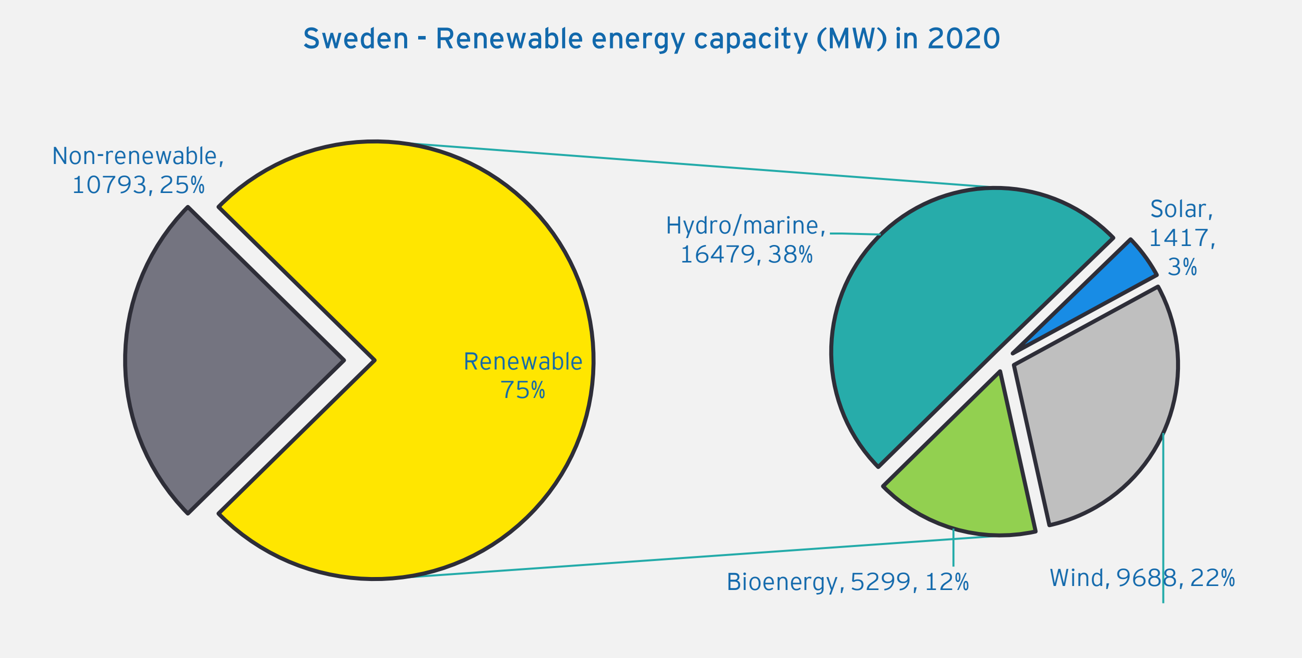


Figure 8: Sweden - RE Capacity (MW) 2020[4]

Below graph represent Generation (GWh) 2020

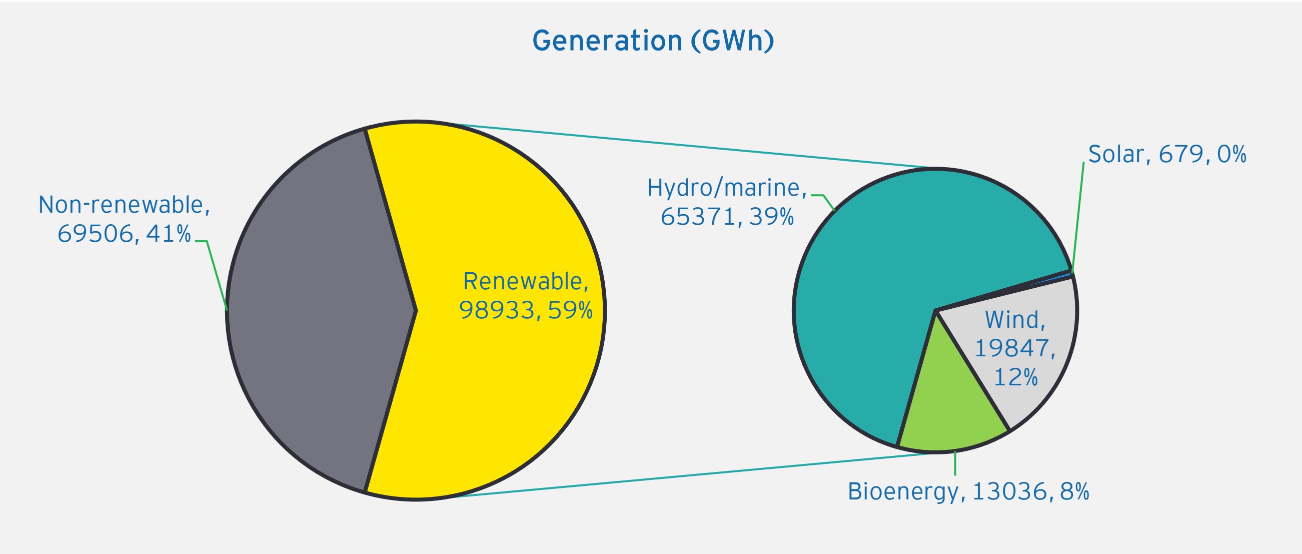


Figure 9: Generation (GWh)[4]

> *The country's power system is almost entirely* ***decarbonized*** *already, based on* ***extensive hydropower resources*** *and nuclear power, as well as district heating fuelled by biomass."*
> *- International Renewable Energy Agency*

4– https://www.irena.org/IRENADocuments/Statistical_Profiles/Europe/Sweden_Europe_RE_SP.pdf

Clean energy target

- In the 2016 Energy Agreement and the Climate Framework from 2017, Sweden set ambitious targets, including the long-term goal of zero net emissions by 2045.
- Sweden has set an ambitious target of achieving 100% renewable electricity generation by 2040.

Hydropower is the most important regulating source

- Hydropower contributes to all types of regulation, from seasonal regulation during the year, down to instantaneous regulation to maintain a frequency of 50 Hz in the system. There are also some multi-year reservoirs in the Nordic system. Most of hydropower's regulating capacity is used for daily balancing, i.e., to adapt production levels to the normal variation in consumption over a 24-hour period.
- The need for hydropower as a regulating resource is increasing as types of power production that cannot be controlled, such as solar and wind, are being expanded.
- Hydropower accounts for 95% of the management of imbalances in the electricity market, but its resources are mainly in northern Sweden.

Case of Finland – 2

In Finland, Renewable energy has the major share in the installed capacity and generation. Among renewables, hydro power and bioenergy occupies the major share when it comes to generation.

Below graph represent renewable energy capacity (MW) in 2020

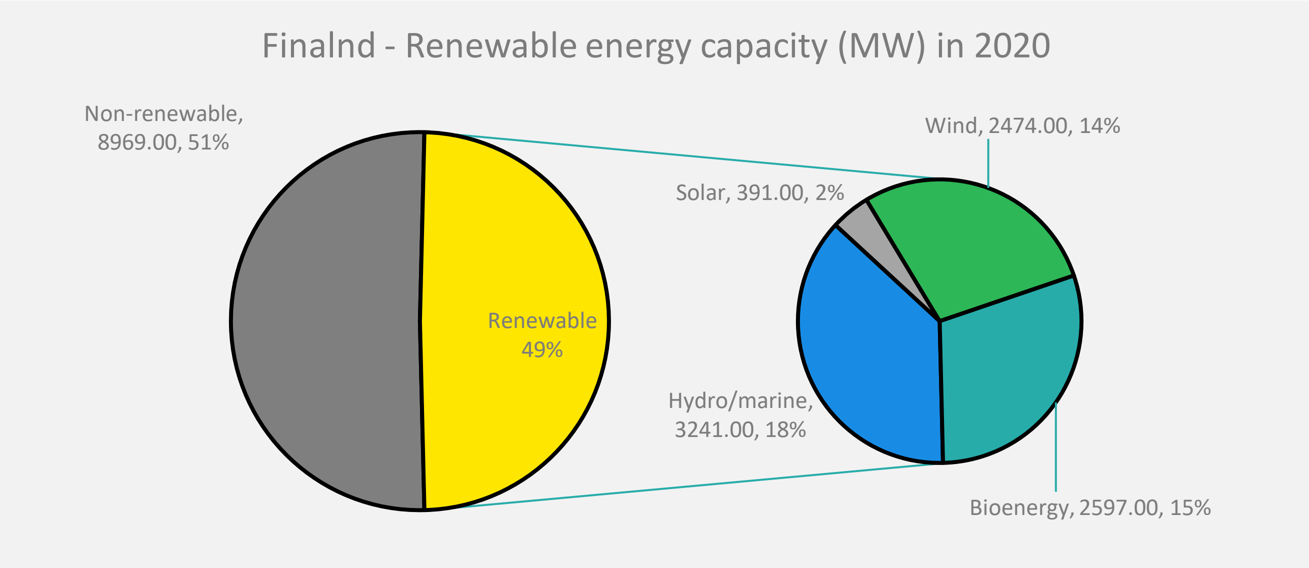


Figure 10: RE Capacity (MW)

Below graph represent Generation (GWh) 2020

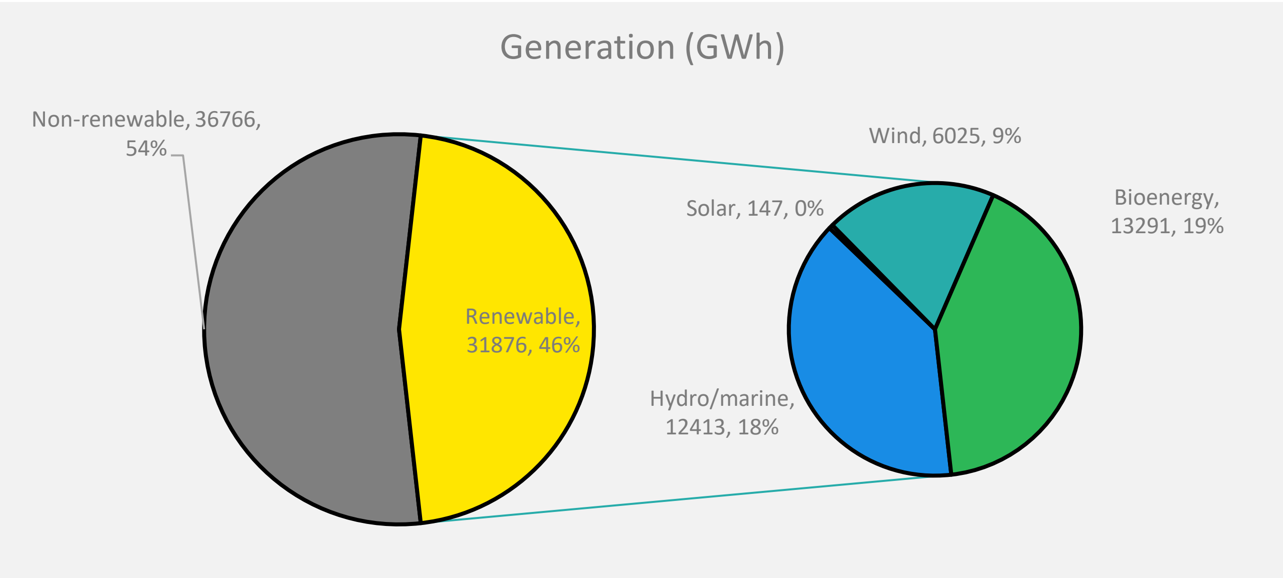


Figure 11:Finland – Generation (GWh) 2020

- Finland to reduce its CO2 emissions by 35 million tonnes by 2035 (as set out in the new EU framework regulations), with half of this reduction attributed to the energy sector.
- Finland's government supports the Helsinki administration and, in view of the country's commitments, has passed a law to ban the use of coal by May 2029 and peat by 2050. This is an ambitious decision considering that 8% of total energy consumption is generated from the former and 5% from the latter.

Source– https://www.irena.org/IRENADocuments/Statistical_Profiles/Europe/Sweden_Europe_RE_SP.pdf

Clean energy target

- In the 2016 Energy Agreement and the Climate Framework from 2017, Finland set ambitious targets, including the long-term goal of zero net emissions by 2035.
- Finland has set an ambitious target of achieving 100% renewable electricity generation by 2050.

Hydropower is the most important regulating source

- The amount of electricity produced by large Hydro power plants is also usually large enough to meet the basic needs of cities and sometimes whole countries, and other sources of energy simply supplement hydropower.
- Hydropower is completely emission-free and renewable in the way it produces electricity.
- Hydropower contributes to all types of regulation, from seasonal regulation during the year, down to instantaneous regulation to maintain a frequency of 50 Hz in the system. There are also some multi-year reservoirs in the Nordic system. Most of hydropower's regulating capacity is used for daily balancing, i.e., to adapt production levels to the normal variation in consumption over a 24-hour period.
- The need for hydropower as a regulating resource is increasing as types of power production that cannot be controlled, such as solar and wind, are being expanded.

Source– https://www.irena.org/IRENADocuments/Statistical_Profiles/Europe/Sweden_Europe_RE_SP.pdf

Case of Austria – 3

In 2018, Austria released its climate and energy strategy, “#mission2030”, for reaching the 2030 targets and advancing the long-term vision of a carbon-free energy sector by 2050. Commendably, the vision addresses all energy sectors, mobility, and urban sprawl in one strategy. #mission2030 forms the basis of Austria’s National Energy and Climate Plan (NECP).

Below graph represent renewable energy capacity (MW) in 2020

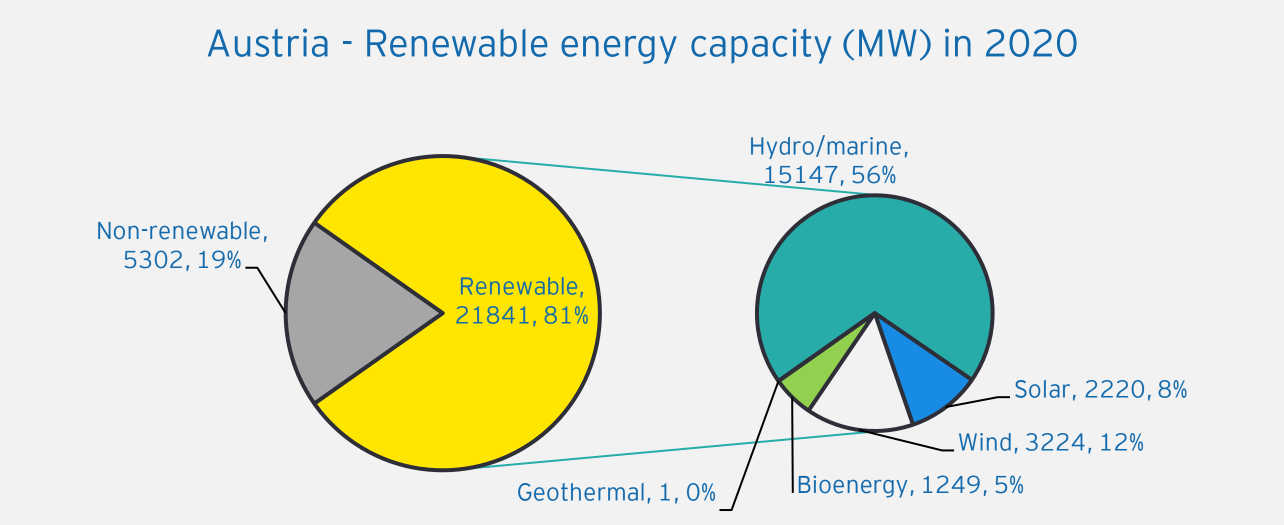


Figure 12: RE Capacity (MW)

Below graph represent Generation (GWh) 2020

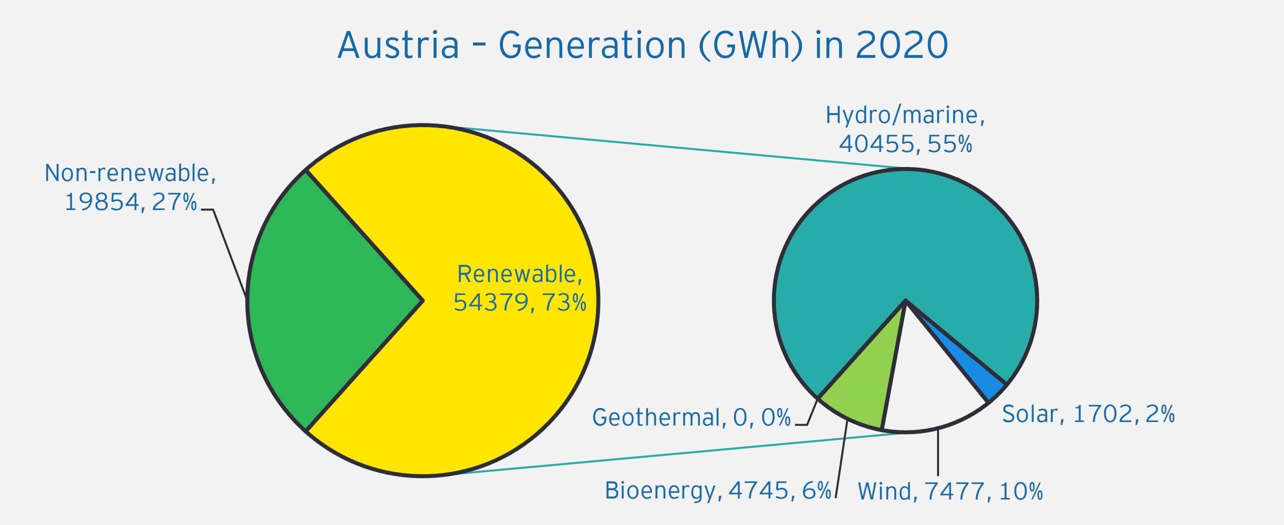


Figure 13: Austria - Generation (GWh) 2020

- RE occupies the major share in the installed capacity and generation to the tune of 80% out of which **hydropower has the maximum segment to the tune of ~55%.** Hydropower has dominated Austria’s electricity generation for decades and has accounted for around 60% of total generation in the last decade.
- The new government plans to add 5 TWh from hydropower towards achieving the overall goal of adding 27 TWh by 2030. Hydropower could therefore account for up to 85% of total electricity generation in 2030.

Source– https://www.irena.org/IRENADocuments/Statistical_Profiles/Europe/Sweden_Europe_RE_SP.pdf

Clean energy target

- Target to achieve carbon neutrality by 2040 which is 10 years earlier than the ambition set by the European Union.
- 100% RE supply (national balance) by 2030.
- Government set the target to instal 1 million PV systems by 2030, which is a substantial increase from the target of “100 000 roof-mounted PV systems” under #mission2030.

Hydropower is the most important regulating source

- Austria has existing huge hydropower installed capacity. It is considered as the largest RE source.
- Even Austria’s geographical terrain support this source. It has alpine topography, multiple rivers along with high precipitation makes this country a rich water source. Hence, it is tapped for electricity generation.

Source– https://www.irena.org/IRENADocuments/Statistical_Profiles/Europe/Sweden_Europe_RE_SP.pdf

Case of Canada – 4

In 2019, Canada became a member of the International Renewable Energy Agency (IRENA). Canada announced a target to cut greenhouse gas (GHG) emissions by 40-45% from 2005 levels by 2030 and legislated a commitment to reaching net zero emissions by 2050.
Below graph represent renewable energy capacity (MW) and generation in 2020

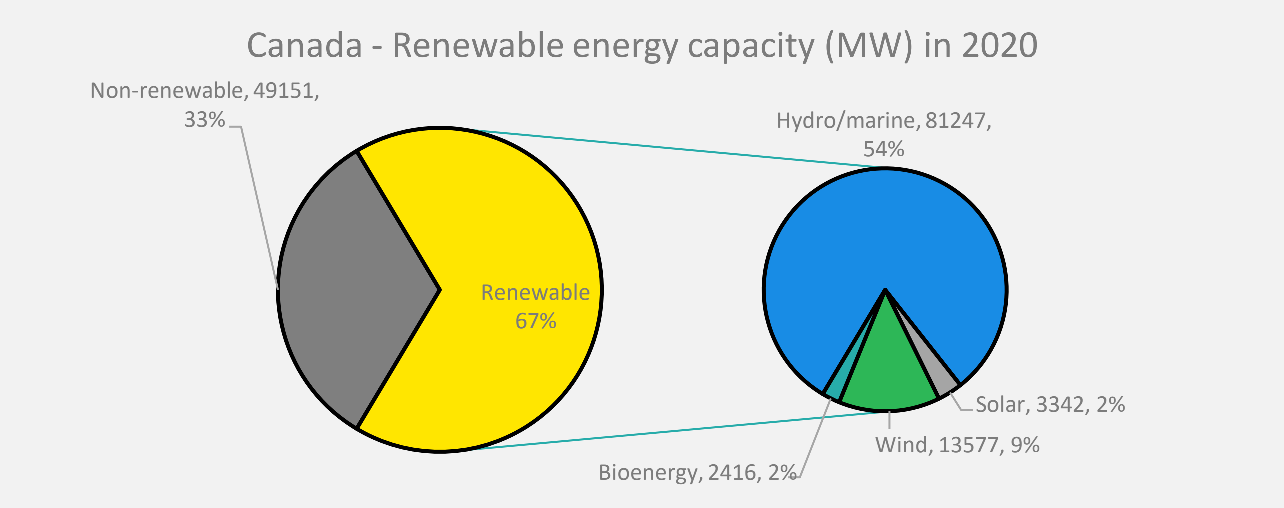


Figure 14: RE Capacity (MW)

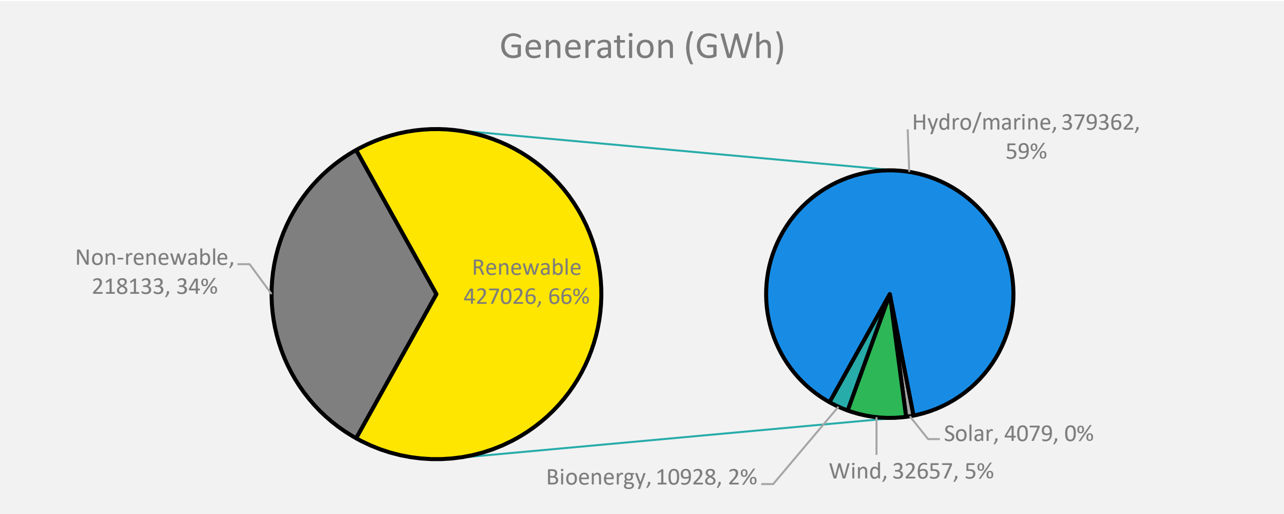


Figure 15: Generation (GWh) 2020

- Canada introduced a carbon pricing scheme in 2019, which will notably provide appropriate price signals to shift consumption to cleaner fuels.
- To complement the carbon price, Canada's policies include: the 2016 Pan-Canadian Framework on Clean Growth and Climate Change (PCF) and 2020 Strengthened Climate Plan, the Greenhouse Gas Pollution Pricing Act, the Clean Fuel Regulations, a commitment to phase out unabated coal use by 2030, nuclear plant extensions, upstream methane regulations, stringent vehicle emissions standards and energy efficiency measures.
- Canada is actively advancing several technologies, most recently announcing additional support for carbon capture, utilisation, and storage (CCUS), hydrogen, and nuclear small modular reactors (SMRs), with a view to serving as a supplier of energy and climate solutions to the world.

Source– https://www.irena.org/IRENADocuments/Statistical_Profiles/Europe/Sweden_Europe_RE_SP.pdf

Clean energy target

- Target to achieve carbon neutrality by 2050.
- Target to cut greenhouse gas (GHG) emissions by 40-45% from 2005 levels by 2030.

Hydropower is the most important regulating source

- Canada’s electricity system is 83% non-emitting and among the cleanest in the world, with heavy dominance of hydropower as well as an important role for nuclear. Considerable variation in electricity generation profiles across jurisdictions means that increased interconnectivity across regions will be crucial to ensuring balanced progress across provinces and territories to meet national targets.
- Canada is the second largest producer of hydropower in the world where RE accounts for two-thirds of Canada’s power generation. Renewable power generation in Canada increased from 78 gigawatts (GW) in 2009 to 100 GW in 2020.
- Canada aims to increase non-emitting electricity system to 90% by 2030. Early actions, like the federal commitment to phase out traditional coal power across the country by 2030 and new hydro projects, will help to meet this goal.
- Over the next twenty years, hydropower project development will benefit Canada with over $125 billion in investments and a million jobs.
- The Canadian hydropower industry works closely with host communities in the planning, construction, and implementation of projects. This is key to the success of project development, ensuring that local and aboriginal communities’ benefit from the project through improved quality of life, employment, business opportunities, capacity building, and long-term revenues.

Source– https://www.irena.org/IRENADocuments/Statistical_Profiles/Europe/Sweden_Europe_RE_SP.pdf

Chapter 2

Indian Energy Scenarios

2.1. OBJECTIVES

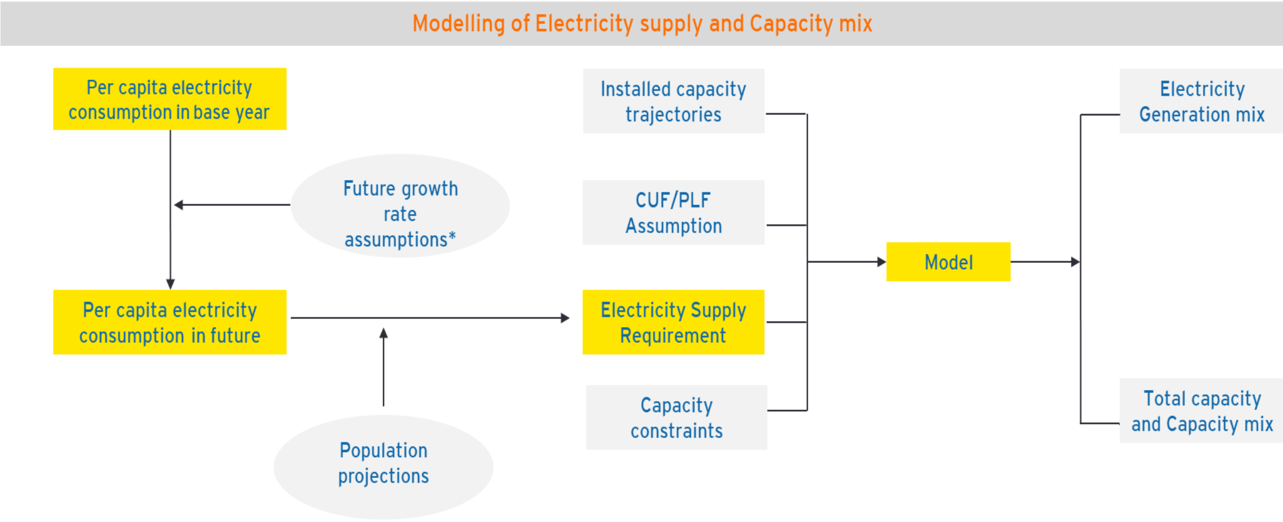
Objective	Context
▶ Indian Energy Scenarios up to 2030, 2040 & 2050. ▶ Projected requirement of Flexibility, Storage, Spinning Reserve and Ramping Capability in the Indian Grid in line with Electricity Demand. ▶ Projected share of Hydropower in the overall Indian Energy scenarios up to 2030, 2040 & 2050.	▶ Achievement of net-zero emissions target does not strictly mean complete decarbonization. A small amount of emissions would still prevail, but they will be absorbed through CCS technology and increased carbon sink (i.e., afforestation). ▶ Power sector is relatively simpler to decarbonize, as compared to industry and transport. Hence, it can be assumed that it will get very close to zero emissions by 2060.

2.2. ASSUMPTIONS

- Per capita electricity consumption (kWh) is assumed to grow at 5.1% CAGR, based on Indian energy security scenarios (IESS2047) model and past trends. Population of India rises likely to 1639 million in 2050 (Ref. World Population Prospects 2019 report).
- Grid emission factors for coal and gas generation (0.98 and 0.43 kg CO2/kWh) are assumed to stay constant throughout the model's timeline. (Ref. CO2 baseline database for emission factors CEA March 2021). Electricity generation from gas is assumed to stay constant at 2020 levels, as the availability of gas is likely to be low in future as well.
- Nuclear (2060 capacity): Low (80 GW), High (200 GW), Medium (125 GW) (Ref. CEEW Net-zero scenarios).CCS (2060 capacity): Low (0 GW), High (80 GW), Medium (40 GW) (Ref. IEA Technology Roadmap for CCS).
- Large Hydro plants (2060 capacity): Low (80 GW), High (140 GW), Medium (100 GW) (Ref. Large hydro identified potential considered as the limiting capacity).
- The technology potentials considered for solar PV and onshore wind in the study(et.al. Deshmukh, R) are higher than the reported MNRE values. Geospatial and techno-economic analysis of wind and solar resources in India. Renewable Energy, 134, 947-960.).
- For other renewable technologies, technical potentials identified by MNRE are considered: Biomass: 28 GW, Small Hydro: 21 GW, Offshore Wind: 70 GW, Waste-to-electricity: 5.7 GW.
- PLF/CUF for technologies in 2019-20 have been estimated from the actual generation and installed capacity values in 2020. Future CUF values for PV and wind plants are assumed to increase. CEA Technology catalogue has also been referred for CUF values (Ref. CEA and DEA, Indian technology catalogue 2022, 2022).

2.3. METHODOLOGY - APPROACH TO PROJECT THE FUTURE ENERGY SCENARIO OF INDIA

Flow Chart



Note: Per capita electricity consumption = Electricity generation/mid-year population.
Future growth rate decided based on past trend, literature survey and IESS2047 scenario results.

Technologies considered in the model: Coal, Gas, Coal-CCS, Nuclear, Hydro, PV, Wind, Biomass, small hydro, waste-to-electricity.

Power, industry, and transport are India's major CO2 emitter sectors. The power sector is relatively easier to decarbonize as compared to other sectors. Hence, it is expected that the power sector will get almost entirely decarbonized by 2060. The government of India also plans a gradual phase-down of coal power plants. Assuming a plant life of 30 years for a coal-based plant, it is expected that by 2060, a significant amount of the coal-based capacity will be retired from the mix. A small but finite amount of electricity generation is assumed to come from the gas power plants. Thus, the power sector will still contribute a small amount of CO_2 emissions in 2060.

Grid Emission Factor: The grid emission factor is defined as the CO_2 emissions per unit of electricity generation. As of 2020, the Indian grid has an average grid emission factor of 0.719 tCO_2/MWh.
Emission factor for coal-based plants: **0.98 tCO_2/MWh**
Emission factor for gas-based plants: **0.43 tCO_2/MWh**
The grid emission factor is a parameter considered to characterize the decarbonization of the grid or power sector. To achieve a net-zero emissions (or near-zero emissions) power sector, the grid emission factor must keep declining from 2020 until 2060. In 2060, the grid emission factor will be very low.

Per capita electricity consumption in India was 1031 kWh in 2020. It has grown at around 4.2% in the last decade. Future per capita electricity demand has been projected by assuming growth rates. These growth rate assumptions are based on past trends, IESS2047 model results, and a literature survey of published studies. The net-zero trajectory is expected to have a high share of demand electrification. Population projections are available in the World Population Prospects report[2]. Thus, future electricity generation requirement is calculated. This forms the first step of calculatiosn in the models, as seen above (Flow chart).

The second step of the model is to estimate the future requirement of energy from different sources such as thermal, PV, wind, hydro, nuclear. Inputs at this stage of calculations are electricity generation requirement, capacity constraints, Capacity factor/Plant load factor assumptions. Apart from these inputs, three trajectories have been created for installed capacity of nuclear, large hydro and CCS technologies. These trajectories are also an input to the model at stage 2. The model balances annual electricity generation and demand to give electricity supply mix, installed capacity requirement and mix as outputs.

Details of Assumptions: -

1. Due to the improvement in the efficiency of thermal power plants, there is likely to be a small reduction in the emission factors for coal and gas power plants. For simplicity, emission factors for coal and gas technologies have been assumed to stay constant in our model.

2. Some coal plants are expected to be in the mix, but they will only be used for backup power generation. Thus, the role of coal-based power plants would be limited to providing grid support in case of emergencies. This scenario is likely to happen as the cost of coal as fuel is also expected to rise in coming years, making coal-based generation more expensive than RE-based generation.

3. Per capita electricity consumption has been calculated on the basis of gross generation by utilities and mid-year population. This definition is slightly different from CEA's definition, as per which,

$$Per\ capita\ consumption\ =\ gross\ available\ electricity/\ midyear\ population$$

Gross available electricity considers electricity generated by utilities, non-utilities, and net imported electricity. To our study, we are focusing only on the electricity generated by utilities. Hence an adjusted definition is being used for per capita electricity consumption.

4. A net-zero by 2050 scenario created by TERI and Shell for India has projections for electricity mix for 2050. There is a finite amount of gas-based electricity. Thus, the grid emission factor is very low but not zero. Values retrieved using a plot digitizer software suggest that the grid emission factor in 2050 for this scenario is ~0.015 tCO_2/MWh. Our study calculates the emission factor trajectory for the various scenarios generated through our model. It can be used to visualize how the grid is being decarbonized over the period.

5. Past per capita electricity consumption trend shows that it has been growing at 4.24% in the last decade. However, to achieve a net-zero emissions target, high electrification of demand sectors is required, especially in the industry and transport sectors. Thus, the future growth rate will be more than what has been observed in the past.

CEEW's study on the net-zero scenario expects around 7500 TWh of electricity generation by 2050 and around 10000 TWh by 2060. As per net-zero scenario created by TERI and Shell mentioned above for India estimates electricity demand to be around 9000 TWh by 2050. The target year in this scenario is 20 years ahead of the declared goal. Hence this is an accelerated growth and decarbonization scenario.

A BAU-efficiency, High-electrification scenario generated from the IESS2047 model suggests that per capita electricity consumption would rise at a CAGR of 5.1% up to 2047. With this growth rate assumption, the total electricity supply in 2050 will be around 7500 TWh in 2050 and 12450 TWh in 2060. By 2060, certain sectors such as transport may achieve demand saturation. Hence the number may come down a little bit. However, the 2050 number is within the range, hence 5.1% CAGR is assumed for further calculations.

Brief details of the IESS2047 scenario:

i) **Residential:** Total number of households increase to 425 million in 2047 from 256 million in 2020 with 51% urbanization achieved by 2047.EPI of households has been growing at an average CAGR 0f 5% over the last decade. Due to the penetration of efficient appliances, this growth rate keeps declining gradually.

ii) **Commercial:** In commercial sector, share of air-conditioned floor space is assumed to increase for the buildings. However, penetration of ECBC-compliant buildings is assumed to rise to 25% by 2047.

iii) **Industry:** Aggressive electrification has been assumed in the industry sector, especially in the industries where coal is used for captive power generation. Share of electricity in fuel mix varies from industry to industry. Overall, grid electricity consumed by industries rises four times from 2020 to 2047.

iv) **Transport:** In transport sector, aggressive fuel substitution is assumed, especially in cars. By 2047, fuel mix of cars is assumed to be 40% electric, 7% Fuel cell-based and 10% CNG based and rest to be petrol/diesel. Similarly, aggressive fuel substitution is assumed in 2-wheelers, 3-wheelers, buses. Moreover, share of public transport in the total passenger transport is also assumed to increase to 65% in 2047, from 55% in 2020. Rail transport has been assumed to get entirely electrified. Share of rail in freight transport is also assumed to increase.

v) **Agriculture:** Diesel pumps are entirely replaced by electric pumps. By 2047, 80% pumps run on grid electricity and rest 20% are entirely solar-PV based pumps. Efficiency of electric pump fleet is assumed to increase to 45%.

vi) **Cooking:** It is assumed that biomass used for cooking will be replaced by cleaner fuels. Share of electric cooking will be 20% and 15% in urban and rural areas respectively, by 2047.

With sectoral assumptions such as aforementioned, scenario has been developed. It gives an overall CAGR of 5.1% for per capita electricity generation.

6. PLF/CUF for technologies in 2019-20 have been estimated from the actual generation and installed capacity values in 2020. Future CUF values for PV and wind plants are assumed to increase gradually. Future generation through gas power plants has been assumed to stay constant. For other dispatchable plants, a constant PLF has been assumed. These PLFs can also be considered as one of the inputs to the model.

2.4. RESULTS - ENERGY SUPPLY MIX 2030, 2040, 2050 & 2060 (HIGH RE SCENARIO VS HIGH HYDRO)

Below table represents Energy Supply Mix (high RE %)

Table 2: Energy Supply Mix (High RE) (%)

High RE Scenario (%)					
Source	**2020**	**2030**	**2040**	**2050**	**2060**
Gas Power Stations	3.50%	1.90%	1.09%	0.64%	0.39%
Coal power stations	71.87%	53.64%	32.99%	12.38%	0.00%
Carbon Capture Storage (CCS)	0.00%	0.00%	0.00%	0.00%	0.00%
Nuclear	3.36%	4.89%	4.54%	4.33%	4.22%
Hydro Power Generation	11.27%	8.16%	5.26%	3.40%	2.25%
Solar PV	3.62%	18.98%	35.08%	50.01%	58.80%
Onshore Wind	4.67%	10.22%	18.89%	26.93%	31.66%
Offshore Wind	0.00%	0.70%	0.95%	1.31%	1.81%
Small Hydro	0.68%	0.59%	0.49%	0.42%	0.37%
Biomass Based Electricity	1.00%	0.88%	0.65%	0.50%	0.39%
Waste to Electricity	0.03%	0.04%	0.05%	0.07%	0.10%

Below table represents Energy Supply Mix (high Hydro %)

Table 3: Energy Supply Mix (High Hydro) (%)

High Hydro Scenario (%)					
Source	**2020**	**2030**	**2040**	**2050**	**2060**
Gas Power Stations	3.50%	1.90%	1.09%	0.64%	0.39%
Coal power stations	71.87%	53.6%	33.4%	13.1%	0.0%
Carbon Capture Storage (CCS)	0.00%	0.0%	0.0%	0.0%	0.0%
Nuclear	3.36%	4.9%	4.5%	4.3%	4.2%
Hydro Power Generation	11.27%	8.2%	6.3%	4.9%	3.9%
Solar PV	3.62%	19.0%	34.1%	48.6%	57.7%
Onshore Wind	4.67%	10.2%	18.4%	26.1%	31.1%
Offshore Wind	0.00%	0.7%	0.9%	1.3%	1.8%
Small Hydro	0.68%	0.6%	0.5%	0.4%	0.4%
Biomass Based Electricity	1.00%	0.9%	0.7%	0.5%	0.4%
Waste to Electricity	0.03%	0.0%	0.1%	0.1%	0.1%

Graphical Representation – Supply Mix

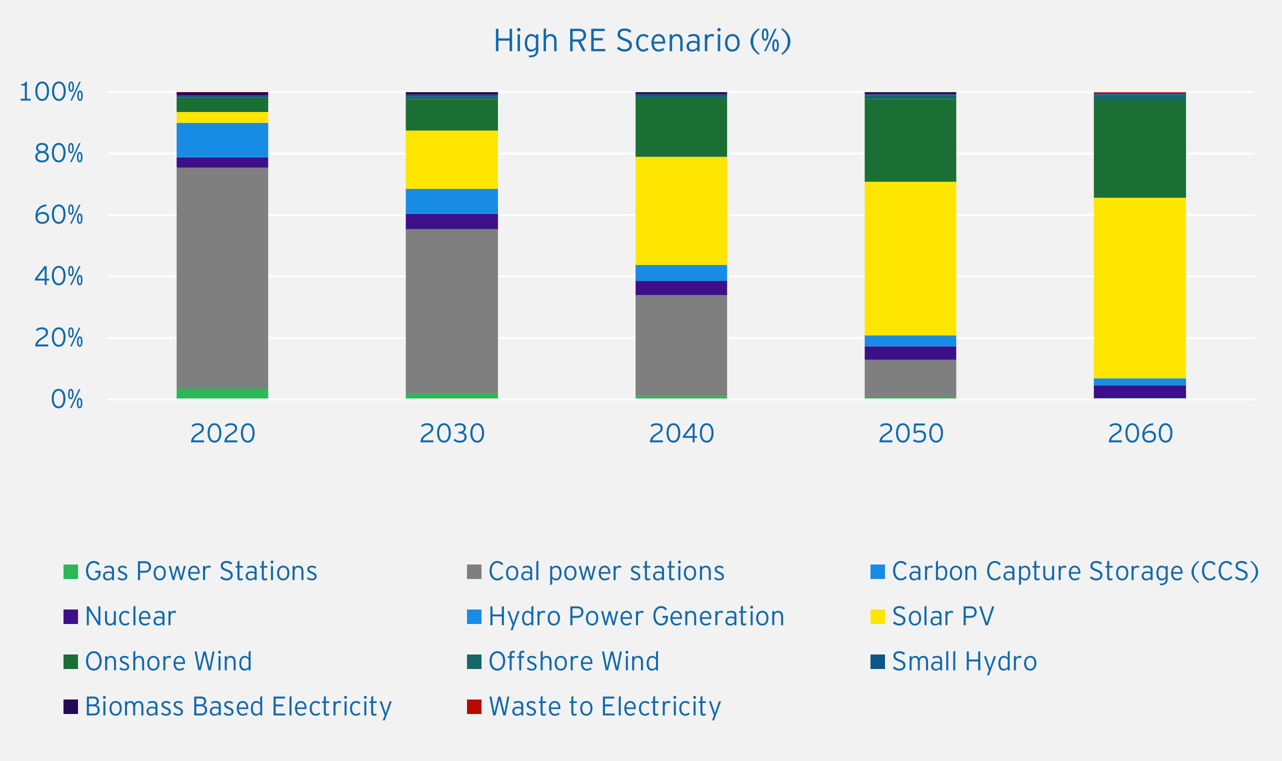


Figure 16: Supply Mix High RE (%)

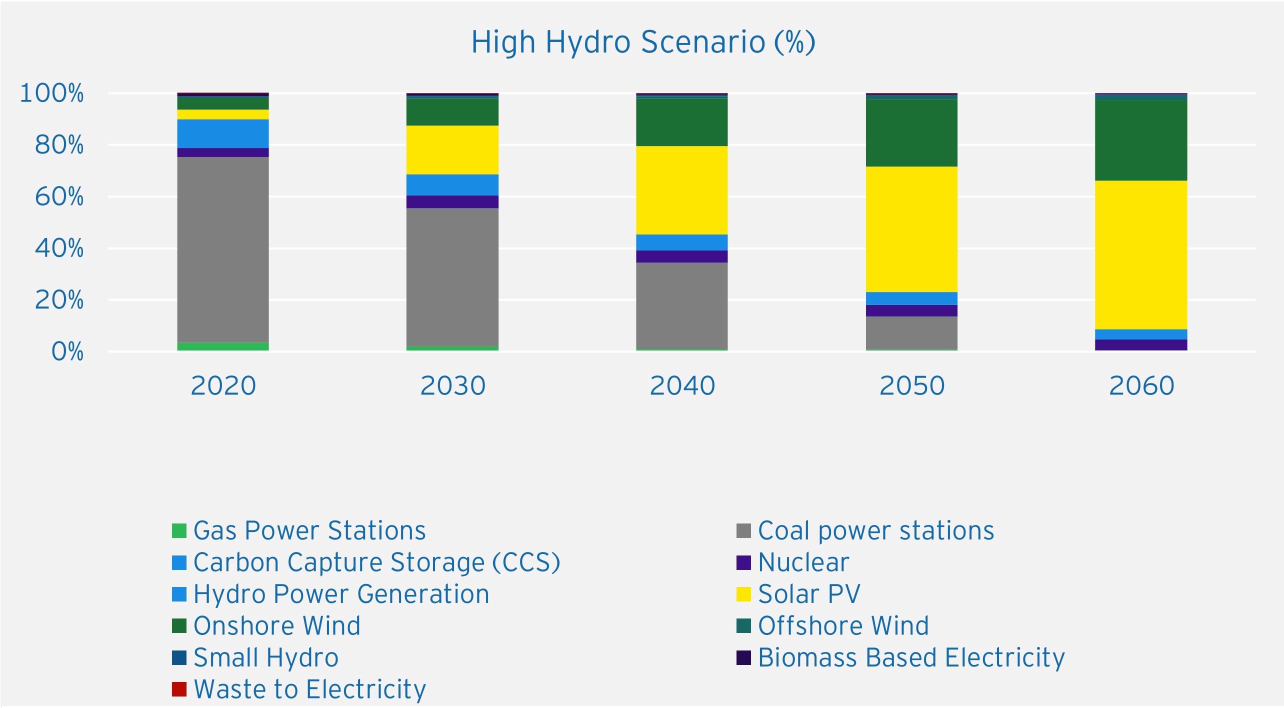


Figure 17: Supply Mix High Hydro (%)

In both the scenarios Solar PV contributes more than 50% of the energy portfolio followed by Onshore Wind, contribution from both Gas and Coal are almost negligible as we come close to 2050 & 2060. However, there is also gradual decrease in Hydro supply.

2.5. RESULTS - ELECTRICITY GENERATION AS PER THE MIX (HIGH RE SCENARIO VS HIGH HYDRO)

Below table represents Generation Mix (high RE % vs high Hydro %)

Table 4: Generation Mix (High RE and High Hydro) TWh

High RE Scenario					
Source, Unit: TWh	**2020**	**2030**	**2040**	**2050**	**2060**
Gas Power Stations	48.40	48.40	48.40	48.40	48.40
Coal power stations	994.00	1368.26	1465.82	930.79	0.00
Carbon Capture Storage (CCS)	0.00	0.05	0.05	0.05	0.05
Nuclear	46.40	124.83	201.57	325.49	525.60
Hydro Power Generation	155.80	208.06	233.71	255.95	280.32
Solar PV	50.10	484.13	1558.74	3758.96	7321.86
Onshore Wind	64.65	260.69	839.32	2024.06	3942.54
Offshore Wind	0.00	17.96	42.12	98.72	226.01
Small Hydro	9.45	15.03	21.82	31.68	45.99
Biomass Based Electricity	13.80	22.40	29.09	37.78	49.06
Waste to Electricity	0.40	0.95	2.23	5.27	12.46
Total	**1383.00**	**2550.75**	**4442.87**	**7517.16**	**12452.29**

High Hydro Scenario					
Source, Unit: TWh	**2020**	**2030**	**2040**	**2050**	**2060**
Gas Power Stations	48.40	48.40	48.40	48.40	48.40
Coal power stations	994.00	1368.26	1484.91	981.99	0.00
Carbon Capture Storage	0.00	0.05	0.05	0.05	0.05
Nuclear	46.40	124.83	201.57	325.49	525.60
Hydro Power Generation	155.80	208.06	281.63	371.70	490.56
Solar PV	50.10	484.13	1515.17	3650.46	7185.20
Onshore Wind	64.65	260.69	815.86	1965.63	3868.96
Offshore Wind	0.00	17.96	42.12	98.72	226.01
Small Hydro	9.45	15.03	21.82	31.68	45.99
Biomass Based Electricity	13.80	22.40	29.09	37.78	49.06
Waste to Electricity	0.40	0.95	2.23	5.27	12.46
Total	**1383.00**	**2550.75**	**4442.87**	**7517.16**	**12452.29**

Graphical Representation – Generation (TWh)

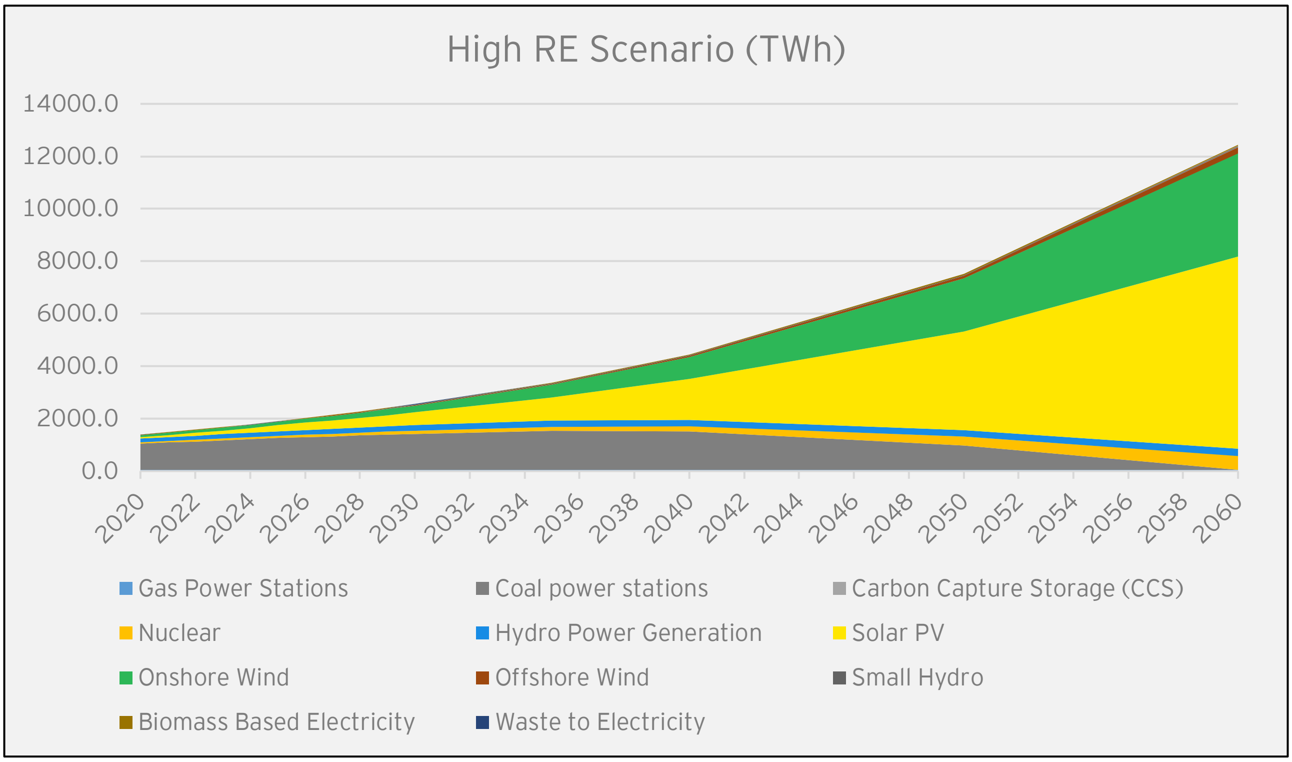


Figure 18: Generation High RE TWh (Graphical)

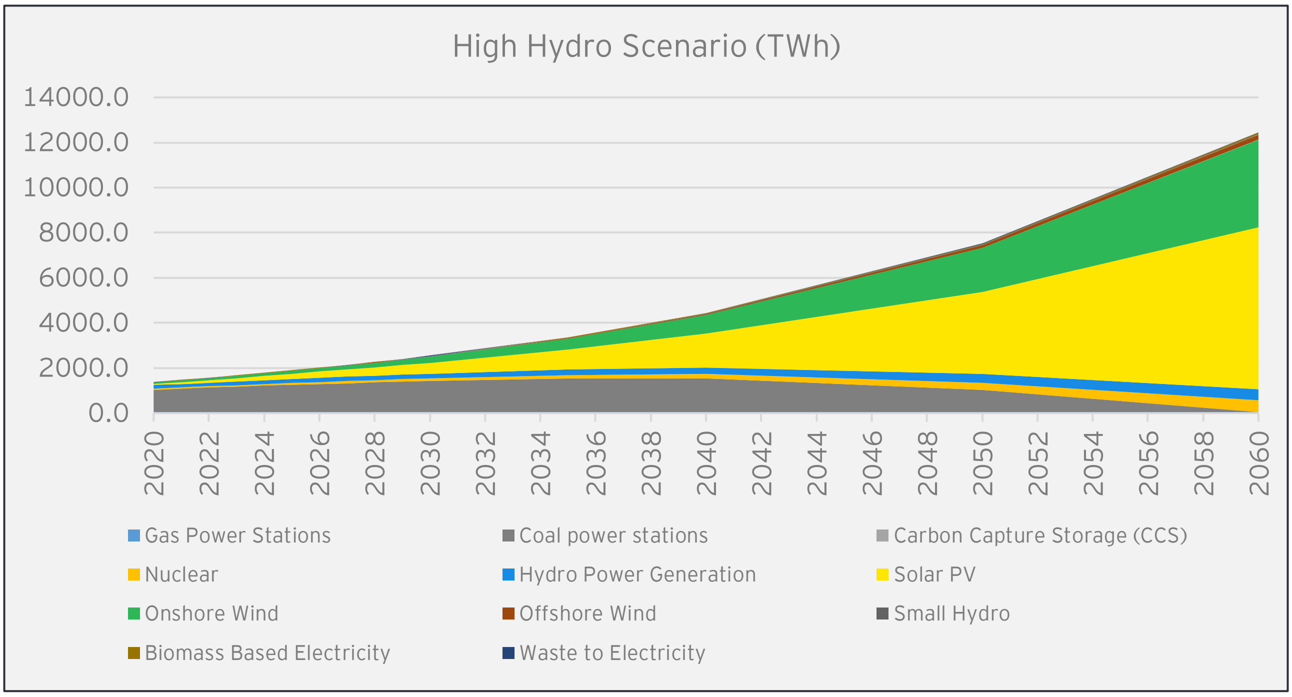


Figure 19: Generation High Hydro TWh (Graphical)

In both the scenarios generation from Solar PV and Onshore Wind are maximum, generation from Coal is almost negligible as we come close to 2060, generation from Gas remains constant in both cases. Generation from hydro in 2060 in high RE and high hydro scenario is 280.3 TWh and 490.6TWh respectively.

2.6. RESULTS – INSTALLED CAPACITY AS PER THE MIX (HIGH RE SCENARIO VS HIGH HYDRO)

Below table represents Installed capacity (high RE % vs high Hydro %)

Table 5: IC as per High RE (GW)

High RE Scenario					
Source, Unit: GW	**2020**	**2030**	**2040**	**2050**	**2060**
Gas	25.00	25.00	25.00	25.00	25.00
Coal	205.08	272.12	278.88	177.09	0.00
CCS	0.01	0.01	0.01	0.01	0.01
Nuclear	6.77	19.00	30.68	49.54	80.00
Hydro	45.71	60.90	66.70	73.05	80.00
PV	32.68	276.33	808.81	1787.94	3343.31
Onshore Wind	37.69	135.27	399.22	888.68	1607.36
Offshore wind	0.00	5.00	11.45	26.21	60.00
Small Hydro	4.73	6.86	9.96	14.46	21.00
Biomass	9.85	12.79	16.60	21.56	28.00
Waste to electricity	0.18	0.43	1.02	2.41	5.69
Total	**367.70**	**813.70**	**1648.34**	**3065.95**	**5250.38**

Table 6: IC as per High Hydro (GW)

High Hydro Scenario					
Source, Unit: GW	**2020**	**2030**	**2040**	**2050**	**2060**
Gas	25.00	25.00	25.00	25.00	25.00
Coal	205.08	272.12	282.52	186.83	0.00
CCS	0.01	0.01	0.01	0.01	0.01
Nuclear	6.77	19.00	30.68	49.54	80.00
Hydro	45.71	60.90	80.37	106.08	140.00
PV	32.68	276.33	786.20	1736.33	3280.91
Onshore Wind	37.69	135.27	388.06	863.03	1577.36
Offshore wind	0.00	5.00	11.45	26.21	60.00
Small Hydro	4.73	6.86	9.96	14.46	21.00
Biomass	9.85	12.79	16.60	21.56	28.00
Waste to electricity	0.18	0.43	1.02	2.41	5.69
Total	**367.70**	**813.70**	**1631.89**	**3031.46**	**5217.98**

Graphical Representation – Installed Capacity

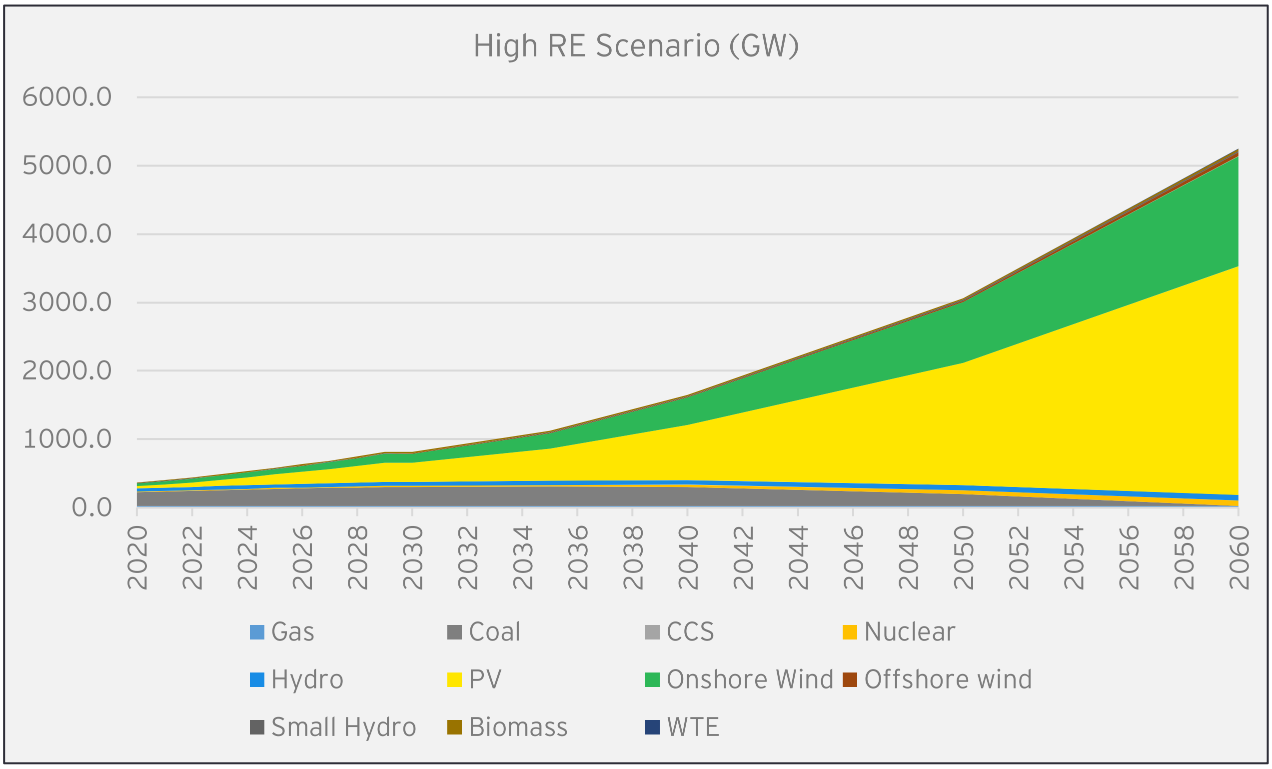


Figure 20: IC as per High RE (GW) graphical

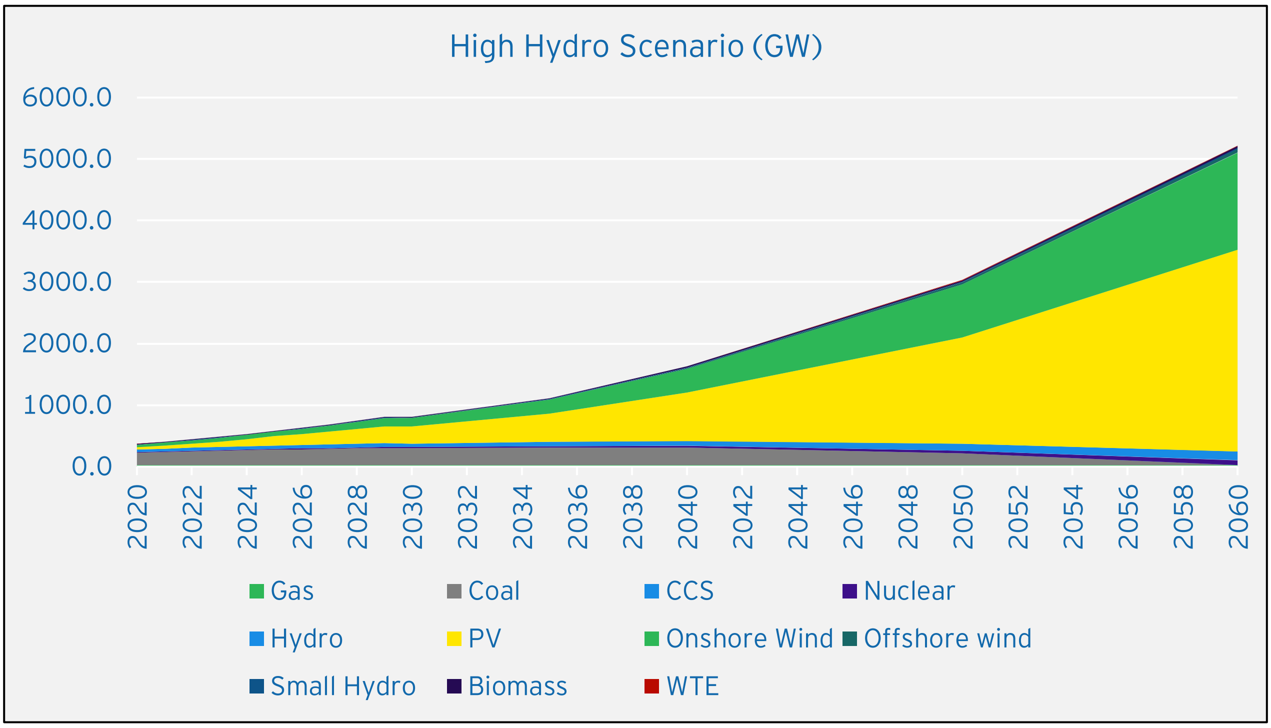


Figure 21: IC as per High Hydro (GW) graphical

In both the scenarios installed capacity Solar PV and Onshore Wind are maximum, Coal installed capacity is almost negligible as we come close to 2060, capacity of Gas remains constant in both cases. Installed capacity of hydro in 2060 in high RE and high hydro scenario is 80 GW and 140 GW respectively.

2.7. RESIDUAL DEMAND CURVE IS REFLECTION OF FLEXIBILITY ESTIMATION

To understand the ramping rate requirements in future, an analysis of hourly demand curves is required. We have hourly demand curves for one representative day of each month for 2015. We can assume it to be the same for the base year, i.e., 2020 as the consumption patterns have not changed within the 5 yrs.

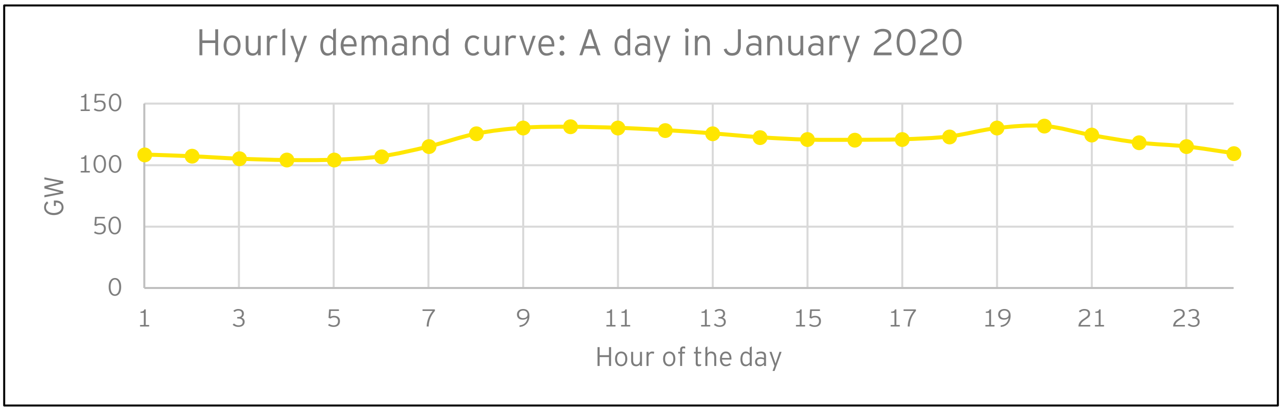


Figure 22: High demand curve- A Day in Jan 2020

- As we create scenarios for 2030, 2040 and 2050, we also need to estimate the hourly demand curves for the respective years. High penetration of electric vehicles is expected in the future, which will contribute to the electricity demand in the future. It is important to examine the effect of EV charging on the shape of the demand curve.
- IF the EV charging is not considered, we can simply scale the current demand curve to any future year by using a scaling factor based on the average electricity demand in the future year as compared to the base year. However, EV charging behaviour is likely to impact electricity consumption behaviour. Most of the electric demand for EVs is expected to come from electric cars and electric buses. These vehicles take more than 3 to 4 hours to get charged. And considering that they are used in the daytime for commute, they will most likely be charged at night, either in depots (buses) or household charging points (cars).
- The study published by AEEE presents a case study for EV charging in Delhi. The charging patterns show that EV charging takes place mainly between 12 midnight to 6 AM, and between 11 AM to 3 PM. For our study we have tried to replicate these patterns with modified charging timings: 11 PM to 6 am, and 12 noon to 4 PM. The charging pattern is shown in the image below.
- Due to this charging pattern, the resultant load shape is altered slightly. During the charging period, the load increases. However, the area under the curve, i.e., the total electricity consumed in the day would remain the same. To account for this fact, the excess load is assumed to be distributed evenly in the non-charging period, i.e., the remaining 13 hours of the day. With this modification the load curve becomes less peaky in nature.

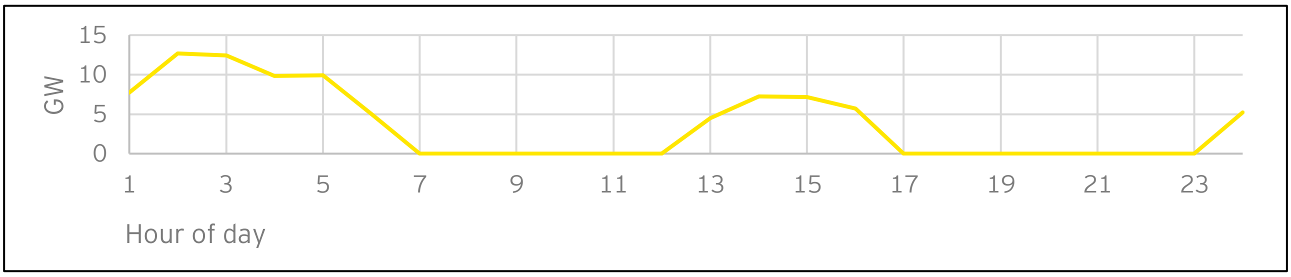


Figure 23: EV Charing pattern for a day

Through the demand analysis in the IESS2047 scenario, it is observed that the electricity demand for electric vehicles is:

Table 7: EV demand analysis

Particulars	2030	2040	2050
Electricity demand for EV (TWh)	76	200	361
Total electricity generation (TWh)	2551	4443	7517
Case: After accounting for T&D losses			
EV charging demand in the total electricity generation	3.5%	5%	5.5%

Considering projections as per the previous slide, an illustrative scenario has been created to compare the demand curve shape with and without the impact of EV charging.

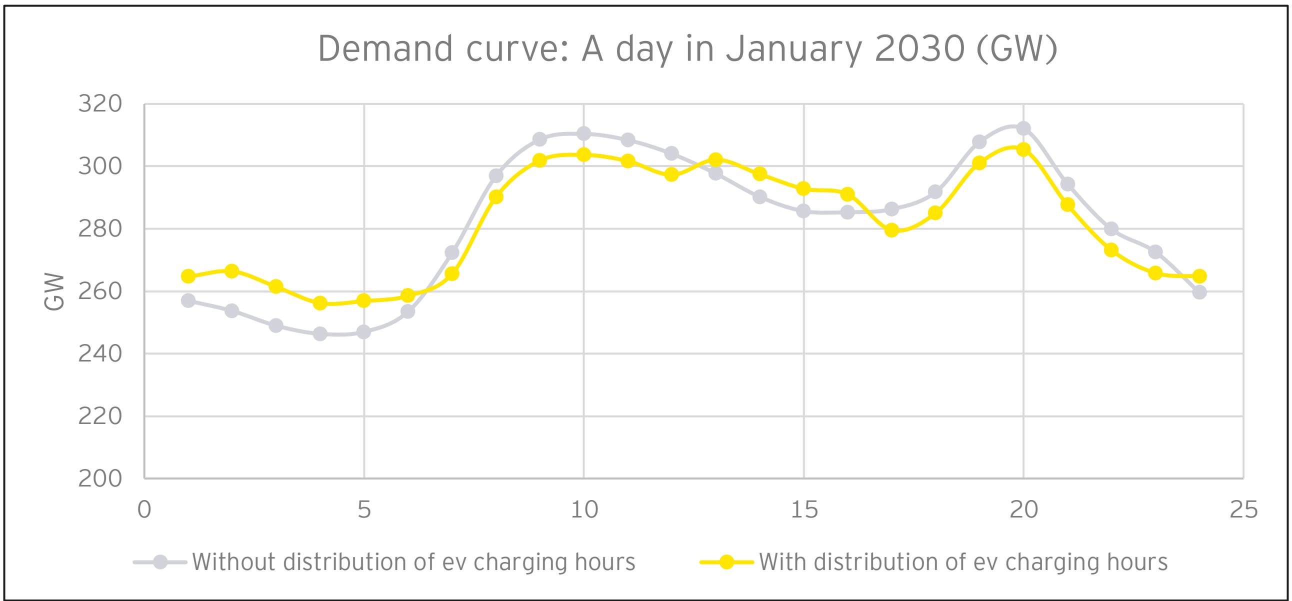


Figure 24: Demand Curve - Day in Jan 2030

The charging patterns show that EV charging takes place mainly between 12 midnight to 6 AM, and between 11 AM to 3 PM, also the EV penetration won't be significantly impacting the load curve.

Note: Due to this charging pattern, the resultant load shape is altered slightly. During the charging period, the load increases. However, the area under the curve remains the same.

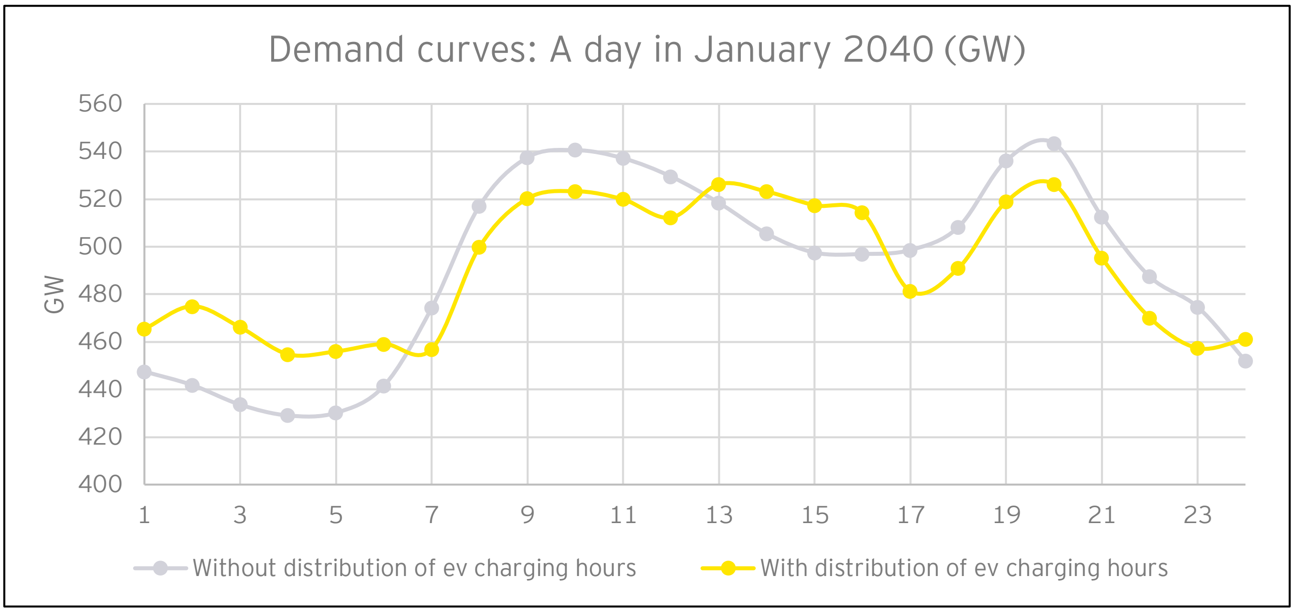


Figure 25: Demand curves - A Day in Jan 2040

- If the EV charging is not considered, we can simply scale the current demand curve to any future year by using a scaling factor based on the average electricity demand in the future year as compared to the base year. However, EV charging behaviour is likely to impact electricity consumption behaviour.
- For our study we have assumed charging timings: 11 PM to 6 am, and 12 noon to 4 PM. During the charging period, the load increases. However, the area under the curve, i.e., the total electricity consumed in the day would remain the same. To account for this fact, the excess load is assumed to be distributed evenly in the non-charging period.

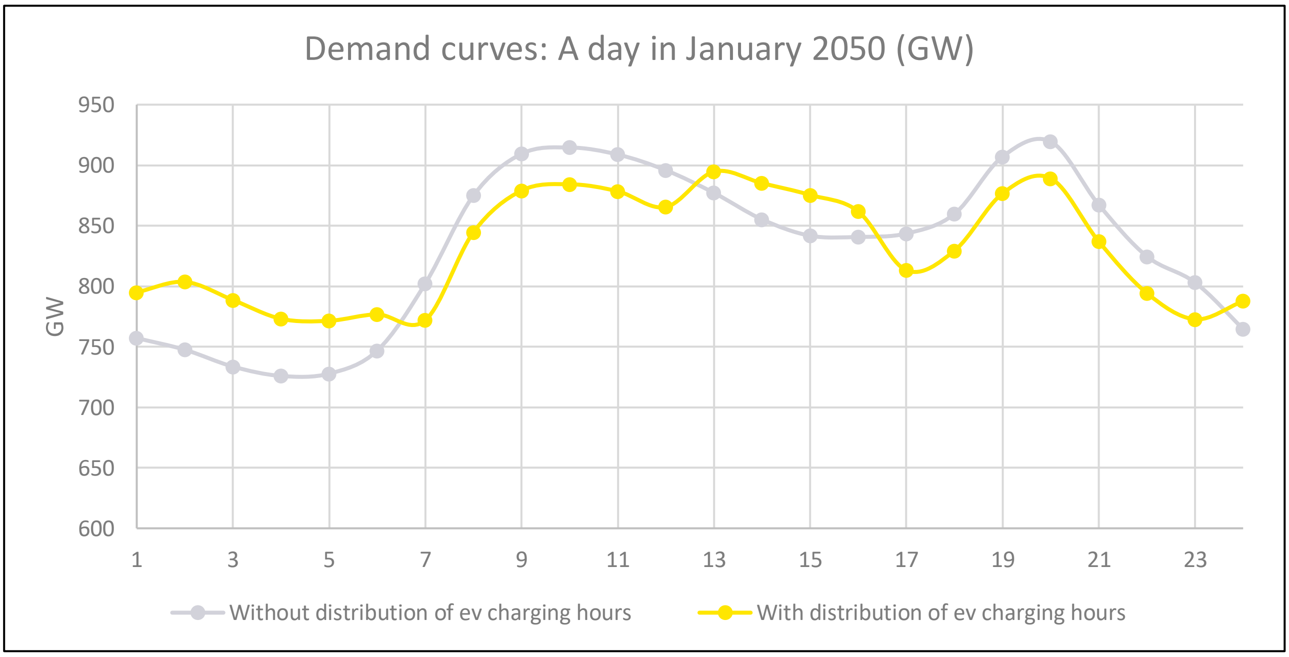
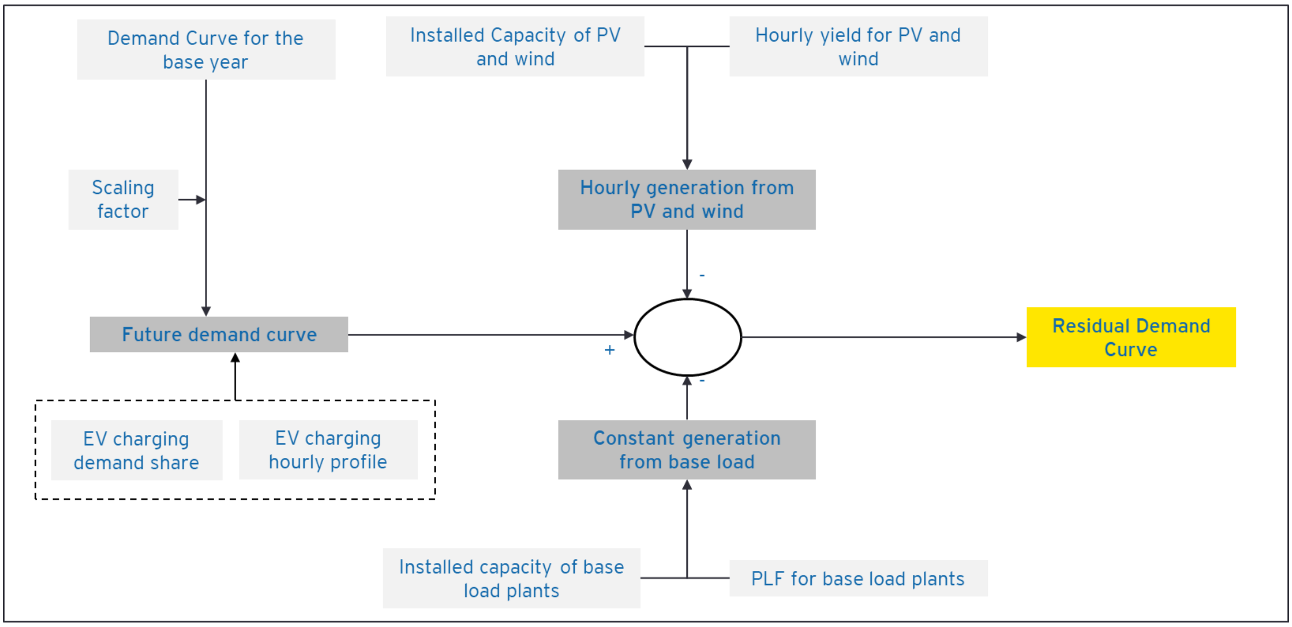


Figure 26: Demand curves in Jan 2050

The charging patterns show that EV charging takes place mainly between 12 midnight to 6 AM, and between 11 AM to 3 PM, also the EV penetration won't be significantly impacting the load curve.

2.8. FLEXIBILITY REQUIREMENTS ESTIMATION – FLOW CHART



Flexibility requirement estimations are partly done outside the model. Based on the average annual demand of electricity, future hourly electricity demand curves are approximated.The calculations are based on PV, wind, nuclear and other RE capacities, PV and wind yield curves, non-dispatchable electricity generation. Finally, residual demand curve is estimated to identify flexibility requirements. Calculations for storage requirements are based on empirical relations and are entirely exogenous to the model.

2.9. RESIDUAL DEMAND CURVE: HIGH RE SCENARIO-DAY IN 2030 (GW)

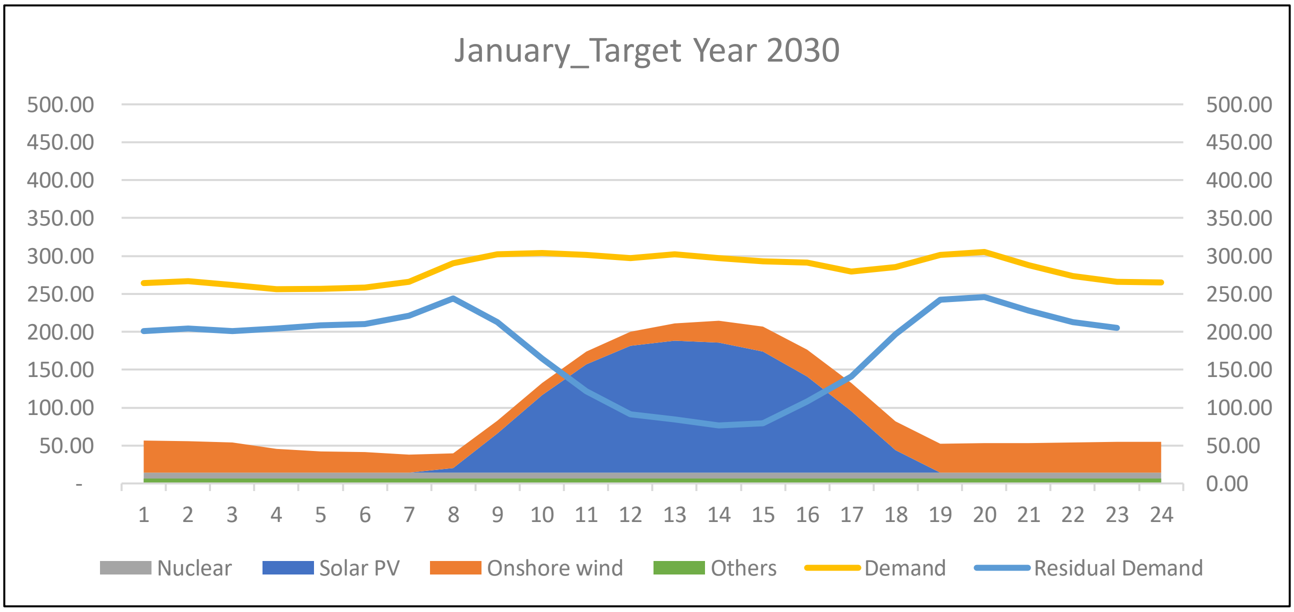


Figure 27: Residual Demand 2030

Residual demand is Demand – Solar + Wind + Nuclear Generation + others. In the above graphs maximum residual demand value is 251.95 GWh, minimum is 68.76 GWh and average is 179 GWh.

2.10. RESIDUAL DEMAND CURVE:**HIGH RE SCENARIO-DAY IN 2040(GW)**

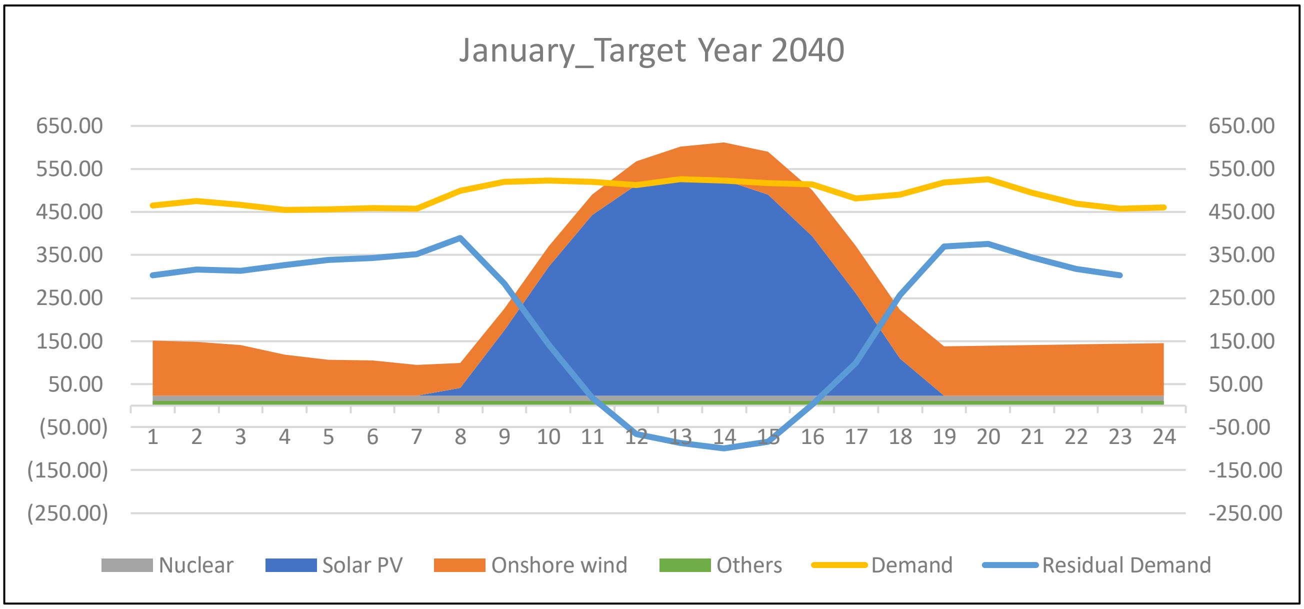


Figure 28: Residual Demand 2040

In the above graph maximum residual demand value is 413.91 GWh, minimum is -100.23 GWh and average is 225.57 GWh.

2.11. RESIDUAL DEMAND CURVE:HIGH RE SCENARIO-DAY IN 2050(GW)

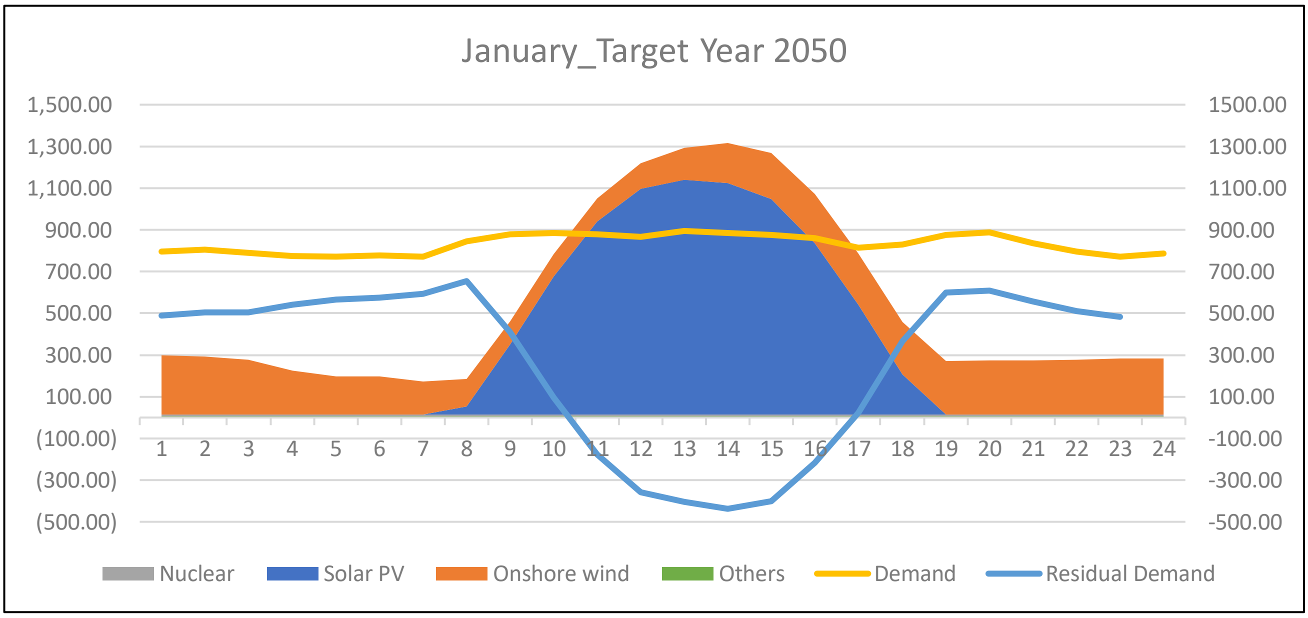


Figure 29: Residual Curve 2050

In the above graph maximum residual demand value is 648.32 GWh, minimum is -503.88 GWh and average is 237.96 GWh.

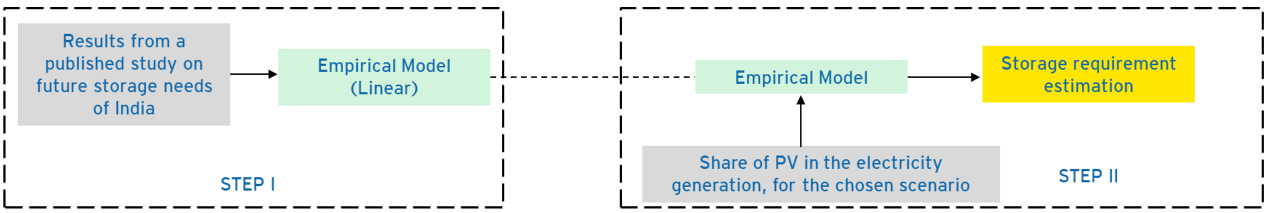
Generation from wind and solar power stations will be more than the required demand as we approach 2040. During such period and beyond, we need to have the energy storage system to provide the required flexibility to the grid in case of high PV and wind penetration.

2.11.1. APPROACH FOR THE STORAGE ESTIMATION CALCULATIONS

Observation - The initial idea was that the overgeneration due to high PV and wind capacities would be considered as the input to the storage systems and accordingly the storage requirements (in GWh and GW) would be calculated. However, as 2030 results show, it is not necessary that storage is needed only when there is an overgeneration in the system.

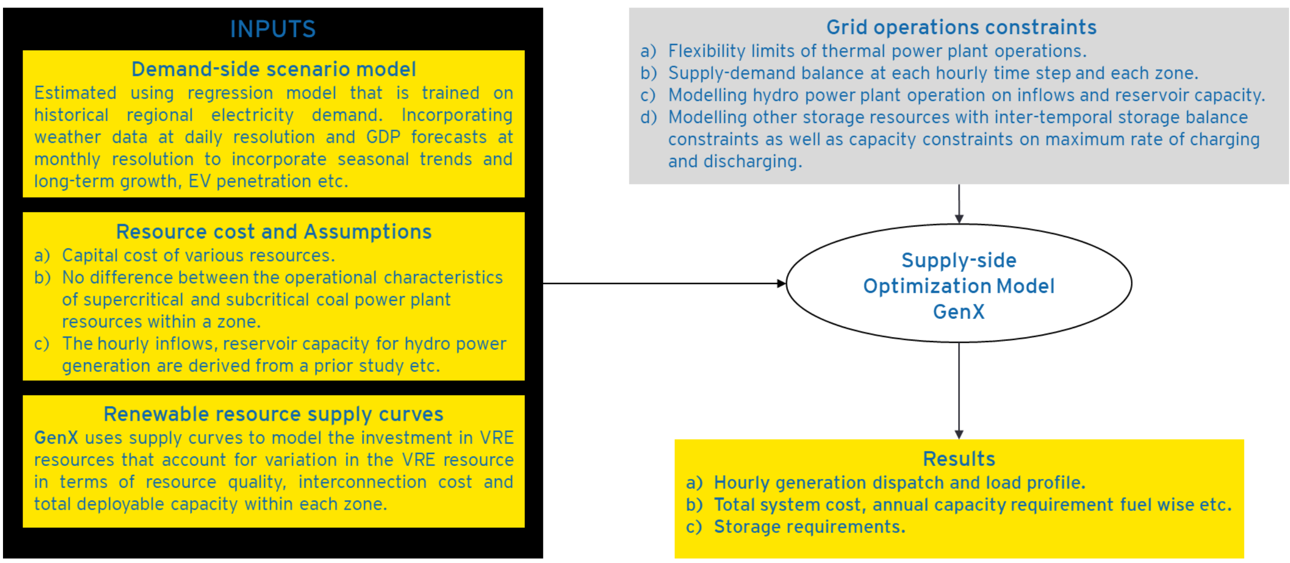
Approach – Many studies have been published about storage requirements for high renewable penetration cases for India. And there is likely to be an empirical relationship between the amount of storage required in the system to the share of installed capacity or electricity generation from PV/RE in the system. So, Linear regression coefficients have been calculated and those values are used to arrive at the storage estimation number

Independent variable: Share of PV in electricity generation
Dependent variable: Amount of storage required per unit of electricity generation



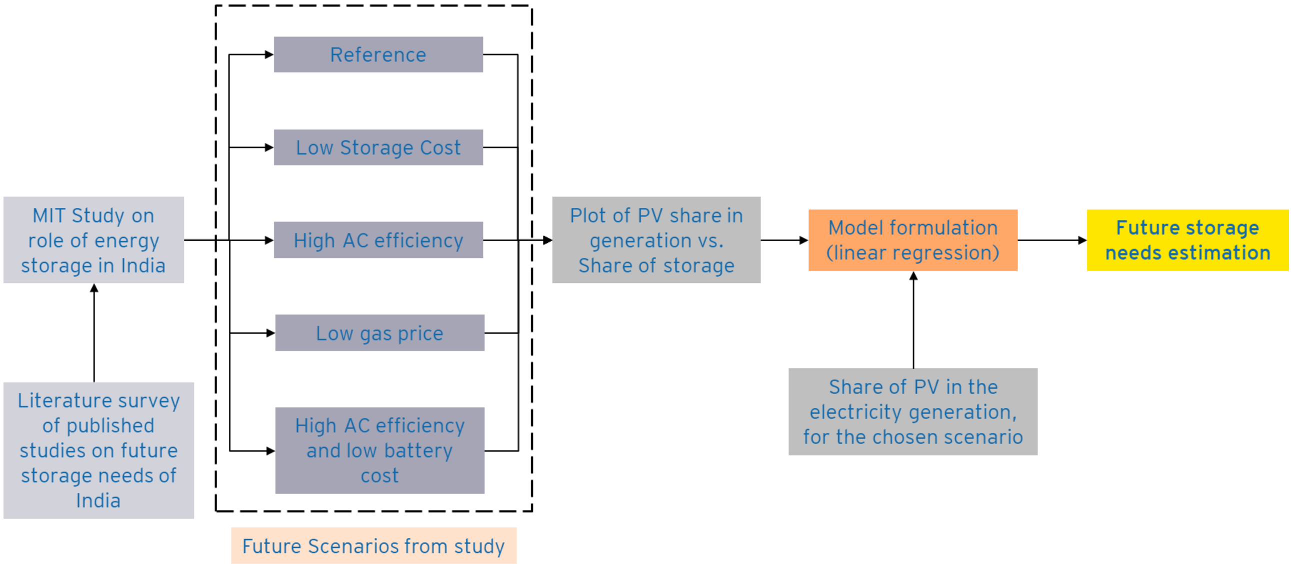
Note: This empirical relationship has been used for estimating the storage requirements in future. Numbers for 2040 and 2050 are within the range of numbers estimated by other studies. However, the numbers obtained for 2030 are lower than the numbers reported by other studies such as the optimal mix report by CEA. It is possible that the relationship may not hold strong for the lower values of the share of PV in the generation mix.

Methodology of the referred MIT study (Flow Chart)



Source – Impact of demand growth on decarbonizing India's electricity sector and the role for energy storage by MIT

Methodology for the storage estimation calculations (Flow Chart)
Empirical relation derived from a MIT study has been used to estimate storage needs



2.12. RESULTS: FLEXIBILITY REQUIREMENT IN HIGH RE SCENARIO

Table 8: Flexibility Requirement

Particulars	2030	2040	2050
Maximum ramping rate requirement (GW/hour)	64.8	164.32	477.32
Storage capacity required (GWh)	50.7	1300	4097
2-Hrs battery storage (GW)	25.35	650	2048.50
6-Hrs PHP storage (GW)	8.45	216.67	682.84
Case: As per Indian Grid Code, 5% of total rotating capacity is required as the spinning reserve			
spinning reserve (GW)	18.9	20.8	18
5% of peak load (GW)	16.7	29	49

- From the above results, there is significant growth in the storage capacity requirement from 50.7 GWh in 2030 to 4097 GWh in 2050.
- To meet the storage requirement of 50.7 GWh by 2030. Either 25.35 GW of BESS system needs to be developed or we can opt for 6 hrs of PSH of capacity 8.45 GW. Similarly, to crater the demand of storage which will reach 4097 GWh by 2050; 2048.50 GW and 682.84 GW for 2 hrs of BESS and 6 hrs of PSH will be required respectively, as per the study.
- Also, the similar pattern can be seen in Maximum ramping rate requirement (GW/hour) which has increased from 64.8 GW/h in 2030 to 477.32 GW/h in 2050.

2.13. COMPARISON OF VALUES FOR STORAGE ESTIMATIONS

Studies	Scenario (GWh)	2030	2040	2050
WEC India (EY + IITB Analysis)	High RE	51	1300	4096
CEA Optimal Mix	Likely Scenario	108	-	-
	5% More Demand	100	-	-
	5% Less Demand	83	-	-
	More battery cost (100$/kWh)	92	-	-
	More battery cost (125$/kWh)	59	-	-
NITI-RMI Report: Need for Advanced Chemistry Cell Energy Storage	Accelerated scenario	128	-	-
	Conservative scenario	49	-	-
TERI: Renewable Energy Pathways: Modelling Integration of Wind and Solar in India by 2030	HRES (High RE scenario)	120	-	-
NREL: Storage Futures Study	Reference Case	380	1100	3200
Impact of demand growth on decarbonizing India's electricity sector and the role for energy storage by MIT	Reference Case	-	1072	1072
	Low Storage Cost	45	2639	4742
	High AC Efficiency	-	690	690
	Low Gas price Scenario	-	990	990
	High AC Efficiency & low storage cost	69	2143	3771

- Multiple scenarios aligned with net-zero future of India have been illustrated.
- Generation mix, capacity mix, flexibility requirements as well as share of hydropower in the mix have been estimated

A Few observations from the results:

- Solar PV and wind are mainstay of the future energy transition in all scenarios
- A rapid deployment of storage (battery or PHP) is required to provide the required flexibility to the grid in case of high PV and wind penetration.
- Power sector emissions need to peak by 2040 and start declining afterwards to reach the decarbonization targets.

RPO and Energy Storage Obligation (ESO):

- The ESO shall be calculated in energy terms as a percentage of total consumption of electricity and shall be treated as fulfilled only when at least **85%** of the total energy stored in the Energy Storage System (ESS), on an annual basis, is procured from renewable resources.
- Following percentage of total energy consumed shall be solar/wind along with/through storage: -

FY	Storage (on Energy basis)
2023-24	1.00%
2024-25	1.50%
2025-26	2.00%
2026-27	2.50%

FY	Storage (on Energy basis)
2027-28	3.00%
2028-29	3.50%
2029-30	4.00%

51 GWh of storage has been estimated in the year 2029-30 with our methodology. The energy supplied through storage contributes to 0.8-0.9% of the total electricity consumption. It is less than the stipulated 4% in the ESO obligation document.

Assuming 15% of T&D losses in the grid, the amount of storage required in the grid is 238 GWh in 2030 as per the ESO obligation, which is much greater than the projections made by multiple studies.

Note: As the energy storage obligation will be calculated in energy terms as a percentage of the total consumption of electricity. Therefore in order to estimate the total electricity consumption, we have assumed 10-15% T&D losses in the system i.e., from generation to consumption.

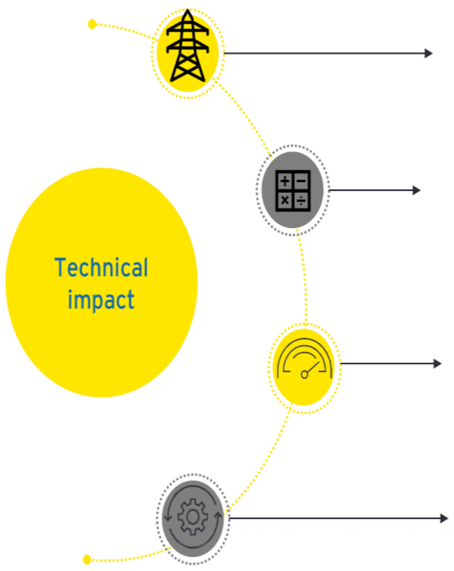
- Our estimation of 51 GWh of storage is based on the share of energy generated by solar PV in the grid. Thus, it is an estimate of the minimum requirement of storage in the grid.
- CEA's estimation is based on the minimum share of energy from storage from 2023-24 to 2029-30. Although the methodology behind those numbers is not available, the regulation has been set up in a way which will push the states/utilities toward including the storage components in their portfolio. It will prepare the grid for accommodating the intermittency.
- This will involve other components such as the use of storage as ancillary services, distribution-side installation, transmission investment deferral, etc.
- Our numbers being an estimate of the minimum requirement of storage and hence less than the storage requirements as specified in the regulation titled "Renewable purchase obligation and Energy storage obligation trajectory till 2029-30."

Chapter 3

Techno commercial impact of high RE

3.1. TECHNICAL IMPACT OF HIGH RENEWABLE PENETRATION IN GRID

Technical impacts that need to be resolved with increased infusion of RE in the grid are discussed below:



Transmission system challenge –

RE capacities are **concentrated in certain regions** within states and in certain states within India. It creates a non-uniform distribution of transmission system requirements leading to **limited availability of transmission capacity.**

Forecasting error –

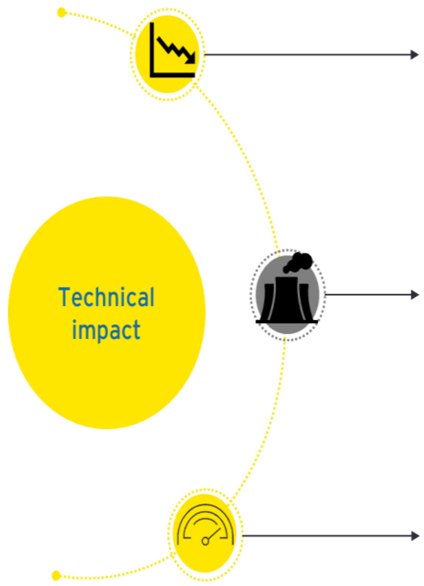
States lack capability in terms of arrangement of real-time solar & wind (renewable) generation data. Even though Renewable Energy Management Centres (co-located with load dispatch centres) are working on this, there is still **inadequacy and inaccuracy in the forecasting**. Even there is a **lack of centralized forecast** by either SLDCs, RLDCs or the NLDC which can be used for system operation.

Increased net load quantum putting stress on conventional sources –

Net load is the load not met by RE and hence must be served by conventional generator. Due to non-coincidental time of load and RE generation, there is a **large ramp in net load.** Even in the absence of tools for load shifting (such as storage or demand response), the **stress on conventional sources to accommodate the ramp** is increased.

Increased congestion time –

Utility-scale solar and wind generation distributed throughout the Southern and Western regions lead to reduced net import by these regions. It reduces interregional energy exchanges, but congestion on interregional interfaces increases as driven by SR-WR and NR-ER corridors. It further leads to **stress on the transmission system by increasing time under congestion and changing trading patterns.**



Reduction in Grid Inertia –

Inertia is the resistance offered by grid system to a change in frequency due to following a generation-load imbalance. It is monitored by inertia provided by synchronous generators that are observable to the system operator, aggregate online conventional generation, the number of units synchronised to the grid as well as aggregate online renewable energy generation.

In India, power system inertia varied between 5 and 9 seconds between January 2014 and June 2021, with a mean value of 6.5 seconds. It has reduced now due to RE penetration because **RE do not use synchronous generators to produce electricity and are intermittent in nature.**

Wear & tear of conventional plants –

Due to increased need of frequent ramping up and down along with reserve shutdown and restarting from cold condition, the conventional plants (coal based and gas based) have to face thermal stress of the equipments. Normally, a gas based station has a life of 1,00,000 EOH. For every start from cold condition, there is a loss of 20 EOH for a gas based power plant. It also leads to **wear & tear of plants.**

Issues of Voltage and reverse flow –

With the rapid deployment of distributed energy resources (such as Electric Vehicles and Rooftop Solar), voltage fluctuation occurs along with increased probability of reverse current flow. It threatens the grid stability scenario.

Source – https://mnre.gov.in/img/documents/uploads/80f821f916274ab9b73ac8869a0fa619.pdf, USAID report titled "Greening the Grid" Vol-I & II, https://posoco.in/wp-content/uploads/2022/01/Assessment-of-Inertia-in-Indian-Power-System.pdf, https://www.nrel.gov/docs/fy20osti/73856.pdf,

Increased operational expenditure –

Increased RE generation causes flexible operation of coal fired stations which causes cost implications due to following –

- *Increase in heat rate and auxiliary consumption,*
- *Operation & Maintenance (O&M) expense due to wear and tear of equipments, and*
- *Increased oil usage due to frequency ramping need.*

An estimate shows that **per unit cost impact is highest at Rs0.40/kWh for a 600MW unit running at 30% minimum load** compared to Rs0.15/kWh for a 210MW plant running at 50% minimum load.

Increased capital expenditure –

Increased RE generation leads to operation of coal fired stations at lower plant load factor. Even operating a thermal unit below 40% load requires implementation of measures that depend on various factors such as the plant's design type, capacity, coal quality, historical operation, maintenance, and age of the units. Siemens has estimated a capital cost of Rs20 crore (US$273m) to operate NTPC's 470MW unit 6 of Dadri thermal power station below 40% load (Rs4.0 lakh/MW).

Extra transmission charge –

As RE capacities have lower capacity utilization factor (CUF), there is a reduced utilization of transmission and distribution system used for RE evacuation. But as systems is already in place, the cost has to be incurred.

Tentative cost-breakup to be borne by RE rich state

Charges (Spread over renewable generation)	Cost (INR/kWh)
Total balancing charge for CGS Coal and gas based station (fixed +fuel charge)(Rs/kWh)-	0.2
Total balancing charge for Tamil Nadu Coal based station (fixed +fuel charge)(Rs/kWh)-	0.03
DSM Impact per unit	0.35
Impact on tariff (Rs./Unit) for Tamil Nadu discom for backing down Coal generation assuming solar and wind at Rs. 4/kWh and coal fuel charge at Rs. 2.0/kWh- (Considering 25% on account of renewables)	0.5
Stand by charge (Rs/kWh)	0.23
Extra transmission charge	0.26
Total impact	**1.57**

Source – https://mnre.gov.in/img/documents/uploads/80f821f916274ab9b73ac8869a0fa619.pdf, USAID report titled "Greening the Grid" Vol-I & II, https://posoco.in/wp-content/uploads/2022/01/Assessment-of-Inertia-in-Indian-Power-System.pdf, https://www.nrel.gov/docs/fy20osti/73856.pdf,

Chapter 4

Macro trends of HEP in India

4.1. KEY TRENDS IN HYDRO POWER PROJECTS IN THE COUNTRY

4.1.1. Current supply mix

Total energy supplied in FY 22 is 1380.94 Twh

Table 9: Total Energy Supplied FY 22[5]

Source	TWh	% Share of Total
Gas	50.94	3.69%
Coal	981.44	71.07%
Nuclear	43.02	3.12%
Hydro	150.30	10.88%
Solar PV	65.14	4.72%
Wind	64.63	4.68%
Small Hydro	9.82	0.71%
Bagasse	10.46	0.76%
Biomass	3.14	0.23%
Others	2.05	0.15%
Total	**1380.94**	**100.00%**

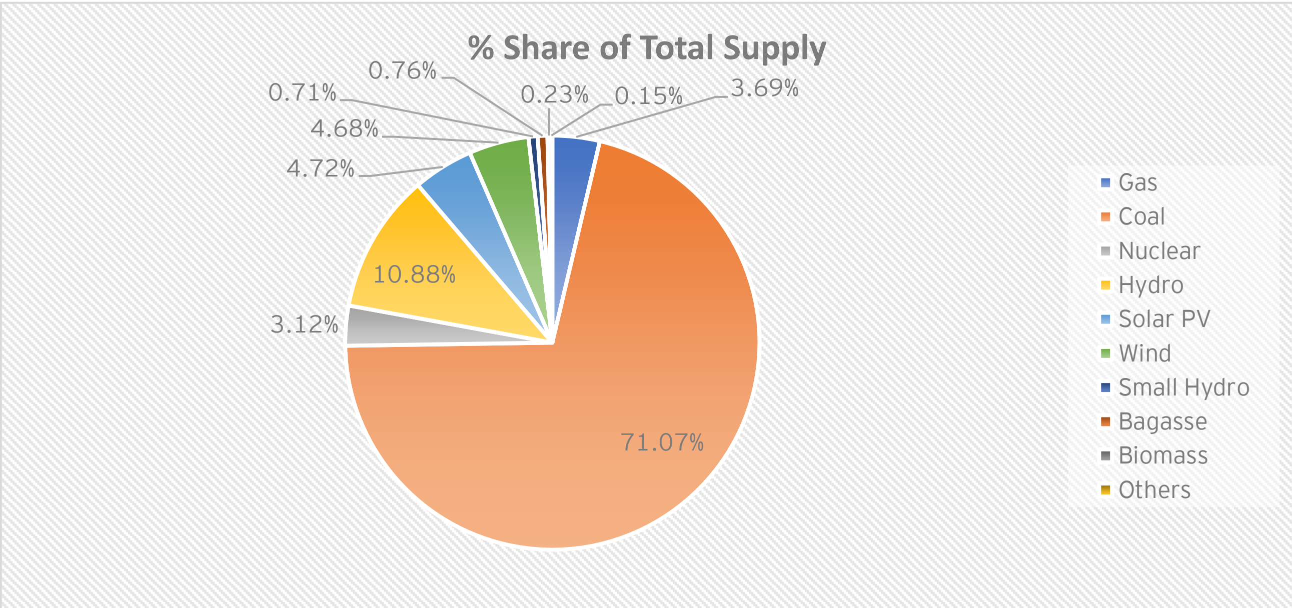


Figure 30: Total Supply (%)[6]

- Based on the data available up to March 2022, it is clear that most of the generation is via coal (71.07%) followed by hydro (10.88%), in renewable source of energy solar is leading with 4.72% followed by wind 4.68%.

5,6– Report by MOSPI, CEA Executive summary 2022 (till March 2022)

4.1.2. HYDRO INSTALLED CAPACITY OF INDIA

- Installed capacity as in Apr 2022 is ~42 GW, in which the northern region has the highest share

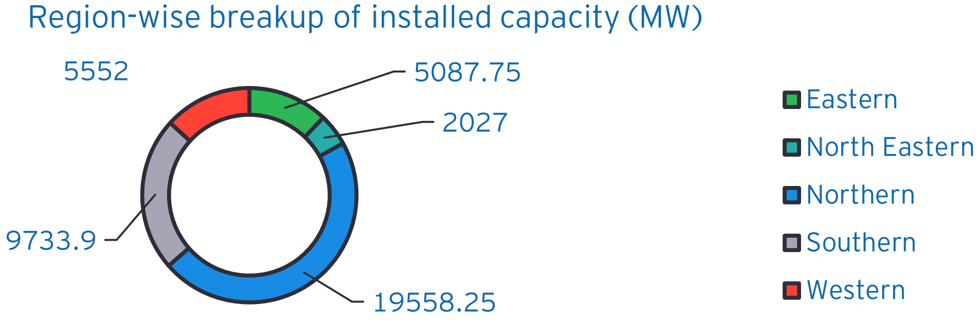


Figure 31: Region-wise breakup of installed capacity (MW)[7]

- Northern and Southern region together occupies 70% of the total installed capacity.

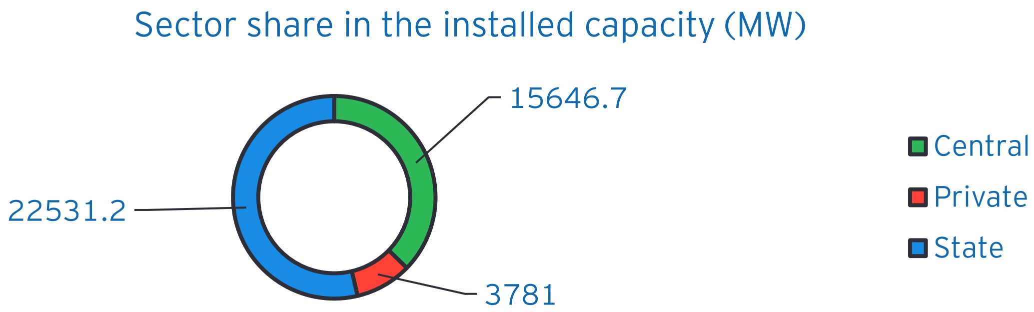


Figure 32: Sector share in the installed cap (MW)[8]

- Majority of the share of hydro IC is higher for state (54%) compared to centre (37%).

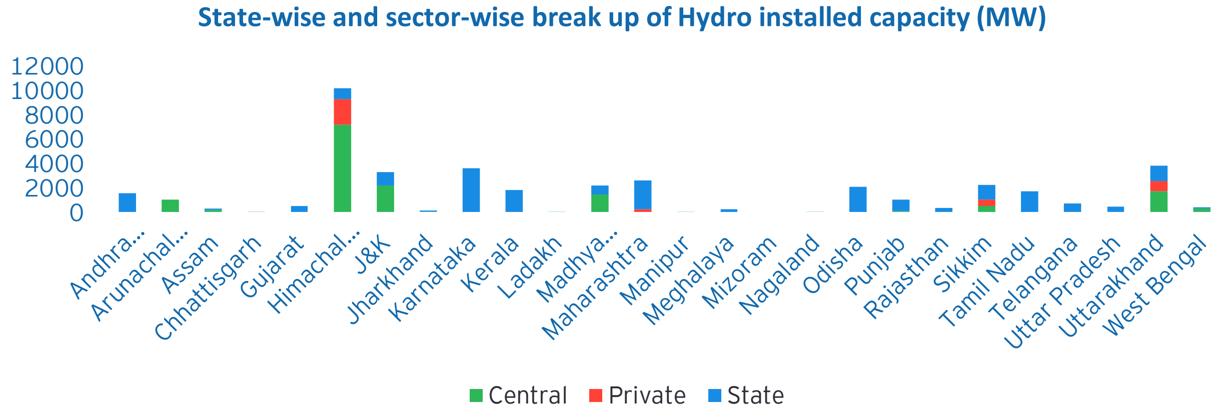


Figure 33: State-wise and sector-wise break up of Hydro installed capacity (MW)[9]

- Majority of share (50% - 21.1 GW) in the total installed capacity is occupied by 4 states. These states are – Himachal Pradesh (10.2 GW), Uttarakhand (3.9 GW), Karnataka (3.7 GW) and J&K (3.4 GW).
- On national basis, state government occupies the majority of share whereas in Himachal Pradesh, the majority of project is done by central sector. Same is the case for Uttarakhand and J&K also whereas 100% share is of state government in Karnataka.

7,8,9 – CEA report titled "Region-wise/Sector-wise Installed Capacity of H.E. Stations in the Country"

State government has the highest share in hydro installed capacity with 22.5 GW capacity as in Apr 2022.
Below graph shows trend in installed capacity for the share of central, state, and private participation in the last 89 years (Y axis – Installed capacity MW):-

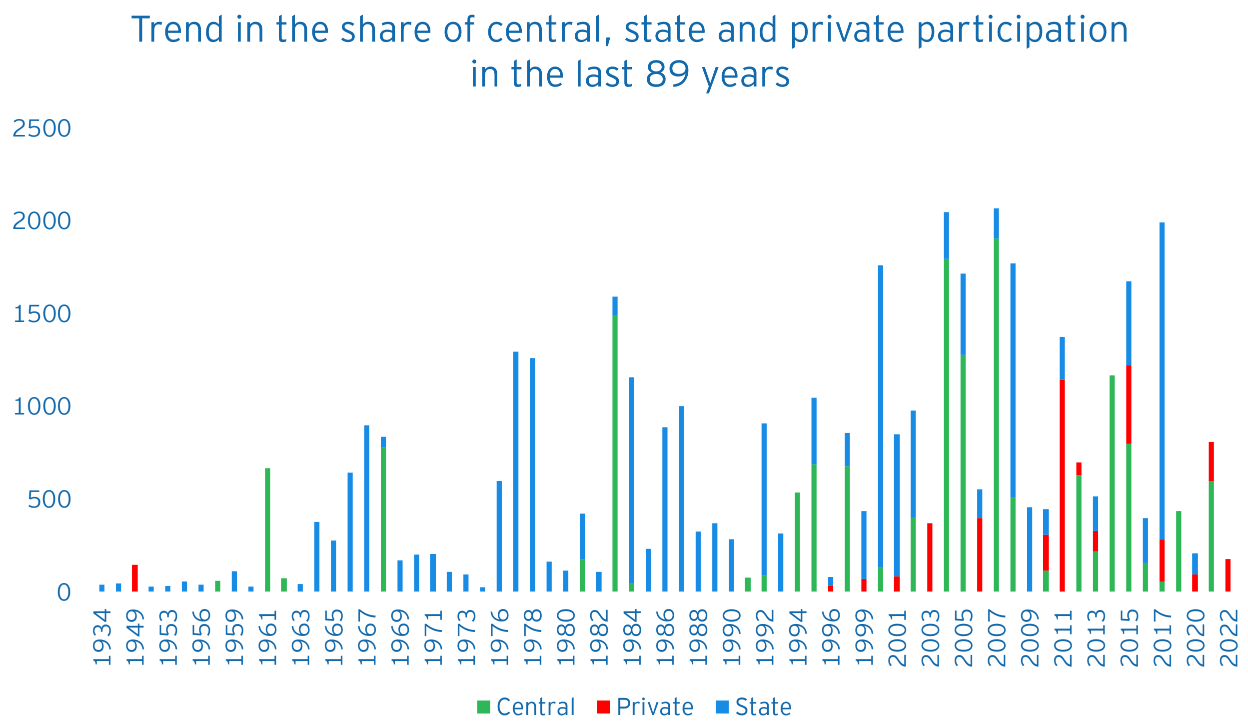


Figure 34: Trend in the share of central, state, and private participation in the last 89 years[10]

- In the last 89 years, participation of state is highest in terms of installed capacity
- State sector also has highest number of years where HEP was commissioned during this timeframe
- The private participation initiated after 1996 only (except the one in 1949 built by TPCL in Maharashtra).
- Most of the private installations occurred in the year 2011 with a capacity of ~1.15 GW.

10 – CEA report titled "Region-wise/Sector-wise Installed Capacity of H.E. Stations in the Country"

4.1.3. HYDRO ELECTRIC SCHEMES CONCURRED/ APPRAISED BY CENTRAL ELECTRICITY AUTHORITY SINCE 2002-03

CEA concurred ~47.7 GW of projects in the time span from 2002-03 to 2021-22

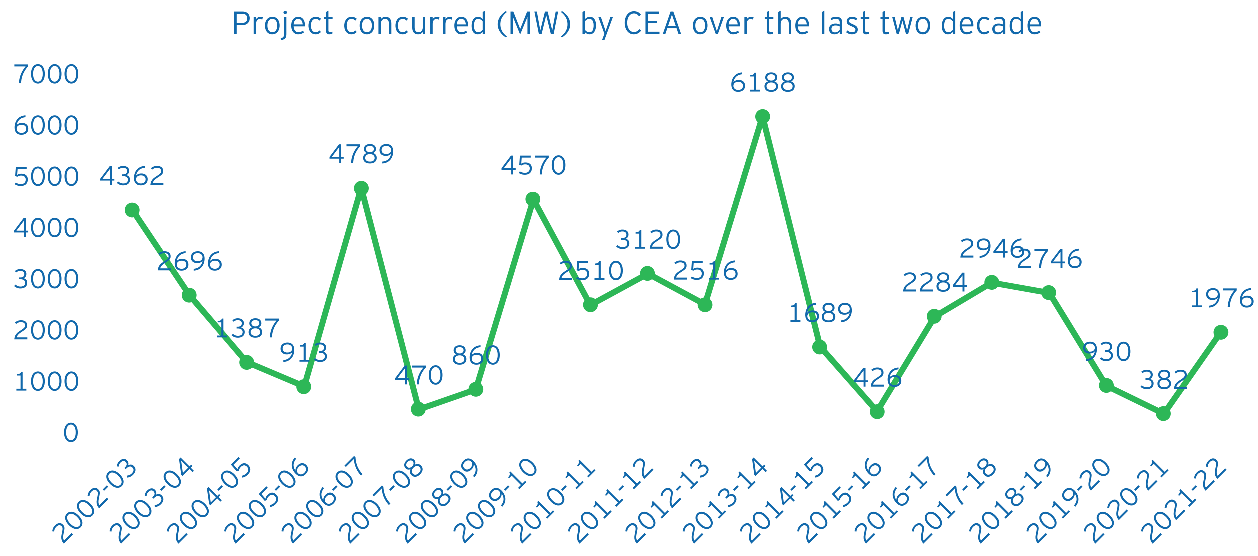


Figure 35: Project concurred (MW) by CEA over the last two decade[11]

- The project being concurred by CEA has seen a decline in the last 4 years (FY 18 – FY 21) and an increase in FY 22.
- Capacity concurred was highest in FY 14 with ~6.2 GW of projects by CEA

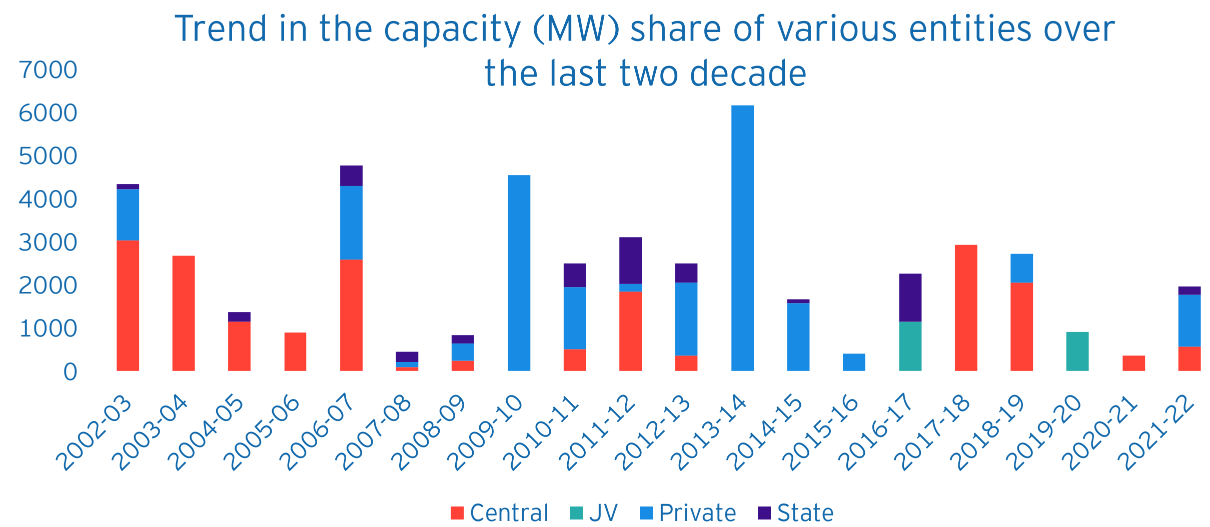


Figure 36: Trend in the capacity (MW) share of various entities over the last two decade[12]

- Out of total capacity of 47.7 GW concurred by CEA, majority of project is of private type with ~21.3 GW followed by central share of 19.5 GW. State occupies only ~4.7 GW of projects.
- Share of Joint Venture (JV) is very less as compared to other entities. Project under JV mode has been concurred in FY 17 and FY 20 only with capacity of ~2 GW.
- Majority of concurrence have occurred in the time span of 2010-14.

11,12 – CEA report titled "Hydro Electric Schemes Concurred/ Appraised by Central Electricity Authority since 2002-03"

4.1.4. HYDRO ELECTRIC SCHEMES UNDER IMPLEMENTATION

~12.5 GW of projects across India are expected to commence in next 4 years

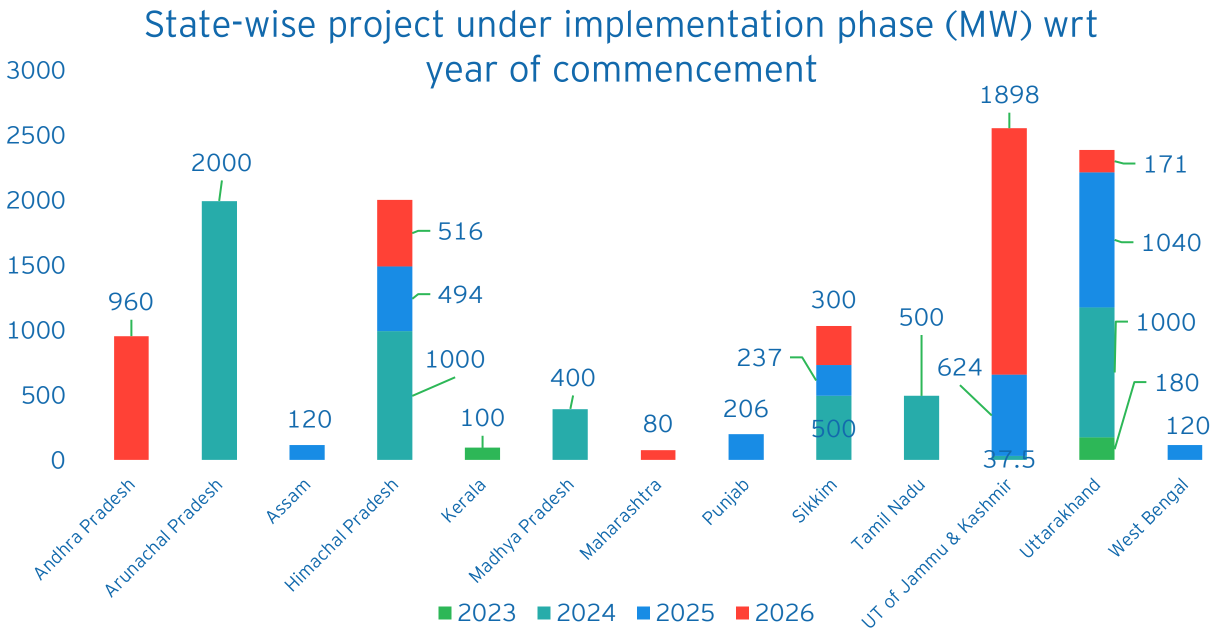


Figure 37: State-wise project under implementation phase (MW) wrt year of commencement[13]

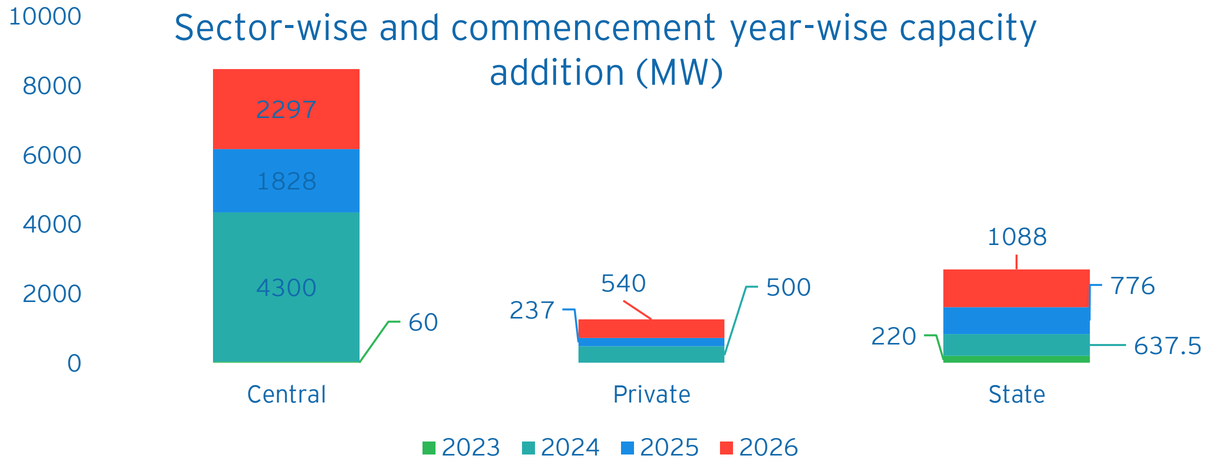


Figure 38: Sector-wise and commencement year-wise capacity addition (MW)[14]

- UT of J&K is expected to have the maximum projects among all states to commence with capacity of ~2.6 GW
- Share of project to commence by 2023 is the least i.e., 280 MW only.
- Maximum capacity of project will commence by 2024 i.e., 5.4 GW.

Maximum projects will commence in the central sector (8.5 GW) whereas private participation (1.2 GW) is the least.

13,14 – CEA report titled "List of Hydro Electric Projects (above 25 MW) under implementation - Sector wise"

4.1.5. HYDRO ELECTRIC SCHEMES FOR WHICH CONSTRUCTION IS HELD UP

~1.2 GW of projects across India are stuck
Below graph represent State-wise capacity (MW) segregation with their reason of stalled projects -

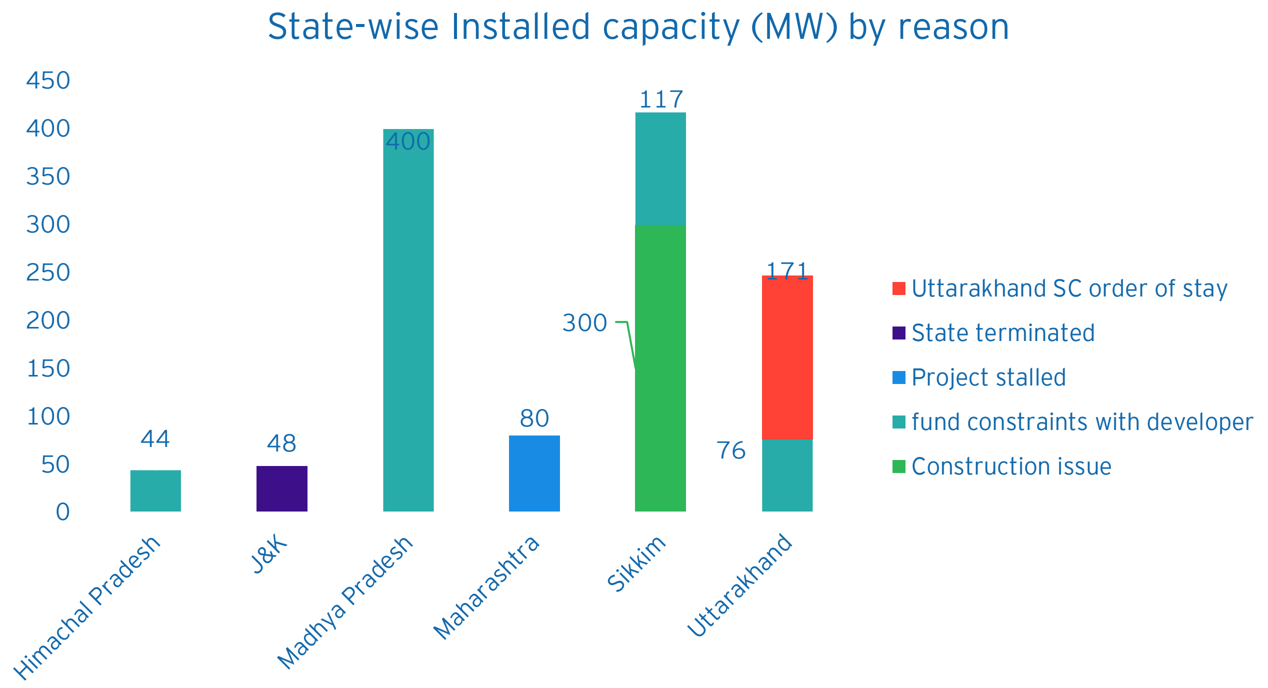


Figure 39: State-wise stalled capacity (MW)[15]

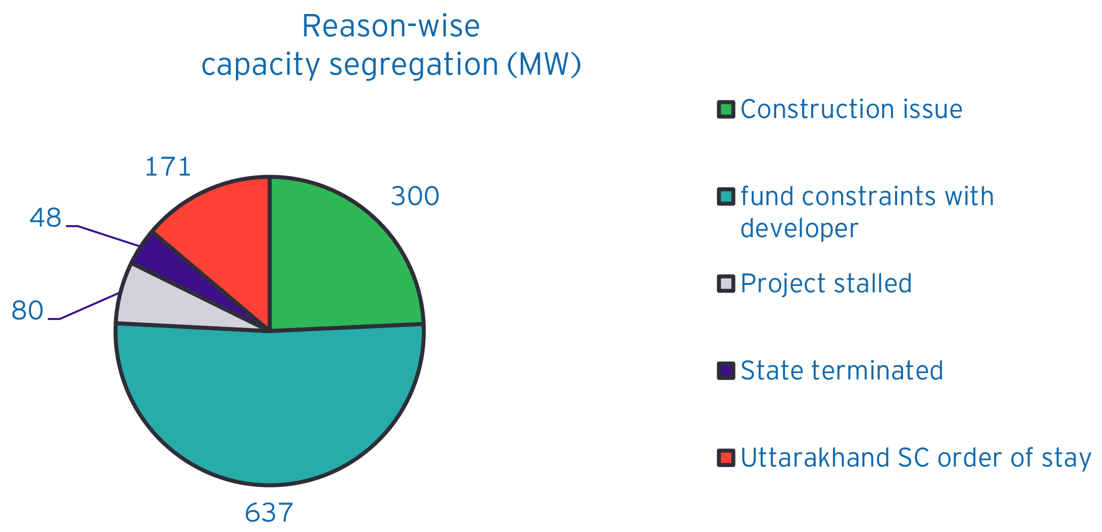


Figure 40: Reason-wise capacity segregation[16]

15,16 – CEA report titled "List of Hydro Electric Projects (above 25 MW) for which construction is held up (As on 31.03.2022)"

Below graph represent State-wise capacity (MW) segregation by sector -

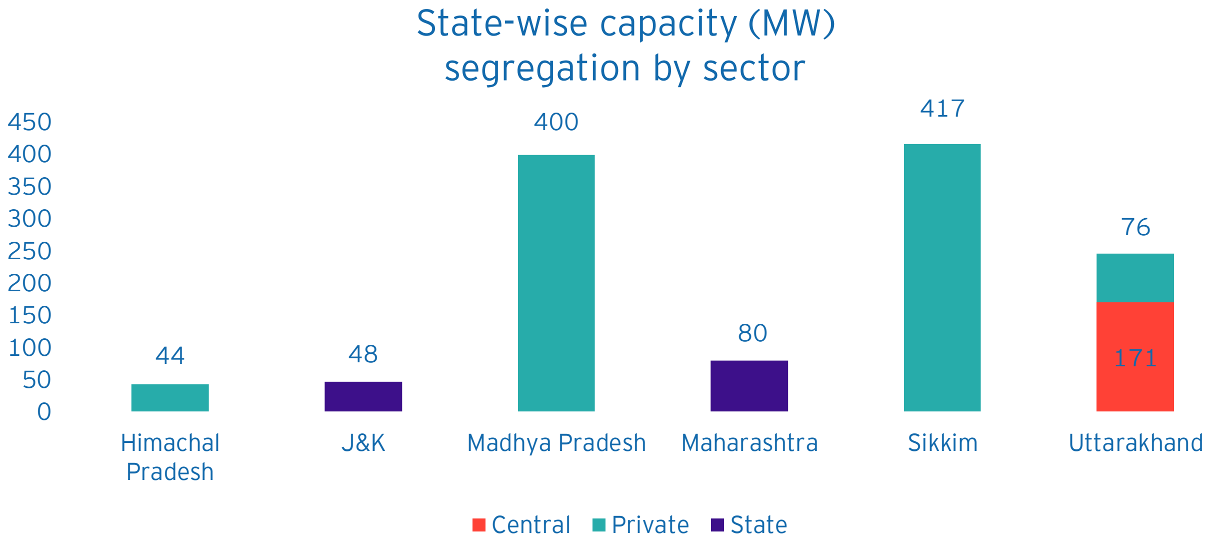


Figure 41: State-wise capacity segregation (MW)[17]

- Sikkim has the highest projects which are stalled up, which are owned by private sector.
- Madhya Pradesh comes after Sikkim, here also full share belongs to private sector.
- Major share in Uttarakhand (~171 MW) is on hold because of Supreme Court order. The Hon'ble Supreme Court vide its order dated 07.05.2014 stayed the construction of 24 Hydro projects in Uttarakhand. Accordingly, all construction activities stopped since 08.05.14 and await clearance to restart the main activities.
- Maharashtra - Project stalled since July 2015. The current expenditure on the project has already reached to almost original administrative approved cost level. Proposal for revival of the project is submitted to the Govt. of Maharashtra.

17 – CEA report titled "List of Hydro Electric Projects (above 25 MW) for which construction is held up (As on 31.03.2022)" , https://cea.nic.in/wp-content/uploads/hydro/2021/01/stalled_hep.pdf

4.2. HEP POTENTIAL AND UTILIZATION

4.2.1. Hydro potential and utilization

~67% of potential is untapped across India with ~93% untapped potential lying in north-eastern region

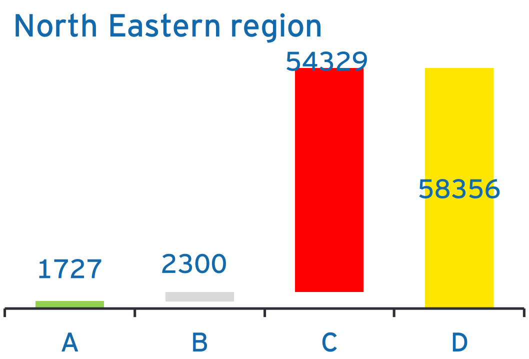


Figure 42: NE region

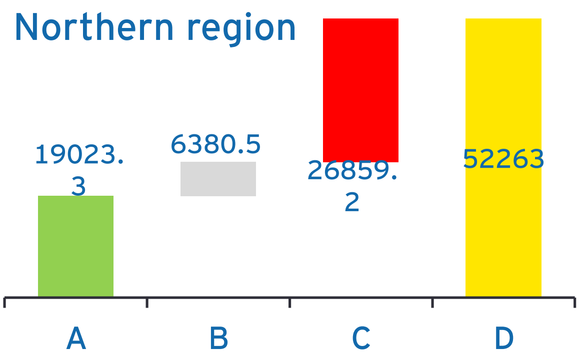


Figure 43: Northern region

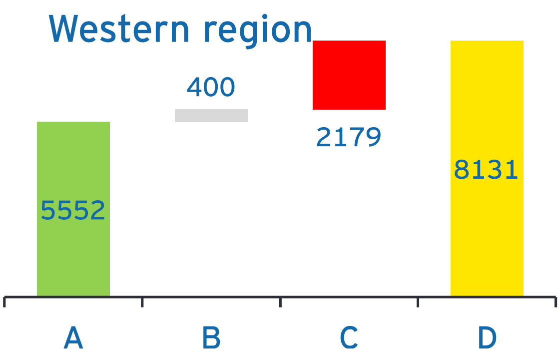


Figure 44: Western region

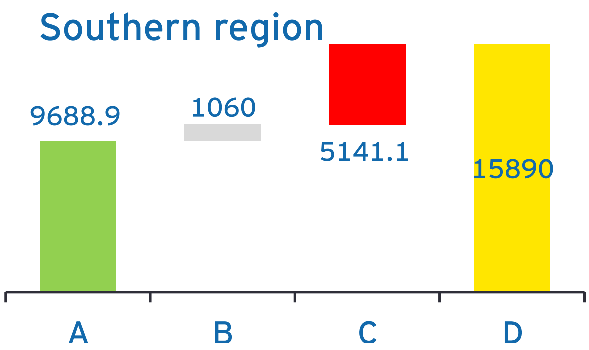


Figure 45: Southern region

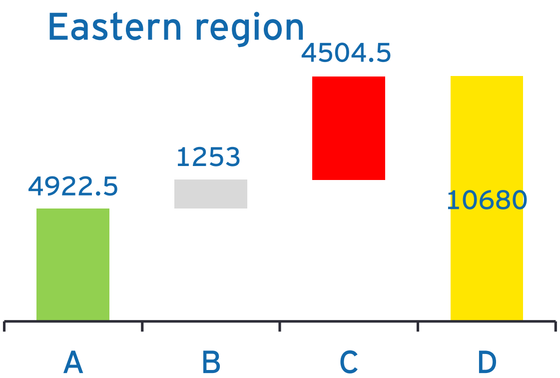


Figure 46: Eastern region

Note for graph – * *Values are in MW*

A - Operational capacity

B - Under construction

C – Yet to be taken up for development

D – Total Identified capacity (A+B+C)

19 – https://cea.nic.in/wp-content/uploads/hepr/2022/03/State_Power_3.pdf

As per the above graph –

- Total Identified hydro capacity is 145.32 GW in which total operational capacity is 40.91 GW, total under construction is 11.40 GW and yet to be taken up for development is 93.01 GW.
- The topmost region with highest potential are north-eastern (40%) and northern (36%) region. They share 76% of the total India hydro potential.
- Apparently, these two regions are also those with highest untapped potential (i.e., project yet to be undertaken with respect to identified capacity) i.e. northern (51%) and north-eastern (93%).
- On an average, only ~8% of the identified capacity in each region is under the stage of construction.
- Two regions with highest operational capacity (with respect to identified capacity) are western (68%) and southern (61%) region.

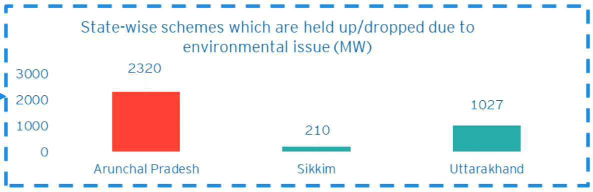
4.2.2. Status of 50,000 mw hydroelectric initiative scheme

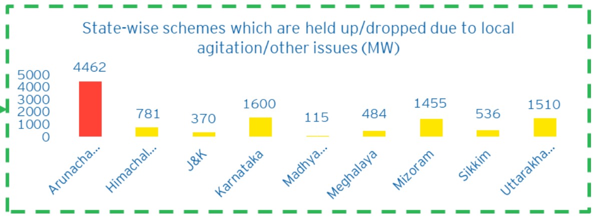
Arunachal Pradesh has the highest unallotted and dropped/upheld schemes to the tune of ~10.15 GW

Table 10: Status of 50,000 MW initiative scheme[18]

Status of 50,000 MW initiative scheme (as on 31.03.22)

S. No.	Particulars	Nos	Cap (MW) as per PFR	Cap (MW) as per DPR
1	DPR prepared	35	19,360	17157
a	In operation	2	300	192
b	Under construction	8	2,308	2491
c	Concurred	14	6,871	6535
d	Under examination	1	280	212
e	Others	10	9,601	7727
2	Schemes under S&I	6	2,414	
3	Schemes yet to be allotted	73	11,286	
4	Work held up/dropped on account of	48	14,870	
a	Environmental issue	12	3,557	
b	Local agitation/other issues	36	11,313	
	Total	162	47,930	





4.3. IDENTIFICATION OF HYDRO POWER PROJECTS

4.3.1. Identification of hydro power projects- central sector

DPR of 8485 MW (central sector) is concurred by CEA

Table 11: List of projects (central sector) concurred by CEA

List of Hydro Electric Projects (above 25 MW) under implementation -Sector wise								
Sl. No.	Name of Scheme (Executing Agency)	State / UT	District	I.C. (No. X MW.)	Cap. Under Execution (MW)	River/Basin	Date of finish/ commissioning	CEA Concurrence date (as inserted from 1st sheet)
Central Sector								
1	Subansiri Lower (NHPC) #	Arunachal Pradesh	Lower Subansiri	8x250	2000	Subansiri/ Brahmaputra	2022-24 ** (Aug'23)	13.01.2003
2	Parbati St. II (NHPC)	Himachal Pradesh	Kullu	4x200	800	Parbati/Beas/Indus	2023-24 (Sept'23)	
3	Luhri-I (SJVN)	Himachal Pradesh	Kullu/Shimla	2x80+2x25	210	Satluj/Indus	2025-26 (Jan'26)	01.05.2018
4	Dhaulasidh (SJVN)	Himachal Pradesh	Hamirpur/ Kangra	2x33	66	Beas	2025-26 (Nov'25)	
5	Pakal Dul (CVPPL)	UT of Jammu & Kashmir	Kishtwar	4x250	1000	Marusadar/ Chenab /Indus	2025-26 (July'25)	03.10.2006
6	Kiru (CVPPL)	UT of Jammu & Kashmir	Kishtwar	4x156	624	Chenab/ Indus	2024-25 (Aug.'24)	13.06.2016
7	Teesta St. VI NHPC	Sikkim	South Sikkim	4x125	500	Teesta/Brahmaputra	2023-24 (Mar'24)	13.05.2010
8	Vishnugad Pipalkoti (THDC)	Uttarakhand	Chamoli	4x111	444	Alaknanada/Ganga	2024-25 (Jun'24)	21.09.2006
9	Naitwar Mori (SJVNL)	Uttarakhand	Uttarkashi	2x30	60	Tons/Yamuna/Ganga	2022-23 (Jan'23)	
10	Tapovan Vishnugad (NTPC)	Uttarakhand	Chamoli	4x130	520	Dhauliganga / Alaknanada & /Ganga	2024-25 (Jun'24)	11.08.2004
11	Tehri PSS (THDC)	Uttarakhand	Tehri Garhwal	4x250	1000	Bhilangna/Bhagirathi/Ganga	2022-24*** (Jun'23)	
12	Rammam-III (NTPC)	West Bengal	Darjeeling	3x40	120	Rammam/ Rangit/Teesta Brahmaputra	2024-25 (Dec'24)	12.09.2016
13	Rangit-IV (NHPC)	Sikkim	West Sikkim	3x40	120	Rangit/ Teesta/Brahmaputra	2024-25 (May'24)	06.07.2007
14	Ratle (RHEPPL / NHPC)	UT of Jammu & Kashmir	Kishtwar	4x205 + 1x30	850	Chenab/Indus	2025-26 (Feb.'26)	19.12.2012
15	Lata Tapovan (NTPC)	Uttarakhand	Chamoli	3x57	171	Dhauliganga /Alaknanada & Ganga	2025-26*	08.02.2006
* The Project is presently stalled.Commissioning is subject to immediate restart of works								
** 2 units (500 MW) likely during 2022-23 & 6 units (1500 MW) during 2023-24								
*** 1 unit (250 MW) likely during 2022-23 & 3 units (750 MW) during 2023-24								
**** 1 unit (50 MW) likely during 2022-23 & 1 unit (50 MW) during 2023-24								

4.3.2. Identification of hydro power projects- state sector

DPR of 2721.5 MW (state sector) is concurred by CEA

Table 12: List of projects (state sector) concurred by CEA

List of Hydro Electric Projects (above 25 MW) under implementation -Sector wise								
Sl. No.	Name of Scheme (Executing Agency)	State / UT	District	I.C. (No. X MW.)	Cap. Under Execution (MW)	River/Basin	Date of finish/ commissioning	CEA Concurrence date (as inserted from 1st sheet)
State Sector								
1	Polavaram (APGENCO/ Irrigation Dept., A.P.)	Andhra Pradesh	East & West Godavari	12x80	960	Godavari/EFR	2024-26	21.02.2012
2	Lower Kopili (APGCL)	Assam	Dima Hasao & Karbi Anglong	2x55+2x2.5+1x5	120	Kopili	2024-25 (Jun'24)	24.05.2016
3	Uhl-III (BVPCL)	Himachal Pradesh	Mandi	3x33.33	100	Uhl/Beas/Indus	2023-24 (Dec'23)	19.09.2002
4	Shongtong Karcham (HPPCL)	Himachal Pradesh	Kinnaur	3x150	450	Satluj/ Indus	2024-25 (Mar'25)	16.08.2012
5	Parnai (JKSPDC)	UT of Jammu & Kashmir	Poonch	3x12.5	37.5	Jhelum/ Indus	2023-24 (Dec'23)	
6	Pallivasal (KSEB)	Kerala	Idukki	2x30	60	Mudirapuzha/ Periyar/ Baypore Periyar/ WFR	2022-23 (Mar'23)	
7	Thottiyar (KSEB)	Kerala	Idukki	1x30+1x10	40	Thottiyar/ Periyar// Baypore Periyar/ WFR	2022-23 (Mar'23)	
8	Shahpurkandi (PSPCL/ Irrigation Deptt., Pb.)	Punjab	Gurdaspur	3x33+3x33+1x8	206	Ravi/ Indus	2024-25 (Aug'24)	
9	Kundah Pumped Storage Phase-I,II&III)	Tamil Nadu	Nilgiris	4x125	500	Kundah/Bhavani/ Cauvery/EFR	2023-24 (Mar'24)	
10	Vyasi (UJVNL)	Uttarakhand	Dehradun	2x60	120	Yamuna/Ganga	2022-23 (May'22)	25.10.2011
11	Lower Kalnai (JKSPDC)	UT of Jammu & Kashmir	Kishtwar	2x24	48	Chenab/ Indus	2025-26 *	
12	Koyna Left Bank (WRD,MAH)	Maharashtra	Satara	2x40	80	Koyna/ Krishna/EFR	2025-26*	

4.3.3. Identification of hydro power projects- private sector

DPR of 1277 MW (private sector) is concurred by CEA

Table 13: List of projects (private sector) concurred by CEA

List of Hydro Electric Projects (above 25 MW) under implementation -Sector wise								
Sl. No.	Name of Scheme (Executing Agency)	State / UT	District	I.C. (No. X MW.)	Cap. Under Execution(MW)	River/Basin	Date of finish/ commissioning	CEA Concurrence date (as inserted from 1st sheet)
Private Sector								
1	Tidong-I (Statkraft IPL)	Himachal Pradesh	Kinnaur	2x50	100	Tidong/Satluj/Indus	2023-24 (Apr'23)****	
2	Kutehr (JSW Energy Ltd)	Himachal Pradesh	Chamba	3x80	240	Ravi/ Indus	2025-26 (Nov'25)	31.08.2010
3	Tangnu Romai (TRPG)	Himachal Pradesh	Shimla	2x22	44	Pabbar/Tons/ Yamuna/ Ganga	2024-25 *	
4	Maheshwar (SMHPCL)	Madhya Pradesh	Khargone & Khandwa	10x40	400	Narmada/CIRS	2023-24 *	
5	Bhasmey (Gati Infrastructure)	Sikkim	East Sikkim	2x25.5	51	Rangpo/ Teesta/Brahmaputra	2024-25*	
6	Rangit-II (Sikkim Hydro)	Sikkim	West Sikkim	2x33	66	Greater Rangit/ Teesta/Brahmaputra	2024-25 *	
7	Panan (Himagiri)	Sikkim	North Sikkim	4x75	300	Rangyongchu/ Teesta/Brahmaputra	2025-26 *	07.03.2011
8	Phata Byung (LANCO)	Uttarakhand	Rudraprayag	2x38	76	Mandakini/Alaknanda Ganga	2024-25*	
Sub-Total: Private Sector					1277			E29:M48F3E3:M48
	Total:				12483.5			
* The Project is presently stalled.Commissioning is subject to immediate restart of works								
** 2 units (500 MW) likely during 2022-23 & 6 units (1500 MW) during 2023-24								
*** 1 unit (250 MW) likely during 2022-23 & 3 units (750 MW) during 2023-24								
**** 1 unit (50 MW) likely during 2022-23 & 1 unit (50 MW) during 2023-24								
# Part of the project lies in Dhemaji district of Assam.								

Chapter 5

Impediments faced by the hydro sector in India

5.1. ISSUES IDENTIFIED FROM SECONDARY RESEARCH

5.1.1. ISSUE ASSESSMENT FROM VARIOUS REPORTS

Brief on Key issues

As per Standing Committee on Energy (18-19) 43rd report presented to Lok Sabha on 4th Jan 2019

- Land acquisition - Acquisition of land for various locations of the project such as Dam, HRT, Powerhouse, Switch yard etc. delay the commencement / progress of works. Example of Koteshwar, Parbati-III HEPs
- Rehabilitation & Resettlement - Dislocation of the people from their houses/fields/workplaces etc. and their resettlement is a sensitive issue and involves a lot of time and money. Many times, this issue leads to court cases resulting in delay in project execution/completion. Example of Koteshwar, Maheshwar HEPs
- Law & order problem & Local issues - Protest by the local people against the construction activities, like blasting, muck disposal, etc. and for various demands like employment, extra compensation, etc. often create law and order problems and delays the completion of works. Example of Uri-II, Subansiri, TLDP-III & IV HEPs.
- High Tariff of Hydro Projects - Tariff from hydro projects tends to be higher compared to other sources of power (conventional as well as renewable sources) mainly due to construction of complex structures which have long gestation period, unavailability of loans of lower interest rate & longer tenures, high R&R cost, infrastructure (roads & bridges) cost etc. As such, many hydro projects even after commissioning are facing financial distress due to dishonouring of PPAs / non-signing of PPAs.
- Financing issues - High cost of Finance and lack of long tenure funding for hydropower projects.
- Levying of Water Cess - Levying of water cess by the States like J&K has also affected the viability of the projects and increased the tariff by about 50p-Rs 1/unit.
- Cumulative Basin Studies - The impact of recommendations of Cumulative Basin studies of different basins results in change in parameters such as FRL, Head and Annual Energy Generation etc. of hydro projects necessitating formulation of new DPR.
- Inter-state disputes: The report also sighted interstate dispute as reasons of delay. However, report does not give any specific examples.
- Environment and Forest issues - Three types of clearances are mandatory from three different wings of Ministry of Environment and Forest (MoEF) i.e., environmental clearance from Expert Appraisal Committee (EAC), Forest Clearances from Forest Advisory Committee (FAC) & Wildlife Clearances from National Board of Wildlife (NBWL). This makes the whole process very cumbersome which otherwise would be easier and less time consuming.
- Technical / Geological issues - Geological surprises resulting from weak geology in the Young Himalayan region, lack of technology to deal with weak geology, lack of major contractors with expertise in hydropower sector, natural calamities like landslides, hill slope collapses, roadblocks, flood, and cloud bursts etc are a cause of severe setbacks in construction schedules

21 delayed projects amounting to ~9.8 GW with time overrun of 2,217 months and cost overrun of INR 36,000 Cr.

As per Standing Committee on Energy (2020-21) 19th report presented to Lok Sabha on Aug 2021 – This report highlighted the major issue with the delayed hydro power projects. Graph below is the Sector-wise share in delayed HEP

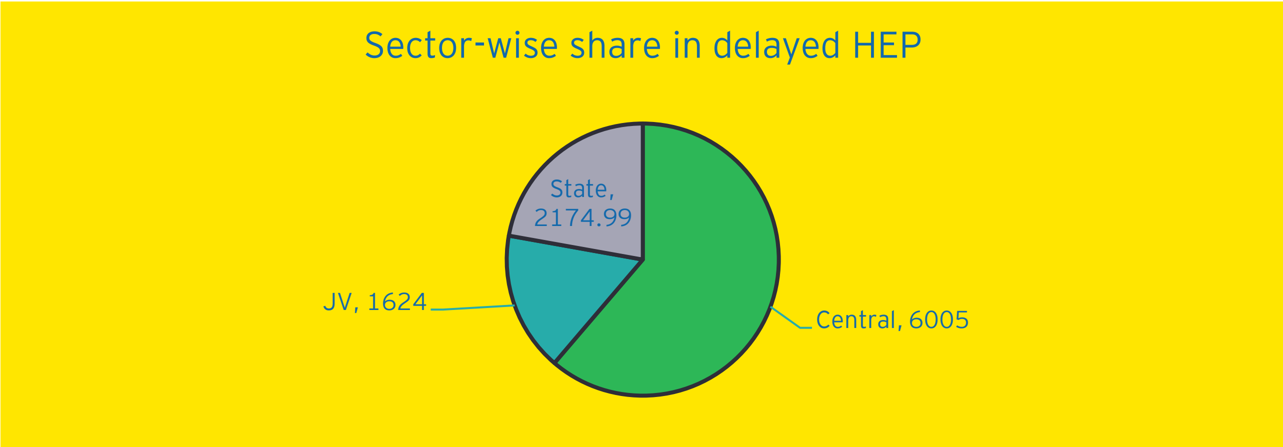


Figure 47: Sector-wise share in delayed HEP

- Major share in the delayed HEP is of centre sector followed by state sector.

Graph below is the State-wise capacity of delayed HEP (MW)-

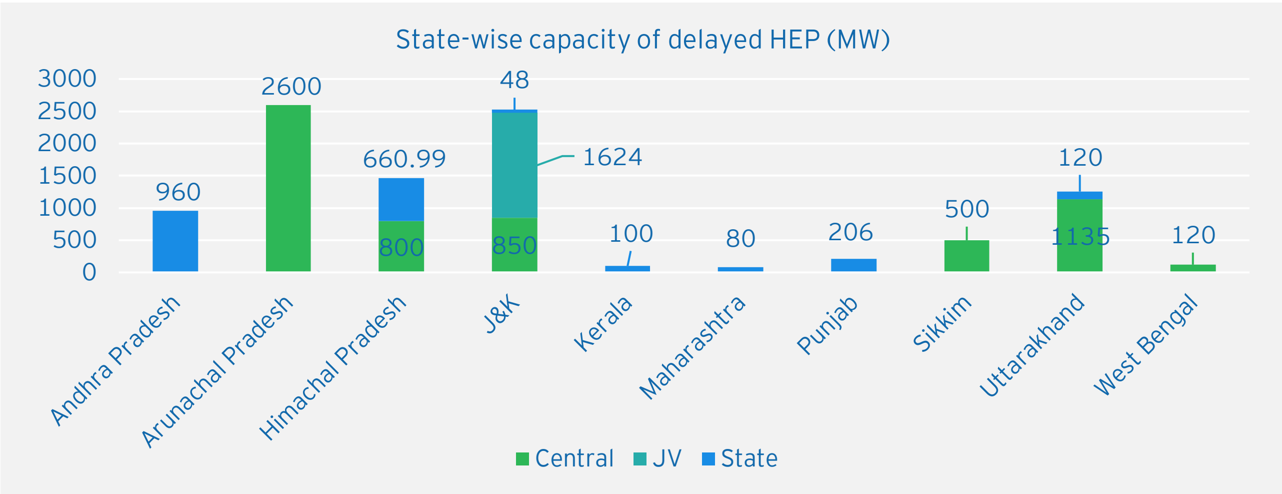


Figure 48: State-wise capacity of delayed HEP (MW)

- Two states with highest share of delayed HEP are Arunachal Pradesh (2.6 GW) and J&K (2.5 GW).
- JV type of structure is there in J&K only.

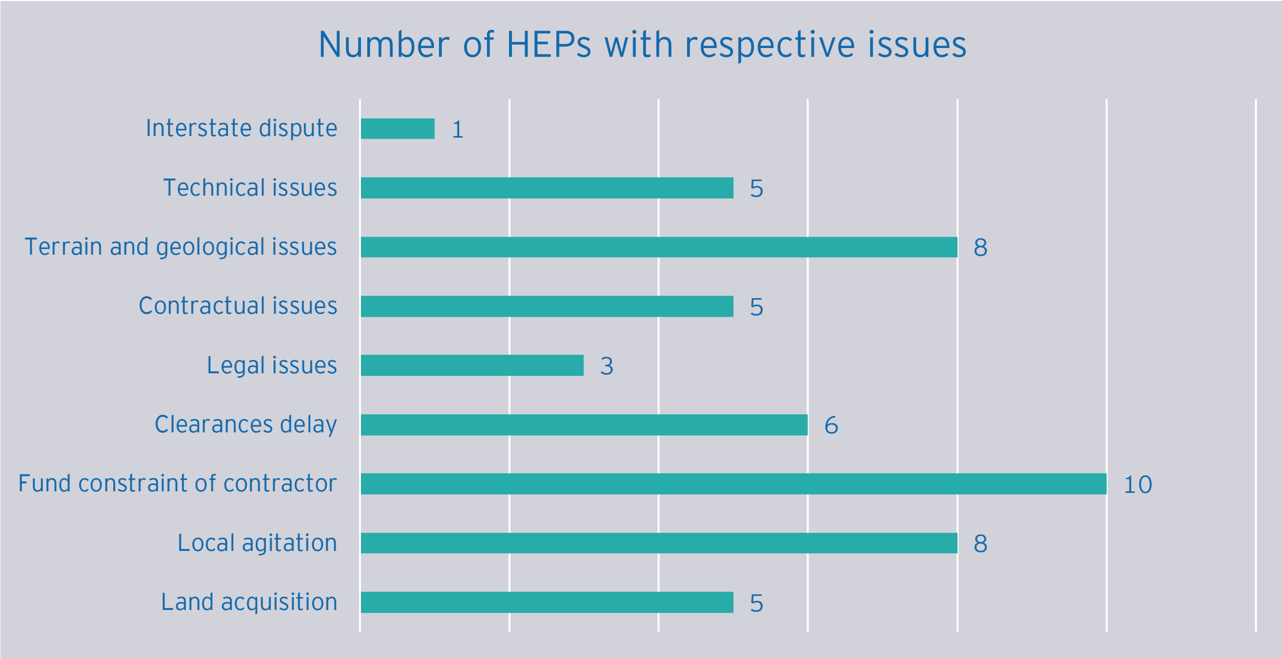


Figure 49: Number of HEPs with respective issues

In the selected 21 projects, majority of the HEPs face the following three issues –

- Fund constraint of contractor
- Local agitation
- Terrain and geological issue

~ 26 GW of hydro projects are stalled at different levels

Table 14: hydro projects stalled at different levels

List of impediments leading to delay/cancellation of hydro projects

Name of the Scheme	State	Installed Capacity	Fund Constraint	Connectivity Issues	Issues related to Clearances			MoU/MoA cancelled/ terminated	Concurrence expired	Other Issues
					EC received, FC yet to be received	Both EC, FC not obtained	EC,FC Subjudice			
Tangnu Romai	HP	44	✓							
Lower Kalnai	J&K	48						✓		
Maheshwar	MP	400	✓							
Koyna Left Bank	MH	80	✓							
Bhasmey Gati	Sikkim	51	✓							
Rangit-II	Sikkim	66	✓							
Panan	Sikkim	300		✓						
Lata Tapovan	UK	171					✓			
Phata Byung	UK	76	✓							
Teesta St-IV	Sikkim	520			✓					
Tawang St-I	AP	600			✓					
Tawang St-II	AP	800			✓					
Talong Londa	AP	225			✓					
Etalin	AP	3097			✓					
Sunni Dam	HP	382			✓					
Wah-Umiam Stage III	Meghalaya	85			✓					
Thana Plaun	HP	191			✓					
Kirthai II	J&K	930			✓					
Turga PSP	WB	1000			✓					
Sawalkot	J&K	1856			✓					

Forest clearance, fund constraint and expiry of CEA concurrence are the major issues

Table 15: Forest clearance, fund constraint and expiry of CEA concurrence are the major issues

List of impediments leading to delay/cancellation of hydro projects

Name of the Scheme	State	Installed Capacity	Fund Constraint	Connectivity Issues	Issues related to Clearances			MoU/MoA cancelled/ terminated	Concurrence expired	Other Issues
					EC received, FC yet to be received	Both EC, FC not obtained	EC,FC Subjudice			
Pinnapuram	AP	1200			✓					
Dikhu	Nagaland	186				✓				
Attunli	AP	680				✓				
Dugar	HP	500				✓				
Kotlibhel-Ia	UK	195					✓			
Kotlibhel-Ib	UK	320					✓			
Alaknanda	UK	300					✓			
Kwar	J&K	540								✓
Loktak Downstream	Manipur	66								✓
Dibang	AP	2880								✓
New Ganderwal	J&K	93								✓
Chhatru	HP	126						✓		
Hirong	AP	500						✓		
Naying	AP	1000						✓		
Lower Siyang	AP	2700							✓	
Demwe Lower	AP	1750							✓	
Kalai-II	AP	1200							✓	
Heo	AP	240							✓	
Tato-I	AP	186							✓	
Miyar	HP	120							✓	

Stalled projects Examples

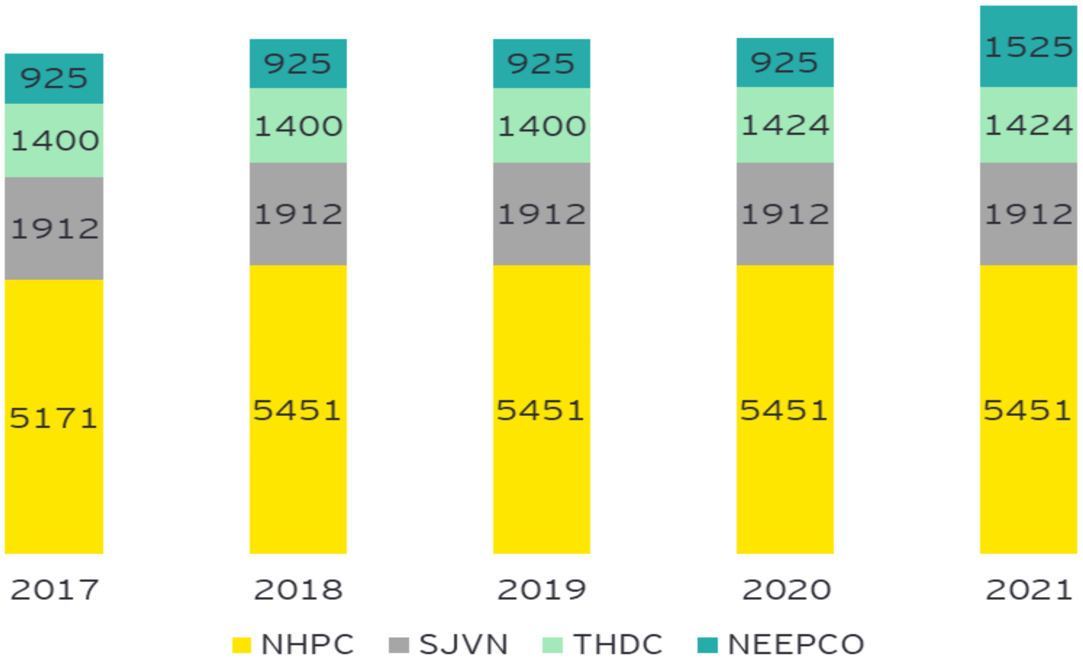
- Teesta IV - The DPR for the project was done in 2010, at the same time Mangdechhu Project in Bhutan was also appraised. However, the Mangdechhu Project in Bhutan is going to be commissioned very soon whereas Teesta IV has not started, and the reason for that is not getting the requisite clearances in time and the FRA could not be done.
- Subansiri Project - One of the biggest projects of the country of 2,000 MW. NHPC have done almost 50% work on the project, but the project was stalled by local pressure groups in December 2011 following which the case was taken to NGT. The NGT has heard the case for two years and in 2017 and given the decision, and the crux is that they did not oppose the project and the only thing said is that downstream some gaps were there that should have been studied.
- Parbati II Project - This project was a very complicated and a very intricate project and started it in 2002. Just one component of the project, which is about 30 km. long tunnel out of which only 3 km. is stuck because of geological reasons.

5.1.2. TREND IN PROJECT GROWTH OF CPSES

Trend in project growth of CPSEs

NHPC, SJVN and THDC have no significance hydro portfolio change in the last 5 years

Figure 50: Installed Capacity MW by Major Player



- The installed capacity of major hydro players has increase at rate of 2.3% over last five years.

5.1.3. PROJECT ALLOCATION ISSUES

Indian context on projects

At every stage, the major share of project is stuck with Arunachal Pradesh

Figure 51: Project allocation issues[19]

19 – https://cea.nic.in/wp-content/uploads/hepr/2022/03/State_Power_3.pdf

- Projects concurred by CEA and yet to be taken up for construction (MW) – Arunachal Pradesh has the projects with capacity 15858 MW, followed by J&K with 3419 MW.
- Total under active phase (in operation + Under construction) (MW) – Uttarakhand has the projects with capacity 4999.35 MW, followed by HP with 12211 MW.
- Projects yet to be allotted by the State for development (MW) – Arunachal Pradesh has the projects with capacity 16161.50 MW, followed by Uttarakhand with 3028 MW.
- Projects in pre-DPR phase (MW) - Arunachal Pradesh has the projects with capacity 22137 MW, followed by Uttarakhand with 5952 MW.

Allocated projects in Arunachal Pradesh are not getting installed

Standing Committee of Energy highlighted the issue in 2019

Table 16: highlighted the issue in 2019

Status of HEP in Arunachal Pradesh	Nos.	Capacity (MW)	%Share of total
In operation	2	515	0.97%
Under construction	3	2,744	5.19%
Concurred by CEA and yet to be taken up for construction	17	16,952	32.04%
Under examination in CEA	0	0	0.00%
DPR returned by CEA to project authorities for resubmission	13	6,329	11.96%
Under S&I	26	3,707	7.01%
S&I held up	20	9,462	17.88%
Yet to be allotted	17	13,205	24.96%
Total	98	52,914	

Findings -

- Out of total 52 GW capacity, ~25% capacity is yet to be allotted.
- Only ~6% of total capacity is in operation and under construction phase.
- No pendency is there with CEA
- ~18% capacity have held up their S&I activity which is the most preliminary step

Inference –

- Major project allocation was done in 2008-09 at a certain premium and without any bidding.
- It is observed that some states like Arunachal Pradesh, in their Hydro Policy, have made provision for State Equity in the project but do not have sufficient funds for equity investment in the project. Subsequently, they have raised demands for additional free power from the project in lieu of foregoing their equity rights in the project which would add to project development cost/tariff."
- Even though a typical MoU has provision of termination, state is playing an inactive role in allocating stalled projects to PSEs. As water is a state subject, centre on its own cannot take steps.

  "In the event of termination of the Agreement under this clause, the Govt. of Arunachal Pradesh shall have the right to take over the Project on "As is where is" basis and no claim of the Company shall be entertained. The Govt. of Arunachal Pradesh shall also have the exclusive right to re-allot such project to any other developer. "

Allocated projects in Arunachal Pradesh are not getting installed

Table 17: Issue is still pertaining as determined from CEA report as on Apr 2022

S. No.	Status	Nos.	Cap (MW)	% Share
	Total	138	56,835	
I	Projects in operation	3	1,115	1.9%
II	Projects under active construction	1	2,000	3.5%
III	Projects allotted by States for development			
(i)	Projects concurred by CEA and yet to be taken up for construction	13	15,858	27.7%
(ii)	Projects returned to project authorities	13	5,323	9.3%
(iii)	Projects under S&I	3	1,400	2.4%
(iv)	Projects allotted for development on which S&I is held up/ yet to be taken up	32	8,696	15.2%
IV	Projects dropped due to basin studies/other reasons	21	4,778	8.3%
V	Projects stuck due to Inter-State/ Other Issues	4	1,940	3.4%
VI	Projects yet to be allotted by the State for development*	47	16,161.5	28.2%

Inference –

- Arunachal Pradesh has the maximum hydro potential (~34% of India total potential) but only 1,115 MW (<2%) is in operation.
- Even share of projects under active construction is ~4% only
- ~28% of the potential is still not allotted by state for development showing non-activeness on their part
- ~15% capacity have held up their S&I activity which is the most preliminary step
- No pendency is there with CEA

Stalled projects: A case of Arunachal Pradesh

Stalled projects impairs the hydro power sector growth

Power scenario HEP of in north-eastern region (MW)

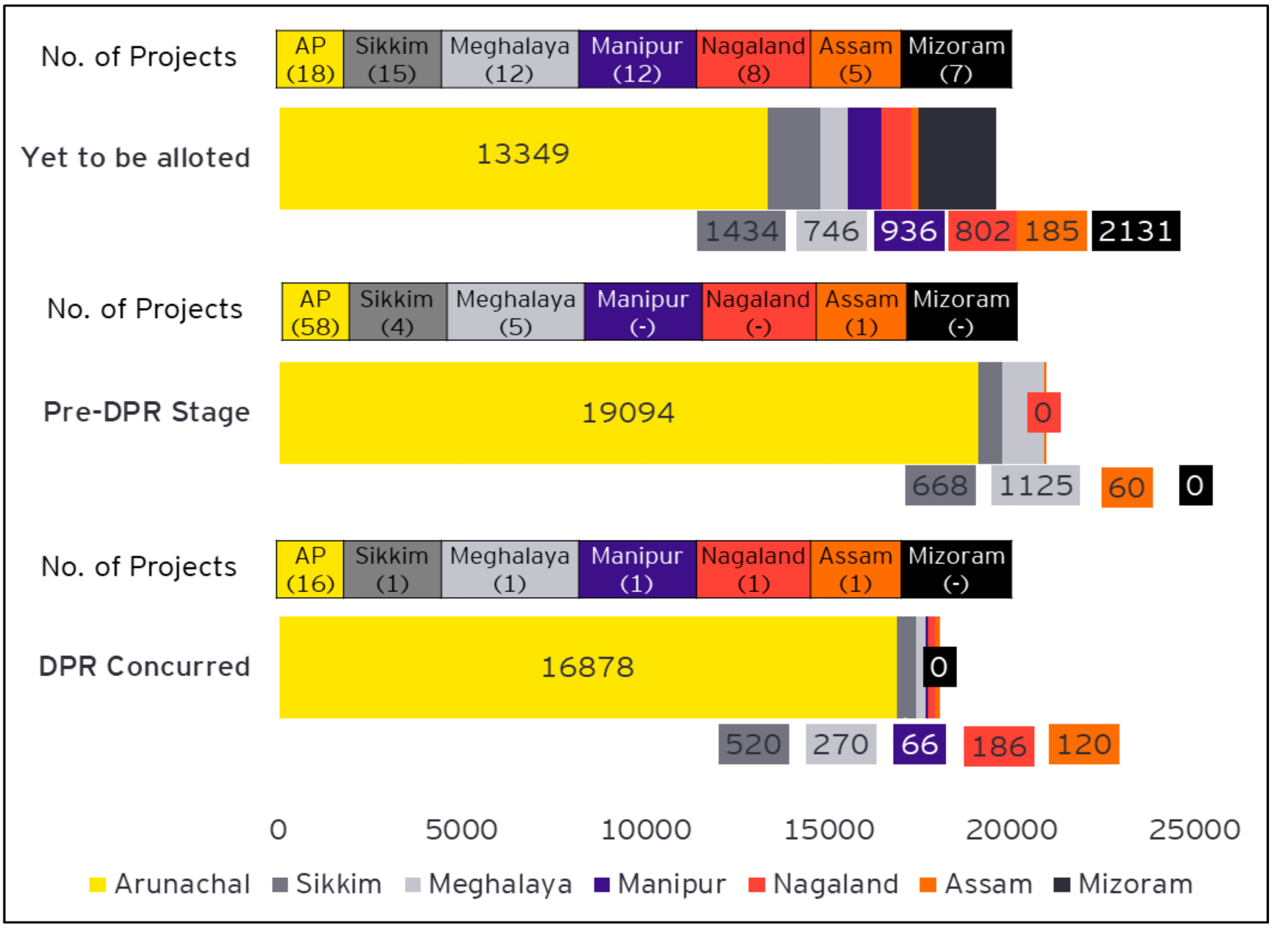


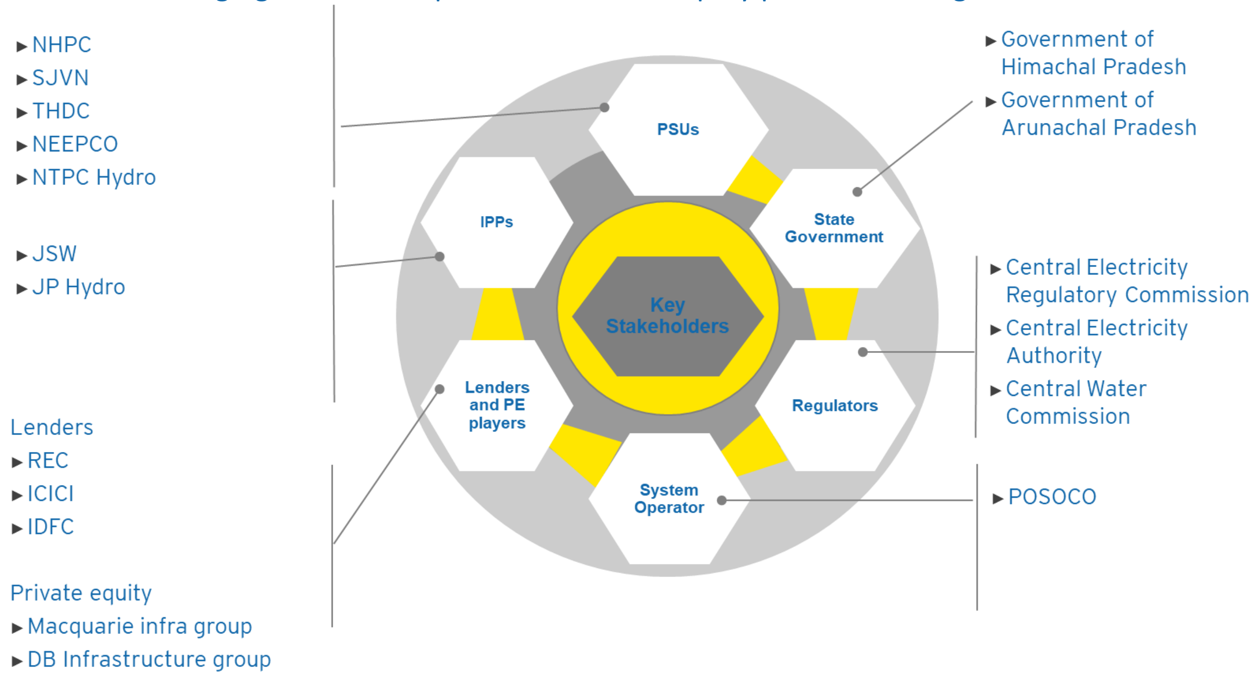
Figure 52: Power scenario HEP in north-eastern region

- India's north-eastern region along with Bhutan, has a total hydropower generation potential of about 58 GW. Of this, Arunachal Pradesh (AP) alone accounts for 50.32GW. While DPRs of 16 projects totalling 16.88 GW in Ap have been completed, 58 projects totalling 19,09 GW are in pre-DPR stage.
- 103 privates HEP in Arunachal Pradesh totalling about 35 gigawatts (GW) are still to take off despite the government's Act East policy focus.
- Arunachal Pradesh government has already issued termination notices to 21 such projects totalling around 2.5GW
- SJVN is now set to invest INR 60,000 cr to harness ~5 GW hydropower in Arunachal Pradesh
- The projects are Etalin HEP (3,097 MW), Attunli HEP (680 MW), Emini HEP (500 MW), Amulin HEP (420 MW) and Mihumdon HEP (400 MW) — are in the Dibang Basin of Arunachal Pradesh
- Previously, an allotment of 168 projects with 46 GW was done but these didn't take off. Hence, State is now starting to reallocate these projects to PSUs.

5.2. STAKEHOLDER CONSULTATION

Most of the key stakeholders were consulted and their views are captured

Stakeholders ranging from developers to lenders to equity providers to regulators were covered



Views of public sector entities (1/4)

NHPC suggested measures such that tariff can be rationalized and project development can be expedited

Views of developers - NHPC

- NHPC team believes that hydro projects are the need of the hour in context to COP targets and visions by India. Storage type projects are the low-hanging fruits because of low R&R issue.
- For project allocation, GoI came up with Hydro Policy 2008 which defined parameters for competitive bidding. It allowed states to opt for competitive bidding which most of the states also adopted such as J&K, Himachal Pradesh, Sikkim, etc. In the public sector projects, competitive bidding was not there and generally allotment was done on negotiation basis.
- NHPC is approaching state government for parameter rationalization. They have prepared a model with varied scenario of each parameter. They have recommended to waive off some of the charges for BOOT model projects, LADF and free power, GST charge along with better depreciation rates and availability of long terms loans.
- Land acquisition – This step takes time and public hearing is a time-taking process. The intervention required in this aspect is to tweak the existing policies. Even SOPs must be there with the local administration to ensure zero tolerance in case of delay. There should also be a mechanism for PMO level monitoring of projects costing more than INR 1,000 cr. State governments also need to be made accountable through the provision of reduction in free power in case of delay.
- Three-seasons study is done for EIA purpose. It includes monsoon, pre-monsoon, and lean period study. To reduce the time in this study, there is a need of data repository. MoEFCC has already done a river basin study and e-flow is already created. The need is to do a similar study for flora and fauna also. There should be use of drones to perform these studies.

- DISCOMs are reluctant to sign PPAs because of higher tariff of hydel projects.
- Infrastructural constraints – Infrastructure development should be the state's responsibility instead of developer's responsibility. There is an issue of availability of drilling contractors because of remote locations.
- There are few other issues as cited by NHPC:
    - Lack of skilled manpower in Arunachal Pradesh
    - Terrain related issues increases the turnaround time for preparation of DPR in few cases

NHPC cited some of the steps which could expedite the project development and reduction of tariff.

Views of public sector entities (2/4)

SJVN suggested measures which could reduce the turnaround time of development

Views of developers - SJVN

- SJVN was allotted Doimukh project in Arunachal Pradesh. It took almost 4-5 years in DPR preparation. It was then determined that the project is not viable/feasible. Hence, it was returned to state government. Though, such incidents are rare but affects the entire corporate plan. It happens because viability cannot be checked at the initial stage.
- Arunachal Pradesh has harnessed only 1 GW out of 50 GW potential. The state is not proactive in allocation whereas in the case of Himachal Pradesh, projects representing ~80% potential has been allotted.
- Project allotment –
    - It is done by state government and the allocation is largely depends upon the extent of lobbying done by the developers.
    - The allocation/auction process needs to be streamlined by the central government.
    - Hydro policy of few states describe project allocation while few gives only broad contour.
- Hydropower sector may also be deregulated and process of concurrence of DPR by CEA should not be there. Instead, CEA should give detailed checklist and guidelines for clearances and should only verify/check the compliance of the checklists and guidelines as listed.
- There is a challenge with acquisition of private land because of association of emotional value of land with landowners. Hence, option of the dividend out of the project profit (profit sharing mechanism) may be given to landowners. It may be better than the employment options.
- There are no SOPs with local administration to handle law and order. The situation depends on up to of district administration. There is a need to fix the state's accountability as law & order is state subject.
- Instead of 12% free power, other incentive structure may be devised for state.
- There is a need of increased awareness and involvement of local administration such as tahsildar, gram panchayat, etc.

- A lot of uncertainty prevails in environmental parameters. If during environmental clearance stage some parameters such as Eflows gets changed, whole DPR gets affected.
- There should be a single window clearance system. There should be one government agency where developer need to approach while opting to develop hydro projects. It is to avoid developer issue for going to multiple departments for various clearances. SJVN highlighted the example of Nepal where Investment Board of Nepal (IBN) is handling all clearances for hydro power projects. Competitive Bidding mode for allocation (TBCB).

Some of the measures suggested by SJVN requires complete policy change

Views of public sector entities (3/4)

SJVN suggested measures which could reduce the turnaround time of development

Views of developers – SJVN

- There are many factors behind high tariff. Some of these factors are free power to state, LADF requirements etc. Even O&M cost can be reduced considering IT automation and adoption of robotics in the process. Interest on Working capital (IoWC) can also be rationalized. In few cases, GoHP agreed to stagger the free power which reduces the tariff in the initial years. Further, waiver of state GST, utilization of CSR funds for LADF also reduces the tariff. These steps of GoHP helps in making tariff viable.
- Telecom connectivity is a problem at few sites. Therefore, facility of satellite phones may be given.
- Not many contractors are equipped with skills required for hydro construction. There is a shortage of good contractors. Even contractors have financial constraints and face challenge with working capital requirement.
- PIB approval criteria for the hydro power projects need to be relooked. Instead of project IRR equity IRR may be seen.
- Currently, many project in Arunachal Pradesh which has been allotted to private developers are stalled. There is no resolution framework which has been proposed by government. Ideally Government of Arunachal Pradesh should reallocate these projects to the developers who could develop the projects. Also, from natural justice perspective, appropriate compensation mechanism for the current developers may also be finalized.
- At current presently, there is no live monitoring of the projects at the State Power Secretary/ Chief Secretary/ Concern Minister level. Similarly, such live monitoring is absent at Ministry of Power, GoI.
- Local agitation is a major issue and should be addressed by local administration. There should be a single window mechanism to deal with such issues.
- No state of art technologies is available for investigation and construction.
- Developers such as NHPC, SJVN etc should only award the contract once statutory clearances (environment, forest, etc.) are in place.

Some of the measures suggested by SJVN requires complete policy change

Views of public sector entities (4/4)

Companies suggested path breaking measures pertaining to DPR studies and allotment letter structure

Views of Public sector developers –THDC, NEEPCO, NTPC Hydro

- THDC proposed single window clearance mechanism for getting all clearances of project. NEEPCO and NTPC Hydro also has similar opinion.
- The companies also suggested measures for tariff rationalization. These measures include:
    - Staggering of free power
    - GST waiver
    - Fund support for infrastructure development etc
- There are some challenges in accessing sites which delay the DPR preparation.
- For strengthening local administrations support, a dedicated office should be made which is to be headed by IAS officials. Also, SOPs for the same needs to be developed.
- THDC and NTPC Hydro are satisfied with PARIVESH portal which has streamlined the process of clearances and approvals. It has enhanced transparency as all the processes can be tracked online. Portal also shows the comments/marking/notes, timeline, date of every step.
- NTPC Hydro prefers projects on BOOM and not on BOOT basis. It also prefers project allocation on MoU route.
- The allotment letter should comprise a clause stating the timeline for various activities. It should also mention that on non-adherence of such timeline, the project will be reverted to state government on as is whereas basis.
- There should be homogeneity in free power percentage across states. LADF should be uniform. State government should support in terms of logistics, law and order, clearances, etc. GST should be foregone
- Once DPR is approved, some studies should be allowed to continue. Substantiation of study findings can be done after consultation begins.
- There should be provision of cess on renewable energy sources owing to their intermittent nature. The collected fund can be used to provide VGF for hydro projects.
- Benefits should be shared with riparian states also.
- Number of sound EPC contractors are limited.

Right clauses in MoA / allotment letter will be helpful in reducing the conflicts and shall expedite the project development.

Views of private developers and system operator

Private developers seek proper risk sharing framework while system operator seeks stable grid operation

Views of private developers –JSW, JP Hydro

- The gestation period is far too high leading to two important issues:
  - It's very difficult to commit funds for projects which will start generating revenues after 8-10 years.
  - The management often lose focus as there are options whereby gestation period is short, and risk return ratio is also balanced.
- Some schemes may be designed whereby some of the risks associated with clearances, land acquisition etc. may be borne by government.
- Private sector developers do not refrain from getting projects via auction. However, commission should clearly assign the responsibilities of each party.
- Once tariff gets discovered, developers should not be pressurized by state government to reduce the tariff.
- Regarding capacity tie up, different views were expressed by different companies.
  - A few companies are of view that at least 20% of the total capacity should be left and the developers should sell such capacities via markets or blend it with other technologies to sell under RTC mode.
  - A few companies are of the view that 100% of the capacity should be tied up under long term PPA to solve missing money problem

Private developers are concerned about the risks associated with projects

Views of system operator

- System operator is concerned regarding the changing supply mix. With greater share of renewables, stable grid operations may be a challenge. The challenge gets aggravated, since must run status is being given to renewable projects.
- In such a scenario, either of the steps is required:
  - Sunset clause on must run status may be given to RE projects i.e., a threshold date may be given to RE project. Any project which may be commissioned after the threshold date may not get must run status
  - Ancillary market needs to be functional. Along with it, system operator should have adequate primary, secondary, and tertiary reserves.
- System operator does not want to procure/underwrite any capacity for long term.
- Shorter term, market-based products would be beneficial for planning and shall also be cost efficient.
- Co-optimization, as done in US, may not be possible to do in India due to different market structures and systemic needs of the two countries.
- Some portion of large hydro power projects, especially with pondage, may be allowed to sell via market. Such enabler will give hydro power producers to innovate which may be helpful for stable grid operation.

System operators' concerns were regarding the stable grid operation.

Views of lenders and private equity players

lenders are concerned over enhanced risks while private equity players seek return

Views of lenders –REC, ICICI, IDFC

- Most of scheduled commercial banks are comfortable for balance sheet financing whereby no interest moratorium is given. However, they are ready for giving principal moratorium.
- REC is ready to fund IDC (interest moratorium) specially to project sponsored by promoters having good credit rating.
- In case of SPV funding, in addition to primary security corporate, guarantee is also desirable. Once project gets commissioned, lenders are ready to forego corporate guarantee.
- In case of SPV funding requirement of DSRA is also envisaged.
- All the lenders are preferring CPSUs followed by State sector PSUs followed by IPPs having good credit rating.
- All the lenders are concerned towards high gestation period of hydro projects. Therefore, lenders compete for refinancing of commissioned projects, while sceptical regarding funding of greenfield project.
- Most of the lenders are not willing to lend with a repayment period of more than 18 years after COD.
- A few banks raise the concern of existing prudential norms which restricts them from taking additional exposure with company.
- The interest rate during construction is relatively higher owing to higher risks leading to higher IDC and hence higher completion cost.
- Lenders are also not comfortable with projects having no power purchase agreement.
- Lenders also need land /land rights in a way that security can be created on it

Lenders suggested that credit enhancement measures to be done during construction to keep interests lower during construction as well.

Views of private equity players

- Private equity players are quite interested to invest in commissioned hydro projects. However, they are not so positive to invest in greenfield projects.
- Some of the inhibitions for investing in greenfield projects:
    - Higher gestation period leads to higher locking of capital.
    - Higher locking period accompanied with fixed returns after COD leads to lower effective returns.
    - This leads to lower liquidity as far as capital rotation is concerned.
    - The return is capped and not proportionate to risk which investor bear during construction period.

  - There are ESG concerns also, as investors yet to see ESG metrics being reported by hydro companies.
- The market currently is dominated by CPSUs and state sector PSU. The barrier to entry is very high. This further ceases the liquidity.
- Private equity players suggested that some portion of capacity (specially for the plants having pondage) may be exposed to market whereby hydro power generators may make additional money.
- Private equity players also see asset monetization of brown field assets as path for private players and investors to enter the space. However, the proposed models should be market centric.

Private equity players suggested means to increase role of private players in the space.

Views of states and regulators

GoAP (Arunachal Pradesh) is concerned about the legal cost while GoHP is progressive in its approach

Views of States – Government of Arunachal Pradesh and GoHP

Views of Government of Arunachal Pradesh

- Government of Arunachal Pradesh may not be very comfortable while terminating the current allocation unless legal opinion is taken as Government of Arunachal Pradesh is concerned about the legal fees associated with arbitration and/or court cases.
- Government of Arunachal Pradesh is not willing to forego upfront premium. Also not willing to grant other concessions.

Views of GoHP

- It is informed that the current developers are uninformed about the particulars being allocated. They need to conduct proper study before execution.
- Land acquisition delays happen based on failed negotiations. Generally, land acquisition takes place by the "Right to fair compensation Act". However, if negotiation fails, then force acquisitions take place by State Govt by paying double the amount.
- In a state which is mostly situated in hills and there is less industrialization taking place, water is the major source of the income for the State. Therefore, if income from water is also compromised then state might lose out on opportunities.
- Currently following concessions have been given by State to developers:
  - No Royalty for 12 years to be given by the developers. Concessions on project increased from 40 years to 70 years.
  - Open access charges are waived-off Inter State transactions for projects below 25 MW.
  - Although tariff of all hydro projects in the state are determined by HPERC, but for projects up to 25 MW, the power is bound to be purchased by HPSEB.
- Currently in HP, majority of the projects are stalled due to reasons pertaining to geological surprises, financing issues while execution

Suggestions

- Catchment Area Treatment plan should be allocated for each project in the area to increase accountability of project owner.
- Effluent Treatment Cost should be closely monitored to ensure effective cost optimization.
- Incentives given to solar should be extended to hydro projects.
- Dumping Area treatment should be done by Project developers to ensure clean site.
- Compulsory acquisition should be initiated by Govt for stalled projects otherwise delay in commissioning shall increase.
- Also, the project site should be covered and must be allocated with heavy security so that local villagers do not hinder the ongoing work.

Views of Central Electricity Authority

Central Electricity Authority advocates greater role of states

Views of Central Electricity Authority

Based on discussion with technical wing

- There are inadequacies in the investigation procedure for DPR finalization. Therefore, the said guideline from CEA should be revised.
- CEA HPP&I cell acts as the coordinating body among the developer and the various concerned government bodies.
- DPR generally completed within one and a half year but in some cases, it takes 3-4 years. It depends upon approach adopted by developers.
- Construction time of hydro power plants can be reduced if land acquisition issue and R&R issue gets resolved. It can be done if state government play an active role.
- Developers should not only come up with one option. For any problem or concern, a few solution options from developers may be put forward. This will further expedite the entire process.
- The strength of CEA and CWC needs to be enhanced. This will expedite the concurrence process.

Based on discussion with commercial wing

- Project appraisal and tariff determination may be done at completed cost levels for both private as well as public sector.
- Free power to state is one of the biggest reasons of higher tariff. Staggering of free power is one of the steps which alleviates the impact to some extent only. Option of foregoing free power may be explored. In return, option of monetary royalty may be given.
- State should play a bigger role for obtaining clearances and land acquisition. The incentives such as free power/ another may get reduced if state fails to meet the obligations during stipulated time limit.
- Competitive bidding may be introduced for allotting new projects. Concession agreement/scheme document should be designed in a way that it is homogeneous for different state, clearly segregates risks and assigns the responsibility of each party. To start with smaller hydro power projects and pumped storage projects may be allotted based on competitive bidding.

- Project developers should hedge the project cost against commodity price variation. It may reduce the completion cost and hence tariff.
- Larger projects may be monitored at PMO/CM level.

Responsibility of states should be assigned. There may be penal provision for states for not meeting the obligations

Views of regulators

Regulators are looking ways to integrate hydro power to power market

Views of Regulator

- The Central Electricity Regulatory Commission (CERC) has approved the introduction of hydropower in the Green Term-Ahead Market (GTAM). This is an enabler for hydro power developers to sell the power via power exchanges.
- Currently, hydro power projects may not be directly exposed to market. It may lead to missing money issue which may impair the financial viability of the hydro project.
- However, some capacity i.e., 20% to 30% may be freed. Developers should be allowed to sell the freed power at their discretion i.e.
    - Can sell directly on power exchanges via DAM or GTAM
    - Can blend it with solar/wind and participate in RTC
    - Projects with pondage may participate in ancillary service market
- There may be a sunset clause for power purchase agreement. Since tthe cost of energy for older power plant is quite low, therefore missing money problem may not emerge.
- Such schemes will not only increase liquidity of market but also helps system operator in grid balancing.
- Option of competitive bidding for allocating hydro power projects may be explored.

Regulators are forward looking and looking for methodologies for integrating hydro power to power markets

5.3. IDENTIFYING PROBLEMS

Identification of issues

Observations–

- Developers are of the view that a few states are not allocating the projects owing to which development of these projects could not kicked off.
- The allotment process to developer(s) are quite subjective and lacks transparency.
- The MOA agreements (instrument of project allocation) are heterogenous even within same state
- The terms of MOAs are loosely drafted owing to which resolution of stalled projects may be done via legal route.

Issue –A

The current methodology of allocation of projects to developers may not be most optimal

Observations–

- There is no standard concession agreement/ allotment scheme for allocation of hydro power projects.
- Hydro power projects are still allocated via MoU route.

Issue –B

For hydro power projects, risk sharing framework yet to be developed and thus there are no standard tariff-based bidding documents.
Also, sector is prone to many geological surprises, therefore estimating tariff upfront may not be prudent.

Observations–

- The total time taken for preparation of survey and investigation, preparation of detailed project report (DPR), concurrence of DPR by CEA and obtaining all clearances is taking too much of time.
- Land acquisition and R&R issues is also taking much of time.
- There are some issues associated with law and order as well.

Issue – C

There are no SoPs to be adhered by either State government or local administration. Hence, there are no obligations on state government and on local administration.

Observations–

- The tariff of hydro power projects is quite high.
- Owing to higher tariff, distribution companies are reluctant to sign the tariff.

Issue –D

- Higher completion cost (upfront fees, enabling infra structure, dedicated transmission line leading to time overrun, GST, IDC, and inflation), free power to state, contribution to local area development fund and tariff norms are key reasons.

Observations–

- Limited fund access (both debt and equity) to private developers.
- Subdued financial returns to both public and private developer
- Limited capital rotation owing to high gestation period

Issue –E

The locking period of capital and revenue start date from the date of capital infusion is very high.

Observations–

- Returns of commissioned project are also capped
- Initial tariff is high owing to which discoms are reluctant to sign PPA. However, in longer term, it's not a problem

Issue –F

- Tariff determination methodology not only caps return but also makes initial tariff high.

Observations–

- The turnaround time of each stage of development is quite high.
- A lot many projects specially in Arunachal Pradesh are stalled.

Issue –G

- There is no active monitoring at PMO/CMO level owing to which neither the developers nor other agencies are under pressure

Chapter 6

Interventions

6.1. REVAMPING THE PROJECT ALLOTMENT PROCESS

Hydro policy analysis of different states

The projects allocation process across states are non-uniform and non-transparent in nature.

Policy context –

- As per Hydro Power Policy, 2008, Transparent selection procedure/ criteria is to be followed by the States for awarding sites to private developers based on a single quantifiable parameter.
- The dispensation regarding exemption from tariff-based bidding, available to the Public Sector under the National Tariff Policy 2006, also extended to private sector hydroelectric projects up to January 2011 (extended up to 15.08.2022 in Revised Tariff Policy, 2016).

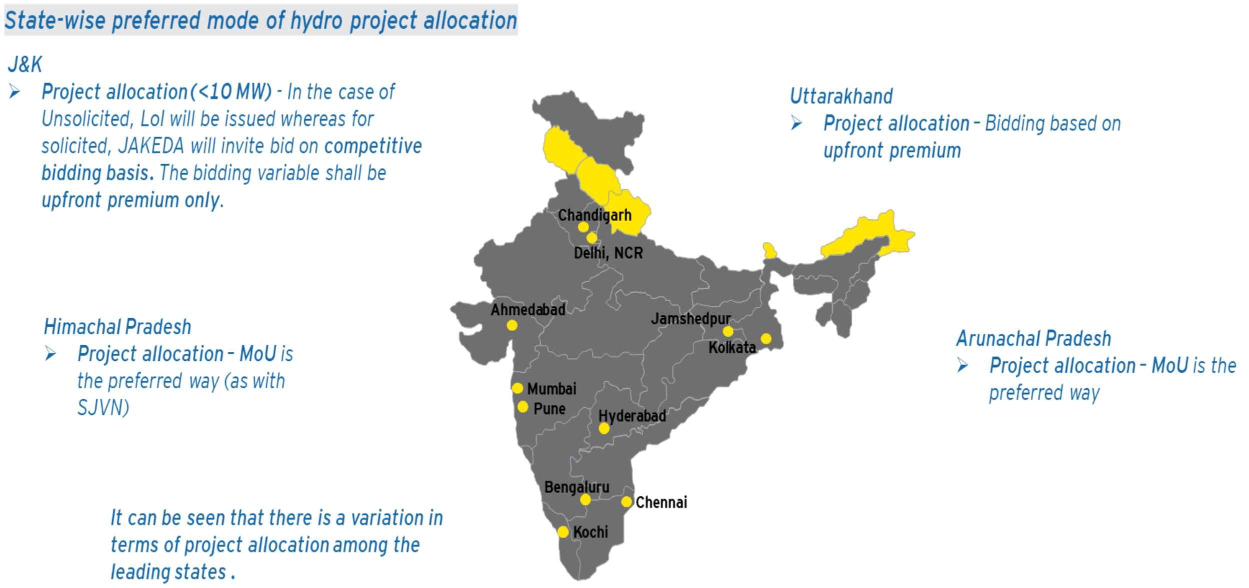


Figure 53: State-wise preferred mode of hydro project allocation

Summary of key clauses which ultimately translates into allotment letter/MOA

State-wise scenario

Case of Himachal Pradesh –

- Royalty (free power) - For the first 12 years of operation = 0 %; For the next 18years of operation = 12%; For next 10 Years of operation = 18%. Here, 12% free power is deferred for initial 12 years acting as an incentive. Going forward, it is fixed at 12% only.
- Premium – It is reduced to INR 1 Lac/MW and Government land is being given only at Rs. 1 per sq. m.
- Project allocation – MoU is the preferred way (as with SJVN)

Case of Uttarakhand –

- Upfront premium - As per policy on private sector investment in hydropower project above 100 MW capacity, bids shall be invited over a minimum premium, payable upfront to the Government of Uttaranchal, at the rate of INR 5 Crores per project.
- Royalty – 12% free power to state during entire project life
- Project allocation – Bidding based on upfront premium

Case of J&K –

- Nodal agency will prepare potential site list for which bids will be invited on the upfront premium basis.
- Upfront premium - As per policy for development of micro/mini hydro power projects - Minimum threshold premium of INR 50k/MW (up to 1 MW) and INR 1 Lacs/MW (> 1MW)
- Project allocation - As per Policy for Development of Small Hydro Energy for Power Generation, 2016 (up to 10 MW), there are two ways of receiving proposal from developers – solicited and unsolicited. In the case of Unsolicited, LoI will be issued whereas for solicited, JAKEDA will invite bid on competitive bidding basis. The bidding variable shall be upfront premium only. The threshold value of upfront premium shall be Rs 3.0 lacs per MW

Case of Sikkim –

- Royalty – 12% of the installed capacity as free power to state
- Project allocation - NA

Case of Arunachal Pradesh (AP) –

- Royalty – Not less than 12% of power generated
- Upfront premium – For project of 100 MW to 499 MW, it is INR 2.50 Lakhs per MW
- Project allocation – For 25 – 100 MW, it can be done through a negotiated MoA route whereas state Government shall allot the projects through the bidding route on such criteria as it may decide in the interests of the state.
- In AP, major project was awarded in 2008-09 without bidding and on MOU basis.

Revamping the project allotment process

The project allotment process may be transparent and homogenous

Project allotment process–

- State government should clearly define the project allotment process to CPSU, state sector PSU & IPPs.
- State government ideally follows the competitive bidding route for allocating the project. For conducting competitive bidding, a standard bidding document may be developed which may be adopted by different states. The principle of competitive bidding is mentioned in subsequent section.
- However, state shall have the option to allot project on MOU basis. The SOP, application format and allocation criteria for allotting the project on MOU basis should be notified by various states.

- The MOA/allotment agreement may need to be homogeneous and concessions to state government shouldn't have a bearing on tariff.
- Moreover, the MOA/allotment agreement should clearly define the milestones and the outcome of not meeting the milestones.

Key elements which may be included in MOA/Allotment agreement –

- Projects may be allotted /awarded either on Build Own Operate (BOO) or on DBFOO (Design Build Finance Own Operate) or on FOO (Finance Own Operate) basis or should be awarded for initial period of 40 years from COD of last unit and further extended for 30 years. BOOT model may not be prudent for developer as it takes away the benefit of sizeable "Terminal Value" making investment far less attractive.
- Upfront premium should not be charged from developers. It increases the project cost and hence tariff.
- 12% free power has the potential to increase the tariff by 13.63%. In current regime, free power is being socialized. Monetary royalty may be taken instead of free power. Also, royalty may be rationalized to 5% of estimated tariff. In India, royalty on hydro power is very high. A comparison with different countries is included in subsequent sections. It may also be noted that staggering of free power though reduces the tariff, but problem of socialization persists. Also, it remains under the discretion of states.
- Allowing provisioning of LADF@ 1.5% chargeable to head other than the Project Cost.
- Outlay of Catchment Area Treatment Plan to be capped at 1.5% of the total Project Cost.
- If the project will be developed under JV route, the state government agency (JV partner) needs to necessarily bring corresponding share of equity during construction. If the state government agency fails to bring the corresponding equity during construction, then either proposed royalty profit will be foregone, or the state government agency would not be a JV partner in the project.
- If state is a JV partner in the project, then state must bring proportionate equity share. Presently, in many projects, especially in Arunachal Pradesh, though state is a JV partner, but corresponding equity is not being infused by the JV partner (companies owned by state government). Such phenomenon is being supported by state hydro policies which empowers state to adjust their proportionate equity share against giving right to sell free power post commissioning.

International case studies with respect to Hydropower Royalties
Case of China – 1/4

China has the richest water potential in the world, but water resources are asymmetrically distributed over its territory: 70% of the hydropower capacity is in four southwest provinces (Sichuan, Yunnan, Guizhou, and Chongqing), while demand is in coastal cities.

Level of Government in Charge

- Provincial with central government coordination.
- In China, the central government manages the system of licenses and has enacted detailed regulations for levying hydro power royalties.

Hydropower Royalty Structure

- In China, the hydropower royalty is clearly considered as a compensation that the operator of a plant shall pay to use the public commodity (hydropower) conceded to him.
- Governing Law - Water law of the PRC (2002) and provincial laws
- Administration - Department of Water Resources of the State Affairs Council + Local departments of Price control, Water resources and Treasury

Hydropower royalty rates in China

Table 18: Hydropower royalty rates in China

Province	Annual Charge Basis	Royalty Rates	Royalty Rates (INR)
Sichuan	Power output in all cases	\$0.75–1.20/MWh	INR 59.20 – 94.71/MWh
Yunnan		\$0.75–2.25/MWh	INR 59.20 – 177.59/MWh
Guizhou		\$0.60–2.25/MWh	INR 47.36 – 177.59/MWh
Chongqing		\$0.75/MWh	INR 59.20 /MWh

Case of Brazil – 2/4

It is estimated that out of the 113 trillion cubic meters of water available for terrestrial life, 17 are in Brazil, which means that 15% of the existing fresh water in the world.

Level of Government in Charge

Federal (National System of Water Resource Management). The Brazilian Constitution enacted in 1988 mentions that states, the Federal District, municipalities, as well as the Federal government, should share the profits of oil or natural gas exploration, as well as water resources for the purpose of power generation

Hydropower Royalty Structure

- In 1989, a specific law about financial compensation was established to regulate the use of water resources for the purpose of electricity generation. Royalty must be paid by concession holders and permits for any hydro potential is 6.75% of the value of the energy generated.
- Governing Law - "Codigo De Aguas", "Lei No. 9074, 1995" and "Lei No. 8.987, 1995"
- Administration - ANEEL (Ministry of Mines and Energy) + ANA (Ministry of the Environment)

Hydropower royalty rates in Brazil

Table 19: Hydropower royalty rates in Brazil

State	Annual Charge Basis	Royalty Rates	Royalty Rates (INR)
All Brazilian states	Revenue of power output	6.75% × sales value/MWh ≈ \$1.58/MWh	INR 124.71/MWh

Case of Canada – 3/4

Canada, like Brazil, produces about 10% of the world's hydropower. This is made possible because Canada holds 7% of the world's renewable freshwater resources.

Level of Government in Charge

Provinces, Since Canadian provinces enjoy exclusive legislative power for the management of water resources and the hydropower sector located on their territory, they can impose rights on water use and electricity production itself using licenses and royalties

Hydropower Royalty Structure

- In Canada, all provincial governments charge a hydropower royalty to plant operators, except New Brunswick and Alberta, where hydropower production remains relatively small.
- Governing Law - Different for each province.
- Administration - Usually the Ministry of Energy.

Hydropower royalty rates in Canada

Table 20: Hydropower royalty rates in Canada

Province	Annual Charge Basis	Royalty Rates	Royalty Rates (INR)
Manitoba	Greater of power output or capacity	<200 MW $1.51/MWh or $5.3/kW >200 MW $3.11/MWh or $10.9/kW	<200 MW INR 119.18/MWh or INR 418.32/kW >200 MW INR 245.47/MWh or INR 860.32/kW
Quebec	Power output	(Indexed annually) $3.852/MWh	INR 304.03/MWh

Case of United States – 4/4

US hydropower accounts for 7.5% (290 TWh) of world hydropower generation. Three states (Washington, Oregon, and Idaho) generate most of their power from hydropower resources, while four states (Washington, Oregon, New York, and California) generate more than 20 TWh per year of hydropower.

Level of Government in Charge

Federal with states residual jurisdiction. Unlike Canada, the US centralizes, at the federal level, part of the hydropower regulation. The FERC issues licenses allowing the construction and operation of dams and powerhouses and sets up different charges collected from licensees operating hydro plants. The FERC levies annual fees from licensees to "repay the U.S. government for the costs of administering the regulatory program of hydropower" and requires charges for government land use, government's dam use or because of the upstream benefits due to projects built by the government.

Hydropower Royalty Structure

- The FERC imposes a fee, applied to all non-federal hydroelectric projects, which could be described as a "reimbursement royalty": it collects charges to offset administration costs. This federal charge can be supplemented with a state royalty.
- Governing Law - Federal Power Act.
- Administration - Federal Energy Regulatory Commission (FERC) with States' Water Department.

Hydropower royalty rates in US

Table 21: Hydropower royalty rates in US

Regulator	Annual Charge Basis	Royalty Rates	Royalty Rates (INR)
Federal Energy Regulatory Commission (FERC)	Non-federal hydro only Based on FERC's administrative costs	Complex rate structure depending on capacity, power output, pumped storage, and charge factor ≈ \$0.48/MWh	INR 37.49/MWh
Washington	Capacity	< 746 kW \$0.2413/kW between 746 and 7460 kW \$0.0483/kW >7460 kW \$0.0241/kW	< 746 kW INR 19.05/kW between 746 and 7460 kW INR 3.81/kW >7460 kW INR 1.90/kW

- In India royalty charges are significantly higher than most of the countries and same need to be rationalized. Following are the proposed options of royalty charges -
    - Royalty power may be brought down to 5% of actual generation.
    - Instead of free power, a fixed percentage of profit (for example 5%) generated from the station may be given as royalty.
    - A flat fee per unit of generation (for example INR 0.10 /unit) may be charged as royalty.
- Either of the approaches will help in rationalizing the tariff which will increase the saleability of hydro power.

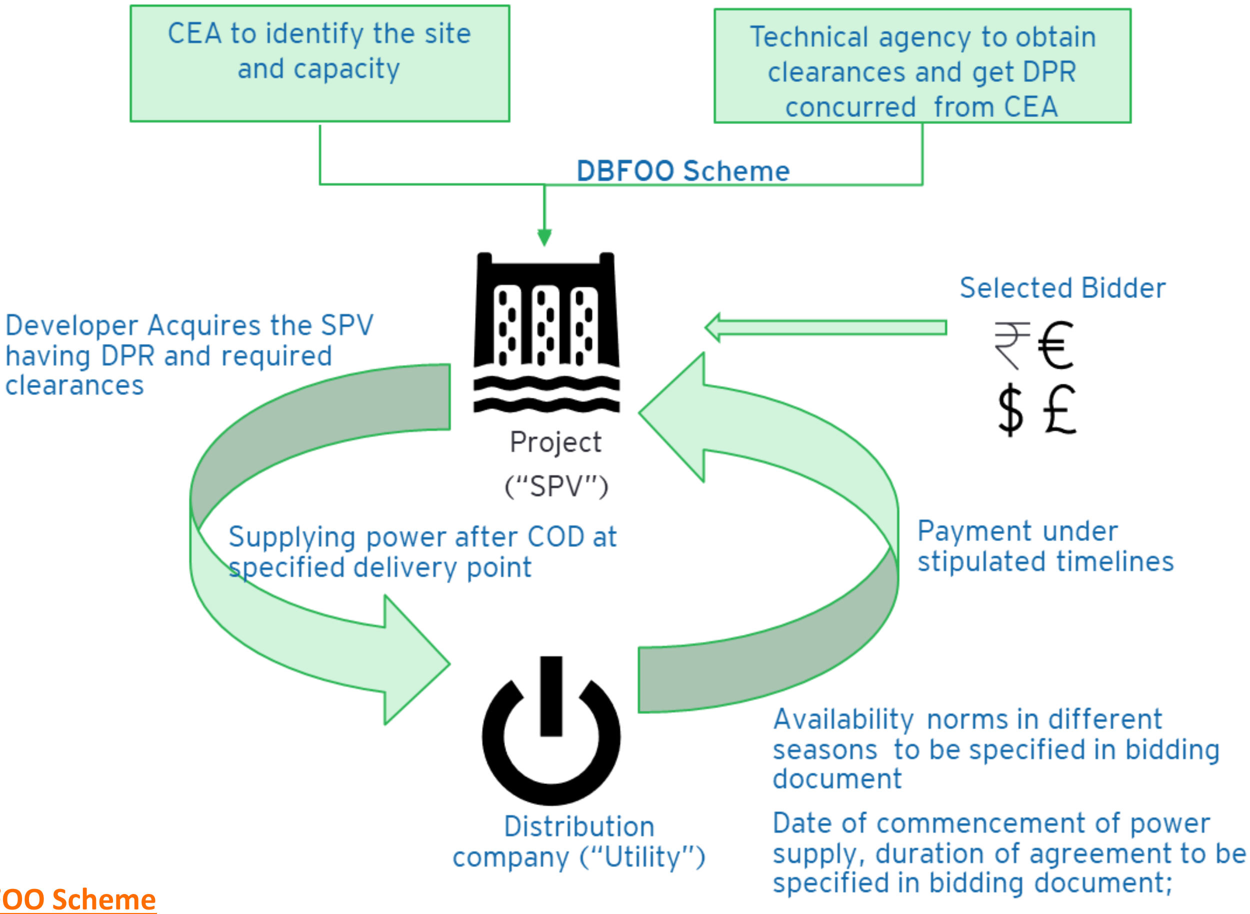
6.2. COMPETITIVE BIDDING MAY BE INTRODUCED

Learnings from global hydropower concessions
Many countries have successfully introduced competitive bidding in hydro power sector

Element	Brazil	Peru	France	Norway	Italy
Bid Model	Build, Own, Operate and Transfer	Design, Build and Operate	Design, Build and Operate	-	Design, Build and Operate
Site identification and	Site identified by Authority in new concessions	Site identified by Authority	Developer's responsibility	Developer's responsibility	Site identified by Authority
Clearances and approvals			Concessionaire		
Hydrology data	Provided by Authority	Provided by Authority	Developer's responsibility	Developer's responsibility	Provided by Authority
Hydrology data			Developer's risk		
Terminal value	No value paid out by either party on expiry of concession		Authority to pay total amounts not amortized at the end of concession period	-	-
Asset transfer	Yes	No; Asset to remain with Developer	Yes	-	Yes
Bidding stages	Two stages - Qualification round and Bidding round	Two stages - Qualification round and Bidding round	Single stage - Composite criterion comprising of price, energy quality and environmental quality	License route, i.e. Allotment basis	Single stage - QCBS split in 80:20 between technical and financial score
Bid award parameter	Renewal concession - Grant of bonus in R$ New concession - Single part tariff as on bidding date	Singe part tariff, i.e. Price for proposed power, as on bidding date	Total score based on composite criteria	Evaluation of application w.r.t minimum impact on environment	Total score based on composite criteria
Duration of concession	Renewal - 30 years New projects - 35 years	15 years	30 - 75 years	60 years	30 years
Performance Guarantee	5 - 10% of total contract amount	5 - 10% of total contract amount	10% of total contract amount	-	10% of total contract amount
Payment and reconciliation	Guarantee Minimum remuneration linked to quoted tariff		Monthly remuneration based on monthly production	Remuneration dependent on energy prices determined in energy markets	Monthly remuneration based on monthly production

Figure 54: Matrix of learnings from global hydropower concessions

Competitive bidding for development of projects
Option 1: Competitive bidding shall be based on DBFOO



DBFOO Scheme

- Developer shall build, finance, own, operate plant of specified MW at specified site. Under this model, the CEA shall identify the site and specify the capacity (MW)
- There shall be a technical agency (a nodal agency for preparation of hydro DPRs across country) which would prepare the DPR and get CEA concurrence
- The technical agency shall incorporate an SPV. All the clearances would be taken in the name of SPV, and associated cost shall be earmarked against the SPV.
- Once DPR concurrence is obtained and all the clearances are available, a bid process coordinator may conduct a bidding. The bidding criteria may be one of the following:
    - A stream of 40 annual tariff quotes- The bidder whose levelized tariff is least may be selected OR
    - Putting a cap on levelized tariff and quoting VGF
- BPC may stipulate a date of COD. In case of force majeure event, the COD may get extended by the same period for which force majeure existed.
- The successful bidder will acquire the SPV and shall pay the acquisition fees which will be sum of cost of all clearances, preparation of DPR and other transaction cost as stipulated.

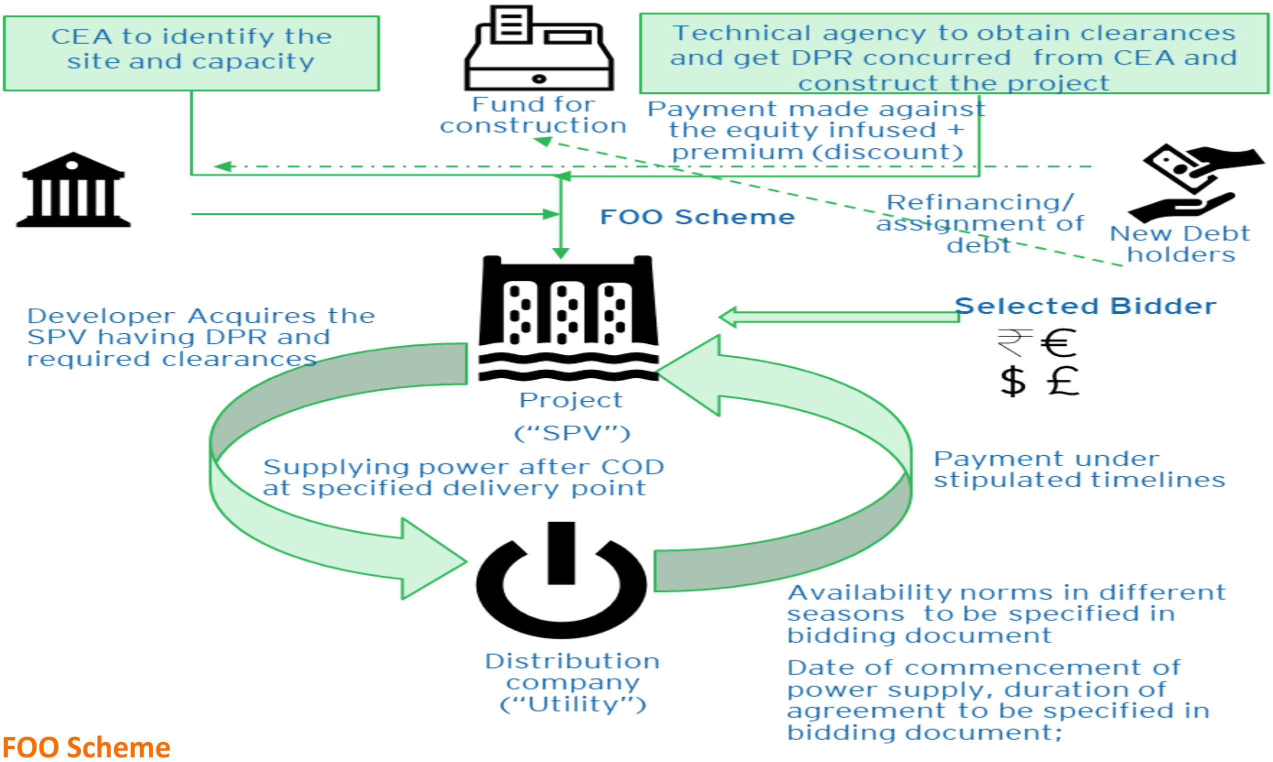
Key consideration of option 1 (DBFOO)

Element	DBFOO (Design Build Finance Own Operate)
Acquisition Price	Bidder to execute Share Purchase Agreement (SPA) with BPC and pay acquisition price for acquisition of SPV; acquisition price may not be the bidding criteria but the cost of preparing DPR, obtaining all clearances and transaction fees
Parties to the PPA	Special Purpose Vehicle (SPV) and Utility
Capacity and location	To be specified by CEA
Minimum Bid Capacity	Same as the specified capacity
Date of commencement of power supply	To be defined in the document
Contract Period / Term of PPA	40 years post commissioning of last unit and shall be further extended for 30 years. If concession gets extended, the tariff of last 30 years will be market based
Normative availability	To be defined in the document - 4 different normative availability to be defined i.e. ▸ High Hydro Season 1 (HH1) ▸ High Hydro Season 2 (HH2) ▸ Lean Hydro Season 1 (LH1) ▸ Lean Hydro Season 2 (LH2) Months for different hydro seasons may be different for different projects.
Bidding parameter	Two options are available: Option 1: Stream of 40 tariff streams- The bidder whose levelized tariff is least may be selected. The discount rate may be defined in the bid document Option 2: Put a cap on levelized tariff, the difference between tariff streams and quote VGF. It may be noted that while putting cap on tariff project economics needs to be seen and tariff is to be estimated at completed cost assuming there might be some geological surprises.
Penalties for commissioning delays	Supplier to pay a fixed % of Monthly Capacity Charges for each day of delay as liquidated damages for a period of 6 months; Further delays would be Developer's Event of Default.
Base Tariff	Base tariff for each Contract Year to be determined by summation of • Quoted non-escalable component for each Contract Year • Escalable component for each Contract Year
Split	Base tariff for each Contract year to be split in "n":"1-n" ratio into Capacity Charge and Energy Charge As per current regime n may be 0.50
Long term PPA	Bidder may be given an option to sell x% of power to market. However, X should not be more than 20% of the capacity.
Designed energy and secondary energy	Design energy will be defined in DPR. Bidders may be given the option to sell secondary energy in open market.
Incentives and penalties on availability	Corresponding incentives and penalties may be levied if actual availability is more than or less than normative availability
Milestones	Milestones should be clearly defined in the agreement. The milestones shall be extended to the extent of force majeure. In case of not meeting the milestones developer needs to surrender the project on as is where is basis to BPC without any claim with all IPRs.
Obligations of state government	State to ensure law and order as per SOP defined; active involvement in land acquisition as per SOP defined. If land acquisition is delayed because of reasons attributed to state government, for every month of delay, there should be (for e.g. 0.2%) decrease in royalty profit.
Rights of state government	Instead of free power and LADF, monetary royalty (say 5% of tariff) may be given to state. Case 1: State has no equity stake in the project , then state will only get the royalty. Case 2: State has equity stake in the project and state bring the corresponding equity amount, then state will get royalty profit and proportionate profit share. Case 3: State has equity stake in the project and state does not bring the corresponding equity amount, then state will only get royalty.

Figure 55: Key consideration of option 1 (DBFOO)

CEA may conduct basin wise study and prepare the basin wise DPR. All the projects in a basin may be allocated/awarded via auction to one developer

Competitive bidding for development of projects
Option 2: Competitive bidding shall be based on FOO (Monetization model)



FOO Scheme

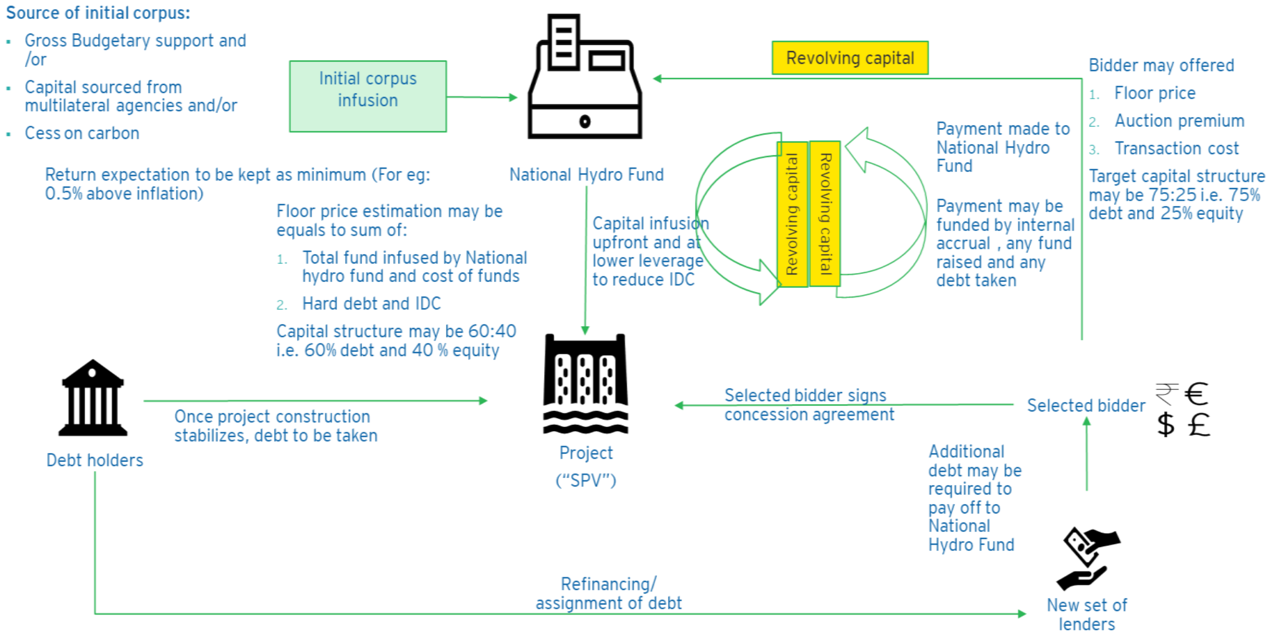
- Developer shall acquire the commissioned plant (within 1 year of commissioning). Therefore, concession is based on finance, own, and operate basis.
- In this philosophy, CEA will identify the site, specify the MW. There will be a technical agency which would obtain clearances, prepare the DPR and get it concurred by CEA. The technical agency may be a firm having competence of developing a hydro power project presently it may be one of the PSUs. Alternatively, a new company, promoted by existing hydro power PSUs, may also be incorporated for the specific purpose of developing large hydro power projects.
- The technical agency shall incorporate an SPV. All the clearances would be taken in the name of SPV, and associated cost shall be earmarked against the SPV. The technical agency shall operate the SPV which will acquire land and start project execution. The project from the conceptualisation stage till the handover will be funded through an initial corpus (one time). The corpus shall be managed by National Hydro Fund. The initial corpus may be funded via Gross Budgetary support of central government.
- Once project is successfully commissioned, the bid process coordinator may conduct bidding to investors to complete the remaining portion within one year post commissioning. The floor price of acquisition and target levelized tariff may be stipulated. Bidders need to quote a premium over floor price. It will help is topping up the "National Hydro Fund". It will also give required churn.
- The successful bidder will acquire the SPV and shall pay the acquisition price which will be sum of floor price, premium quoted and transaction fees. The successful bidder shall be given the option to structure and fund the transaction.

- The lender(s) of incoming bidder (or consortium) will assign the corresponding debt of existing lenders; balance amount shall be paid to National Hydro Fund. Hence the fund will be revolving in nature and will be used to develop further projects.

This model may attract Investors/ PEs/Funds as capital rotation improves. It also brings the benefits of standardisation of DPRs and improves debt financing climate for large hydro projects

Capital rotation in National Hydro Fund

Initial corpus may be churned once about to commissioned assets gets monetized



Key consideration of option 2 : FOO

Element	FOO (Finance Own Operate)
Acquisition Price	Bidder to execute Share Purchase Agreement (SPA) with National Hydro Fund and pay acquisition price for acquisition of SPV; Acquisition price shall be sum of floor price as stipulated, auction premium (parties who quote highest auction premium) and transaction cost. The option of paying transaction cost to BPC is open and depend on process design
Parties to the PPA	Special Purpose Vehicle (SPV) and Utility
Capacity and location	To be specified by CEA
Minimum Bid Capacity	Same as the specified capacity
Date of commencement of power supply	To be defined in the document
Contract Period / Term of PPA	40 years post commissioning of last unit and shall be further extended for 30 years. If concession gets extended, the tariff of last 30 years will be market based
Normative availability	To be defined in the document - 4 different normative availability to be defined i.e. ▸ High Hydro Season 1 (HH1) ▸ High Hydro Season 2 (HH2) ▸ Lean Hydro Season 1 (LH1) ▸ Lean Hydro Season 2 (LH2) Months for different hydro seasons may be different for different projects.
Bidding parameter	Premium over Floor price against the target levelized tariff. Floor price shall be sum of total fund infused by National Hydro Fund and cost of funds; hard debt disbursed and associated IDC.
Base Tariff	Base tariff for each Contract Year to be determined by summation of • Quoted non-escalable component for each Contract Year • Escalable component for each Contract Year Bidder need to ensure that tarif stream should not go beyond levelized tariff. Any other constraint on tariff of subsequent year to be complied.

Figure 56: Key consideration of FOO

Element	FOO
Split	Base tariff for each Contract year to be split in "n":"1-n" ratio into Capacity Charge and Energy Charge As per current regime n may be 0.50
Long term PPA	Bidder may be given an option to sell x% of power to market. However, X should not be more than 20% of the capacity.
Designed energy and secondary energy	Design energy will be defined in DPR. Bidders may be given the option to sell secondary energy in open market.
Incentives and penalties on availability	Corresponding incentives and penalties may be levied if actual availability is more than or less than normative availability
Milestones	Milestones should be clearly defined in the agreement. The milestones shall be extended to the extent of force majeure. In case of not meeting the milestones developer needs to surrender the project on as is where is basis to BPC without any claim with all IPRs.
Obligations of state government	State to ensure law and order as per SOP defined;
Rights of state government	Instead of free power and LADF, monetary royalty (say 5% of tariff) may be given to state. Case 1: State has no equity stake in the project , then state will only get the royalty. Case 2: State has equity stake in the project and state bring the corresponding equity amount, then state will get royalty profit and proportionate profit share. Case 3: State has equity stake in the project and state does not bring the corresponding equity amount, then state will only get royalty.

Figure 57: Key consideration of FOO

Risk allocation among parties in two options

Risk allocation done in a manner to a party best equipped to handle such risks

- As an underlying principle, risks have been allocated to the parties that are best suited to manage them
    - Commercial and technical risks relating to construction, operation and maintenance are being allocated to the developer, as it would be best suited to manage them

Risk	DBFOO		FOO	
	Developer	Government	Developer	Government
Site selection	×	✓	×	✓
Hydrology	✓	×	✓	×
Land acquisition	✓	×	×	✓
Consents and Clearances	×	✓	×	✓
Technology	✓	×	×	✓
Financing	✓	×	✓	✓
Construction	✓	×	×	✓
Operations	✓	×	✓	×
Scheduling and Dispatch (Market risk)	✓	×	✓	×
Behaviour of Utility (Credit risk)	✓	×	✓	×
Conclusion	Less attractive to Institutional investors		Preferrable to Institutional investors	

Figure 58: Risk allocation

Key comparison between DBFOO and FOO

Finance Own Operate competitive bidding model is superior than Design Build Finance Own Operate.

Bidder	DBFOO	FOO
Superior equity returns	To some extent, still time value of money has some bearing on the return	Yes, as time value of money does not have a great bearing for investors
Risk taken by the state	Relatively lower	Relatively higher
Risk taken by developer	Relatively higher	Relatively lower
Requirement of budgetary support	Not required	Maybe required to kick off the National Hydro Fund (only initial corpus)
Requirement of development of concession agreement	Yes	Yes
Monitoring requirement	Yes	Reduced significantly
Attractiveness for investors	Lower	Higher

Figure 59: Key comparison between two options

6.3. EXPEDITING THE PROJECT DEVELOPMENT PROCESS

Process flow mapping for the hydro project development
Project construction could not start unless all clearances been accorded to project

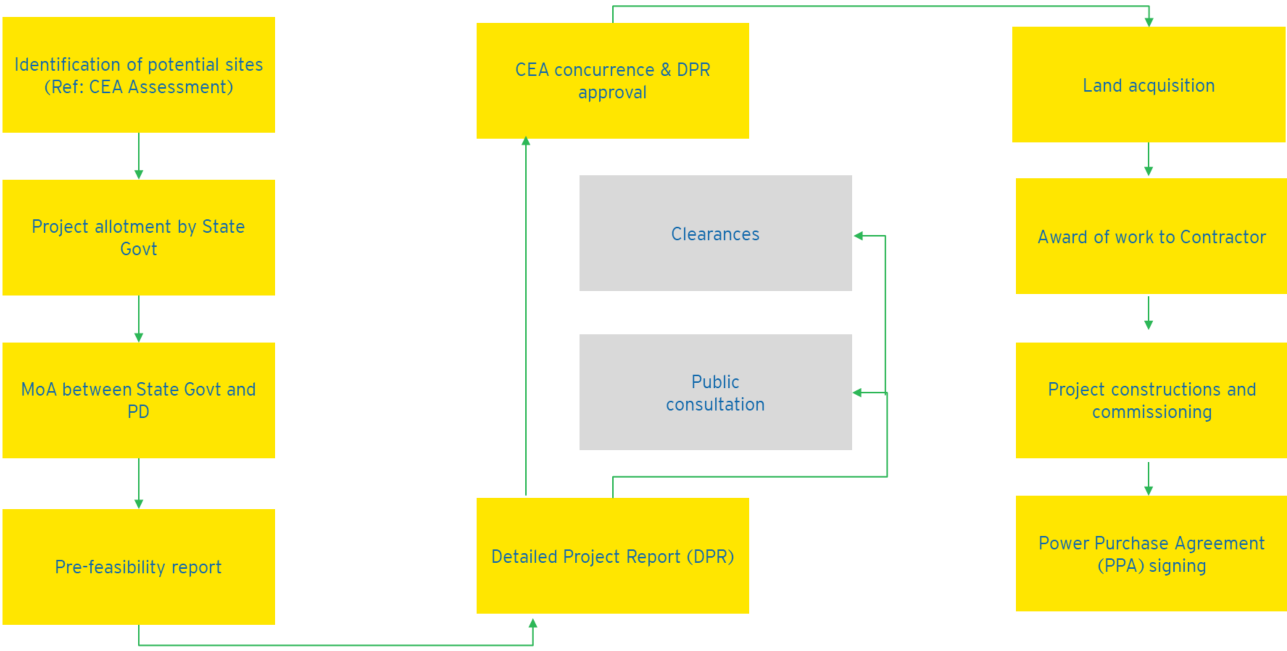


Figure 60: Process flow mapping for the hydro project development

Process flow associated with preparation of Detailed Project Report
Estimated time taken for the preparation of DPR is 30 months

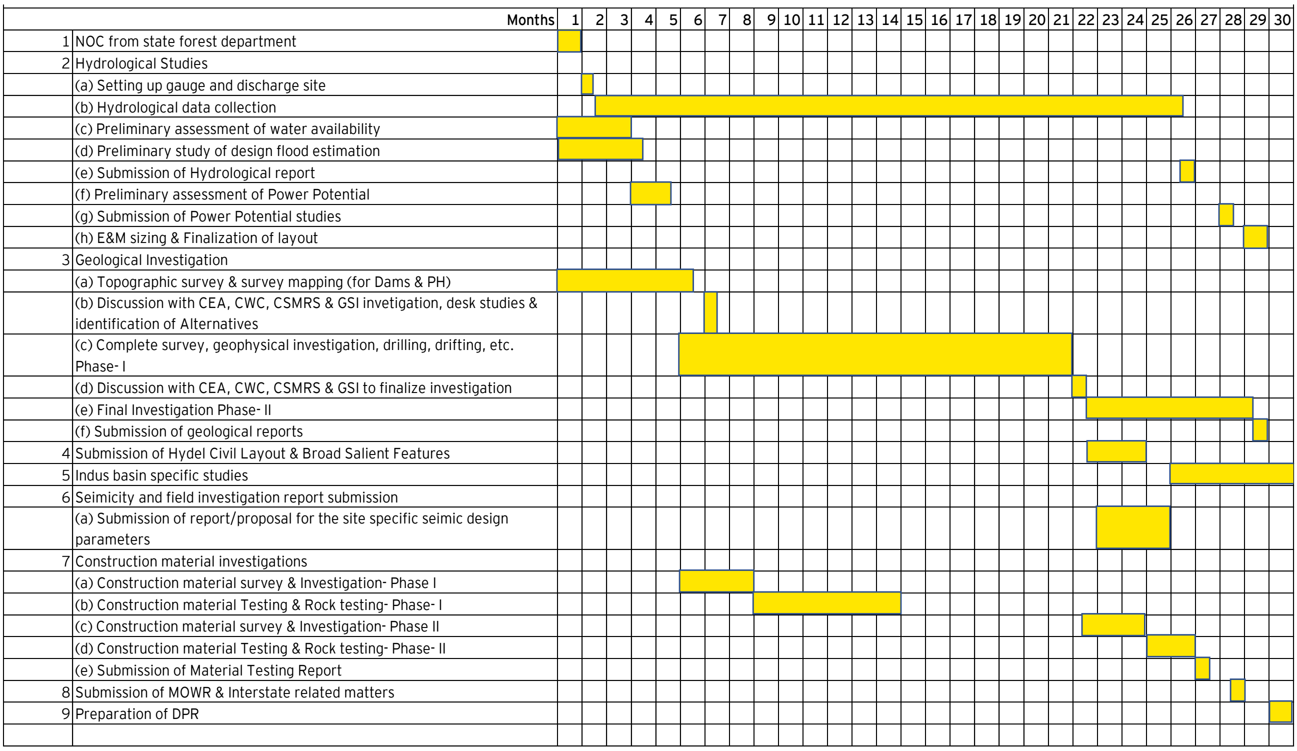


Figure 61: Process flow associated with preparation of Detailed Project Report

Gant chart of Activities to be carried out by CWC/ CEA/MoWR/GSI & CSMRS

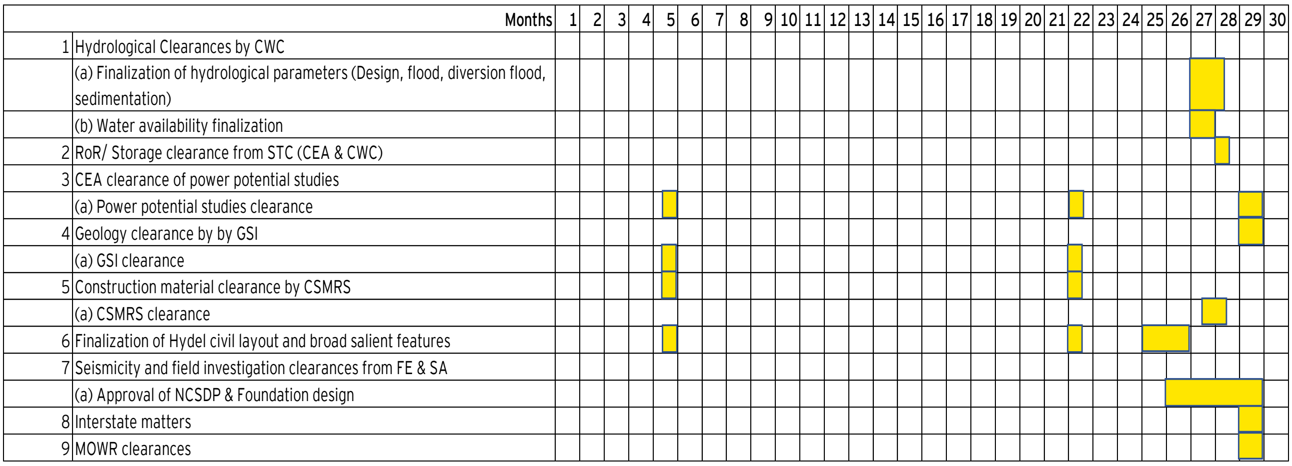


Figure 62: Gant chart of Activities to be carried out by CWC/ CEA/MoWR/GSI & CSMRS

Reducing the turnaround time for various activities

Table 22: Reducing the turnaround time for various activities

Sl No	Activity	Period
1	Time allotted to prepare DPR:	30 Months
2	Actual time taken by developer to prepare a DPR	Varies
3	Ideal Time for Environment Clearance	25 Months (2 months- application + TOR; 18 months- EIA - EMP report; 1.5 months- Public hearing; 3.5 months- final approval)
4	Forest Clearance- I	10 Months (310 Days)
5	Forest Clearance- II	4 month (125 Days)

- As per the CEA data, many of the projects are stuck at different stages.
- Projects that were concurred way back in 2007/ 2010 could not have been started because few of the clearances are still pending
- Teesta St- IV, the project was concurred in 2010 however, its construction is not yet started since FC- II is not cleared till date.
- Kothlibhel Stage- IB: concurrence accorded in 2006 however, EC withdrawn in 2010. Project is under SC's review as of now.
- Rupsiyabagar Khasiyabara: Concurrence accorded in 2008, FC- II yet to be received.
- It has been found post stakeholder's discussion that at times developer(s) does not submit the DPR and other relevant studies in specified format. At times certain specified content/studies are also not available owing to which the time taken for granting concurrence becomes higher.
- Therefore, it may be imperative to make entire process easy and transparent.
- It has also been observed that required proactive approach is absent at times from developers which increases the turnaround time.

Interventions required to expedite the project development

First step is to streamline the process of obtaining clearances and getting DPR concurrence

Online form for DPR submission

- CEA may prepare a detailed online form for submitting the DPR. Developer(s) need to submit the DPR in the stipulated online format. If there is any information which is not available with the developer, the DPR won't be submitted for concurrence. This will ensure the transparency.

Define maximum turnaround time for every process and sub process

- Once the application for a clearance gets submitted, the same can be tracked. Also, the maximum turnaround time for decision may be specified. If application is in accordance with the stipulated guidelines, then clearance may be accorded within specified turnaround time. However, if application is not as per stipulated guideline, then application may be reverted to developer within specified turnaround time.

One stop window for getting clearances

- Concept of one stop window for obtaining clearances may also be introduced. In this case, an agency (for e.g., CEA) may be appointed as one stop window. Developer(s) need to apply for all clearances to the specified agency only. The developer need not to interact with any other agency and shall act as a single point of contact for all communication. The appointed agency may interact with other organization.

Two stage clearances on feasibility

- CEA may grant feasibility in two stages. First is clearance may be given basis on initial assessment so that land acquisition process can be started. CEA may conduct further deliberation and grant final clearance after required study however it will help in reducing the construction time.

State government needs to be made accountable

Accountability of state government

Role in land acquisition

- State government should extend its full support in land acquisition. It may be noted that land may be acquired by state government at the cost of developer and allotted to developer. A senior officer not below the rank of commissioner may be appointed as a nodal person who shall be responsible for land acquisition, maintain law and order and state government specific matter pertaining to project.
- Project affected families may be offered dividends in addition to the compensation paid. This will an additional incentive for the local population and hence they will be supportive of the project for its entire lifetime. This will also increase the economic IRR of the project.
- In case state fails to do so in stipulated timeframe (e.g., 12 months, may be extended by another 6 months), royalty may be cut by 0.2% for every month of delay. In case, the situation is beyond the reasonable control of state government, it may be classified as “Force Majeure” event. All such event may be explicitly written in hydro policy

Role in maintaining law and order

- Maintaining law and order of the project premises and enabling infrastructures including dedicated transmission network shall be responsibility of state government. However, security of plant premises may come under the ambit of CISF.
- There should be a coordination between CISF and local administration (state government).
- Developer conducts a detailed study on law-and-order requirement for the areas and share the same with local administration (state government) and CISF. Local administration (state government) and CISF team can give a comment on it over a stipulated period (e.g., 45 days) and propose a security, law, and order plan to developer. Developer needs to revert with their concerns within specified period (e.g., 15 days).
- Local administration (state government) and CISF prepare final blueprint (for their responsibilities and areas respectively) to the satisfaction of developer in next specified period (e.g., 30 days).
- A detailed SOP in accordance with final blueprint needs to be formulated and same needs to be adhered by local administration (state government) and CISF.
- A coordination mechanism governing coordination between CISF team and local administration (state government) needs to be defined and agreed upon by both parties.
- In case of any dispute between CISF and local administration, the same shall be resolved by a committee. The committee shall comprise of five senior officials – two from CISF, two from local administration and one from developer. The designation of the officials may be decided later.

Extension of perimeter- security by CRPF

- Security, law, and order of the concerned areas shall be continuously monitored. Any change in area (perimeter) and responsibilities between local administration (state government) and CISF shall be done only if developer shall give its consent and concerned committee approves it.

Role of government in obtaining clearances

Role of central government

Role in land acquisition

- State government should extend its full support in land acquisition. It may be noted that land may be acquired by state government at the cost of developer and allotted to developer. Private land may be acquired by developers on its own.
- In case state fails to do so in stipulated timeframe (e.g., 12 months, may be extended by another 6 months), royalty may be cut by 0.2% for every month of delay. In case, the situation is beyond the reasonable control of state government, it may be classified as “Force Majeure” event.

Role of state government

Active cooperation for holding public hearings

- It may be noted that public hearings are conducted for Environment Impact Assessment (EIA) and Forest Rights Act (FRA) 2006. However, cooperation of local administration and state government is discretionary in nature as there is no SOP in place.
- Therefore, a SOP needs to be devised defining the contours of active cooperation of local administration and state government. The local administration needs to gather the public concerns along with the requirement of concerned departments such as SPCB and give due

feedback to developer beforehand. This will help developer(s) in chalking out the resolution of the concerns in an appropriate manner.

- The concerned state departments shall share their views and hold public hearing within stipulated time frame.
- The maximum turnaround time required from both sides i.e., from developer and from local government / state government needs to be defined.
- Local administration and state government shall also ensure that developer meet their commitment and roll out the plan as agreed.
- Similar approach may be followed for Social Impact Assessment (SIA) and Resettlement & Rehabilitation (R&R) plan consultation.

6.4. RESOLUTION OF STALLED PROJECTS

Allotment agreement/MOA are heterogeneous in nature within same state.

1. There are MOAs which clearly defines Event of default, milestones, and results of not meeting milestones – Kamala HEP

Events of default / Milestones	Outcome of not meeting milestones
The JV Company shall achieve the financial closure within a period of 12 (twelve) months (or further period as the State Government may agree) from the date of receipt of the Techno-economic Clearance (TEC), if required, from the Central Electricity Authority (CEA), approvals from Ministry of Environment and Forest (MoEF) and other statutory clearances	In the event that It is confirmed as impossible or impractical to achieve Financial Closure or if the Financial Closure is not achieved on or before the expiry of twelve months from the aforesaid date, for the reasons other than those attributable to the Government of Arunachal Pradesh, the Govt, of Arunachal Pradesh reserves the right to terminate the agreement.
In the event of stoppage of the construction works of the project by the JV Company, for a period of more than 12(twelve) months for reasons not covered under Force Majeure and for reasons attributable to the Company and/or abandonment of the project by the Company.	The State Govt, shall, after giving due opportunity to the JV Company to resume the work, have the right to terminate the agreement. In the event of termination of the agreement under this clause, the Govt, of Arunachal Pradesh shall have the right to take over the project on "**As is where is**" basis and **no claim** of the Company shall be entertained. The Govt, of Arunachal Pradesh shall, also have the exclusive **right to re-allot** such project to any other developer.
In case the Company does not commence implementation of the project within a period of 4 (Four) years from the date of signing of this agreement or within a period of 1 (One) year from the date of receipt of all the statutory clearances, such as Forest & Environment, Techno- economic clearance etc, whichever is earlier.	The project shall be reverted to the State Government on "**As is where is**" basis along with all the reports, other documents etc, free of cost. However, the above time period shall be automatically extended by the aggregate of the period during which the Company could not take steps to commence implementation by reason of Force Majeure conditions. Thereafter, the State Govt, shall have the **exclusive right to re-allot** the project to any third party for further development of the project. The Company, if interested, on its own may take necessary steps for reimbursement of its expenditures from such third party without any involvement of the State Govt.

As we analyse the MOA for Kamla HEP we can see that it clearly defines event of defaults, milestones, and results of not meeting the milestones.

2. There are MOAs which clearly defines Event of default and milestones but not the results of not meeting milestones – Etalin HEP

Events of default / Milestones	Outcome of not meeting milestones
The JV company will be allowed a total period of five and half years for completion of S&I, preparation & submission of DPR, obtaining all statutory clearances and achieving financial closure from the date of signing JV Agreement. The JV Company will be allowed a further period of 8 (eight) years for implementation of the project(s).	In the event of failure to achieve Financial Closure before the expiry of five and half years for the reasons other than covered under Force Majeure, the Government of Arunachal Pradesh after giving due opportunity to the JV Company to achieve Financial Closure reserves the right to withdraw/take-over the Project(s). **However, such right to withdraw/take-over the Project under this clause would accrue in favour of the GoAP only if the JV Co. fails to fulfil its Signing Date Linked Commencement Obligation due to reasons other than those covered under Force Majeure.**
In the event of failure to start construction work on stoppage of the construction work of the Project(s) during the period of construction by the JV Company for a continuous period of more than 12 (twelve) months for reasons not covered under Force Majeure or for reasons attributable to the JV Company and/or abandonment of the Project(s) by the JV Company.	The Stale Government shall, after giving due opportunity to the JV Company to resume the work, have the right to take-over the Project(s) without owning any liabilities towards the JV company.

In Etalin HEP case although it clearly defines the event of defaults and milestones but it lacks a detailed clause for not achieving the milestones.

3. There are MOAs which are in favour of developers – Lower Siang HEP

Events of default / Milestones	Outcome of not meeting milestones
If the company doesn't commence the implementation of the project within 4 years from initial MOA execution date or within 1 year of obtaining all the statutory clearances, '**Whichever is Later**'.	The project shall be reverted to GoAP on 'As is Where is' basis at Free of Cost.

We understand that the clause is kept open-ended as it mentions, 'Whichever is later', which indeed favours the developers.

Broad profile of stalled projects and resolution methodology (1/3)

The profiling of stalled projects may be done based on allotment agreement/MoA

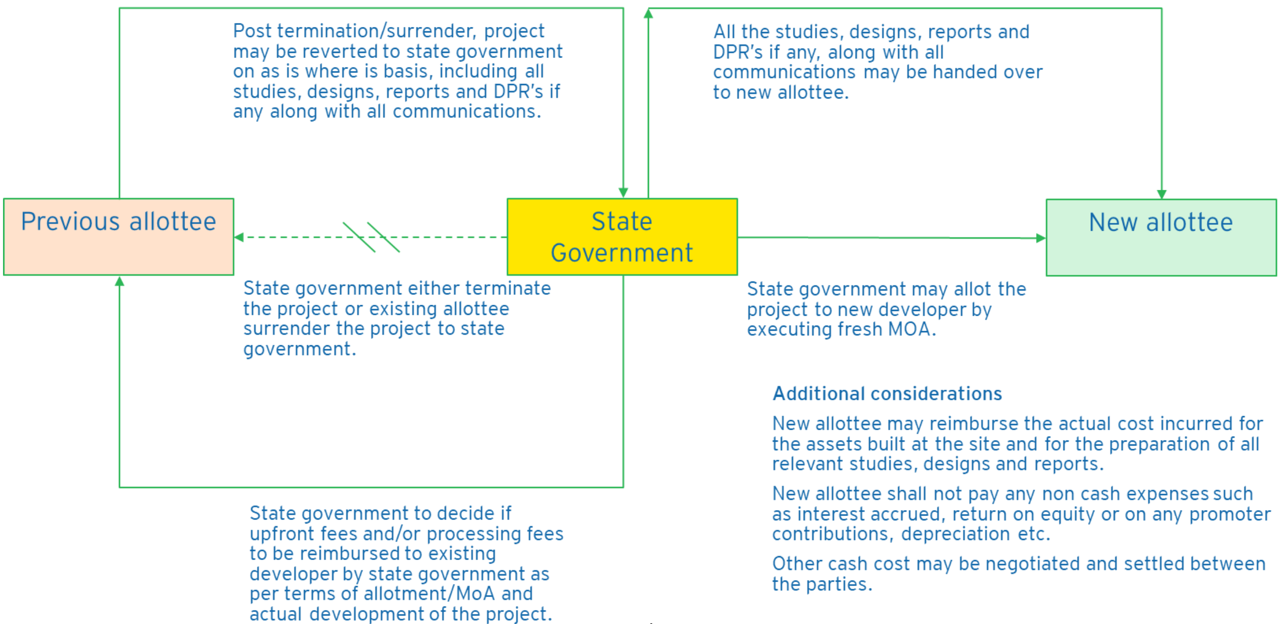
Table 23: Broad profile of stalled projects and resolution methodology

No financial creditor involved and case is not under insolvency proceedings	Event of default triggered and no extension is granted and if extensions are granted, it get lapsed	Either event of default about to happen or extensions granted about to lapse	Event of default -not happened and will not happen in recent future
Allotment agreement/MOA which clearly defines milestones and results of not meeting milestones. The agreement also defines either the case of termination or the case of deemed revert to state	1 State government should terminate the current allocation, even if MoA stipulates that project is deemed revert to state. State need to reallocate to different developer (PSU) by issuing fresh allotment agreement/MOA. Option of reimbursement of upfront money is at the judgement of State Government as MoA stipulates the same. .	2a State government may observe the progress and discuss with developer. Post discussion, state government may examine if there is a case of termination or deemed revert. If there is no significant progress and current developer are not in position to develop, MoA need not to be extended. Once MoA get lapsed then it will follow the process as explained in block 1.	3 State government may observe the progress and discuss with developer. If the project is not on track, state government may issue the notice to current developer clearly specifying the milestone. In this case three scenario emerges: 1. Developer either agrees and develop the project 2. Developer agrees and defaults on meeting milestones. In such case project gets terminated. 3. Developers does not agree and surrender.
Allotment agreement/MOA which does not clearly defines milestones and results of not meeting milestones. The agreement also not clearly defines either the case of termination or the case of deemed revert to state		2b State government may observe the progress and discuss with developer. If the project is not on track, state government may issue the notice to current developer clearly specifying the milestone. Agreeing to milestones may be a condition precedent for extending the MOU. If developers does not agree, state government may terminate the project.	

- In case project gets terminated, state government to decide if upfront fees to be reimbursed or forfeited. Most of Memorandum of Agreement allows state government to do so.
- Sufficiency and prudency of other expenses to be examined and reimbursed by new allottee.

Broad profile of stalled projects and resolution methodology (2/3)

Post reallocation studies needs to be handed over to new allottee and clearances needs to be assigned in the name of new allottee



Broad profile of stalled projects and resolution methodology (3/3)
Procedures may be laid out for time bound transfer of clearances

Steps for time bound transfer of clearances

- New allottee may examine the clearances which were accorded to the projects and segregate into three buckets
    - Clearances which are still valid
    - Clearances which were accorded but rescinded or lapsed
    - Clearances which were not accorded. Further this group may be divided into two

Clearances which are still valid

- New allottee shall apply for the transfer of clearances. Concerned agencies shall examine the application and conditions under which clearances were accorded. If there are change in landscape resulting in inclusion /exclusion of some conditions, the applicable conditions shall be finalized accordingly. Transfer of clearances with stipulated conditions may be transferred within specified (e.g., 45 days) time.

Clearances which were accorded but rescinded or lapsed

- New allottee shall apply for obtaining the clearances. Allottee shall have the option to conduct any other study and substantiate its application. Concerned agencies shall examine the application. If there is no change in landscape and there is no additional submission from new allottee, then clearances may be accorded within specified time (e.g., 45 days).
- However, if there is change in project landscape, the clearances may be accorded after proper deliberation and analysis. The maximum turnaround time for according the clearances/ declining the application may be defined (e.g., 75 days)

Clearances which were not accorded

- New allottee needs to file fresh application along with history, previous minutes and action taken. Concerned agencies were to fast track the application process, provided the application is in accordance with the guidelines.

6.5. Tariff reduction measures

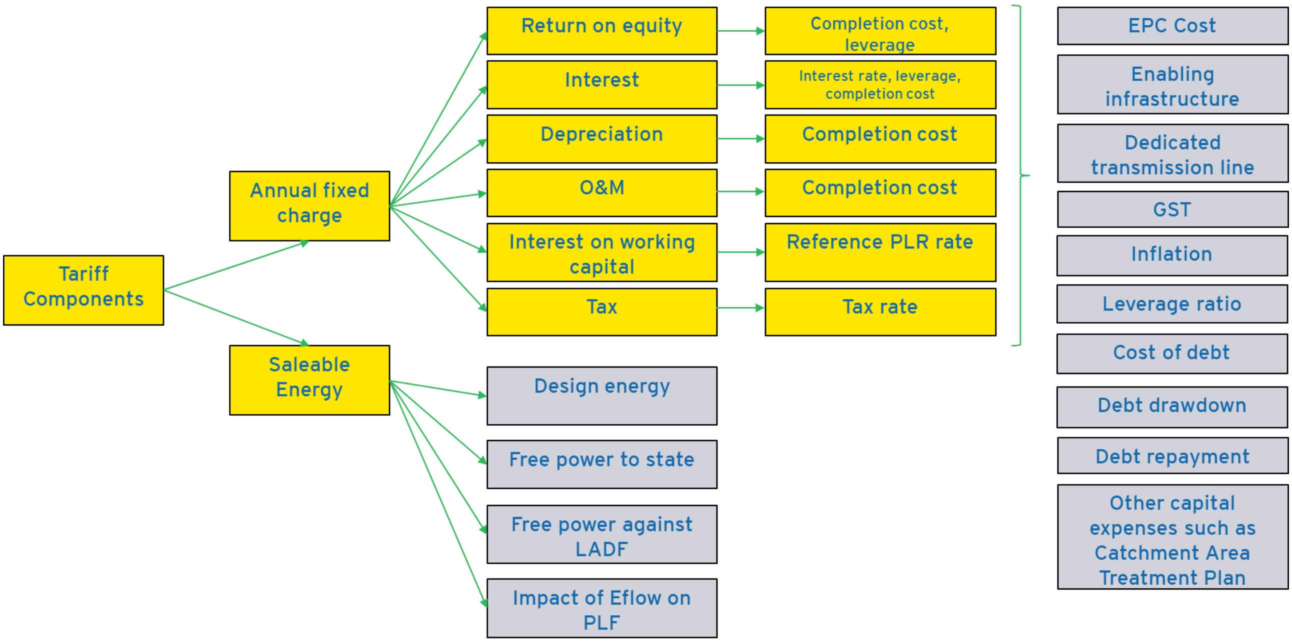


Figure 63: Tariff reduction measures

Tariff reduction measure (1/3)

GST waiver

- Reduction of GST rate or waiver of GST will reduce the capital cost and hence completion cost and tariff. By means of illustration, a present effective GST rate is 18%, in case project gets GST waiver, the levelized tariff gets reduced by 13.6%. If it is brought to the level of Solar Projects i.e., 5%, the levelized tariff gets reduced by 13%.
- Alternatively, partial, or full GST amount may be reimbursed by either state and/or central government,

Expanding the scope of enabling infrastructure

- Office memorandum date March 08, 2019, mandates budgetary support against cost of enabling infrastructure i.e., roads/bridges. Its INR 1.5 Cr/ MW for projects up to 200 MW or INR 1.0 Cr/ MW for projects over 200 MW. Post consultation with developers, it has been found that the entire support is rarely used in the project. Therefore, scope of enabling infrastructure may get extended and dedicated transmission line connecting plant with nearest substation may be covered. This will increase the grant amount and reduce the tariff.

Waiver of upfront premium

- Upfront premium should not be charged from developers. It increases the project cost and hence tariff.

Replacement of free power to state against monetary royalty

- 12% royalty free power has the potential to increase the tariff by 13.63%. In current regime, free power is being socialized. Instead of free power, option of royalty profit i.e., a percentage of profit may be given to state. Staggering of free power though reduces the tariff but problem of socialization persists.

- However, royalty profit will reduce the free cash flow for the plant and thereby reduces the payoff to developer.
- Research indicates that in case of hydro power projects royalty free power is highest in India therefore if it is not possible to give complete wavier of free power same may be reduce significantly for e.g., 5%. Alternatively a fixed per unit charge may be collected for e.g., INR 0.1/unit instead of free power.
- Any GST if applicable on free power/monetary royalty may be waived.

Replacement of free power earmarked for LADF against monetary consideration

- To providing long term sustained streams for revenue generation towards upliftment of the residents under Project Allotted Areas, the state government in line with the National Hydro Power Policy 2008, incorporated provision for providing 1% Additional Free Power on account of LADF. It increases the tariff by 1%. Option of replacing the free power earmarked for LADF against monetary consideration (e.g.: 1% of profit). It may be considered as part of CSR spending to compensate the developer(s).

Waiver of water cess and other state specific taxes

- As state government is already benefitted by royalty free power as on date (may be replaced with royalty profit as per report), water cess levied by few states such as J&K may be discouraged.

Minimizing IDC

- Interest during construction (IDC) is a function of three important parameters namely – leverage ratio, phasing, and cost of debt. For any project whose expected tariff is going beyond target, option of increasing leverage may be given.
    - As per simulations, increasing the leverage from 70% to 80%, project cost increases by 3.34% owing to increase in IDC. However, levelized tariff decreases by 9.92% as ROE at 16.5% is only charged on 20% of capital. In this case, power cost of later year may be lesser.
- Upfront equity also reduces the IDC; however, it reduces the equity IRR.
- During construction also cheaper source of capital may be brought. Such cheaper source of capital include tax free bonds, proceeds from securitization of future cash etc.
    - For every 1% decrease in interest rate, IDC reduces by ~13.67% and total project cost by ~2.7% and levelized tariff by 3.63%.
    - Developers may monetize their cash generating stations and use the proceeds in development of greenfield projects. However, it may be noted that owing to its peculiarity limited options of asset monetization is possible. One of the successful models are securitization of future cash flows which NHPC has done recently for coupon rate which is more attractive than that of cost of debt. Other option could be selling stakes for limited concession period.
    - It may be noted that other asset monetization options such as InvIt may not be successful in case of hydro power projects. For any InvIT, to be a success, provided sponsors gives either a pool of cash generating assets or a growth story or both. Since gestation period of hydro projects are relatively high (7-8 years), therefore sponsors cannot commit a growth, hence sponsors need to put a pool of at least 4-5 assets for InvIT. However, if sponsors put more assets under the InvIT route, the cash position in future year gets worsened.

- Financing may also be done via tax free/ tax saving bonds. The interest rate /coupon rate of these bonds are lower than the conventional loans.

Table 24: Tax free bonds & Tax saving bonds

Tax free bonds	Tax saving bonds
Interest (income) is tax-exempt	Initial investment is tax-exempt
Falls under Section 10 of the Income Tax Act	Falls under Section 80CCF of the Income Tax Act
Offer higher interest rates than tax-saving bonds	Lower interest rates compared to tax-free bonds
The higher maturity period of 10,15 and 20 years	Has a buyback clause –can redeem investments after 5 or 7 years

Reducing interest obligations during operations

- Lenders agrees that post commissioning of the project, risk gets reduced significantly and therefore ready to finance the project at lower interest rate. However, tenure of loan may or may not be changed. But, developers need to bear prepayment charges to previous lender(s). RBI may discourage the prepayment charges in case hydro power projects are refinanced. This will reduce the financing charges.

Increasing the repayment period

- Increase in repayment period, reduces the rate at which principle gets amortized. And as per tariff determination methodology, depreciation is considered same as repayment, therefore depreciation amount gets reduced. However, interest outgo gets increased as rate of amortization reduces. The returns also take a hit. By means of illustration, if repayment tenure is increased to 18 years and depreciation is also charged accordingly, levelized tariff gets reduced by ~2%.

Waiving ISTS charges and losses

- Currently, ISTS charges and losses are waived for non-hydro renewable power generations such as solar or wind power projects. If the same is extended for hydro power project, the cost implication for distribution companies for procuring hydro power projects gets reduced by 14% to 19%

Rationalizing interest on working capital

- Instead of allowing interest on working capital at normative rate, it may be allowed at actual short-term rate which developer can borrow. However, it may reduce the cash flow to project.

Policy intervention for increasing the availability of capital

- Lenders may get tax concessions on the interest charged (till certain rate say MCLR plus 50 bps) against the loan disbursed for the development of hydro power projects. This will act as an incentive for funding hydro power projects.

- The Reserve Bank of India has mandated the banks to fix limits on their exposure to specific industry or sectors and has prescribed regulatory limits on banks' exposure to single and group borrowers in India. Further, RBI's prudential exposure norms mandate that a bank exposure to a single borrower should capped to 20% of a lender's tier -I capital base and to 25% limit to a group of connected entities with effect from April 1, 2019. Further banks must classify the sum of all exposures of 10% or above as 'large exposure' and report them to the central bank.
- For Hydropower CPSUs the limit of 25% may be extended to 30%.

Tariff sensitivity analysis for Hydro project

Case study: Hydro project- LCOE (INR/kWh) – 5.49

Individual impact	LCOE	Reduction in Tariff (%)
Interest rate decreased by 1%	5.30	3.46%
IoWC (bringing the IoWC to the actual level)	5.47	0.36%
Grant against enabling infrastructure (maximum 1 Cr/MW)	4.70	14.39%
GST wavier (same as renewable) reduce to 5%	4.78	12.93%
Wavier of free power	4.78	12.93%

Cumulative impact	LCOE	Reduction in Tariff (%)
Interest rate decreased by 1%	5.30	3.46%
IoWC (bringing the IoWC to the actual level)	5.26	4.19%
Grant against enabling infrastructure (maximum 1 Cr/MW)	4.51	17.85%
GST wavier (same as renewable) reduce to 5%	3.92	28.60%
Wavier of free power	3.41	37.89%

The sequence is based on the controllable parameters followed by the parameters where concession / assistance from government is required.

6.6. Active monitoring at high level

Monitoring mechanism

Active monitoring shall highlight the issues at appropriate level with immediate effect

Monitoring at State Government level

- All under construction projects having capacity more than 50 MW and/or investment size more than INR 500 Cr shall be monitored in real-time by state power secretary.
- Weekly report may be sent to state chief secretary office and monthly update may be sent to honourable chief minister.
- District commissioner shall ensure that information disseminated in system and reports regarding the project progress is correct.
- Any delay from the schedule needs to be analysed and reported to honourable state power secretary, state chief secretary level, power minister and chief minister.
- A live portal may be developed for the same where real time project update is available.
- All reports may be updated on the portal.
- The portal may be integrated with existing Pragati Portal.

Monitoring at central government level

- All under construction projects having capacity more than 100 MW and/or investment size more than INR 1000 Cr shall be monitored in real-time by honourable power secretary.
- Weekly report may be sent to power minister office and monthly update may be sent to prime minister office.
- Any delay from the schedule needs to be analysed and reported to power minister office and to prime minister office.
- Pragati Portal may be upgraded so that where real time project update is available.
- All reports may be updated on the portal.
- A special task force may be prepared comprising of senior officers of MoP, CEA and State government which shall visit the project quarterly.

6.7. Other interventions

Enhanced Delegation to Board of Directors of CPSUs

Enhanced delegation shall ensure faster decision making

Table 25: Enhanced delegation shall ensure faster decision making

S.No.	Category of PSE	Ceiling on equity investment
1	Maharatna, (DPE OM dated 4.02.2010)	15% of the NW in one project limited to INR 5,000 Cr. Overall ceiling in all projects - 30% of the NW
2	Navratna, (DPE OM dated 5.08.2005)	15% of the NW in one project limited to INR 1,000 Cr. Overall ceiling in all projects - 30% of the NW
3	Miniratna, (DPE OM dated 5.08.2005), Category -I, Category -II	Category -I: 15% of the NW in one project limited to INR 500 Cr. Overall ceiling in all projects - 30% of the NW Category -I: 15% of the NW in one project limited to INR 250 Cr. Overall ceiling in all projects - 30% of the NW
4	Non -Ratna	Nil

Hydro CPSE	Networth (INR Cr) March 21	Category
NHPC Limited	31,647.31	Miniratna, Category I
SJVN Limited	12,761.84	Miniratna, Category I
THDC	9,550.00	Miniratna, Category I
NEEPCO	6,404.00	Miniratna, Category I

- All four major hydro power companies are Miniratna, Category I PSU. So as per DPE guidelines, power of board is restricted to make equity investment decision till INR 500 Cr for one project.
- As per current trend completion cost of hydro power projects are INR 10 Cr /MW, hence for any project of size more than 200 MW (25% of 2000 Cr assuming D:E is 75:25), concerned PSUs need to reach Ministry of Power for getting investment approval.
- To expedite the decision process, Board of Hydro Power PSUs must be empowered to take investment decision over hydro power project up to size 500 MW.
- It may be an aberration as Board of Navratna PSU are empowered to take decision till equity investment of INR 1,000 Cr. However, such deviation may be required for the benefit of hydro power sector.
- Also, delegation of Board of Navratna as well as Miniratna may be increased in line with increase in WPI (Wholesale price index - it will help in absorbing the inflation shock).

Rationalizing parameters for Public Investment Board (PIB) and Cabinet Committee on Economic Affairs (CCEA) clearance

The threshold parameters may be rationalized as per market dynamics

- Average gestation period of hydro power project is 7 years as considered in most cases which means there is no cash flows for 7 years. Post commission of the project the only cash flow, having certainty, is 16.5% return on equity. Further, as tariff reduction measure, entire equity is brought upfront.
- The entire mechanism brings down the effective return of the project. A simulation of the same is shown below:

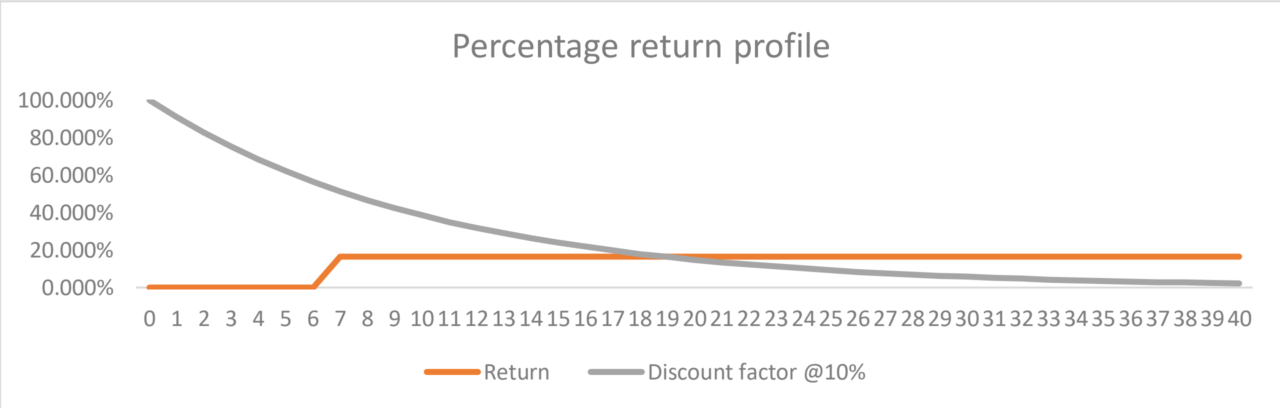


Figure 64: Percentage return profile

Construction period	7 Years	6 Years
Regulated ROE rate	Levelized return	Levelized return
16.50%	7.61%	8.38%
17.00%	7.84%	8.64%
18.00%	8.31%	9.15%
19.00%	8.77%	9.65%
20.00%	9.23%	10.16%
21.00%	9.69%	10.67%
22.00%	10.15%	11.18%
23.00%	10.61%	11.69%
24.00%	11.08%	12.19%
25.00%	11.54%	12.70%

- The levelized returns are in conformity with market expectations i.e., based on CAPM model market, mean market return of NHPC is 9.15% and of SJVN is 8.87%. Hence for public sector hydro companies, average cost of equity may be considered as 9%.
- The cost of debt for hydro power PSUs are below 7.5%. Assume tax rate is 17.47% and considering a capital structure (debt to equity ratio) is 70:30, reference WACC may be considered as 7.03%.
- Hence for PIB and CCEA clearance following parameters (mechanism) may be considered:

- The threshold of equity IRR must be determined dynamically, hence reference rate for listed hydro power PSU should be determined using CAPM model. The reference rate for unlisted hydro power PSU should be either same as of parent or equals to average threshold rates of listed hydro power PSU. Project IRR may not be made a metric for decision making.

Implementing HPO - Commercial penalties may be ensured for non-compliance

Hydro Purchase Obligation (HPO) as a separate entity within Non – solar Renewable Purchase Obligation

- Hydropower Purchase Obligation (HPO) is notified as a separate entity within Non-Solar Renewable Purchase Obligation (RPO).
- The HPO shall cover all LHPs commissioned after 08.03.19 as well as the untied capacity (i.e., without PPA) of the commissioned projects.
- This HPO will be within the existing Non-Solar RPO after increasing the percentage assigned for it so that existing Non-Solar RPO for other renewable sources remains unaffected by the introduction of HPO.

Table 26: HPO

Year	Wind RPO	HPO	Other RPO	Total RPO
2022-23	0.81%	0.35%	23.44%	24.60%
2023-24	1.60%	0.66%	24.81%	27.07%
2024-25	2.46%	1.08%	26.37%	29.91%
2025-26	3.36%	1.48%	28.17%	33.01%
2026-27	4.29%	1.80%	29.86%	35.95%
2027-28	5.23%	2.15%	31.43%	38.81%
2028-29	6.16%	2.51%	32.69%	41.36%
2029-30	6.94%	2.82%	33.57%	43.33%

- HPO benefits may be met from the power procured from eligible LHPs commissioned on and after 8.3.2019 and up to 31.03.2030 in respect of 70% of the total generated capacity (excluding free power and LADF) for a period of 12 years from the date of commissioning.
- HPO liability of the State/ Discom could be met out of the free power being provided to the State from LHPs commissioned after 08.03.2019 as per agreement at that point of time excluding the contribution towards LADF.
- In case the free power, as above, is insufficient to meet the HPO obligations, then the State would have to buy the additional hydro power to meet its HPO obligations or may have to buy the corresponding amount of Hydro Energy Certificate to meet the non-solar hydro renewable purchase obligations.
- The Hydro Energy Certificate mechanism would have a capping price of Rs.5.50/Unit of electrical energy i.e., 8th March 2019 to 31st March 2021 with annual escalation @5%, for purposes of ensuring HPO compliance.
- Hydro power imported from outside India shall not be considered for meeting HPO.

- On achievement of HPO compliance to the extent of 85% and above, remaining shortfall, if any, can be met by excess solar or other non-solar energy consumed beyond specified Solar RPO or Other Non-Solar RPO for that particular year.
- HPO compliances yet to be meet by the distribution companies.
- Commercial penalties may be enforced for not meeting the compliances. Such penalties may be reduction of return on equity. For example, for every 10% of shortfall of HPO, there should be reduction in 1% of return on equity.
- Linking HPO with free power will motivate different state governments to continue with existing regime and strongly oppose any policy which will either reduce or forego free power.
- HPO obligation should vary from state to state - keeping in view the national target and varying availability of Hydro resource in different states.

Market design for hydro power project

Striking a balance between missing money and injecting liquidity in market

Table 27: Various market design

Elements	USA	Australia	Europe
Market design	• Many hydro power stations are acting as integrated systems. • Some of the hydro power stations participate in markets	• Tariff discovery of new/ old projects happened via market. • Most of the older projects have revenue certainty as they are backed by CFD. • Most of new projects are exposed to price volatility.	• Most of the hydro power stations are old. • Some of the hydro power stations are participating via markets • Most of the hydro power stations are integrated units • There are some evidence of blending as well

- In India development of hydro power is quite tricky as all the projects needs to be developed in Himalayan region. Most of the projects are in border areas. Moreover, development of hydro power is related to flood control, irrigation etc. Therefore, it is important for hydro power projects to be developed.
- If tariff of the projects will only be discovered via market, then there will be risk of missing money.
- Therefore, following design may be proposed:
    - 70% of the capacity may be under long term PPA
    - The tariff may be determined via cost plus or governed under price quote
    - The term of PPA may be 25/30 years beyond which developers shall have the freedom to sell power in market/ blending with renewable/ new hydro power stations
- Developers may be allowed to sell 30% of power in market/ blending with renewable/ other hydro stations.

Blending hydro power with renewables (solar/wind)

Blending will help in reducing the levelized tariff and improving the saleability

- As compared to a single source, bundling combines the benefits of different sources which has been bundled and reduces variability in power supply as supply is no longer dependent on a single source.
- For example, solar power is generated from 8 AM to 6 PM. These times may vary depending on solar irradiation. Therefore, solar power may not be available during evening peak. However, hydro power stations having small pondage system may supply electricity during the said period.
- Under the revised guidelines issued by Ministry of Power, bundling with hydro power is promoted for tackling intermittency and deliver bundled power at competitive average tariffs.
- Matching of generation profiles of hydro and RE sources is essential to reduce excess power generation as is there when the total capacity being installed in such cases is more than the tied-up capacity under PPA.

Hydro power companies may be allowed to bundle power during signing fresh PPA for newly commissioned projects. This will ensure the viability of the project.

Chapter 7

Conclusion

India's Nationally Determined Contribution (NDC) captures citizen centric approach to combat climate change. Recognizing that lifestyle has a big role in climate change, the Hon'ble Prime Minister of India, at COP 26, proposed a 'One-Word Movement', to the global community. This one word is LiFE…L, I, F, E, i.e., Lifestyle for Environment. The vision of LiFE is to live a lifestyle that is in tune with our planet and does not harm it. India set a noble yet ambitious target to achieve net zero by 2070. This will require our country to shift to cleaner sources of electricity generation, which will require higher solar and wind power projects installations. Though, solar and wind generation provides cleaner alternative of power, which is marred by grid variabilities. Hydro power has the potential absorb the said variabilities. The total hydro power potential of the country is ~145 GW out of which ~46 GW have been developed till date. A lot of projects specially in Arunachal Pradesh, as on date are stranded. The hydro power companies are experiencing a moderate growth. For tapping maximum of the said potential, some key changes are required in the landscape in which hydro power development is taking place.

To start with, the project allotment process may be kept transparent and should be homogenous at national level. Though, the experience with the IPPs pertaining to development of hydro power project were not very good in the past, however, they should not be ruled out. However, any allocation to private developer may be done via competitive bidding. But, before conducting competitive bidding, balanced risk segregation framework may be finalized. CEA may also conduct basin wise study and all the projects in a basin may be allocated/awarded via auction to one developer. There are also scope of introducing means which will crash the time schedule. Such means include submission of online form based DPR, defining maximum turnaround time for every process and sub process, and introducing one stop window for getting clearances. In addition to it, participation of state government in entire process needs to be increased. State government should play an active role in organizing public hearings, conducting awareness outreach program, acquiring land, preparing, and executing a SOP based law and order maintaining program etc.

To reduce the cost of storage, concessions from state and central government may be required which will improve the saleability of power and increase the viability of the plant. Some of these concessions include CGST and SGST waiver, including the dedicated transmission line under enabling infrastructure, waiver of upfront premium, reducing royalty free power and LADF and collecting in form of monetary consideration, waiver of GST on royalty free power, if any. State should also consider waiver of water cess and state specific tax. Waiver of ISTS charges, like renewable, may also makes hydro power lucrative. An active monitoring mechanism may be introduced at state and central level. Appropriate escalation matrix at both centre and state level shall keep developers on toes.

Developers may also need to adopt innovative means of finance to fund the project in a way that completed capital cost may be minimized. In addition to it, policy interventions are required to increase the availability of capital for hydro power projects. Lenders may get tax concessions on the interest charged (till certain rate say MCLR plus 50 bps) against the loan disbursed for the development of hydro power projects. This will act as an incentive for funding hydro power projects. The sector cap may also be relaxed for funding hydro power projects. We have also analysed two different competitive bidding model i.e. Design Build Finance Own Operate (DBFOO) and Finance Own Operate (FOO). While comparing the two models, FOO competitive bidding model comes out as better option than DBFOO.

Last but not the least, resolution mechanism for stalled projects may be devised appropriately. In cases, where event of default has been triggered, state government should terminate the current allocation, even if project is deemed revert to state, and reallocate to different developer (PSU) by issuing fresh allotment agreement/MOA. In cases, where allotment agreement/ MOA is valid but event of default about to trigger, state government may observe the progress and discuss with developer. Post discussion, state government may examine if there is a case of termination or deemed revert. If there is no significant progress and current developer are not in position to develop, MOA need not to be extended. Once event of default gets triggered, state government should terminate the current allocation, even if project is deemed revert to state, and reallocate to different developer (PSU) by issuing fresh allotment agreement/MOA. Majority of the projects in Arunachal Pradesh can be resolved using such approach.

We are blessed with hydro resources, and we can utilize it in a maximum possible way. It is required to change the entire landscape for stimulating the growth in the sector.