International Hydrogen Ramp-up Programme – H2Uppp

Study on the Green Ammonia Supply Chain: Production, Storage and Export of Green Ammonia from India via seaborne transport

Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ) GmbH

Indo-German Energy Forum

As a federally owned enterprise, GIZ supports the German Government in achieving its objectives in the field of international cooperation for sustainable development.

Published by:

Deutsche Gesellschaft für

Internationale Zusammenarbeit (GIZ) GmbH

Registered offices

Bonn and Eschborn, Germany

Friedrich-Ebert-Allee 32 + 36
53113 Bonn, Deutschland
T +49 228 44 60-0
F +49 228 44 60-17 66

Dag-Hammarskjöld-Weg 1-5
65760 Eschborn, Deutschland
T +49 61 96 79-0
F +49 61 96 79-11 15
E info@giz.de
I www.giz.de

Authors:

Mr. Himadri Singha, Deloitte
Mr. Anish Mandal, Deloitte
Mr. Adhiraj Sharma, Deloitte
Mr. Purab Mohapatra, Deloitte
Mr. Shubham Munot, Deloitte

Contributors:

Mr. Kamal Katiyar, ACME Group India
Mr. Nilanjan Mahata, ACME Group India

Reviewers:

Mr. Mridul Chadha, CRISIL
Ms. Neha Makol, CRISIL
Mr. Clemens Antretter, GIZ
Mr. Kumar Abhishek, GIZ
Mr. Karan Arora, GIZ

Layout:

peppermint werbung berlin gmbh, Berlin

The International Hydrogen Ramp-up Programme (H2Uppp) of the German Federal Ministry for Economic Affairs and Climate Action (BMWK) promotes projects and market development for green hydrogen in selected developing and emerging countries as part of the National Hydrogen Strategy.

Delhi, August 2024

Foreword

Green hydrogen and its derivatives have gained momentum as agents for decarbonisation of industry, transport and power sectors worldwide. Initially, the demand is expected to come from industries such as fertiliser production and oil refining. In the long-term, sectors such as iron and steel, cement, and chemicals as well as heavy duty road transport, aviation, and shipping are foreseen to deploy green hydrogen and its derivates.

While the demand for green hydrogen and green ammonia has been showcased by several countries, including the European Union (EU) which is expected to be a major user, the supply side development can be expected by well-placed geographies that will emerge as supply hubs.

Recognising India's renewable energy capacity and green hydrogen potential, the Government of India launched the National Hydrogen Mission (NHM) in 2021 which aims to take annual green hydrogen production to a minimum of 5 million metric tonne per annum (MMTPA) by 2030 thereby capturing around 10 percent of the estimated global demand. The Government has approved the provisions of the NHM by sanctioning INR 19,744 crore (EUR ~2.18 billion) in January 2023. In January 2024, the Government through Solar Energy Corporation of India (SECI) has successfully auctioned direct subsidies for green hydrogen production, direct incentives for green ammonia production and Production Linked Incentives (PLI) for electrolyser manufacturing.

This joint study on the "Green Ammonia Supply Chain - Production, Storage and Export of Green Ammonia from India via seaborne Transport" was conducted under the International Hydrogen Ramp-Up Programme (H2Uppp) in cooperation with RWE Supply & Trading India Pvt. Ltd. It details the potential for India to produce and export green ammonia by sea to Europe along the entire value chain. Analysing the different steps of the value chain, the study offers inputs on the general framework conditions for renewable electricity supply, regulatory framework conditions for exporting green ammonia to the EU and provides further insights into the required export infrastructure and transport logistics.

The aim of this study is to increase the knowledge and expertise in India required to ramp up green hydrogen and ammonia production for exports. National and international investors shall gain additional insights into the viability of green ammonia exports from India to be better placed at making future investment decisions.

We thank the authors and partners of this study for their thorough analysis and contributions. May this work guide us on our transformative journey towards India becoming a global hub for green hydrogen production and export.

Tapas Kapadia
Chief Executive Officer
RWE Supply & Trading India Pvt. Ltd.

Table of Contents

List of Tables

List of Figures

Abbreviations

AEL	Alkaline Electrolysis
AEM	Anion Exchange Membrane
AEMEL	Anion Exchange Membrane Electrolysis
ANERT	Agency for New and Renewable Energy Research and Technology
APEPDCL	Andhra Pradesh Eastern Power Distribution Company Limited
APLDC	Andhra Pradesh State Load Despatch Centre
ARR	Annual Revenue Requirement
AS	Additional Surcharge
ASU	Air Separation Unit
ATEX	Atmosphere Explosible
BCM	Billion Cubic Meters
BEE	Bureau of Energy Efficiency
BESS	Battery Energy Storage Systems
BMWK	Federal Ministry for Economic Affairs and Climate Action of Germany
BOG	Boil of Gas
BOP	Balance of Plant
CAGR	Compound annual growth rate
CBM	Cubic Meter
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
CO2	Carbon dioxide
CSS	Cross Subsidy Surcharge
CUF	Capacity Utilization Factor
CY	Calender Year
DA	Delegated Act
DAM	Day Ahead Market
DC	Disconnect Coupler
DGVCL	Dakshin Gujarat Vij Company Limited
DM	Demineralized
DNV	Det Norske Veritas
DWT	Dead Weight Tonnage
EC	European Commission
EDG	Emergency Diesel Generator
EDI	Electro-de-ionization
EHT	Extra high tension
EIA	Environment Impact Assessment
EMS	Energy Management System
EPC	Engineering, Procurement and Construction
EMSA	European Maritime Safety Agency
EPS	Electric Power Survey
ETP	Effluent Treatment Plant
EU	European Union
FPPPA	Fuel & Power Purchase Price Adjustment

FY	Financial Year
G-DAC	Green Day Ahead Contingency
GDAM	Green Day Ahead Market
GERC	Gujarat Electricity Regulatory Commission
GHG	Green House Gas
GIZ	Deutsche Gesellschaft für Internationale Zusammenarbeit
GNH3	Green Ammonia
GRIDCO	Grid Corporation of Odisha
GTAM	Green Term Ahead Market
GUVNL	Gujarat Urja Vikas Nigam Limited
GW	Giga Watt
HIS	Information Handling Services
HP	High Pressure
HPX	Hindustan Power Exchange
HT	High Tension
IACS	International Association of Classification Societies
IEA	International Energy Agency
IEX	Indian Energy Exchange
IGC Code	The International Code of the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk
IGEF	Indo-German Energy Forum
IMO	International Maritime Organization
INR	Indian Rupees
InSTS	Intra State Transmission System
ISGOTT	International Safety Guide for Oil Tankers and Terminal
ISO	International Organization for Standardization
ISTS	Inter State Transmission System
JNPT	Jawaharlal Nehru Port Trust
KOH	Potassium Hydroxide
KSEB	Kerala State Electricity Board
KSERC	Kerala State Electricity Regulatory Commission
KTPA	Kilo Tonnes per Annum
LOA	Length Overall
LCOA	Levelised Cost of Ammonia
LCOH	Levelised Cost of Hydrogen
LCOS	Levelised Cost of Storage
LGC	Large Gas Carriers
LP	Low Pressure
LPG	Liquified Petroleum Gas
LV	Low Voltage
MCR	Main Control Room
MERC	Maharashtra Electricity Regulatory Commission
MGC	Medium Gas Carriers
MGO	Marine Gas Oil

MJ	Mega Joule
MLD	Million Liters per Day
MMTPA	Million Metric Tonnes Per Annum
mmWC	Millimeters of Water Column
MNRE	Ministry of New and Renewable Energy
MoEF	Ministry of Environment and Forests
MSEDCL	Maharashtra State Electricity Distribution Company Limited
MT	Metric Tonne
MU	Million Units
MW	Mega Watt
MWh	Mega Watt hour
MYT	Multi Year Tariff
NASDAQ	National Association of Securities Dealers Automated Quotations
NH_3	Ammonia
NHDC	National Handloom Development Corporation
NHM	National Hydrogen Mission
NHPC	National Hydroelectric Power Corporation
NREDCAP	New & Renewable Energy Development Corporation of Andhra Pradesh
NTPC	National Thermal Power Corporation
OCIMF	Oil Companies International Maritime Forum
OEM	Original Equipment Manufacturer
OERC	Odisha Electricity Regulatory Commission
PCKL	Power Company of Karnataka
PED	Pressure Equipment Directive
PEM	Proton Exchange Membrane
PEMEL	Polymer Electrolyte Membrane Electrolysis
PLI	Production Linked Incentive
PMC	Project Management Consultancy
PPA	Power Purchase Agreement
PPE	Personal Protective Equipments
PSA	Pressure Swing Adsorption
PSP	Pumped Storage Projects
PTL	Porous Transport Layer
PUF	polyurethane foam
PV	Photo Voltic
PXIL	Power Exchange of India Limited
QC	Quick Connect
RE	Renewable Energy
RED	Renewable Energy Directive
RES	Renewable Energy Sources
RFNBO	Renewable Fuels of Non-Biological Origin
RFP	Request for Proposal
RO	Reverse Osmosis
RPO	Renewable Purchase Obligation
RTC	Round-the-Clock

RVUNL	Rajasthan Rajya Vidyut Utpadan Nigam Limited
RWE	Rheinisch-Westfälische Elektrizitätswerk
SECI	Solar Energy Corporation Of India
SEZs	Special Economic Zones
SGST	State Goods and Service Tax
SIGHT	Strategic Interventions for Green Hydrogen Transition
SIGTTO	Society of International Gas Tankers and Terminals Operators
SJVN	Satluj Jal Vidyut Nigam
SLM	Straight Line Method
SOE	Stage of Ground Water Extraction
SOEC	Solid Oxide Electrolyser Cell
SOEL	Solid Oxide Electrolysis
SOLAS	International Convention for Safety of Life at Sea
SOPs	Standard Operating Procedures
SPE	Solid Polymer Electrolyte
STU	State Transmission Utility
SWRO	Sea Water Reverse Osmosis
TANGEDCO	Tamil Nadu Generation and Distribution Corporation
TPCODL	Tata Power Central Odisha Distribution Limited
TPOA	Third Party Open Access
TSA	Temperature Swing Adsorption
UPNEDA	Uttar Pradesh New and Renewable Energy Development Agency
USA	United States of America
USD	United States Dollar
UV	Ultraviolet
VGF	Viability Gap Funding
WDV	Written Down Value

1 Executive Summary

With the European Green Deal announced in 2019, Europe was the first to declare its ambition to be a climate-neutral continent by 2050. It was one of the main drivers of the 2015 Paris Agreement and it set the target of reducing its emissions by 40% compared to the levels in 1990 by 2030. Various directives, regulations and legislative packages have been introduced since then to fight climate change.

Hydrogen is primary to climate-neutrality across all sectors of the economy and a resilient energy system. The "Fit for 55" package, launched in July 2021, is the first step into this direction laying down the rules for the production and use of renewable hydrogen. Later, in May 2022, the Commission launched REPowerEU in response to the global energy market disruption caused by Ukraine crisis; it was intended to reduce Europe's dependence on Russian Oil and Gas and tackle the climate crisis. This plan targets 45% penetration of renewable energy in Europe by 2030. On green hydrogen, the target was to produce 10 million MT and to import 10 million MT by 2030. It also envisages to deploy a Carbon Contracts for Difference (CCfD) to create a green hydrogen market.

A key element in the 'fit for 55' package is the revision of the Renewable Energy Directive to help the EU deliver the new 55 % GHG target. The Renewable Energy Directives were launched in 2009 setting a renewable energy target of 20% by 2020. The minimum targets, which varied between Member States, collectively ensured that the overall EU-level target of 20% would be met. The RED II came into effect in 2018 with a target of 32% renewable energy target by 2030 which was further amended in October 2023 (RED III) with a target of 42.5% at the EU level by 2030.

Key to the implementation of renewables across Europe, is to utilize renewable fuels of non-biological origin (RFNBO), commonly referred to as renewable hydrogen, in sectors where direct electrification is not possible. RED II defined RNFBO as "liquid or gaseous fuels which are used in the transport sector other than biofuels or biogas, the energy content of which is derived from renewable sources other than biomass"; RED III set out Union-wide targets for the use of RFNBO in the industry at 42% by 2030 and 60% by 2035.

The EU policy framework was completed with 2 delegated acts, formally adopted in June 2023, applicable to renewable hydrogen under the Renewable Energy Directive. The first one covers renewable fuels of non-biological origin (RFNBOs) and sets the criteria for products that fall under the 'renewable hydrogen' category. The other one puts forward a detailed scheme to calculate the life-cycle emissions of renewable hydrogen and recycled carbon fuels to meet the greenhouse gas emission reduction threshold set in the directive. Therefore, any Indian project aiming to export green hydrogen to EU has to comply with the criteria defined under RED II.

In the above context, this study has been commissioned to assess the viability and potential for India to produce and subsequently export green ammonia by sea from India to Europe along the entire value chain. The study dives deep into the regulatory framework conditions for trading (green) ammonia, followed by a techno-economical scoping for a green ammonia project (600kt/yr.) in India and a study on the required transport and port infrastructure for both exporting ammonia and using ammonia for shipping.

Regulatory framework in EU defined the sustainability criteria and emission threshold for producing RFNBO

The first Delegated Act to Article 27 of RED II defines three criteria i.e., additionality, temporal correlation, and geographical correlation. The principle of additionality aims to ensure that electrolysers to produce hydrogen will have to be connected to new renewable electricity production. This delegated act further introduces criteria aimed to ensure that renewable hydrogen is only produced when and where sufficient renewable energy is available, known as temporal and geographic correlation. As part of this framework, hydrogen producers will have to match their hydrogen production with their contracted renewables on a monthly basis until January 2030; a stricter norm will be introduced post 2030.

The second Delegated Act to Article 28 of RED II provides a methodology for calculating life-cycle greenhouse gas emissions for RFNBOs. The methodology takes into account greenhouse gas emissions across the full lifecycle of the fuels, including upstream emissions, emissions associated with taking electricity from the grid, from processing, and those associated with transporting these fuels to the end-consumer. The act defines the maximum GHG emission intensity threshold for RFNBOs as 70% below a fossil fuel comparator of 94 gCO2eq/MJ. This translates to ~3.4 tCO2eq./ton emission threshold for hydrogen. Given the hydrogen content in Ammonia, the emission threshold for Ammonia turns out to be **~0.61 tCO2eq./ton**.

Options for Green Ammonia production in India to export to EU

Any Indian project aiming to export green ammonia to EU has to comply with the above regulations as stipulated in the Renewable Energy Directive. Based on the emission intensity threshold and the criteria of additionality, temporal & geographical correlations, multiple setups for green ammonia production can be configured. The electricity sourcing options range from off-grid electricity production to a combination of off-grid and grid electricity.

Further, five locations have been analysed for setting up the 600 ktpa green ammonia plant – Gujarat (Kandla region), Andhra Pradesh (Vizag region), Kerala (Cochin), Maharashtra (Mumbai) and Odisha (Gopalpur). The study analysed the current power mix of these states, industrial HT tariff and regional grid emission intensities, which varies from 680 g/kWh to 875 g/kWh.

Based on the emission intensity threshold and the criteria of additionality, temporal & geographical correlations, the study evaluates four (4) setups for green ammonia production. It is important to note that EU allows maximum GHG emission intensity threshold for green hydrogen as ~3.4 tCO2eq./ton emission threshold for hydrogen, which translates to an emission threshold for Ammonia as **~0.61 tCO2eq./ton**.

In general, shipping emission from any Indian port to major European port, such as Hamburg and Rotterdam via suez canal is expected to be 0.080 – 0.085 tonne CO2/ton of ammonia. Therefore, considering India's national as well regional grid intensity, RED would allow 6.5 – 7.5% sourcing of grid electricity and still be compliant with the EU norms.

The options for RE procurement are:

- **Option 1** (Off-grid arrangement): In an off-grid setting, the power for the electrolyser and the ammonia loop must be sourced from a solar-wind hybrid power plant with storage to mitigate the intermittency of RE sources. This is an island solution with no grid connection.
- **Option 2** (Co-located RE+BESS+ Permissible Grid+GDAM): With a grid connection, the intermittency from the RE sources can be mitigated through power procurement from the grid. During non-solar hours, the power from grid can be used to ensure constant feed of hydrogen to the ammonia loop. However, a procurement from the grid cannot be beyond the permissible thresholds to meet EU RED guidelines.
- **Option 3** (Co-located RE+BESS+ Unconstrained Grid+ GDAM): In this option sourcing of electricity from Grid is not constrained; therefore, the entire production cannot be sent to Europe/ be labelled as green. The quantum of ammonia production attributable to excess grid power consumption than permissible would be termed as grey.
- **Option 4** (BEST RE+BESS+ Permissible Grid+GDAM): In place of co-located RE capacities, the solar generation from Northern region (Rajasthan profile) and wind generation from Southern region (Tamil Nadu profile) is considered for electrifying the electrolyser and ammonia loop along with permissible grid power (as per emission norms) and GDAM procurement.

Methodology for Sizing optimisation

Optimising the green ammonia production configuration is crucial to minimise the levelised cost of ammonia. **An advanced excel based optimisation tool (using Open Solver) has been developed, which minimises the annual cost of operating the ammonia plant.** The annual cost has two components: (1) the annualised fixed cost of solar, wind, BESS, electrolyser, and hydrogen storage and (2) the operational expenses including power procurement from the grid and GDAM.

The tool optimises the size of RE capacity, grid power to be sourced, battery storage capacity, hydrogen storage capacity and hydrogen storage capacity. RE generation profile, annual fixed cost of technologies (RE, electrolyser, BESS, H2 storage etc.), continuous flow of hydrogen to ammonia loop, T&D charges, grid tariff and GDAM tariff are provided as input in the optimisation algorithm. Key outputs are sizing of technologies and electrolyser CUF. Based on the sizing of technologies, Levelised Cost of Ammonia (LCoA) is determined through a financial model.

Option 4 is likely to be the most practical and cost-effective option to produce green ammonia. Barring a few regions, the strong presence of both solar and wind generation profiles is not available across all regions in India. Keeping it in view, a simulation has been run for all the identified locations to understand the sizing requirement with best solar and wind profile available in India. However, this would attract the additional cost of transmission system (STU charge). **The solar profile of Northern India (Rajasthan) and Wind profile of Southern India (Tamil Nadu) have been considered for modelling the results**.

Gujarat and Andhra Pradesh are the two most preferred states for setting up Green Ammonia facility. However, there may be tailor made incentives on capex, electricity cost and provision of common infrastructure. Selection of the right state should be done based on the real impact on LCOA from the state specific incentives. Key observations on all the options are:

- **Option 1** (Off-grid island solution) is the highest cost (LCOA) option for all states due to large scale requirement of energy storage.
- **Option 2** (with permissible grid sourcing) optimises the LCOA by 10 – 20%, depending on regional grid tariff, by minimising the requirement of battery storage.

- **Option 3** (no constraint on sourcing of grid power) could offer incremental benefits over Option 2; however, acceptance of hydrogen in EU with emission footprint higher than the threshold indicated in RED II could be a challenge. In addition, grey ammonia market is not likely to pay a premium for a low carbon ammonia
- **Option 4** (Best RE profile and permissible grid sourcing) is the most logical and practical option for any green ammonia developer. However, this may attract additional state specific transmission charge.

Comparison of LCOA across all the options are provided below:

State	LCOA (USD/ton)				Remark
	Option - 1	Option - 2	Option - 3	Option -4	
Gujarat	1030	924	924	916	Gujarat is one of the most sought after state with respect to resource availability, port infrastructure, state level policies and ease of doing business. The state has one of the best solar and wind potential in the country. Also, in order to serve European market, Gujarat ports are better placed than other ports.
Andhra Pradesh	1080	930	922	936	Southern region also has reasonably good solar and wind profile. AP also ranks good in ease of doing business, has good port infrastructure and lower industrial tariff.
Kerala	1190	1023	1000	1027	Wind and solar profile in these regions are not the best in country and low wind periods call for either deployment of battery storage or sourcing of power from grid. Grid power as well as transmission charges are higher in these states.
Maharashtra	1350	1114	1110	1051	
Odisha	1340	1098	1065	933	

Some of the major considerations of this optimisation exercise are:

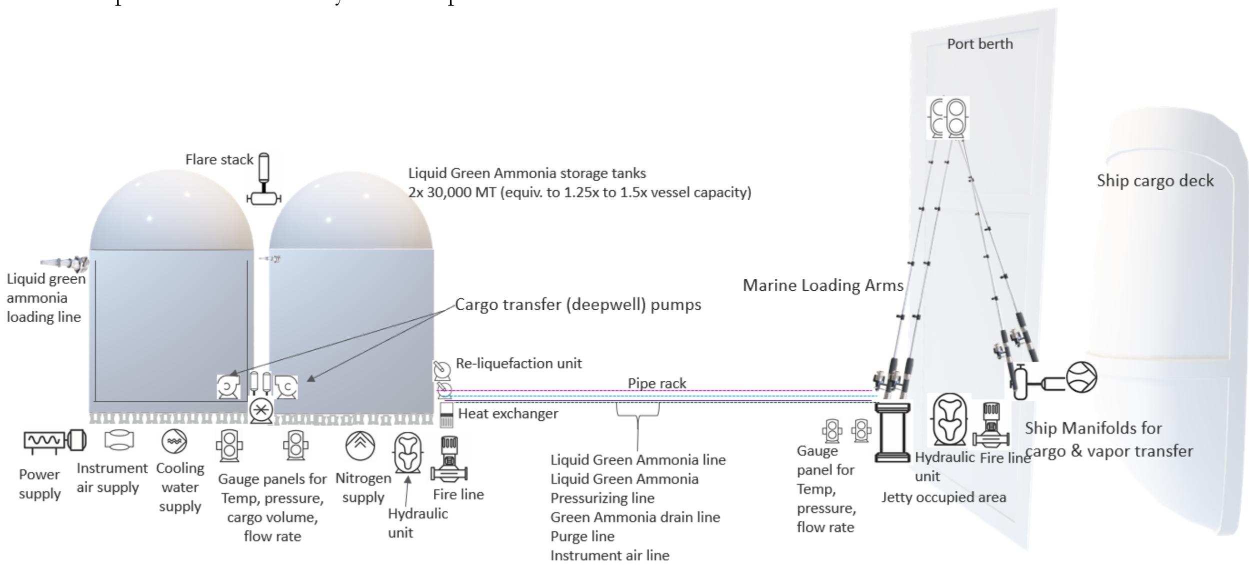
- This optimisation doesn't include any incentive or subsidy in capex or T&D charges
- However, several states have announced support measures which would reduce the cost of development. For example, **~15% capex subsidy would reduce the LCOA by USD 60 – 70/ton and a 30% capex subsidy results in bringing LCOA down by USD 120 – 140/ton**.
- Any subsidy in the transmission charge would further optimise the cost of production – INR 1/kWh (US cents 1.2 per kWh) reduction in landed cost of electricity would reduce **LCOA by ~USD 120/ton**
- No flexibility has been considered in **Ammonia loop operation.**

Assessment of Export infrastructure

Ammonia imports in bulk are reported to be handled at 12 seaports in India located at Kandla, Sikka, Dahej, Mormugao, Mangalore, Cochin, Haldia, Paradip, Visakhapatnam, Kakinada, Ennore and Tuticorin. These ports have the necessary marine infrastructure needed to handle ships which are being used for export/imports of ammonia. With dedicated cargo handling infrastructure comprising of pipelines from ammonia storage tanks located at the site of green ammonia production plant to the dedicated marine loading arms units which may be set up at the respective port's berth, seaborne exports of green ammonia may prove to be a techno-economically viable option. It is further relevant to highlight that all the ports are giving priority to handling green cargo. Therefore, the opportunity of handling 0.6 MMTPA of green ammonia cargo shipments would invite interest from all the above listed ports. Also, with the increasing focus on deepening the ports marine facilities, the port's cargo handling capacity also increases. This shall make it a viable proposition for all major ports to attract the proposed 0.6 MMTPA green ammonia cargo volumes. Besides, all major ports handle LPG shipments at one or multiple berths. The ports will be incentivized to increase cargo handling volumes of liquefied gases by requisite planning of their respective berths' occupancy.

Storage tanks for refrigerated green ammonia may be established at the port if direct pipelines connectivity from the site of ammonia production plant to the port berth is not feasible. A dedicated pipe rack comprising of liquid green ammonia line, liquid green ammonia pressurizing line, green ammonia drain line, purge line and instrument airline may be needed to be set up between the ammonia storage tanks and the port berth. The cargo carrying pipelines may be connected with dedicated marine loading arms installed at the port's berth. These marine loading arms may be accompanied with gauge panels for temperature, pressure and flow rate. Two marine loading arms to enable loading of green ammonia into vessels calling upon the port may be needed to be set up at the port's berth. The marine loading arm may need to be OCIMF compliant w.r.t. the design, fabrication, material, inspection, and testing requirements. Hydraulic panels facilitating transfer of green ammonia to the vessel's cargo manifolds via marine loading arms may be needed to be in place. Required firefighting infrastructure may be needed to be established at the berth.

A visual representation of the layout for export infrastructure is illustrated below:



The main risk prone areas on board ships when transporting green ammonia include storage tanks, tank hold spaces, tank connection space, fuel preparation rooms, bunkering stations, spaces containing liquid or gaseous ammonia piping and vent mast. To mitigate the potential risks for seafarers and onboard equipments, compliance towards safe working practices as outlined in the International Safety Guide for Oil Tankers and Terminals (ISGOTT) , Society of International Gas Tankers and Terminals Operators (SIGTTO), International Code for the construction and equipments of ships carrying liquefied gases in Bulk (IGC Code), Safety of Life at Seas (SOLAS) and International Maritime organization (IMO) may need to be ensured.

With increasing focus on green shipping; green ammonia as marine fuel is likely to gain increasing demand from deep sea shipping vessels. Green ammonia as bunker can be supplied using marine loading arms set up at the port berth for ships that can be brought alongside the berth. Alternatively, green ammonia may be filled in bunker supply vessels which can fulfil bunkering requirements of ammonia powered ships located at alternate port berths/offshore locations. Green ammonia may be filled in bunker supply vessels from the marine loading arms. As per their assessments of IACS member firms ammonia supply vessels having semi-refrigerated ammonia tanks may provide larger capacity than those supply vessels which have pressurized ammonia tanks. Further ammonia bunker supply vessels having semi refrigerated tanks offer greater flexibility when bunkering ships with semi-refrigerated fuel tanks and owing to a limited cost premium.

Most ammonia is currently shipped long distances via Medium Gas Carriers (MGCs) with 25,000 -50,000 m^3 cargo carrying capacity and Large Gas Carriers (LGCs). For illustration purposes, seaborne transportation costs for exports of green ammonia via Suez Canal between Kandla (India) to Hamburg (Germany) and Paradip (India) to KrK (Croatia) using MGCs are estimated to range between \$2.4mn -\$2.9mn and between \$2.1mn-\$2.5mn respectively. If the shipments are made in LGCs the respective costs increase by \$0.3mn-\$0.5mn. For the voyages that transverse Cape of Good Hope rather than Suez Canal; the seaborne transport costs of exports of green ammonia between Kandla (India) to Hamburg (Germany) and Paradip (India) to KrK (Croatia) using MGCs are estimated to range between \$3.4mn -\$4.2mn and between \$3.6mn -\$4.4mn respectively. If the shipments are made in LGCs the respective costs increase by \$0.3mn-\$0.6mn.

2 Introduction

Globally, green hydrogen and its derivatives have gained wide recognition as decarbonisation agents for industry, transport and shipping sectors. Many countries have announced hydrogen strategy, roadmap, targets and several support measures. Future hydrogen demand is expected to see a dramatic rise. As projected by prominent agencies, hydrogen demand could reach 500–660 MTPA by 2050. The proportion of low carbon hydrogen is expected to increase significantly as most of the new demand will come from new applications to meet the emission reduction targets. Initially, the demand is expected to come from greening of existing industrial uses of hydrogen, notably for fertiliser production and refinery applications. However, in the medium to long-term, new industry sectors (iron and steel, chemicals, and cement) and transportation (aviation, shipping, and heavy road transport) are expected to drive the demand of green hydrogen.

While the demand side use cases have been clearly laid out by several countries, supply side development is expected to be supported by specific geographies emerging as supply hubs. These hubs are characterised by availability of low cost renewables, robust port infrastructure and supportive regulations and incentives. Such hubs could create a foundation for global trading markets, by meeting domestic demand and exporting any surplus production to regions that require (and will pay for) economically viable clean hydrogen. As analysed by the International Energy Agency (IEA), the Middle East, North Africa, India, Chile, and Australia are expected to have low production cost.

Recognizing the country's green hydrogen potential, in 2021, the Government of India launched the National Hydrogen Mission (NHM), which was followed by the release of the National Green Hydrogen Policy. The government approved the provisions of NHM by sanctioning INR 19,744 crore (USD 2.37 Bn) in January 2023. The mission aims to take annual green hydrogen production to a minimum of 5 MMTPA by 2030 and capture 10 percent of the global demand (expected to become 100 MMTPA by 2030).[1] In January 2024, the Government (through SECI – Solar Energy Corporation of India) has successfully auctioned direct subsidy for green hydrogen production and Production Linked Incentive (PLI) for electrolyser manufacturing.

In the hydrogen economy, Ammonia plays a pivotal role. Ammonia is widely considered to be a more cost-effective method of shipping hydrogen than pure liquid or compressed hydrogen. This is due to its high energy density by volume and relative ease of handling. In addition, ammonia also has direct uses in Fertiliser and Shipping. However, the hydrogen-ammonia-hydrogen process entails an additional cost towards ammonia synthesis and energy loss during the re-conversion process.

The European Union is expected to be a major user of green hydrogen or ammonia driven by its ambitious plans, such as Fit-for-55, RePowerEU etc. These plans have laid out objective targets for consumption and sourcing of low carbon hydrogen or ammonia. In addition, Renewable Energy Directive – II (RED – II) delegated acts specify the stringent requirements for certifying hydrogen or ammonia as green.

As per current scenario, green ammonia is costlier than grey ammonia even after penalizing for carbon emission in EU. Therefore, it is important to produce green ammonia in a cost effective manner by optimising cost of electricity and capex. A techno-economic assessment is necessary to assess the economics of production and to ensure emission intensity is compliant with Delegated Act in EU.

In this context, GIZ, in partnership with RWE Supply & Trading GmbH has conducted this comprehensive study to assess the viability and potential for India to produce and subsequently export green ammonia by sea to Europe along the entire value chain. The study consists of different parts which analyse different steps in the value chain. These include:

- General framework conditions for renewable electricity supply, water supply and further investment framework conditions.
- Regulatory framework conditions for exporting (green) ammonia to EU.
- A techno-economical scoping for a green ammonia project (600kt/yr.) in India and
- A study on the required transport and port infrastructure for both exporting ammonia and using ammonia for shipping.

It is important to note that in a prior study by IGEF (Indo-German Energy Forum) titled "Market Study & location assessment for green ammonia production in India"[2], clusters for green ammonia were identified in the states of Gujarat, Maharashtra, Andhra Pradesh, Uttar Pradesh, and Kerala. Considering the recent project developments, Odisha has also been included in the analysis.

[1] Source: India National Hydrogen Mission document

[2] IGEF. Market Study & location assessment for green ammonia production in India. (access here)

Each of the selected state has been assessed basis certain general framework conditions which include renewable energy, water supply and further conditions viz. land, suppliers, and sustainability dimensions. In addition to these general framework conditions, the states are also assessed for specific framework for Green Ammonia based on RED II delegated acts.

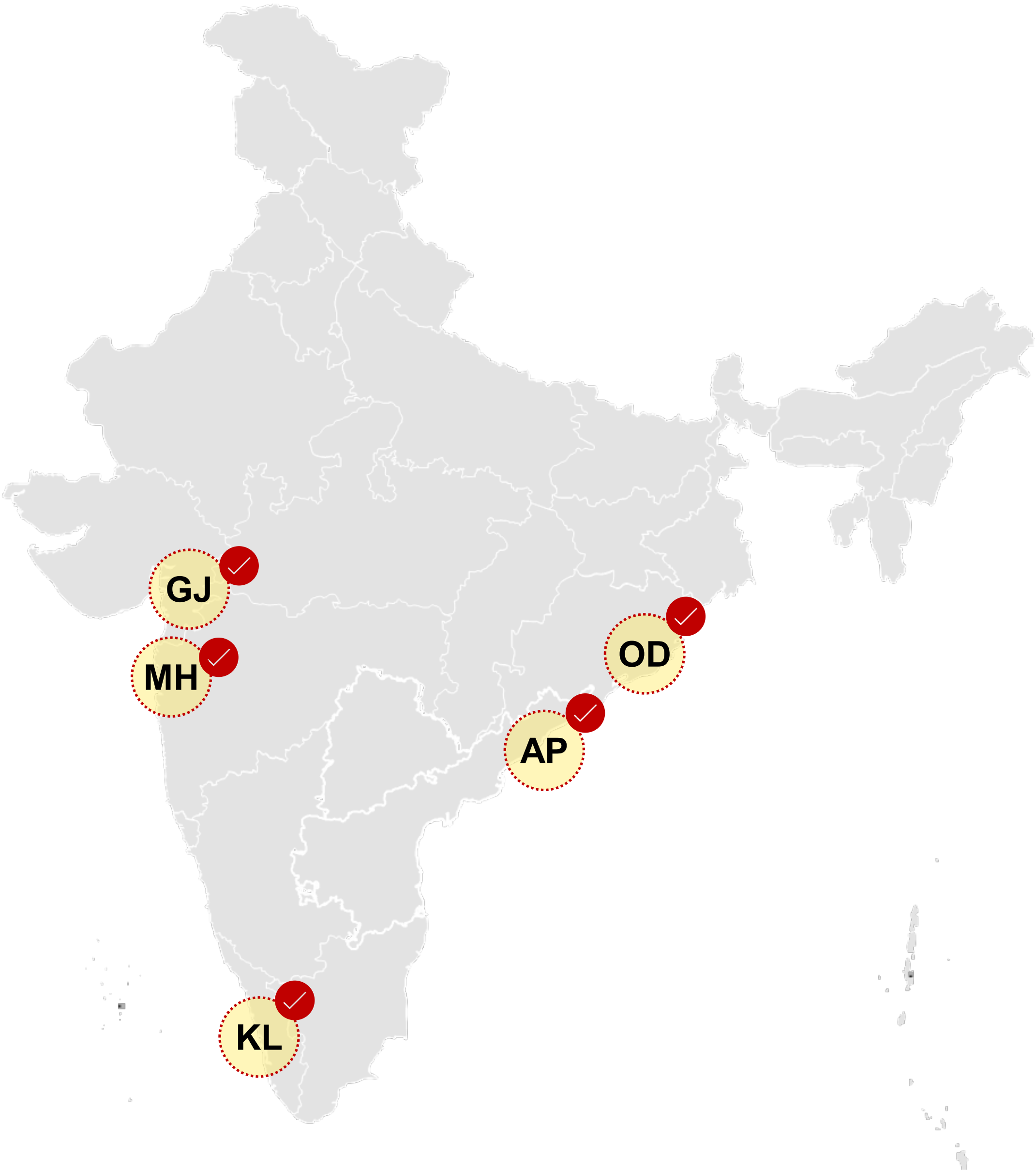


Figure 1: Selected states for assessment

3 General framework conditions

Availability of cheap renewable energy and water are two crucial parameters for green ammonia production. In addition, availability of land and local suppliers is also important for sustained operation of green ammonia production. Keeping these in view, the target states have been studied on the three parameters – Power mix and RE landscape, water source and availability, and land & ecosystem availability.

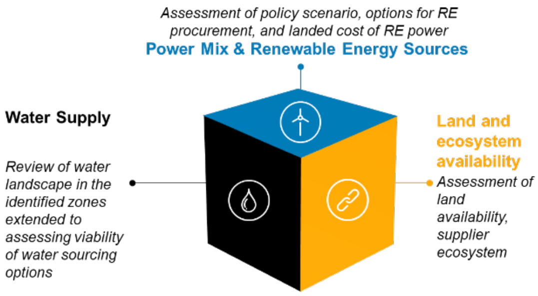


Figure 2: Elements of general framework conditions

In each state, distribution utilities have their tailored power procurement strategies which includes different fuel technology procured from central, state, and independent power producers. Basis this fuel mix, the emission intensity of states would vary. Similarly, the availability of water in the regions would depend on availability of rivers and ground water. In case of unavailability of river and ground water, seawater can be sourced with integrated desalination plant. Availability of SEZs and industrial complexes around the suggested regions would be preferred locations for green ammonia production.

3.1 Power mix and renewable energy sources

The power sector in India has transitioned from situations of power deficit to near surplus in the last decade. Power deficit of ~9% in FY13 (fiscal year) has been reduced to more than half to ~3.7% in FY23 with historic low of ~0.4% in FY21.

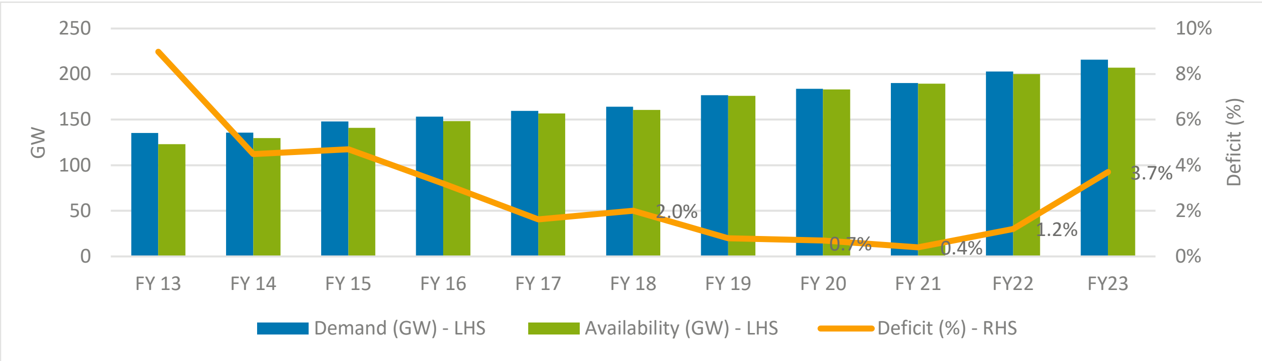


Figure 3: Electricity demand, availability and deficit in Indian power market[3]

The reduction in power deficit can be attributed to the growth in the installed capacity of the nation from ~223 GW in FY13 to ~416 GW in FY23. The majority of the capacity additions have been through the private sector (other than central and state entities) and through the renewable energy routes.

[3] CEA Annual report (access here)

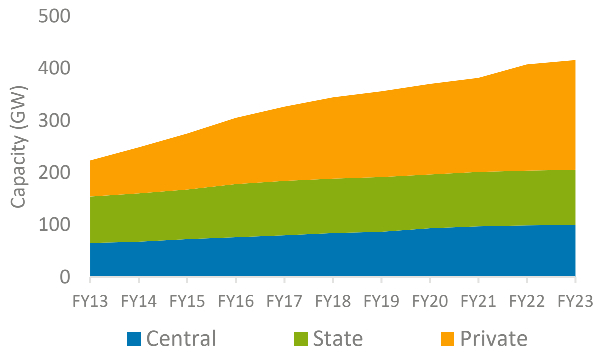


Figure 4: Capacity addition trajectory[3]

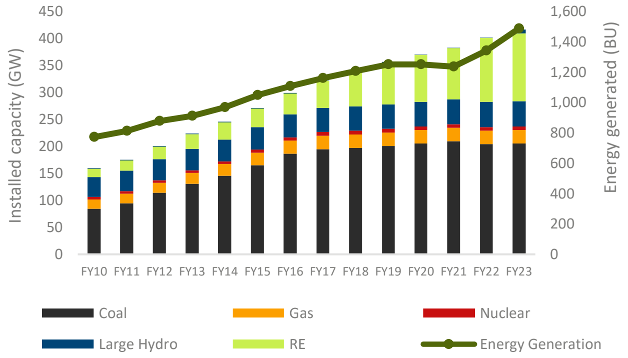


Figure 5: Source wise capacity breakdown[3]

As of FY23, more than half of the installed capacity was added by the private sector (51%) and the share of renewable energy in the overall energy capacity has grown up to 30%. Over the years, there has been a noticeable shift in the share of electricity generation across various sources in the region. In FY02, thermal power dominated the landscape with an 82% share, while hydro and nuclear sources contributed 14% and 4%, respectively with no contribution from RE sources. In FY23, the landscape has evolved significantly. Although thermal power still holds a substantial share at 74%, there is a notable increase in the contribution of renewable sources, reaching 13%. According to CO2 baseline database for the Indian power sector, weighted average emission factor of the Indian grid for FY22 (including cross-border power transfers and inclusive of RES) is **0.711 t CO2/MWh**[4].

State wise emission intensities have been estimated based on current power mix – coal, gas, hydro and renewables. Different emission intensities have been considered for different technologies - 1049 g CO2/kWh for lignite (mean), 975 g CO2/ kWh[4] for Hard coal (old) and 340 g CO2/kWh for natural gas (new combined cycle gas turbine)[5].

3.1.1 State wise grid power mix

The five (5) states being studied have multiple distribution companies (Discoms) serving residential as well as industrial consumers. Specific Discoms are responsible for serving the locations considered in each of the states as indicated below:

Table 1: Probable plant location and Discoms serving the load in those areas for target States

Sl.	State	Probable plant location	Discom service area
1.	Andhra Pradesh	Kakinada, Vishakhapatnam	APEPDCL
2.	Gujarat	Kandla, Sikka, Jamnagar, Hazira	DGVCL
3.	Kerala	Kochi	KSEB
4.	Maharashtra	Thal, Trombay, Taloja	MSEDCL
5.	Odisha	Paradip, Gopalpur	TPCODL

Each of the discoms have specific emission intensity based on power purchase mix, and tariffs prescribed for industrial consumers at different voltage levels. Industrial tariffs have been calculated as per latest available tariff orders and state specific regulations.

3.1.1.1 Andhra Pradesh (APEPDCL)

APEPDCL (Andhra Pradesh Eastern Power Distribution Company Limited) procured ~29 BU of electricity in FY24[6]. The power procurement mix and trend for HT tariffs in the state are illustrated below:

[4] CEA, CO2 baseline database for the Indian power sector (access here)
[5] Volker Quaschning 2024 (access here)
[6] As per Tariff Order

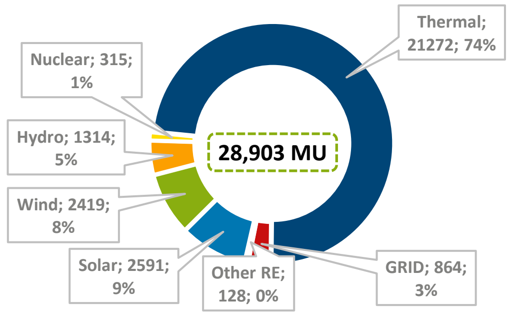


Figure 6: Power procurement mix for APEPDCL in FY24 (MU)[7]

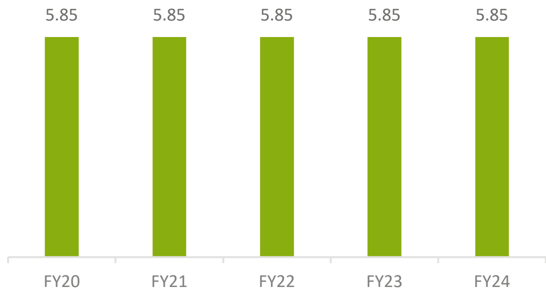


Figure 7: HT tariffs offered by APEPDCL (INR/kWh)[7]

The state meets ~74% of its demand through thermal power stations (including central and state generators); renewables (including large hydro) contributes ~22%, followed by another ~3% contributed by power exchanges. Emission intensity of exchange procured power is considered as the national average of India[8]. The emission intensity of the Discom is estimated to be ~191 gCO2eq./MJ or 0.688 tCO2eq./MWh.

HT tariff in APEPDCL is one of the most competitive tariffs among the states in the country and has remained same in last five (5) tariff orders. The stated tariffs include an electricity duty of 10 paise/kWh which has been outlined by the state and the fuel price adjustment component of 40 paise/unit stated by the regulatory commission on a yearly basis. APEPDCL also offers a green tariff at a premium of **INR 0.75/kWh**. Grid green tariff is a mechanism to ensure that the power served to the consumers is attributable to renewable energy procured by the Discom. As per the regulatory regime of Andhra Pradesh, all consumers other than function halls/ auditoriums[9] are eligible for green tariff.

3.1.1.2 Gujarat (DGVCL)

The power procurement in Gujarat on behalf of the four (4) Discoms is carried out by GUVNL, the holding company for all Discoms. The power mix of GUVNL and the HT tariff trend of DGVCL are captured below:

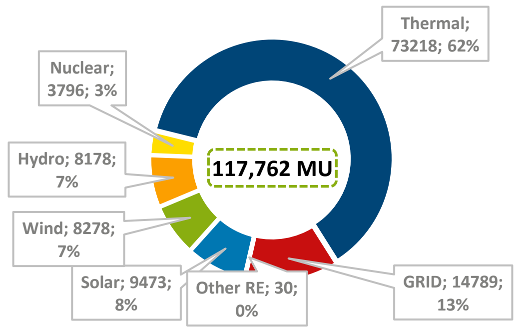


Figure 8: Power procurement mix for GUVNL in FY24 (MU)[10]

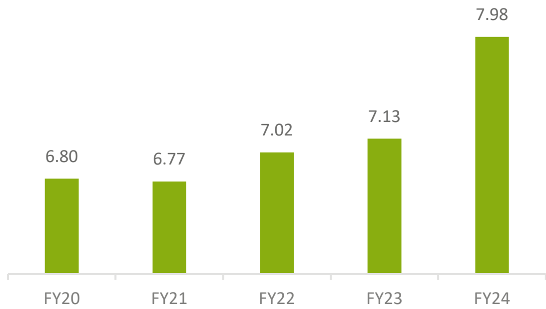


Figure 9: HT tariffs offered by DGVCL (INR/kWh)[10]

Despite being endowed with rich renewable resources, the state of Gujarat depends on fossil fuel-based energy for ~62% of its electricity and on exchange power for 13% electricity. Renewable and nuclear contributes another 22% and 3% respectively. With the current power mix, the emission intensity of DGVCL grid is ~194 gCO2eq./MJ or 0.699 tCO2eq./MWh.

The tariffs of DGVCL (as shown in Figure 9) are inclusive of the FPPPA (fuel & power purchase price adjustment) which is additionally charged to the HT industrial consumers and the electricity duty of 15% on the power procurement cost of the consumer. The tariff has increased at a CAGR of ~4.1% from FY20 to FY24 and the state also provides a green tariff at a

---

[7] APEPDCL retail supply tariff (access here)
[8] 0.711 tCO2/MWh
[9] Category II(A) (iii); as per ARR filings of FY24 of APEPDCL
[10] GERC, DGVCL. Truing up for FY 2021-22 and Determination of Tariff for FY 2023-24. (access here)

premium of INR 1.5/kWh. All EHT (extra high tension), HT (high tension), and LV (low voltage) consumers in the state of Gujarat are allowed to procure grid green power.

3.1.1.3 Kerala (KSEB)

As per the regulatory filings with KSERC (Kerala State Electricity Regulatory Commission), the power procurement mix and the trend in HT tariffs offered by KSEB (Kerala State Electricity Board) are indicated below.

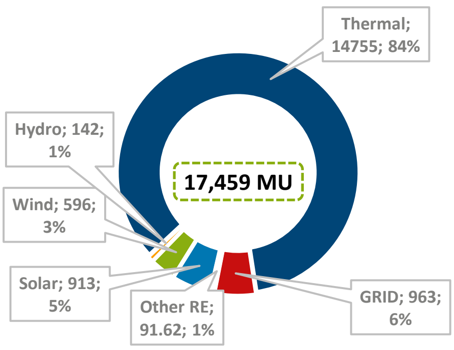


Figure 10: Power procurement mix of Kerala in FY24[11]

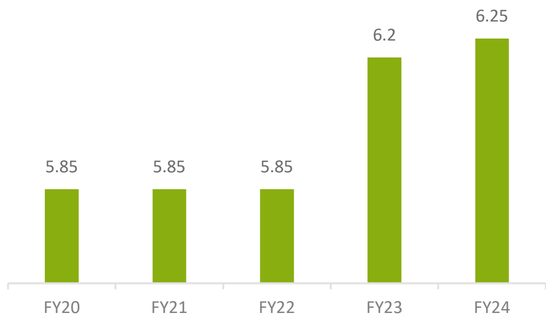


Figure 11: HT tariffs offered by KSEB (INR/kWh)

Fossil fuel-based power procurement (including power exchange) amounts to ~90% of the electricity demand and another 10% is contributed by various RE sources. The emission intensity of the state, based on the current mix, is **~242 gCO2eq./MJ or 0.873 tCO2eq./MWh**.

The HT tariff from KSEB has risen in the recent years after being stagnated for last three years (2020 – 2022) including the FPPPA (9 – 10 paise/kWh) and electricity duty (10 paise/kWh) in the state. The green tariff is offered to consumers with a premium of INR 0.77/kWh over the general tariff.

3.1.1.4 Maharashtra (MSEDCL)

MSEDCL (Maharashtra State Electricity Distribution Company Limited) serves more than 80% of the state's electricity demand[12]. The power mix and trend of HT tariffs for the utility are shown below:

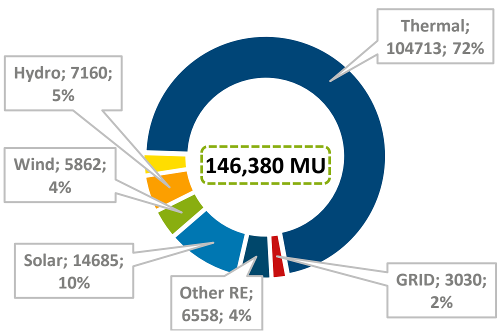


Figure 12: Power procurement mix of Maharashtra in FY24[13]

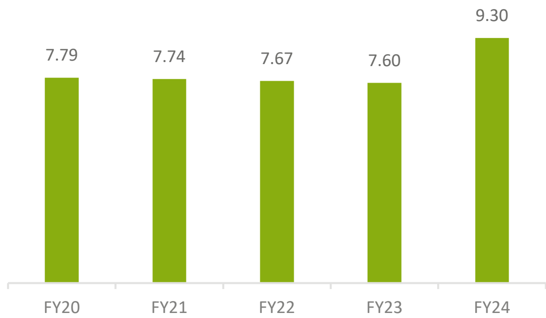


Figure 13: HT tariffs offered by MSEDCL (INR/kWh)

[11] KSERC, Interim order in the matter of 'schedule of tariff and terms and conditions for retail supply of electricity with effect from 01.11.2023 to 30.06.2024' (access here)

[12] As per the 20th EPS Survey

[13] MERC, Case of Maharashtra State Electricity Distribution Company Limited for Final True Up of FY 2019-20, FY 2020-21 & FY 2021-22, Provisional True Up for FY 2022-23 and Revised Tariff & Projection for FY 2023-24 to FY 2024-25 under Section 62 of The Electricity Act, 2003 and MERC MYT Regulations, 2019 (access here)

In FY24, ~74% of power was sourced from fossil fuel based plants and power exchangese3. Renewable and nuclear contributed another ~23% and 3% respectively. The emission intensity of the utility is **~198 gCO2eq./MJ or 0.712 tCO2eq./MWh**.

The tariff for industrial consumers in Maharashtra showed a declining trend from FY20 to FY23; however, there has been an increase of ~INR 1.7/kWh in FY24. The increase in the tariff can be attributed to the FPPPA of 35 paise/kWh in FY24 and electricity duty of 7.5% on the power purchase cost and additional cess of 19.04 paise/kWh. Green tariff is available at a premium of INR 0.66/kWh for all consumers.

3.1.1.5 Odisha

In Odisha, Gopalpur and Paradip are two potential port locations for setting up green ammonia production facility. The region is served by TPCODL (Tata Power Central Odisha Distribution Limited). Bulk supply procurement on behalf of the Discoms is carried out by GRIDCO (Grid Corporation of Odisha) and the power mix has also been highlighted below.

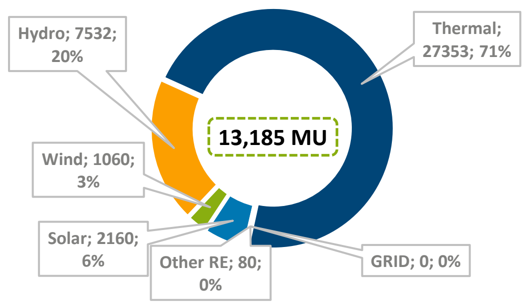


Figure 14: Power procurement mix of Odisha in FY24[14]

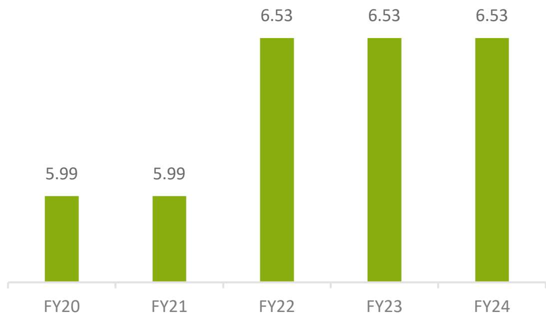


Figure 15: HT tariffs offered by TPCODL (INR/kWh)[15]

In FY24, ~71% of the power procured for the state comes from thermal energy and the rest is dependent in non-fossil sources. With the above procurement mix, the emission intensity for the state is **~194 gCO2eq./MJ or 0.698 tCO2eq./MWh**

At INR 6.53/kWh, the HT tariff has remained constant for the last 3 fiscal years, which is inclusive of the electricity duty of 8% on the procurement cost and FPPPA of 20 paise/kWh. Green tariff is available at a premium of INR 0.25/kWh (for FY24) over and above the tariff applicable.

3.1.1.6 Summary of emission intensity and landed HT tariff

Table 2: State wise power procurement mix and emission intensity

Particular/ State	**Andhra Pradesh**	**Gujarat**	**Kerala**	**Maharashtra**	**Odisha**
Fossil based power (MU, %)	22137 MU (77%)	88007 MU (75%)	15717 MU (90%)	107743 MU (74%)	27,353 MU (72%)
Non-fossil based power (MU, %)	6767 MU (23%)	29755 MU (25%)	1742 MU (10%)	38637 MU (26%)	10,833 MU (28%)
Emission intensity	191 g/MJ 688 g/kWh	194 g/MJ 699 g/kWh	242 g/MJ 873 g/kWh	198 g/MJ 712 g/kWh	194 g/MJ 698 g/kWh
Landed HT tariff (INR/kWh), 2024	5.85	7.98	6.25	9.30	6.53

---

14 MERC, Case of Maharashtra State Electricity Distribution Company Limited for Final True Up of FY 2019-20, FY 2020-21 & FY 2021-22, Provisional True Up for FY 2022-23 and Revised Tariff & Projection for FY 2023-24 to FY 2024-25 under Section 62 of The Electricity Act, 2003 and MERC MYT Regulations, 2019 (access here)

15 OERC, ARR for TPCODL and other distribution companies (access here)

Among the five states considered, Kerala and Odisha have higher emission intensities compared to the national grid emission intensity of 711 gCO2eq./kWh. However, these intensities are as per the current power procurement practices of the state which is subject to change on a YoY basis due to shift towards low-carbon electricity mix.

The regulations in India as well as EU allow a threshold emission intensity in green hydrogen and ammonia production. Therefore, regional grid emission intensity will be critical to decide on the permissible share of grid supplied electricity in ammonia production to be compliant with the regulations.

3.1.2 Renewable energy sources for green ammonia production

Industrial consumers in India have multiple options to procure green power from sources other than Discoms, supported by favorable open access policy. As per the Electricity Act, open access is "non-discriminatory provision for the use of transmission lines or distribution system or associated facilities with such lines or system by any licensee or consumer or a person engaged in generation in accordance with the regulations specified by the Appropriate Commission". With open access, consumers can enter into agreement with generators and procure power from the power market for fulfilling their desired demand. Multiple available routes for RE power procurement are illustrated below:

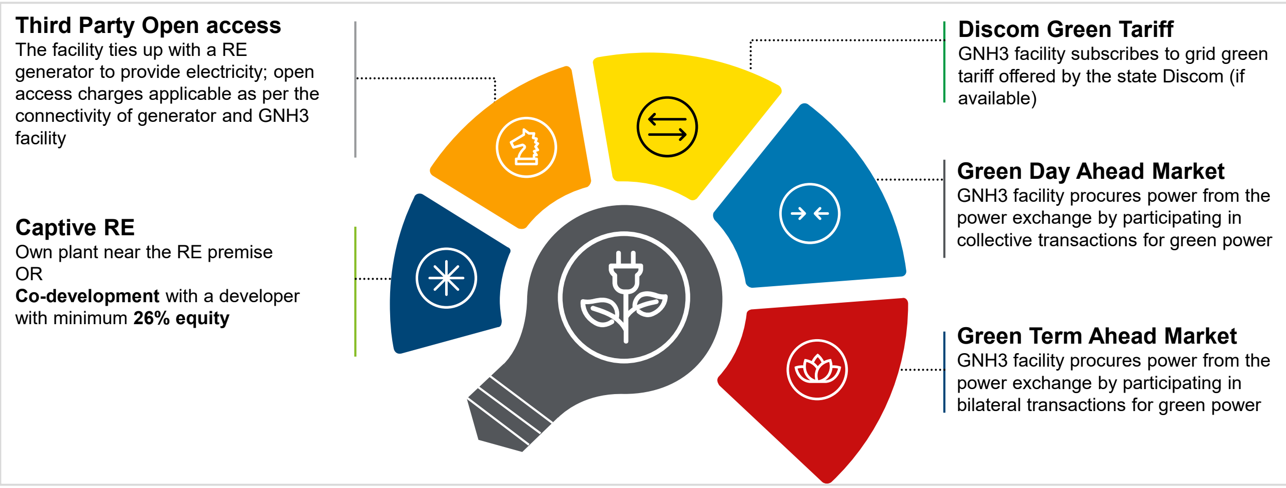


Figure 16: Options for renewable energy procurement for GNH3 production facility

Each of the RE power procurement route has several pros and cons pertaining to economics and operational complexities, as elaborated in the later sections.

3.1.2.1 Third party open access (TPOA)

Consumers opting to procure power through TPOA can negotiate independently with RE developers and obtain a tariff for their respective demand. However, the consumers have to pay the Discoms open access charges in the form of wheeling, transmission[16], cross-subsidy surcharge and additional surcharge. In India, industrial consumers are charged higher tariffs compared to that of residential consumers due to cross-subsidization. Keeping this in view, the open access consumers are subjected to cross-subsidy surcharge. Additionally, surcharge is also levied on the open access consumers to compensate the distribution utility for the fixed charges paid by them to the tied-up generators. These charges are governed by the state regulations. Several states have exempted cross subsidy surcharge and additional surcharge for electricity sourced to produce green hydrogen or ammonia.

As the ammonia production facility would require electricity round the clock, plain vanilla solar or wind developers would not be able to meet its demand. Round the clock RE with a combination of solar, wind and battery will be critical to ensure continuous operation of the ammonia loop.

State specific open access charges are captured below:

---

[16] Transmission includes ISTS (Interstate transmission system) charges and InSTS (Intrastate transmission system) charges

Table 3: State specific open access charges

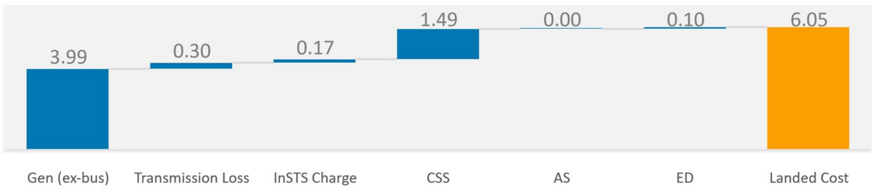
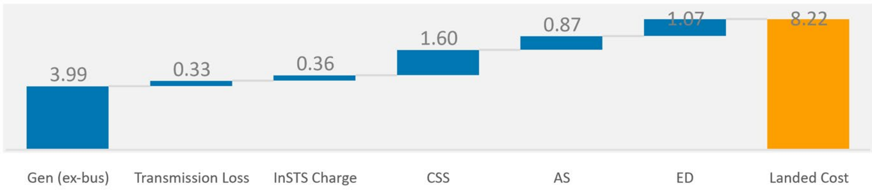
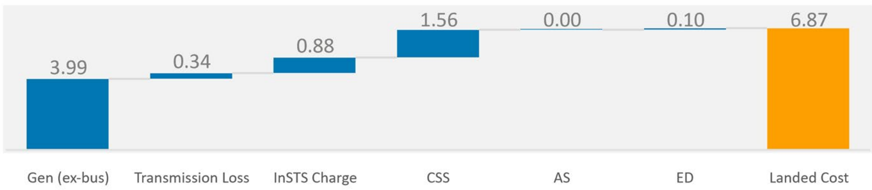
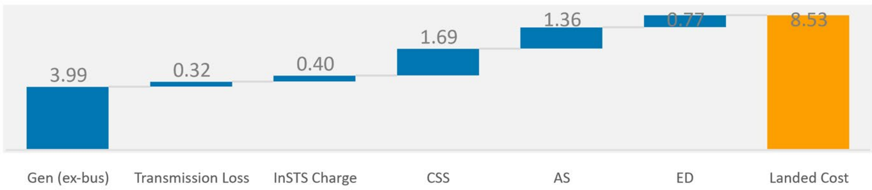
Particular \ State	Andhra Pradesh	Gujarat	Kerala	Maharashtra	Odisha
InSTS loss (%)	3.00%	3.60%	3.30%	3.18%	3.00%
InSTS charges (INR/kWh)	0.17	0.36	0.88	0.40	0.48
Cross subsidy surcharge (INR/kWh)	1.49	1.60	1.56	1.69	0.85
Additional surcharge (INR/kWh)	-	0.87	-	1.36	-

Note: The open access charges have been sourced from the FY24 tariff orders

For the purpose of calculating the landed cost, it has been assumed that the generation plant would be connected at the ISTS (Inter-State Transmission System) network and the ammonia plant is connected in the STU (InSTS) network. Therefore, the landed cost of electricity would include the ISTS, InSTS charges and ISTS losses of 4% in addition to the cross-subsidy and additional surcharges[17]. For estimation of landed cost of RE RTC, recently discovered tariff of INR 3.99/kWh has been considered as ex-bus generation cost. However, this cost is on optimistic side, which may further be increased due to complexities associated with electrolyser and ammonia loop operation.

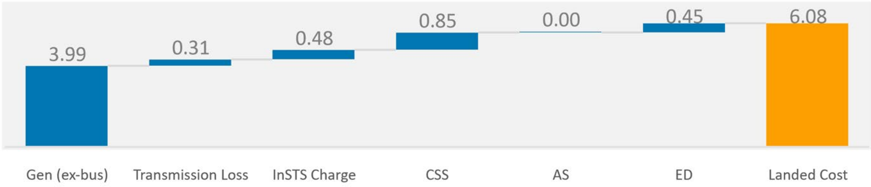
The stack of landed cost of electricity for all the states is shown below:

Table 4: Landed cost of electricity via Third party open access route

State	Landed cost of electricity through TPOA in FY24 (INR/kWh)[18]	FY24 grid tariff (INR/kWh)
Andhra Pradesh		5.85
Gujarat		7.98
Kerala		6.25
Maharashtra		9.30

[17] These are assumed because the consumer moves away from Discom to procure power on its own behalf. ISTS Charges are expected to be waived off for developers having commissioned their plants before October 2023

[18] Deloitte analysis; the ISTS, InSTS, and Wheeling charges have been computed after taking losses into account

State	Landed cost of electricity through TPOA in FY24 (INR/kWh)[18]	FY24 grid tariff (INR/kWh)
Odisha		6.53

3.1.2.2 *Captive RE procurement*

Captive status for a generating entity can be obtained in two ways – 1) the generation unit can be placed inside the consumer's premises, or 2) the consumer can invest at least 26% of the equity in the project and have an agreement to off-take at least 51% of the power from the project[19]. As per regulations, CSS and AS are not applicable for captive generating stations. The landed cost of electricity in different states captive sourcing are captured below:

Table 5: Landed cost of electricity from captive open access

State / Particular	Andhra Pradesh	Gujarat	Kerala	Maharashtra	Odisha
Landed Captive power cost (INR/kWh)	4.46	4.68	5.21	4.71	4.78

Note: The above figures are indictive for collocated facilities. Actual cost may vary depending on the profile of solar and wind and complexities associated with electrolyser and ammonia loop operation.

The landed cost of electricity from the captive route is generally lower in comparison to RE TPOA in all the states on account of reduction in CSS and AS. However, if CSS and AS are exempted in any specific state, TPOA could be a preferred option. If banking is also considered, additional charge will be levied, which is 2 – 10% of total energy charge. For this specific analysis, banking is not considered.

3.1.2.3 *Green Day ahead market (GDAM)*

The Indian wholesale electricity market has three power exchanges namely, IEX (Indian Energy Exchange), PXIL (Power Exchange of India Limited), and HPX (Hindustan Power Exchange). The power exchanges provide a platform for buyers and sellers to submit their bids and to get cleared/ matched with suitable counterparts. The Day ahead market (DAM) is the most popular product of Power Exchange. As part of DAM, the Green Day Ahead market (GDAM) was launched in October 2021 which is an exclusive market for trading electricity with green attribute. The volume of electricity traded in the GDAM since its inception, and the weighted average cleared price are captured below[20]:

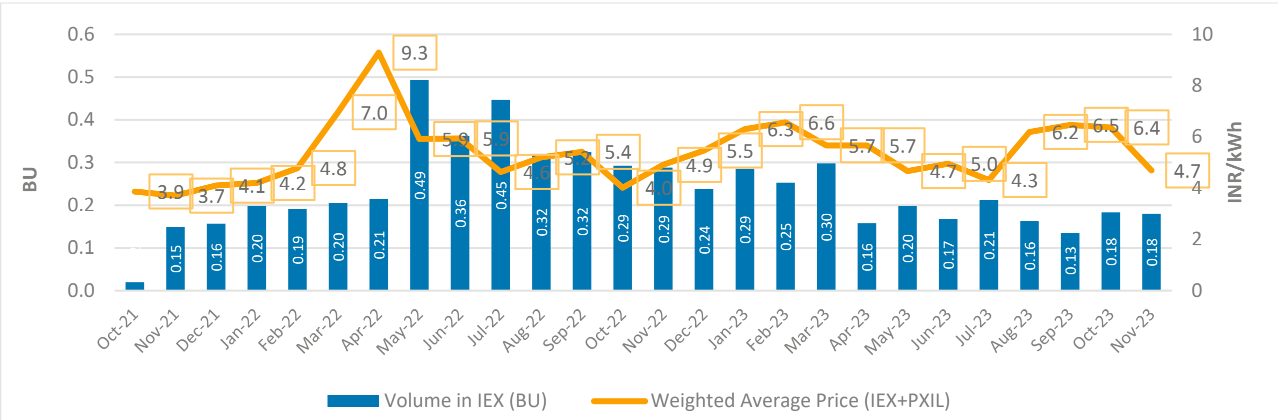


Figure 17: Volume of electricity transacted and weighted average price in GDAM

[19] Enabled by Electricity Act, 2003

[20] CERC Market Monitoring Reports (access here)

In the above duration, the weighted average price of the GDAM was ~INR 5.39/kWh. However, the seasonal variations in the market should be considered before allocating power procurement from the GDAM. The liquidity in the GDAM is illustrated below[21]:

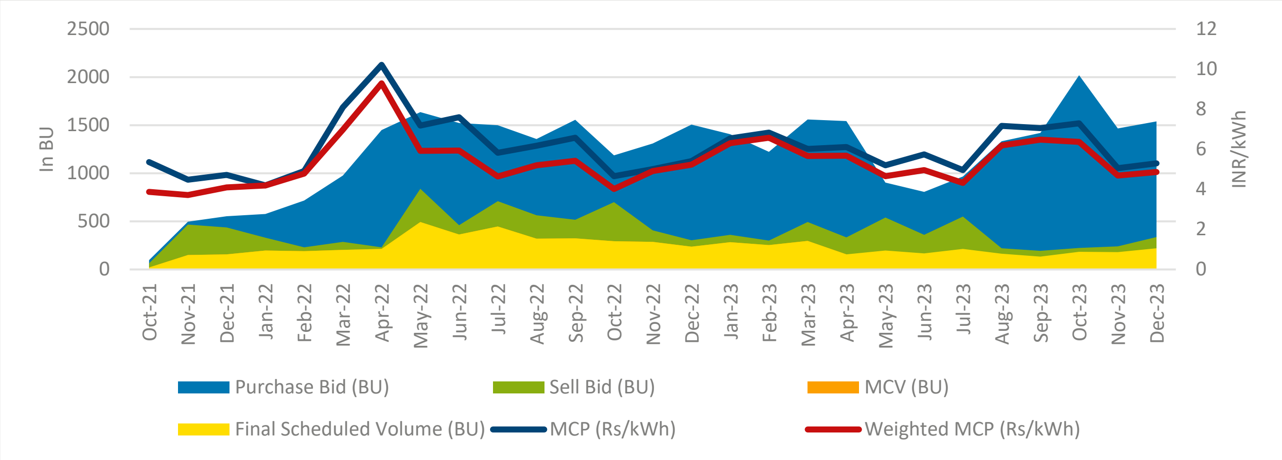


Figure 18: Liquidity in the IEX GDAM

Note: MCV: Market Cleared Volume, MCP: Market Cleared Price

The current structure of the market leads to higher buy side liquidity and lower sell side liquidity (as mostly RE generators participate). The market has observed higher quantum of sell bids in summer months whereas they are lower in winter periods.

For a 600 kTPA Green Ammonia facility, the GDAM can be a significant source of green power procurement. However, adequate forecasting of power requirement (both volume and price) will be critical. Also, acceptability of GDAM as green power could be a challenge in few geographies like the EU owing to aspects such as additionality.

3.1.2.4 Green term ahead market (GTAM)

Term Ahead Market in Indian power exchanges provides buyers and sellers multiple options to trade power in multiple time durations viz. monthly, daily, weekly, day ahead contingency, intra-day, etc. Similar to the day ahead market, the term ahead market has also been extended to provide power with green attribute through the Green Term Ahead Market (GTAM). The GTAM was introduced in August 2020, and the segment trades power through Green-Intraday, Green-Day-ahead Contingency (DAC), Green-Daily and Green-Weekly products.

The volume of electricity traded through the GTAM and its weighted average price are shown below:

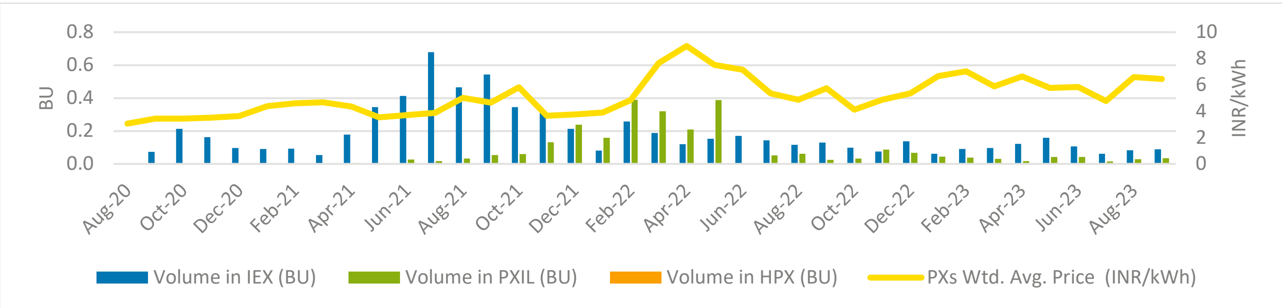


Figure 19: Volume and weighted average power price in GTAM

The Green Term ahead Market permits continuous/spot trading for G-Intraday, G-DAC and G-Daily contracts and double-sided, open auction for G- Weekly. The segments can be utilized to procure power if the procurement form GDAM is not fulfilled. However, the volume in this segment is limited.

3.1.2.5 Grid green tariff from Discoms

In a bid to provide green power procurement options to consumers, Discoms in multiple states of India have come up with Grid green tariffs. Such tariffs, usually carrying a premium over general grid tariffs, can be used by consumers to label their

[21] IEX

power as green. Discoms in India have renewable power purchase obligations (RPO) which mandate them to procure certain portion of their power requirements through renewable sources of energy. The Discoms allocate the green electrons to the consumers subscribing to grid green tariffs offered by them[22]. The status of grid green tariff in the 5 key states for ammonia exports is indicated below.

Table 6: Grid green tariffs status in target states

State / Particular	Andhra Pradesh	Gujarat	Kerala	Maharashtra	Odisha
Grid green tariff availability	✓	✓	✓	✓	✓
Tariff applicability	All Consumers other than those covered under Category II(A) (iii): (function halls / auditoria – HT	All consumers (Extra High Voltage, High Voltage and Low Voltage)	All consumers	All consumers	All consumers
Green tariff premium	0.75 INR/kWh	1.50 INR/kWh	0.77 INR/kWh	0.66 INR/kWh	0.25 INR/kWh

Grid green tariffs can be a key source of green power procurement; however, the cost of power through the route can be prohibitive in comparison to other options available. In addition, international regulations may not allow this procurement mechanism as legible sourcing of green power.

3.1.3 Transmission grid availability

The availability of transmission grid is critical for HT consumers as they are connected with STU. The unavailability of transmission grid can lead to curtailment of RE power which can lead to disruptions in the ammonia loop operations.

Usually, HT consumers are connected to the state transmission grid rather than being connected at the Distribution network. The primary reason for such an arrangement is the high voltage level requirements (for large size electrolyser, it will be 132 kV and above). For the 5 target states, the availability of state transmission grids in the last 5 years has been captured below:

Table 7: Transmission system availability in target states

State / Particular	Andhra Pradesh	Gujarat	Kerala	Maharashtra	Odisha
Transmission utility	APTRANSCO	GETCO	KSEB	MSETCL	OPTCL
Transmission availability	>99.98%[23]	>99.46%[24]	-	>99.58%[25]	>99.97%

Based on the availability statistics approved by the state electricity regulatory commissions and investments planned in the transmission sectors, transmission constraints are not likely to be bottleneck for the green ammonia facility in above states.

3.2 Schemes for green hydrogen ecosystem

Availability of low cost renewable and optimisation of capex are two most important cost levers for green hydrogen or ammonia production. The Government of India and specific states have been actively promoting green energy and sustainable development through various support measures and incentives for projects related to green power, green hydrogen, and electrical storage. Major schemes and policies announced by the Government of India are elaborated below:

---

[22] Note: Renewable energy attributes associated with power procured at green tariff are retained by DISCOMs. As a result, end consumer cannot claim traceable renewable energy attributes. However, the power purchased can be labelled green by the Discoms.

[23] APERC; APTRANSCO tariff order 2020 to 2024 (access here)

[24] GERC; GETCO tariff order FY24 (access here)

[25] MSETCL, System availability (access here)

3.2.1 Central government schemes

In 2021, the Government of India launched the National Hydrogen Mission (NHM) to lay out its vision, intent, and direction for harnessing hydrogen energy. It was followed by the release of National Green Hydrogen Policy. The policy intends to facilitate green hydrogen adoption by bringing down the costs of green hydrogen and easing the setting up of green hydrogen projects. The government's hydrogen vision was further cemented as the Union Cabinet approved the provisions of NHM by sanctioning INR 19,744 crore outlay with an aim to make India a global hub for green hydrogen in January 2023. The mission aims to reach an annual green hydrogen production to a minimum of 5 MMTPA by 2030 and sets an aspirational target to capture 10 percent of the global demand.[26] The announcement of incentives along with the aspirational production target, positions India as one of the attractive destinations globally for green hydrogen production.

3.2.1.1 Green Hydrogen Policy

The Green Hydrogen policy promotes Renewable Energy (RE) generation as RE will be the basic ingredient in making green hydrogen. Key highlights of the policy are:

- Green Hydrogen / Ammonia manufacturers may purchase renewable power from the power exchange or set up renewable energy capacity themselves or through any other, developer, anywhere.
- Open access will be granted within 15 days of receipt of application.
- The Green Hydrogen / Ammonia manufacturer can bank his unconsumed renewable power, up to 30 days, with distribution company and take it back when required.
- Distribution licensees can also procure and supply Renewable Energy to the manufacturers of Green Hydrogen / Green Ammonia in their States at concessional prices which will only include the cost of procurement, wheeling charges and a small margin as determined by the State Commission.
- Waiver of inter-state transmission charges for a period of 25 years will be allowed to the manufacturers of Green Hydrogen and Green Ammonia for the projects commissioned before 30th June 2025.
- The manufacturers of Green Hydrogen / Ammonia and the renewable energy plant shall be given connectivity to the grid on priority basis to avoid any procedural delays.
- The benefit of Renewable Purchase Obligation (RPO) will be granted incentive to the hydrogen/Ammonia manufacturer and the Distribution licensee for consumption of renewable power.
- To ensure ease of doing business a single portal for carrying out all the activities including statutory clearances in a time-bound manner will be set up by MNRE.
- Connectivity, at the generation end and at the Green Hydrogen / Green Ammonia manufacturing end, to the ISTS for Renewable Energy capacity set up for the purpose of manufacturing Green Hydrogen / Green Ammonia shall be granted on priority.
- Manufacturers of Green Hydrogen / Green Ammonia shall be allowed to set up bunkers near Ports for storage of Green Ammonia for export / use by shipping. The land for the storage for this purpose shall be provided by the respective Port Authorities at applicable charges.

3.2.1.2 Incentives under NGHM

Under the National Green Hydrogen Mission, Rs 17,490 crore has been set aside for the Strategic Interventions for Green Hydrogen Transition (SIGHT) programme to bolster domestic electrolyser manufacturing and green hydrogen production. The programme consists of two distinct financial incentive mechanisms to support domestic manufacturing of electrolysers and production of Green Hydrogen. In addition, the Mission has a provision for supporting pilot projects for low-carbon steel, mobility, shipping, and ports. A total of Rs 1,466 crore has been allocated to pilot projects - Rs. 456 crores is set aside for steel, Rs. 495 crores for transport, Rs. 115 crores for shipping and Rs. 400 crores for other projects.

Direct subsidy for green hydrogen production

Under this initiative, direct subsidies are provided to Green Hydrogen developers. The scheme outlines a structured incentive plan, offering financial support to developers based on the amount of Green Hydrogen produced over a span of three years from the commencement of commercial operation. The Bureau of Energy Efficiency (BEE) at the Ministry of Power shall

[26] Source: India National Hydrogen Mission document

be the Nodal Authority for accreditation of agencies for the monitoring, verification, and certification for green hydrogen production projects.

The incentives are calculated at a specified rate per kilogram of Green Hydrogen produced, with a decreasing cap over the three-year period. In the first year of production, developers can avail a maximum subsidy of Rs 50/kg, which reduces to Rs 40/kg in the second year and further decreases to Rs 30/kg in the third year of production. The government has allocated a fund of INR 13,050 Crores (approximately USD 1.7 Billion) for the implementation of this incentive program.[27] The incentive payout in a given year is determined by multiplying the incentive rate for that year (expressed in Rs/kg of Green Hydrogen) by the lower value between the allocated capacity and the actual production during that year. The allocated capacity, a fixed quantity assigned to each successful bidder, remains constant throughout the duration of the Hydrogen Purchase Agreement. The disbursement of incentives occurs on an annual basis, and the successful bidder is eligible to receive the incentive payout after submitting the requisite claim. This scheme not only encourages the growth of the Green Hydrogen sector but also ensures efficient allocation of resources in line with the industry's development trajectory.

SECI is the nodal agency for this scheme and first round of auction took place in December 2023.

Table 8: Status of auction, Tranche – 1 of direct subsidy for green hydrogen

S. No	Company	Capacity Allocated (Tonnes)	Average Annual Subsidy Quoted for 3 years (Rs/kg)
1.	UPL Limited	10,000	0
2.	CESC Projects Limited	10,500	0
3.	Reliance Green Hydrogen and Green Chemicals Limited	90,000	19
4.	Welspun New Energy Limited	20,000	20
5.	HHP Two Private Limited	75,000	25
6.	Torrent Power Limited	18,000	29
7.	ACME Cleantech Solutions Private Limited	90,000	30
8.	Greenko ZeroC Private Limited	90,000	30
9.	JSW Neo Energy Limited	6,500	35
Total Capacity Allocated (tonnes) / Wgt Avg. Annual Subsidy (Rs/kg)		**410,000**	**25**

The implementation of a subsidy averaging INR 30 per kilogram has the potential to decrease the Levelised Cost of Hydrogen (LCOH) by USD 0.11 – 0.12 per kilogram and the Levelised Cost of Ammonia (LCOA) by USD 20 - 25 per ton.

Production Linked Incentive (PLI) for electrolyser manufacturing

This subsidy scheme aimed at promoting the production of electrolysers through a Production Linked Incentive (PLI) scheme. It offers incentives based on the production output over a span of five years. The incentives are calculated per kilowatt (kW) of electrolyser produced.

Under this scheme, the base rate incentive starts at INR 4,440 per kW in the first year and is gradually reduced by INR 740 per kW annually for a period of five years, reaching INR 1,480 per kW by the end of the incentive period. The allocation for this scheme stands at INR 4,440 crores (approximately USD 0.5 billion).

The incentive payout is determined by multiplying electrolyser sales volume, the quoted base support rate, performance multiplier, and domestic value addition. This multi-faceted approach ensures that the incentives are linked to the actual performance and contribution of manufacturers to the development of a robust domestic green hydrogen ecosystem.

First round of auction took place in January 2024, and the outcome is indicated below:

Table 9: Status of auction, Tranche – 1 of PLI for electrolyser

S. No	Company	Capacity Allocated (MW)	Max. Incentive Allocation (Rs Cr)
Bucket 1 (Based on Any Stack Technology)			
1.	Reliance	300	444
2.	Ohmium Operations	137	203
3.	John Cockerill Greenko Hydrogen Solutions	300	444
4.	Advait Infratech (Consortium with Rakesh Power Service)	100	148

[27] Scheme guidelines for implementation of SIGHT programme – component II (access here)

5.	Matix – Gensol	300	444
6.	L&T Electrolysers	63	93
	Total	**1,200**	**1,776**
Bucket 2 (Based on Indigenously Developed Stack Technology)			
1.	Homi Hydrogen	101.5	150
2.	Adani New Industries	198.5	294
	Total	**300**	**444**

The implementation of a subsidy averaging INR 1.5 crore per megawatt can result in a noteworthy impact, leading to a reduction of USD 0.08 – 0.10 per kilogram in the Levelised Cost of Hydrogen (LCOH) and a reduction of USD 15 – 18 per ton in the Levelised Cost of Ammonia (LCOA). However, the current allocation can only support 1500 MW/year of electrolyser capacity.

3.2.1.3 Viability Gap Funding for development of Battery Energy Storage Systems (BESS)

The Union Cabinet, chaired by the Hon'ble Prime Minister approved the Scheme for Viability Gap Funding (VGF) for development of Battery Energy Storage Systems (BESS) in September 2023. The approved scheme envisages development of 4,000 MWh of BESS projects by 2030-31, with a financial support of up to 40% of the capital cost as budgetary support in the form of Viability Gap Funding (VGF).

Salient features of the scheme are:

- The VGF for development of BESS Scheme, with an initial outlay of Rs.9,400 crore, including a budgetary support of Rs.3,760 crore, signifies the government's commitment to sustainable energy solutions. By offering VGF support, the scheme targets to lower the Levelised Cost of Storage (LCoS). The VGF shall be disbursed in five tranches linked with the various stages of implementation of BESS projects.
- VGF will be disbursed to BESS developers. The selection of BESS developers for VGF grants will be carried out through a transparent competitive bidding process, promoting a level playing field for both public and private sector entities.
- The projects under the scheme will be approved during a period of 3 years (2023-24 to 2025-26).
- To ensure that the benefits of the scheme reach the consumers, a minimum of 85% of the BESS project capacity will be made available to Distribution Companies (Discoms). This will not only enhance the integration of renewable energy into the electricity grid but also minimise wastage while optimising the utilization of transmission networks.

The selection of developers under the VGF scheme has not commenced yet.

3.2.2 State government schemes

3.2.2.1 Andhra Pradesh

Table 10: Schemes on green power, green hydrogen and energy storage in Andhra Pradesh

Policy	Details
Solar Power Policy, 2018[28] and Wind Power Policy, 2018[29]	• Target – 5,000 MW • Nodal agency – New & Renewable Energy Development Corporation of Andhra Pradesh Ltd. (NREDCAP) • Transmission & Distribution charges were exempted initially, but post amendment dated 18-11-2019 charges will be determined by the APERC. • Monthly banking throughout the entire year, energy banking is allowed at a rate of 100% with a 5% charge for banking, and any unutilized banked energy is considered a deemed purchase by Discoms at 50% of the Average Pooled Power Purchase Cost, with the payment capped at 10% of the total banked energy. Although, post amendment dated 18-11-2019, the facility of energy banking and drawal has been withdrawn.
Andhra Pradesh Wind-Solar Hybrid Power Policy, 2018[30]	• Monthly energy banking is permitted throughout the entire year, incurring a 5% charge. Deemed energy banking, recognized from synchronization to Commercial Operation Date, results in unutilized banked energy being considered a purchase by Discoms at 75% of the Average Pooled Power Purchase Cost, with payment capped at 10% of the total banked energy during the year.

[28] Solar Power Policy, 2018 (access here)
[29] Wind Power Policy, 2018 (access here)
[30] Wind-Solar Hybrid Power Policy, 2018 (access here)

	Although, post amendment dated 18-11-2019, the facility of energy banking and drawal has been withdrawn. • Transmission & Distribution exemption up to 50% were given, but post amendment dated 18-11-2019 charges will be determined by the APERC • 50% exemption on Electrical Duty • CSS – 50% payment for third-party sale
APERC Regulation 2023 Draft[31]	• State nodal agency – Andhra Pradesh State Load Despatch Centre (APSLDC) • Monthly banking with 8% charges, and 30% limit on Green Energy Open Access consumption and 12% charge for withdrawals during peak hours
Andhra Pradesh Green Hydrogen & Green Ammonia Policy – 2023[32]	• 100% reimbursement of net SGST for the sale of green hydrogen and green ammonia during the initial five years • 100% exemption from Electricity Duty for power consumed in production lasting five years from CoD • 100% exemption from the payment of stamp duty for green hydrogen/ammonia production, consumption, storage and transportation • 25% reimbursement of intrastate transmission charges for renewable energy power within the state, for five years, subject to a maximum cap of ₹1 million per MW of installed electrolyser capacity • Reimbursement of cross-subsidy surcharge for energy drawn from in-state renewable projects for green hydrogen and green ammonia production for five years from the commissioning date • Prioritized grid connectivity to intrastate transmission system at the generation and production end of renewable projects • Contribution towards fulfilling the renewable purchase obligation of consuming entity by renewable energy consumed in production • Government land allocation at ₹31,000 per acre per year with 5% escalation every two years during the project period or establishment in proposed industrial zones/parks • 100% exemption from land-use conversion charges and stamp duty payments

3.2.2.2 *Gujarat*

Table 11: Schemes on green power, green hydrogen and energy storage in Gujarat

Policy	Details
Gujarat Renewable Energy Policy 2023[33]	• The policy targets a cumulative 100 GW of renewable energy capacity by 2030, attracting investments of ₹5 lakh crores and utilizing 4,00,000 acres of land • This policy is not applicable to RE projects set up for the purpose of supply of power to the units producing Green Hydrogen and Green Ammonia.
Policy-2023 for leasing the government fallow land for green hydrogen production[34]	• In May 2023, the Gujarat government's revenue department released the draft Policy 2023, aimed at leasing government fallow land for establishing manufacturing facilities to produce green hydrogen through non-conventional energy sources like solar and wind. This policy offers a 40-year lease term for implementing such energy projects. Any unit or company can apply for land allocation under Policy 2023, with a minimum production requirement of 1 lakh metric tons per year. The Gujarat Power Corporation Limited will identify government-owned waste, fallow, and non-fertile land to create a land bank for leasing purposes. • Under this policy, solar, wind, and wind-solar hybrid projects for green hydrogen production will receive a 40-year land lease. Additionally, the annual land rent set by the government is Rs. 15,000 per hectare, with a 15% increment every three years. • The state government has already assigned 1.99 lakh hectares of land along the Kutch-Banaskantha border to various companies, including Reliance, Adani, Torrent, and ArcelorMittal[35]
GERC Regulations, 2024[36]	• Nodal agency – Gujarat State Load Dispatch Centre • The permitted quantum of banked energy by the green energy open access consumers shall be at least 30% of total consumption of electricity The Banking Charge at rate of Rs. 1.50 will be effective up to

[31] APERC Regulation, 2023 Draft (access here)
[32] Andhra Pradesh Green Hydrogen & Green Ammonia Policy – 2023 (access here)
[33] Gujarat Renewable Energy Policy 2023 (access here)
[34] Policy-2023 for leasing the government fallow land for green hydrogen production (access here)
[35] News article (access here)
[36] GERC Regulations, 2024 (access here)

Policy	Details
	30th September 2024. Banking charges starting from 1st October 2024 and onwards to be notified separately

3.2.2.3 Kerala

Table 12: Schemes on green power, green hydrogen and energy storage in Kerala

Policy	Details
Solar Energy Policy, 2013[37]	• Nodal agency – Agency for New and Renewable Energy Research and Technology (ANERT) • Full exemption from Electricity Duty for energy generated under the policy • Conditional Banking facility available to captive generators considering system constraints • No open access charges for solar projects wheeling power within the state • Wheeling charges and T&D losses not applicable for Captive Solar generators within the state
Renewable Energy Policy 2002[38]	• Nodal agency – Agency for New and Renewable Energy Research and Technology (ANERT) • Banking of power is permitted at 100% from June to February each financial year, with the option to bank with KSEB from March to June. Unutilized banked energy is considered lapsed, and any sold banked energy is purchased by KSEB at the average selling rate applicable for the corresponding year, with settlements conducted on a monthly basis.
Kerala Draft Green Hydrogen Policy, 2023[39]	• Open Access Provision: Green hydrogen and green ammonia facilities will have access to renewable energy sources within 15 days of submitting a complete application. • Charges Exemption: The policy suggests a 50% waiver on wheeling charges, a 50% reduction in intra-state transmission charges, and a full exemption from cross-subsidy surcharge. • Energy Banking: Renewable energy utilized in green hydrogen and green ammonia production can be banked for up to 30 days. • Connectivity Priority: Priority will be given to establishing connectivity for both power generation and manufacturing ends, as well as to the transmission and distribution network. • RPO Compliance: Renewable energy used in green hydrogen and green ammonia production will contribute towards the consuming entity's renewable purchase obligations. • Demand Aggregation: ANERT may consolidate demand from various sectors to procure green hydrogen and green ammonia at competitive prices through designated agencies. • Floating Solar Projects: Plots will be leased for floating solar projects on water bodies, reservoirs, and saline/brackish water-flooded uncultivable farmlands. • Land Bank Creation: Allocation of funds for procuring land along the west coast canal waterways and for developing an industrial and infrastructure corridor around the Vizhinjam international seaport. • Funding Support: Allocation of Rs 2 billion from the 2023-24 state budget to establish green hydrogen hubs in Kochi and Thiruvananthapuram within the next two years.

3.2.2.4 Maharashtra

Table 13: Schemes on green power, green hydrogen and energy storage in Maharashtra

Policy	Details
Maharashtra Green Hydrogen Policy, 2023[40]	• Target – 500 kTPA of Green Hydrogen by 2030 • Nodal agency – Mahurja office • 30% capital cost subsidy available for projects related to hydrogen and similar production, specifically the first three anchor units in the state. • 100% subsidy in electricity tariff for 15 years for the Prime 3 anchor units • 50% reduction in transmission charges and wheeling charges for a duration of 20 years

[37] Solar Energy Policy, 2013 (access here)
[38] Renewable Energy Policy 2002 (access here)
[39] Kerala Draft Green Hydrogen Policy, 2023 (access here)
[40] Maharashtra Green Hydrogen Policy (access here)

3.2.2.5 Odisha

Table 14: Schemes on green power, green hydrogen and energy storage in Odisha

Policy	Details
Odisha Renewable Energy Policy, 2022[41]	• Captive and open access consumers in the state will receive a 50 paisa per unit exemption on Electricity Duty for 15 years from the commissioning date of renewable energy projects, with an extension to 20 years if the project is commissioned before March 30, 2026 • 50% exemption on Cross-Subsidy Surcharge for 15 years to open access consumers utilizing renewable energy • 20 paise per unit exemption on STU charges for 15 years to captive or open access consumers utilizing renewable energy • 25% exemption on wheeling charges for 15 years to captive or open access consumers utilizing renewable energy • 100 % exemption on stamp duty on purchase/lease of land, land conversion charges and registration charges for RE projects
Industrial Policy Resolution, 2022[42]	• Nodal Agency: Industrial Promotion and Investment Corporation of Odisha Limited (IPICOL) • Tax: Reimbursement of 100% of net SGST paid, subject to the limit of 200% of the cost paid towards plant and machinery • Electricity duty: 100% exemption from payment of electricity duty for a period of twenty years from the date of commencement of commercial production • Stamp duty: No stamp duty will be applicable on (i) transfer of land or shed by government, IDCO, and private industrial estate to new industrial units; (ii) purchase of fresh land by the existing industrial units • Transmission cost: The state transmission charges for renewable energy consumed for manufacturing of green hydrogen/ammonia will be exempted/reimbursed for a period of 20 years from the date of commencement of commercial production • Cross-subsidy surcharge: Cross subsidy surcharges & additional surcharges for the renewable energy consumed for manufacturing of green hydrogen and green ammonia, will be exempted/ reimbursed for a period of 20 years from the date of commencement of commercial production • Land: Land will be provided at a special subsidised rate of 50% of the concessional industrial rate for new industrial units if such units create direct employment for not less than 1000 state domiciled people.

2 states, Andhra Pradesh and Maharashtra, have Green Hydrogen/ Ammonia policies in place providing certainty to investors to develop projects. All identified states have policies towards renewable energy to enabling RE infrastructure however, the viability of RE projects is dictated by the regional solar and wind profiles due to which developers prefer setting up RE capacities in certain regions.

3.2.3 Existing certification schemes in India to prove electricity origin

A Guarantee of Origin (GoO) is a tracking instrument within the renewable energy sector to (i) define the origin of the power and (ii) the evidence that the power is from a given source of generation (i.e., wind, solar, biomass, etc.). Globally, there are several GoO schemes.

In India, Green Hydrogen Standard was published in August 2023. It decided to define Green Hydrogen as having a well-to-gate emission (i.e., including water treatment, electrolysis, gas purification, drying and compression of hydrogen) of not more than 2 kg CO_2 equivalent / kg H_2. However, the country doesn't have a robust certification scheme to track and monitor the Guarantee of Origin.

A detailed methodology for measurement, monitoring, reporting, onsite verification, and certification of green hydrogen and its derivatives shall be specified by Ministry of New and Renewable Energy. Bureau of Energy Efficiency (BEE) will be the nodal authority for accreditation of agencies for monitoring, verification and certification for green hydrogen projects.

Contrary to the GoO scheme for renewable energy, India has REC (Renewable Energy Certificate) mechanism which enables designated customers to the reach their renewable purchase obligations (RPO) by purchasing them from RE developers. **However, if GoO for renewable energy is to be introduced in India, its scope would be defined by the MNRE (Ministry of New and Renewable Energy), standardization and implementation would be managed by the BEE.**

[41] Odisha Renewable Energy Policy, 2022 (access here)
[42] Industrial Policy Resolution, 2022 (access here)

As per current practice, the certifying agencies do validate the GoO for RE while certifying green hydrogen or any other PtX product.

3.3 Water supply assessment

The Central Water Commission has evaluated that the country's average annual water availability is 1869 Billion Cubic Meters (BCM). However, when accounting for topographic, hydrological, and other limitations, the utilizable water resources are estimated to be approximately 1123 BCM, consisting of 690 BCM of surface water and 433 BCM of replenishable groundwater.

3.3.1 Assessment of state-wise ground and surface water availability

Table 15: State-wise total annual replenishable ground water resource

State / Particular	Andhra Pradesh	Gujarat	Kerala	Maharashtra	Odisha
Total Annual Replenishable Ground Water Resource (In BCM)	35.89	18.57	6.69	33.95	17.78
Percentage with respect to Total Annual Replenishable Ground Water Resource	8.3%	4.3%	1.5%	7.8%	4.1%

As per the 2023 assessment, the Stage of Ground Water Extraction (SOE), which is a measure of annual ground water extraction for all uses (irrigation, industrial and domestic uses) over annual extractable ground water resource, is 59% for the country as a whole.[43] In addition to ground water, surface water from rivers, canals can be another source for supplying water to the electrolyser. The table below captures the statistics around ground water extraction, its availability for future use, and the major rivers passing through the districts in which the integrated ammonia facility is expected to be commissioned.

Table 16: Ground Water Extraction along with major rivers near port areas

Location, District	Current Ground Water Extraction (Ham)				Net Ground Water Availability for Future Use (Ham)	Major Rivers
	Domestic	Industrial	Irrigation	Total		
Visakhapatnam	27	1	85	113	464	Sharada, Varaha, Thandava, Machkand, Champavathi and Gostnani
Kandla, Kachchh	0	0	5073.10	5073.10	3576.22	Luni, Bhuki, Bharud, Nara, Kharod, Banas, Saraswati, Rupen, Bambhan, and Machchhu.
Kochi, Ernakulam	150.18	9.29	199.18	358.64	1039.05	Muvattupuzhayar and Periyar
JNPT, Raigad	51.51	0	104.21	155.73	1604.77	Kalu, Patalganga, Amsa, Kundalika, Ghod, Ulhas, Bhogawati, Savitri and Gandhar
Gopalpur, Ganjam	58.57	0	0	58.57	605.05	Rushikulya, Badanadi and Lohorakhandi

Majority of ground water in any district is allocated towards irrigation and domestic usage. Industrial usage is not sought for the available ground water sources and running water sources such as rivers and canals are expected to be utilized for providing water to the electrolyser facility. Water from rivers is directed to end users through canals and waterways which can be replicated for the integrated green ammonia production facility.

---

[43] Extraction of Ground Water (access here)

Surface water sources such as rivers and canals are expected to **be better option compared to groundwater for providing** the **resource** required for **hydrogen production.** Canals and waterways would need to be built for the facility in case they are unavailable.

3.3.2 Seawater for the integrated green ammonia production facility

Use of seawater using a desalination plant could be another viable option to meet the water requirement for green ammonia facility. However, additional capital expenditure must be allocated towards setting up the desalination plant. Major components of desalination plant are seawater intake and brine outfall, Pre-treatment, RO system, Post treatment, Sludge treatment facility etc. Brief description of major components are provided below:

Sea Water Intake and Brine Outfall System:

A study will be required to identify sea water intake and outfall (SWIO) location based on dispersion of brine/ reject water from the process complex. Accordingly, the intake system shall draw sea water from the sea with intake head structure at the sea and convey water by gravity through submarine pipeline to onshore intake pump house located at the foot of the cliff. The SWIO system would consist of the following major components:

- Offshore intake head
- Buried offshore gravity main (pipeline) from offshore intake head to onshore intake pump house.
- Onshore intake pump house. There will be elevation difference between the seashore and plant location; hence the pump house has to be located at the foot of the cliff.
- Onshore pumping main (pipeline) to convey sea water from onshore pump house to Desalination plant.

The brine/reject water from the plant will be discharged into the sea in line with environmental regulations. The outfall system for the plant will consist of a pumping/gravity main (pipeline) with suitable diffuser arrangement designed to disperse the saline water in line with state specific environmental regulations.

Desalination Unit

The sea water will be pumped from the sea water intake area to the desalination package, which is a part of the main process plant. The pumped sea water from intake area shall be fed to the pre-treatment facility. The pre-treated water will be then desalinated in membrane-based Sea Water Reverse Osmosis (SWRO) unit. Permeate of SWRO shall further be treated in Brackish Water Reverse Osmosis (BWRO) unit. Demineralization facility feed from BWRO will be treated in a mixed bed unit to produce demineralized water (DM).

The desalination system will be used to produce low salt water from seawater. Low salt water will mainly be used as Raw water and DM water.

- Permeate stream from SWRO system shall be supplied as Raw water for following usage:
    - Cooling Tower make-up water
    - Feed to Potable water generation package
    - Utility/Service water
    - Fire water storage tank filling/make-up
- Permeate stream from BWRO system shall be fed to DM water Plant to generate DM water for following usage:
    - Feed water for Electrolyser Unit
    - Feed water in Ammonia Plant

The SWRO permeate shall be stored in raw water cum fire water tank. The raw water cum fire water tank shall be sized to hold fire water reserve, two days Cooling tower make-up and two days and service water requirement of the plant. Potable water will be stored in a potable water storage tank sized to hold one day's requirement of the plant. Potable water shall meet required guidelines. DM water storage tank shall be designed for two days hold-up capacity to supply uninterrupted feed to Electrolyser and ammonia unit in the event of abnormal situation in upstream system.

Sizing and commercial viability of desalination unit

Sea water is directed to the DM (De-mineralized) water system and the desalination package system. Ultrapure DM water is necessary for green hydrogen production. A 600kTPA integrated green ammonia production facility would require Raw water (from the desalination unit) of ~15 MLD (million liters per day) and ~6 MLD of DM water[44].

Table 17: Desalination requirement

Key parameters	Unit	Value
Ammonia plant capacity	KTPA	600
Ammonia plant capacity	TPD	1650 - 1700
Raw water requirement	MLD	~16
DM water requirement	MLD	~6
Total desalination plant capacity	MLD	~22
Capex for desalination unit (including intake and outfall system)	INR Cr	220 - 250

While desalination unit would minimise the risk of availability of ground water or surface water, it would attract additional capex of INR 220 – 250 Cr.

3.4 Renewable energy companies

In recent 5 years, installed capacity of renewable energy sources (RES) in India has increased from ~74,082 MW[45] to ~1,33,886 MW[46] i.e., by ~59,804 MW out of which 98.94%increase in installed capacity is driven by the private sector. Thus, it is vital to identify key RES companies in India and understand their portfolios.

3.4.1 ReNew Power (ReNew)

Founded in January 2011, ReNew Power (or ReNew) is one of the largest RE IPPs in India. It has diverse interest in the RE sector which includes utility scale RE capacity addition, manufacturing of solar cell and module, green hydrogen and carbon removal. Information on shareholding, portfolio, key achievements and future plan are captured below:

Areas	Description
Major investors	CPP Investment Board – 30.04%, Abu Dhabi Investment Authority – 22.84%, JERA – 11.2%
Installed capacity	10 GW; Solar – 5 GW, Wind – 4.7 GW, Hydro – 0.1 GW
Achievements and portfolio	• ReNew has a deep presence across the country with over 150 renewable energy sites across 10 Indian states • In 2021, it became the 1st Indian RE company to be listed on the NASDAQ index • In FY24, ReNew contributed ~10% of India's total solar and wind energy generation. The Company has India's largest wind portfolio of 4.7 GW. • It has also achieved backward integration through the manufacturing of solar modules and cells. • Partnered with Fluence (A Siemens subsidiary) to provide battery solutions, bundled with other sources to provide low-cost firm RE power • ReNew has also sizeable presence in the corporate PPAs, serving marquee customers such as Amazon, Microsoft, Toyota, Suzuki, Ultratech Cement and DCM Shriram • Formed JV with IOCL and L&T to develop hydrogen and PtX projects in India and globally; started participating in international auctions for green hydrogen (e.g., HINT.CO auction)
Future plan	• RE asset portfolio to 20 GW by 2027/28

[44] Details of DM water and desalination plant have been provided in the Techno-economic scoping for GNH3 Production Facility Chapter
[45] CEA report, Dec 2018 (access here)
[46] CEA report, Dec 2023 (access here)

	• Development of both domestic and export focused green hydrogen and derivatives project; signed several MoUs with Indian states, such as Karnataka, Kerala, Odisha etc.

3.4.2 Greenko Group

Greenko Group is an India-based renewable energy company, with focus on long duration energy storage to reduce the variability of RE. The Company is a provider of integrated decarbonised energy and grid assets enabling sustainable energy.

Information on shareholding, portfolio, key achievements and future plan are captured below:

Areas	Description
Major investors	GIC – ~51%, Orix Corporation – ~16%, ADIA – ~14%, Promoter – ~13%
Installed capacity	7.3 GW; Solar – 2.2 GW, Wind – 3.2 GW, Hydro – 1.8 GW
Achievements and portfolio	• Greenko has in total 135 project sites across 15 states in India, including both the operational projects as well as the projects that are under construction • The Group is developing multiple pump storage projects, with the 1.6 GW storage project is under construction in Andhra Pradesh. Another 10 GW+ capacity are under consideration. • The Group has also interest in green molecules i.e. hydrogen and ammonia. Setting up a 2 GW alkaline electrolyser manufacturing capacity in partnership with John Cockerill Group. • Signed an MoU for supplying 250 KTPA green ammonia from India to Uniper, Germany
Future plan	• 2- 3 MTPA green ammonia by 2030 • Development of integrated renewable energy project (with focus on pump storage projects)

3.4.3 Adani Green Energy Limited

Adani Green Energy Limited (AGEL) is an India-based holding company. The Company is engaged in renewable power generation and other ancillary activities. The Company develops, builds, owns, operates, and maintains utility-scale grid-connected solar power, wind power, hybrid projects, and solar parks. It is listed on both BSE as well as NSE in India.

Information on shareholding, portfolio, key achievements and future plan are captured below:

Areas	Description
Major investors	Adani Trading Services Llp – 29.94%, Adani Family – 20.76%, Universal Trade & Investment Ltd. – ~16.20%
Installed capacity	9 GW; Solar – 5.6 GW, Wind – 1.3 GW, Hybrid – 2.1 GW 11 GW capacity is under development
Achievements and portfolio	• Leveraging in-house module manufacturing capacity and EPC capability • Developed one of the largest solar-wind cluster in India • Developing 30 GW solar park in one place in Khavda • Green Molecule business is being looked after by a separate entity Adani New Industries Limited (ANIL)

Future plan	• Target to set up 45 GW RE capacity by 2030

3.4.4 Tata Power Renewables

Tata Power is one of the most prominent IPP in India. Along with conventional generation fleet, it has a sizeable RE portfolio of ~4 GW. In 2023, INR 4,000 Cr capital was infused into RE business by external investors – BlackRock and Mubadala.

Information on shareholding, portfolio, key achievements and future plan are captured below:

Areas	Description
Major investors	Tata Group Companies – 46.79%, LIC – 7.90%, Nippon Life India Asset Management Limited – 1.8%
Installed capacity	4.1 GW; Solar – 3.1 GW, Wind – 1.0 GW
Achievements and portfolio	• The company has expanded renewables business significantly across the value chain - EPC, utility-scale, group captive and rooftop as well as manufacturing; • Currently, adding up capacities through participation in competitive bidding process. Won several tenders in last few years in solar, wind and solar-wind hybrid space.
Future plan	• The company aims to increase RE share in overall generation mix to 60% over the next five years; it plans to achieve its portfolio of >15 GW of renewable assets by 2028 and become a market leader with clean & green capacity of 70% by 2030 and 100% before 2045.

3.4.5 ACME Cleantech Private Limited

ACME Cleantech Solutions Pvt. Ltd., popularly referred to as the ACME Group, is one of the leading global sustainable and renewable energy companies. In 2008, ACME Group forayed into solar power generation by establishing the first solar thermal power project in Asia based on tower technology. In 2011, the Company commissioned the first solar photovoltaic power plant in the State of Gujarat. In 2015, the Group became India's largest solar power developer with a portfolio of over 1500MW in that year. ACME Group played a crucial role in bringing down Solar tariffs by nearly half in India after commissioning the project at Bhadla solar power park in Rajasthan.

Information on shareholding, portfolio, key achievements and future plan are captured below:

Areas	Description
Major investors	Parent entity – 72.14%; Founder – 9.4%
Installed capacity	4.1 GW; Solar – 4.1 GW
Achievements and portfolio	• ACME Group has participated in multiple competitive bidding process invited by SECI, Discoms and other implementing agencies • In addition to renewables, the Group has interest in Green hydrogen and ammonia. • The Group has set up India's first green hydrogen plant in Rajasthan. • Later, started construction of a green ammonia plant in Oman; it has also signed MoUs with several states of India, such as Odisha, Karnataka etc. • Signed an offtake agreement with Yara, Norway for 100,000 Tons of Green Ammonia

	• Signed an MoU with fertiliser producer IFFCO for supply of green ammonia (for 200,000 Tons)
Future plan	• Target of 10 MTPA green hydrogen production

3.4.6 Azure Power Company Limited

Azure Power Global Limited, founded in 2008, is an India-based independent sustainable energy solutions provider. It developed India's first private utility scale solar project in 2009. Since then, it has grown to become the leader in developing and operating renewable power plants in India. Currently, it has a portfolio of 4.3 GW, with over 3 GW of operational capacity and 1.3 GW of contracted & awarded capacity.

Information on shareholding, portfolio, key achievements and future plan are captured below:

Areas	**Description**
Major investors	CDPQ – 53.39%, OMERS – 21.45%
Installed capacity	3 GW; Solar – 3 GW, no operational wind portfolio Another 1.3 GW is under development
Achievements and portfolio	• Founded in 2008, built India's first private utility-scale solar project in 2009 • Majority owned (53.4%) by long-term Canadian pension funds CDPQ; OMERS owns another ~21.4% stake • Fully integrated business from development to EPC, financing and O&M • Developed and operating largest owned and operated single site solar project (600 MW) in India
Future plan	• NA

While these are some of the large RE players active in India, there are 20+ RE platforms operating in India. They have participated in competitive bidding processes and have been executing multiple hybrid and RTC projects. A list of RE projects along with discovered tariff, awarded since 2017 are provided in the Annexure.

The renewable energy ecosystem in India is matured, and more than 25 RES companies are active. Competition has led to reduction in discovered tariff over time. With the exemption of ISTS charges on green hydrogen and ammonia facilities, power can be procured at competitive tariff irrespective of the plant location.

3.5 Assessment of eco-system players and local suppliers

Availability of local players across the value chain is crucial to optimise the capital expenditure and reduce the lead time of project development. An illustration of key components of the value chain is provided below:

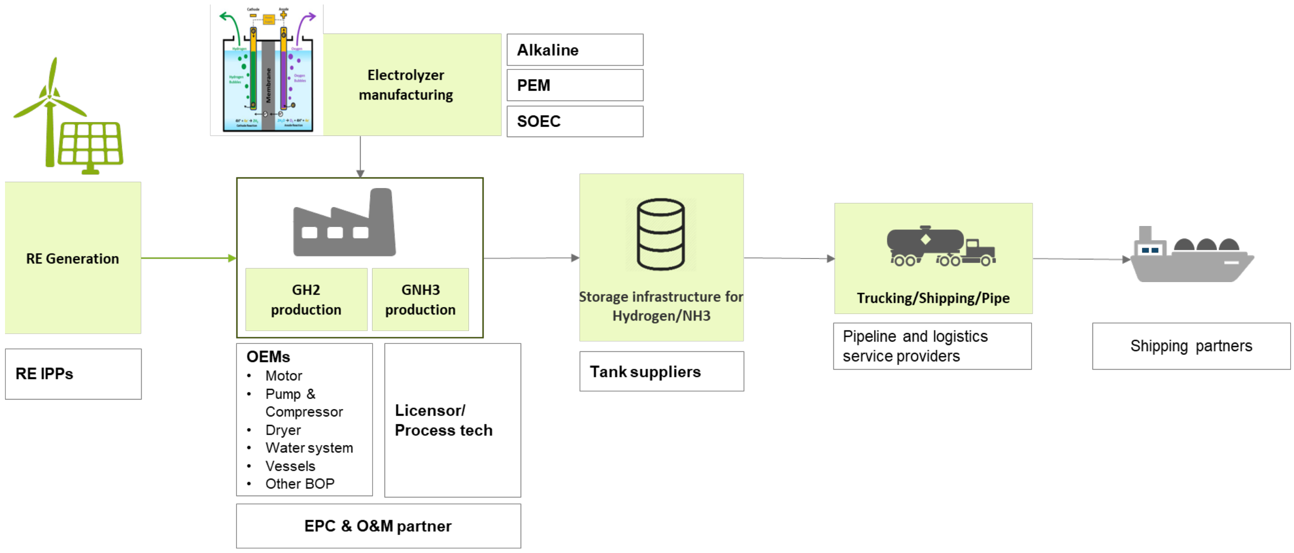


Figure 20: Ecosystem players and local suppliers

Many of the major players along the green hydrogen and ammonia value chain have presence in India, which could be leveraged to optimise cost and project development time. Further German companies in the Green Hydrogen / PtX sector can be found in the Supplier Directory P2X of the *Verband Deutscher Maschinen- und Anlagenbau VDMA – German Engineering Federation*[47].

Table 18: Ecosystem players and local suppliers

Value chain area	Description/Remarks	Local (Indian) suppliers	Major global players	Major German players
RE generation	India is the second most attractive country for investment in renewable energy after China. More than 30+ active developers are present in India	ReNew, ACME Group, Greenko Group, Azure Power, Tata Power Renewables, Hero Futures and multiple global RE platforms operating in India	Most of the major global players are present in India	Zeppelin PS, Vestas, Enercast, Siemens Gamesa, RWE, Enercon, Nordex, Wattkraft
Electrolyser manufacturing	Following the auction conducted by SECI India in early 2024, several Indian players have shown interest and announced domestic manufacturing of electrolyser system (stack).	**Alkaline** • Greenko-John Cockerill • L&T – Mcphy • Reliance Industries (New Energies) • Adani New Industries Ltd • Matix - Gensol **PEM** • Ohmium (operating plant) **SOEC** • Homi Hydrogen	**Alkaline** • John Cockerill • McPhy • HydrogenPro • Stiesdal • NEL Hydrogen. • LONGI (China) • PERIC (China) • Sungrow (China) **PEM** • Cummins • ITM • Siemens • Plug Power • NEL Hydrogen **SOEC** • Topsoe • Bloom Energy • Ceres • Sunfire	**Alkaline** • Sunfire • Thyssenkrupp Nucera • VIRIDI • Whitecell-Eisenhuth **PEM** • Whitecell-Eisenhuth • H-Tec System **SOEC** • Sunfire **AEM** • Enapter

47 https://www.vdma.org/documents/34570/4106139/VDMA+P2X4A+Herstellerverzeichnis+03_2024.pdf/65d066dd-616b-bf7c-f547-7adde0273c12?t=1710158240982

	BOP electricals include transformer, inverter, motors, cables, switchgear etc.	Several established manufacturers are present in India, such as Siemens, ABB, Schneider, CG Power, BHEL, Polycab, Havells etc.	Most of the major players are present in India	SIMERICS, Stiwa, Stromag, Sunfie, Voith Group, WAGO, WAchendorff, Weidmüller, WIKA, Wilo, ZBT, Zeppelin Baumaschinen, Bosch, Siemens Energy, Lanxess, Linde, Calorie
Water system	This includes desalination plant, pre-treatment plant, DM plant etc.	Thermax, Ion Exchange, Va-tech wabag etc.	Metito, Doosan, Hitachi, Acciona etc.	Harbauer (India) Private Limited, Evonik, EMCEL, Phaeson GmbH, Aqua Engineering, WLT Deutschland GmbH
Technology licensor for Ammonia loop	Ammonia synthesis technology is available with handful of technology licensors	-	Topsoe, KBR, Casale	
Ammonia plant EPC	Capability is mostly available with global EPC players	-	Technip, Mcdermott, Tecnimont, KBR, SNC-Lavalin, Wood Group etc.	Linde Group, CALORIC Anlagenbau
Ammonia plant FEED	Basic engineering including sizing and preparation of design basis report	Engineers India Limited (EIL)	Tecnimont, Technip, Mott Macdonald	Thyssenkrupp, Fichtner, Dornier
Other EPC (infrastructure, buildings, T&D etc.)	Other BOP infrastructure	L&T, Tata Projects, KEC, Techno-Electric etc.		Dornier, Fichtner
Logistic and pipeline service provider	This is the bridge between production plant to port or consumption point	Mysore Ammonia, GAIL, Petronet LNG, Jaysons		GAS, Linde, HYDAC, Goetze KG Armaturen, Zwick Armaturen
Hydrogen/ Ammonia storage tank	For storing hydrogen or ammonia at the plant end or at port	Thyssenkrupp Industrial Solutions, Linde, Air Liquid	Air Liquid	Linde Group, Storage Erzel GmbH, Hydogenious LOHC, SMA Altenso, AMBARtec AG

3.6 Sustainability dimensions along the project value chain

Any responsible investor should consider specific sustainability dimensions along the project value chain for undertaking socio-economic and environmental impact studies.

Table 19: Sustainability dimensions along the project value chain

Dimensions	Key issues	Description
Energy, Emissions and Climate change	GHG emissions	• Reduce total CO2 equivalent emissions per ton of product • Reduce Scope 2 and 3 emissions • Develop and prioritize a list of viable greenhouse gas reduction capital projects.
	Energy Management	• Reduce Specific Energy Consumption by implementing energy efficiency measures and potential fuel shift
	Air Quality	• Maintain a clean air quality with continuous monitoring mechanism
	Water Management	• Identify and evaluate a list of viable water reuse/ reduction projects. • Develop integrated water resource management plans to ensure sustainable withdrawals and discharges.
Workplace & Communities	Workforce Health and Safety	• Train and certify compliance with the Environmental, Health, Safety, and Security Policy for all employees annually
	Process Safety, Emergency Preparedness, & Response	• Train the employees and workers on process safety and emergency response; develop SOPs and make those accessible to everyone.
	Training and Development	• Develop training programs and design growth paths for employees
	Inclusion, Diversity, & Equity	• Increase representation of females in leadership roles • Train on inclusion, diversity and equity matters for all employees annually. • Develop pathways for traditionally underrepresented employee groups with the ultimate goal of increasing the hiring and promotion of underrepresented groups. • Increase engagement and support with local communities and expand the corporate giving philosophy to include environmental sustainability
	Safety & Environmental Stewardship of Chemicals	• Identify and complete safety critical equipment inspections per schedule
Ethics & Governance	Ethics	• Train and certify compliance with the Code of Corporate Conduct for all employees annually. • Train and certify compliance with the Anti-corruption Compliance Policy for all employees annually
	Reporting, Management of Legal & Regulatory Environment	• Begin to report and disclose Company data in accordance with the Task Force on Climate-related Financial Disclosures (TCFD) framework for climate related risks and opportunities, in addition to the Global Reporting Initiative (GRI) and Sustainability Accounting Standards Board (SASB) • Engage suppliers and service providers that annually represent 50% of the Company's total procurement and supply chain expenditures and assess their ESG performance and commitment.

Each of the above dimensions are aligned with UN SDGs and investors should focus on prioritizing the above issues and work closely with stakeholders to address those along the project value chain.

4 Specific framework for green Ammonia

Ammonia is the basic building block of the global nitrogen value chain (**~190mmts** production in 2023e)[48]. The ammonia market serves the captive production of fertiliser and other industrial products. Nearly 75% of the gross ammonia consumption is concentrated with fertilisers, with Urea having the largest share; the remaining is consumed in other industrial applications viz. chemicals, textiles, pharmaceuticals, mining, others.

From a regional consumption perspective, China is the largest consumer as well as producer with more than 30% share, followed by USA (10%), India (10%) and EU (8%).

Ammonia is a globally traded commodity, with global exports equating to more than 10% of total production. Urea, its most common derivative, is traded even more widely, at just under 30% of its production[49].

USA and China are the largest domestic merchant markets for ammonia as the volumes of the chemical stays within country borders. Deep sea trade and merchant volumes of ammonia largely includes the transactions between large players and imports done by traders. The merchant volumes primarily cater to the industrial demand for ammonia concentrated in the chemical industries. Currently, USA and India are the largest importers of ammonia while Trinidad & Tobago and Russia are the largest exporters.

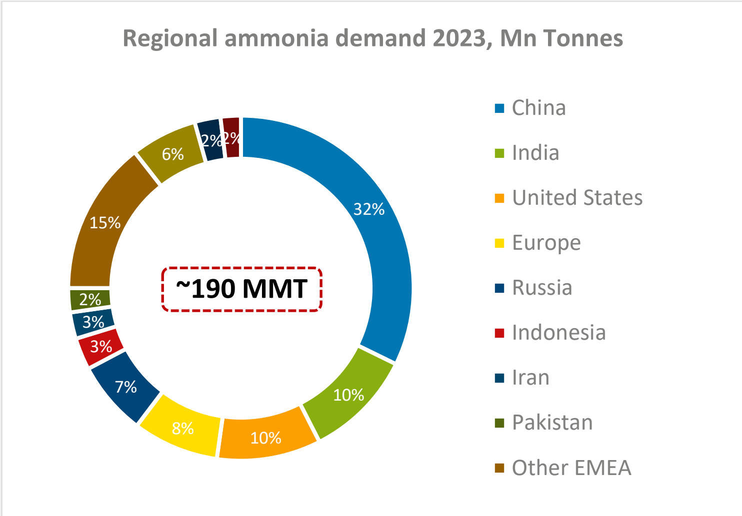


Figure 21: Regional ammonia demand in 2023

Ammonia is typically transported around the world in the form of anhydrous ammonia, in its pure form containing no water, or, alternatively, as an ammonia solution, dissolved in water, usually with 24.5% content. Anhydrous ammonia is normally liquified, which requires compression to around 7 times atmospheric pressure or chilling to around -33°C. Of the 190 mmts of Ammonia demand globally, only 10% is traded due to challenges with the transportation and storage[48]. However, the dynamics of product has changed with Ammonia emerging as an energy vector due to its hydrogen content.

With increasing focus on industrial, transportation and maritime decarbonisation, green hydrogen or ammonia is expected to play a critical role as a decarbonisation agent. Among several geographies, EU has emerged as a major demand centre. At the same time, EU's initiatives to promote green hydrogen or ammonia is most encouraging. Several schemes, directives and regulations have been announced and enacted to support hydrogen economy in EU – few prominent announcements include "Fit for 55", "RePowerEU", Renewable Energy Directives (RED) etc.

4.1 Regulatory framework and initiatives in Europe

With the European Green Deal announced in 2019, Europe was the first to declare its ambition to be a climate-neutral continent by 2050. It was one of the main drivers and architects of the 2015 Paris Agreement and set the target of reducing its emissions by 40% compared to the levels in 1990 by 2030. Various directives, regulations and legislative packages have been introduced since then to fight climate change.

4.1.1 Summary of initiatives

Table 20: Summary of EU regulatory and policy initiatives

Event	Timeline	Policy description
European Green Deal	December 2019	Goal of making Europe the first climate-neutral continent by 2050
European Industrial Strategy	March 2020	Foundation for an industrial policy to support the transition to a green and digital economy, making EU industry globally competitive

48 IHS Markit, Fertecon, Analyst reports
49 Source: IEA (access here)

Event	Timeline	Policy description
Fit for 55 packages	July 2021	This legislative proposal was announced alongside European Climate Law targeting to reduce net GHG emissions by 55% by 2030 (vs 1990 base). The programme included plans for an updated EU Emissions trading system (ETS) and the creation of a Euro 65bn Social Climate Fund.
REPowerEU	May 2022	Launched in response to the global energy market disruption caused by Ukraine crisis, it was intended to reduce Europe's dependence on Russian Oil and Gas and tackle the climate crisis. This plan targets 45% penetration of renewable energy in Europe by 2030. On green hydrogen, the target was to produce 10 million MT and to import 10 million MT by 2030. It also envisages to deploy a Carbon Contracts for Difference (CCfD) to create a green hydrogen market.
Renewable (Green) hydrogen initiatives	2022-23	Multiple initiatives have been announced to promote renewable hydrogen in the EU: • **Important Projects of Common European Interest ('IPCEI'):** Public funding support for two important large scale hydrogen projects - announced funding for two important hydrogen project - EUR5.4bn Hy2Tech and the EUR5.2bn Hy2Use projects. These projects address both "demand" and "supply" side of GH2 projects. • **European Hydrogen Bank:** This is a market making mechanism. The pilot phase of the Bank would start in 2023 with a direct subsidy scheme that aims to close the market price gap between renewable green hydrogen and its fossil-derived grey counterpart through the Euro 3bn European Hydrogen Bank (EHB). Funding support will be provided for 10 years • **H2Global (Germany):** Double-sided auction-based mechanism, the difference between supply prices (production and transport) and demand prices will be compensated using **€ 900 million** grant funding from the German government. Auction process is expected to be concluded by the first half of 2024. • **EU Innovation Fund:** EU will allocate **€ 1 billion** for electrification and renewable hydrogen production and use in industry. It will support mid-sized pilot projects with deep decarbonisation potential.

Source: European Commission, Deloitte analysis

"Fit for 55 packages" were central to Europe's energy transition. The plan aims to reduce greenhouse gas (GHG) emissions by at least 55% by 2030 compared to 1990 levels. It contains a set of proposals to revise, tighten and update existing EU legislation and to introduce some new initiatives to ensure the EU's policies are in line with the 2030 climate goal. Key initiatives, regulatory processes and policy measures under "Fit for 55" are captured below:

- **Reform in EU's Emission Trading Scheme (ETS):** ETS was launched in 2005 as a carbon 'cap-and-trade' emission trading mechanism. Under this mechanism, free allowance allocation is used to safeguard the competitiveness of the regulated industries and to avoid carbon leakage. The new proposal phases out free allowances to companies from 2026 until 2034, and an ETS-II is planned for the building and road transport sectors from 2027-28. Maritime and aviation sectors are also proposed to come under the ambit of ETS scheme. Overall, more carbon-emitting sectors will have to pay for CO2 emissions under the EU ETS and the cost of CO2 quotas under the scheme will increase
- **Carbon Border Adjustment Mechanism (CBAM):** The EU Parliament adopted rules for the CBAM aiming to prevent "carbon leakage" by subjecting certain groups from non-EU and non-EFTA to a carbon levy. From October 2023, goods such as iron, steel, cement, aluminium, fertilisers, electricity, hydrogen will be covered by the CBAM. While the implementation of CBAM will likely be beneficial for European industrial producers that come under the EU ETS, this will force major exporters to EU to reduce their emissions.
- **ReFuelEU Aviation**: The package mandates a minimum use of Sustainable Aviation Fuel (SAF) by airlines in the EU. This is currently set to be 2% of fuel use by 2025, 5% by 2030, 20% by 2035, up to a maximum of 70% by 2050

- **FuelEU Maritime**: The goal of this **initiative i**s to reduce the emission intensity of the maritime sector by up to 80% by 2050. The new rules promote the use of renewable and low-carbon fuels in shipping

Fit for 55 package stands as a bold step forward in the EU's efforts to combat climate change, setting a precedent for other regions to follow. With its wide-ranging set of legislative proposals and targets, the package has set a strong example for global climate action. A key element in the 'fit for 55' package is the revision of the Renewable Energy Directive to help the EU deliver the new 55 % GHG target.

The Renewable Energy Directives were launched in 2009 setting a renewable energy target of 20% by 2020. The minimum targets, which varied between Member States, collectively ensured that the overall EU-level target of 20% would be met. The RED II came into effect in 2018 with a target of 32% renewable energy target by 2030 which was further ammended in October 2023 (RED III) with a target of 42.5% at the EU level by 2030.

Key to the implementation of renewables across Europe, is to utilize renewable fuels of non-biological origin (RFNBO), commonly referred to as renewable hydrogen, in sectors where direct electrification is not possible. RED II defined RNFBO as "liquid or gaseous fuels which are used in the transport sector other than biofuels or biogas, the energy content of which is derived from renewable sources other than biomass"[50]. RED III set out Union-wide targets for the use of RFNBO in the industry at 42% by 2030 and 60% by 2035.

Major policy and regulatory initiatives impacting import of hydrogen are described below:

Carbon Border Adjustment Mechanism (CBAM)

The Carbon Border Adjustment Mechanism (CBAM) entered into application in its transitional phase on 1 October 2023. CBAM is EU's landmark tool to fight carbon leakage and one of the central pillars of its ambitious *Fit for 55* agenda. The mechanism envisages to equalize the price of carbon between domestic products and imports. This will ensure that the EU's climate policies are not undermined by production relocating to countries with less ambitious green standards or by the replacement of EU products by more carbon-intensive imports.

General principles of CBAM

- It aims to prevent 'carbon leakage' by subjecting the import of certain groups of products from 3rd (non-EU and non-EFTA) countries to a carbon levy linked to the carbon price payable under the EU Emissions Trading System (ETS) when the same goods are produced within the EU.
- Currently, only few categories of goods, such as iron and steel, cement, fertilisers, aluminum, electricity, and hydrogen are in scope of the CBAM. Scope will additionally include certain precursors, and a limited number of downstream products. Further scope extensions to include additional products (such as chemicals and polymers) are to be determined by 2026, and the full inclusion of all EU ETS products is planned by 2030.
- With the start of certificate trading from 1 January 2026, importers are obliged to purchase sufficient emission allowances for imported embedded emissions during the year. Within the framework of an annual CBAM declaration, the amount of imported embedded emissions will be compared with the acquired emission allowances.
- Direct and indirect CO2e emissions contained in imported CBAM goods are to be verified and tested by a certified testing body.

Transitional phase (1.10.2023 – 31.12.2025)

- During the transitional phase (as of 1 October 2023), importers of CBAM goods will be required to submit quarterly reports with the following content:
    - Quantities of CBAM goods imported during the quarter, specified per country of origin per production site where the goods are produced.
    - The embedded direct (and - if applicable -, indirect) greenhouse gas emissions thereof; and (If applicable) the carbon price due in the country of origin.
  - During this period, importers of goods in the scope of the new rules will only have to report greenhouse gas emissions (GHG) embedded in their imports (direct and indirect emissions), without making any financial payments or adjustments.

[50] European Commission

- In its transitional phase, CBAM will only apply to imports of **cement, iron and steel, aluminum, fertilisers, electricity, and hydrogen.**
    - **EU importers of those goods** will have to report on the volume of their imports and the greenhouse gas (GHG) emissions embedded during their production, but without paying any financial adjustment at this stage.
- Indirect emissions will be covered in the scope after the transitional period for some sectors (cement and fertilisers), based on a defined methodology outlined in the Implementing Regulation published on 17 August 2023 and its accompanying guidance.
- The Implementing Regulation on reporting requirements and methodology provides for some flexibility when it comes to the values used to calculate embedded emissions on imports during the transitional phase.
    - Until the end of 2024, companies will have the choice of reporting in three ways: (a) full reporting according to the new methodology (EU method); (b) reporting based on an equivalent method (three options); and (c) reporting based on default reference values (only until July 2024).
- As of 1 January 2025, only the EU method will be accepted, and estimates (including default values) can only be used for complex goods if these estimations represent less than 20% of the total embedded emissions.
- The transitional phase will serve as a learning period for all stakeholders (importers, producers, and authorities). It will allow the European Commission to collect useful information on embedded emissions to refine the methodology for the definitive period, which starts on 1st January 2026.

The Commission has also developed dedicated IT tools to help importers perform and report these calculations, as well as in-depth guidance, training materials and tutorials to support businesses when the transitional mechanism begins.

Definitive period (1.1.2026-31.12.2034)

Once the permanent system enters into force on 1 January 2026, importers will need to declare each year the quantity of goods imported into the EU in the preceding year and their embedded GHG. They will then surrender the corresponding number of CBAM certificates. The price of the certificates will be calculated depending on the weekly average auction price of EU ETS allowances expressed in €/ton of CO2 emitted. The phasing-out of free allocation under the EU ETS will take place in parallel with the phasing-in of CBAM in the period 2026-2034.

The CBAM, which is a supplementary measure to the EU ETS, operates by imposing a charge on the embedded carbon of certain imports, which is equal to the charge imposed on domestic goods under the ETS, with adjustments being made to this charge to consider any mandatory carbon prices in the exporting country. This is designed to prevent carbon leakage, which would occur if consumers switched from buying EU-produced goods to purchasing substitutes from non-EU countries where a lower (or no) carbon price is levied or if firms shifted production activities from the EU producers to such countries.

Currently, no geographies other than EU have imposed any trade restriction or penalty for emission intensive products. However, with the increasing focus on emission reduction, similar initiatives are expected from other developed nations.

FuelEU Maritime Directive

The Council's adoption of the new regulation marks a significant step forward in decarbonizing the maritime sector within the EU through the FuelEU maritime initiative. This initiative, integral to the EU's Fit for 55 package, aims to bolster the utilization of renewable and low-carbon fuels, thereby diminishing the carbon footprint of maritime activities.

Aligned with the EU's climate ambitions for 2030 and 2050, the legislation sets forth key provisions including a gradual reduction of greenhouse gas intensity in shipping fuels, incentivizing the adoption of high-decarbonisation potential renewable fuels, and excluding fossil fuels from certification processes. The regulation outlines measures to reduce GHG intensity by shipping sector by 2% in 2025 and as much as 80% in 2050[51].

[51] European Council (access here)

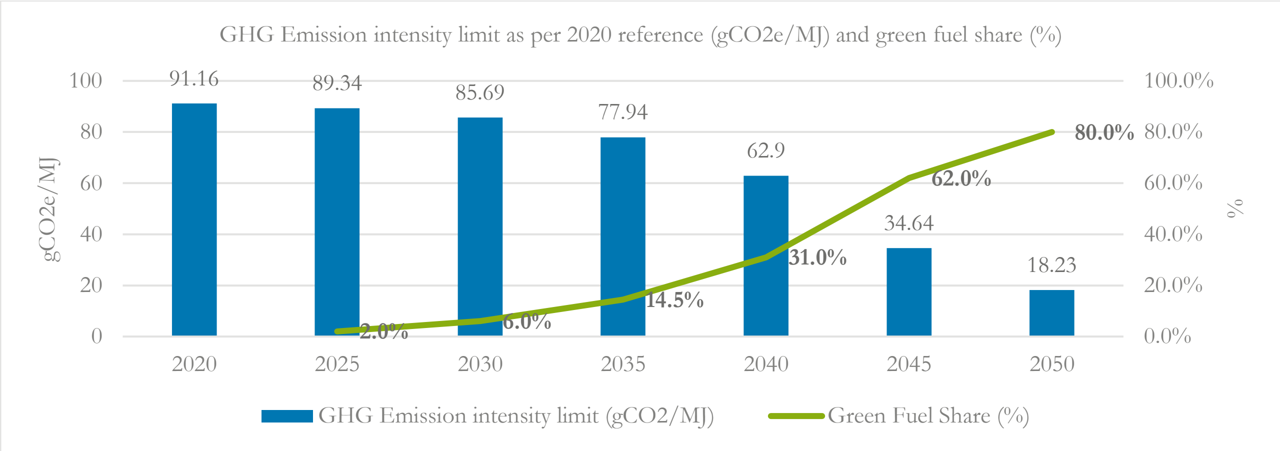


Figure 22: GHG Emission intensity from shipping as per FuelEU Maritime

Source: DNV (access here), Safety4Sea (access here)

The above targets are expected to become more ambitious over time to stimulate and reflect the necessary developments in technology and the uptake in production of renewable and low-carbon fuels. The targets also covers methane and nitrous oxide emissions, in addition to CO2 emission, over the full lifecycle of the fuels used onboard. FuelEU Maritime is expected to enter into force from 1 January 2025.

The FuelEU Maritime Directive promotes the use of renewable, low-carbon fuels and clean energy technologies for ships, essential to support decarbonisation in the sector. This would lead to uptake of low emission fuels viz. green methanol, green ammonia, etc. in the industry.

European Hydrogen Bank

The European Hydrogen Bank is a financing instrument designed to accelerate the establishment of a full hydrogen value chain in Europe. It was launched in 2022 by the European Commission, with the goal of creating investment security and business opportunities for European and global renewable hydrogen production. The bank is not a physical institution but rather a financing mechanism run internally by European Commission services. Its main objective is to unlock private investments in hydrogen value chains, both within the EU and globally, by connecting renewable energy supply to EU demand and addressing the initial investment challenges[52].

It aims to establish an initial market for renewable hydrogen. Funding will be awarded as a fixed premium in €/kg of verified and certified renewable fuel of non-biological origin (RFNBO) hydrogen produced. The European Hydrogen Bank has already conducted its first auction, which awarded nearly €720 million to 7 renewable hydrogen projects across Europe under the Innovation Fund. The successful projects were selected by the European Executive Agency for Climate, Infrastructure and Environment (CINEA) who evaluated 132 bids submitted to the auction between November 2023 and February 2024 and ranked them according to their bid price. The projects will receive the awarded fixed premium subsidy for up to 10 years for certified and verified renewable hydrogen production.

H2Global

H2Global is a project focused on positioning Europe as a global leader in the green hydrogen economy. It uses a "double-auction" model to bridge the gap between the high global prices for green hydrogen and the lower prices at which it can be sold and used economically in Europe[53].

The program established an intermediary body called the Hydrogen Intermediary Network Company (HINT.CO) to sign long-term agreements. Through a double auction scheme, the lowest purchase agreement and the highest sale agreement resulting from the auctions would be awarded the contract, while too high purchase offers, and too low sale offers would be rejected. Price difference will be paid using contracts-for-difference (CfD) to compensate the difference between supply and demand price through federal funding assistance (allocated Euro 900 million for pilot auction, with a further Euro 3.6 bn earmarked for the scheme in the government's 2023 draft budget, making it to ~€ 4.5 Bn contribution from the German Government).

---

[52] European Commission (access here)

[53] BMWK, What exactly is H2Global? (access here)

HINT.CO GmbH has recently called for tenders on PtX products; HINT.CO will purchase green hydrogen or derivatives from overseas producers, via 10-year Hydrogen Purchase Agreements (HPAs). European customers will then bid for short-term supply contracts via separate tenders. The programme will run for 10 years from the award of its first contract. By improving the cost-competitiveness and availability of green hydrogen, the scheme aims to drive decarbonisation of refineries (facilitating substitution of green H2 for fossil fuels and grey hydrogen), steel (substituting for coke/natural gas), and the chemicals sector (substituting for gas/oil).

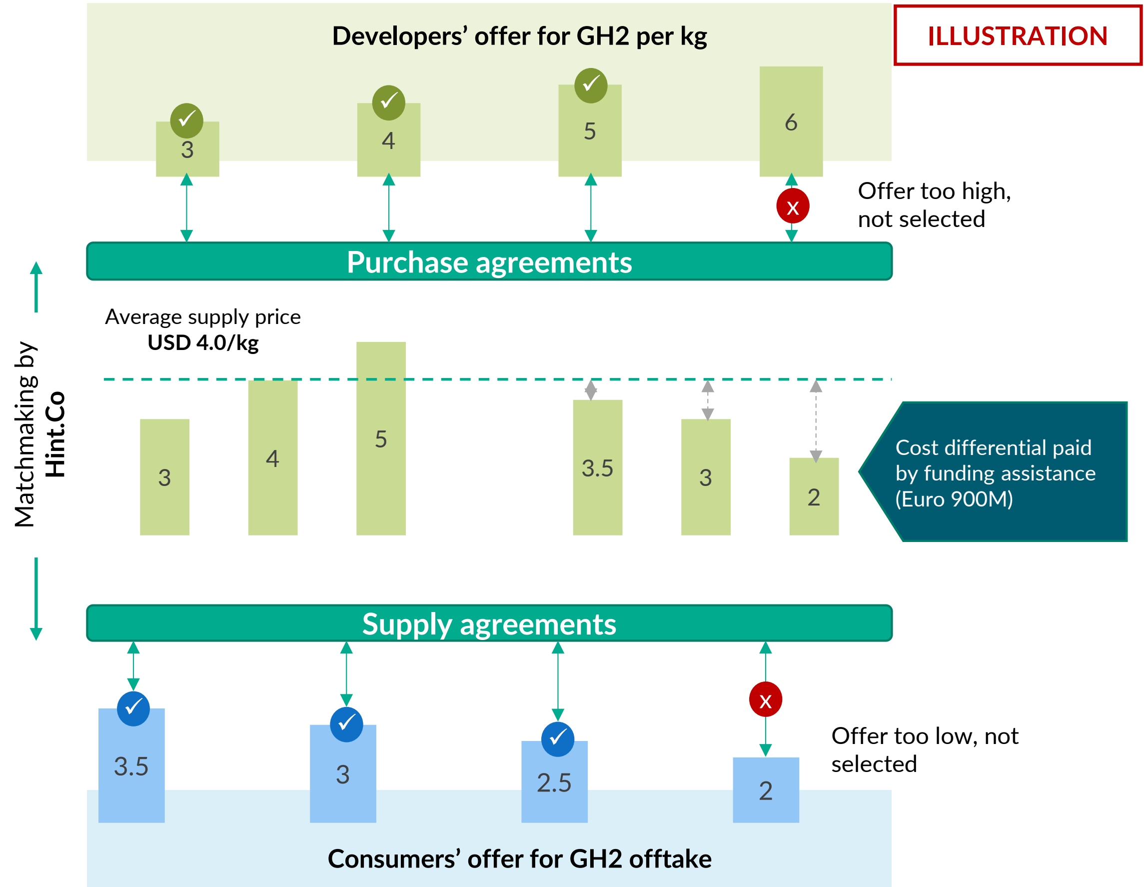


Figure 23: Illustration of H2Global scheme

Source: IRENA, H2Global

PtX Development Fund

The PtX Development Fund is a German initiative that provides €270 million in grants to enhance hydrogen production in selected countries like Morocco, South Africa, Brazil, Egypt, Georgia, India, and Kenya. The fund is managed by KGAL through an internationally tendered mandate from the KfW group[54].

The fund is part of the broader PtX Platform of KfW Banking Group, which provides comprehensive advice and integrated financing solutions for large-scale PtX (Power-to-X) projects outside of Europe[55]. The planned funding phase is from Q1 2024 – Q4 2027 and the targets mature industrial-scale green hydrogen projects related to the PtX value chain[56].

The fund aims to stimulate the market ramp-up of green hydrogen and contribute to the decarbonisation of the global economy by closing the "bankability gap" for capital-intensive PtX projects. The PtX Platform provides a mix of grants and other financing instruments from KfW Group, including promotional loans, equity, debt, and mezzanine financing, to support investments in the production, transport, and use of green hydrogen in partner countries.

[54] KGAL (access here)
[55] KfW (access here)
[56] PtX Fund (access here)

4.1.2 Sustainability criteria as per Delegated Act (DA) to Article 27 of RED II of 2022

This Delegated Act sets out the criteria for sourcing renewable electricity used in the production of RFNBOs including renewable hydrogen. The act defines three criteria i.e., additionality, temporal correlation, and geographical correlation.

Table 21: Sustainability criteria as per Delegated Act

Additionality	Temporal Correlation	Geographical correlation
When renewable energy is used for hydrogen production, • The power should be generated in the same installation; OR • The power should be sourced through a PPA with renewable power project	Hydrogen production takes place: • In the same calendar month than the sourced RES E generation until Dec 2029) • In the same hour than sourced RES E generation (from Jan 2030) OR	Electrolyser and renewable energy generation plants are located in the same bidding zone OR
Renewable energy projects used for powering the electrolyser should have started operating no more than 36 months prior to the installation of the electrolyser	Hydrogen Storage options: • Electricity is sourced from a storage facility with the same grid connection point than the electrolyser or RES-E plants • Storage facility is charged at the time of generation of the contracted RES-E plants OR	Electrolyser and RE generation plants are located in interconnected bidding zones • Electricity prices of the day ahead market in this zone are ≥ the prices in the electrolyser's bidding zone OR
The renewable energy projects should be unsupported and should not have received operating or investment support.	Hydrogen production takes place: • during a one-hour period where the day ahead price of the concerned bidding zone is < 20 €/MWh; OR • Is < than 0.36 times the price for a certificate of 1 ton of CO2 equivalent	RES-E generating plants are located in an offshore bidding zone interconnected to the electrolyser's bidding zone

4.1.3 Compliance with RED II in India

The EU imposes the sustainability rules as per RED II to renewable hydrogen produced inside the territory of the EU as well as outside, making them essential to third countries who want to export renewable hydrogen to the EU. Therefore, Indian projects aiming to export green hydrogen to EU have to comply with the criteria defined under RED II, viz. Additionality, Temporal Correlation, and Geographical Correlation.

Different options for sourcing renewable electricity for hydrogen or ammonia production have been assessed along the RED criteria:

Table 22: Compliance matrix of green electricity sourcing

Criteria / RE Route	RE Third party open access	Captive Open access	Green Day ahead market[57]	Green term ahead market	Grid green tariff by Discom
Additionality	✓ Can be ensured by entering into PPA with RE developer having started operations no more than 36 months prior to the installation of the electrolyser	✓ Can be ensured by equity investment in a RE project which started operations no more than 36 months prior to the installation of the electrolyser	✗ Cannot be ensured as the power is traded through double sided blind auctions; exchanges don't publish one on one matching data	✗ Matching is 'one on one', however, the exact whereabouts of the RE developer (viz. CoD) are not available to the buyer	✗ The power is labelled green, however, the Discom cannot identify RE project being used to power the electrolyser
Temporal correlation	✓	✓	✓	✓	✓

[57] The power market in India especially the GDAM (Green Day ahead market) works on the principle of "One Nation One Grid" which considers the entire country as one bidding zone. Thus, the conditions of geographical correlation are met through the power market for sourcing green power.

Criteria / RE Route	RE Third party open access	Captive Open access	Green Day ahead market[57]	Green term ahead market	Grid green tariff by Discom
Geographical correlation	✓	✓	✓	✓	✓

Note: From Jan 2030, RE projects which will use banking facility will not be in compliance with "Temporal Correlation" criteria as the RE generation and consumption should happen in the same hour.

Based on the current regulations, the power sold in GDAM and GTAM is not likely to qualify as per the additionality criteria mentioned in the Delegated Acts. Buyers (Green hydrogen/ ammonia producers) should procure power from individual projects instead of portfolio with greater preference to GTAM compared to GDAM. The one on one matching on the GTAM can be leveraged to procure the power from individual projects instead of state Discoms.

In order to allow green market power, the Power Exchange bye-laws in India require certain changes to add disclosure of data viz. location, date of commissioning, and existing PPAs to align with the additionality requirements. Concerted efforts from Power exchanges, renewable power project developers is required to seek the approval from the CERC for additional data disclosures.

4.1.4 Emission threshold as per Delegated Act (DA) to Article 28 of RED II of 2022

The second delegated act defines the maximum GHG emission intensity threshold for RFNBOs as 70% below a fossil fuel comparator of 94 gCO2eq/MJ. This translates to ~3.4 tCO2eq./ton emission threshold for hydrogen. Given the hydrogen content in Ammonia, the emission threshold for Ammonia turns out to be **~0.61 tCO2eq./ton**.

The total emissions from the use of fuel (E) is calculated as follows:

$$\boldsymbol{Total\ emissions\ from\ use\ of\ fuel\ (E) = E_i + E_p + E_{td} + E_u - E_{CCS}}$$

- E_i - emissions from supply of inputs (gCO2eq / MJ fuel),
- E_p - emissions from processing (gCO2eq / MJ fuel),
- E_{td} - emissions from transport and distribution (gCO2eq / MJ fuel),
- E_u - emissions from combusting the fuel in its end-use (gCO2eq / MJ fuel)[58] and
- E_{ccs} - emission savings from carbon capture and geological storage (gCO2eq / MJ fuel).

GHG Emission savings are estimated with respect to total emissions of fossil fuel comparator for hydrogen.

$$\boldsymbol{GHG\ emission\ savings = (E_F - E)\ /\ E_F}$$

Where, E_F is the total emissions of fossil fuel comparator (94 gCO2e/MJ for H2) and E is the total emissions of H2 (gCO2eq./MJ).

Permissible emissions for exporting ammonia from India to Europe basis RED II criteria

Based on the criteria defined in delegated acts, the GHG emissions from green ammonia cannot exceed 0.61 tCO2eq./t to be qualified as "green" in EU. This includes emission from hydrogen production, Haber-Bosch conversion, air separation, transportation, and pumping of ammonia at source and destination ports. An illustration of the same has been provided below.

[58] This would also include the emissions from cracking the ammonia in the destination

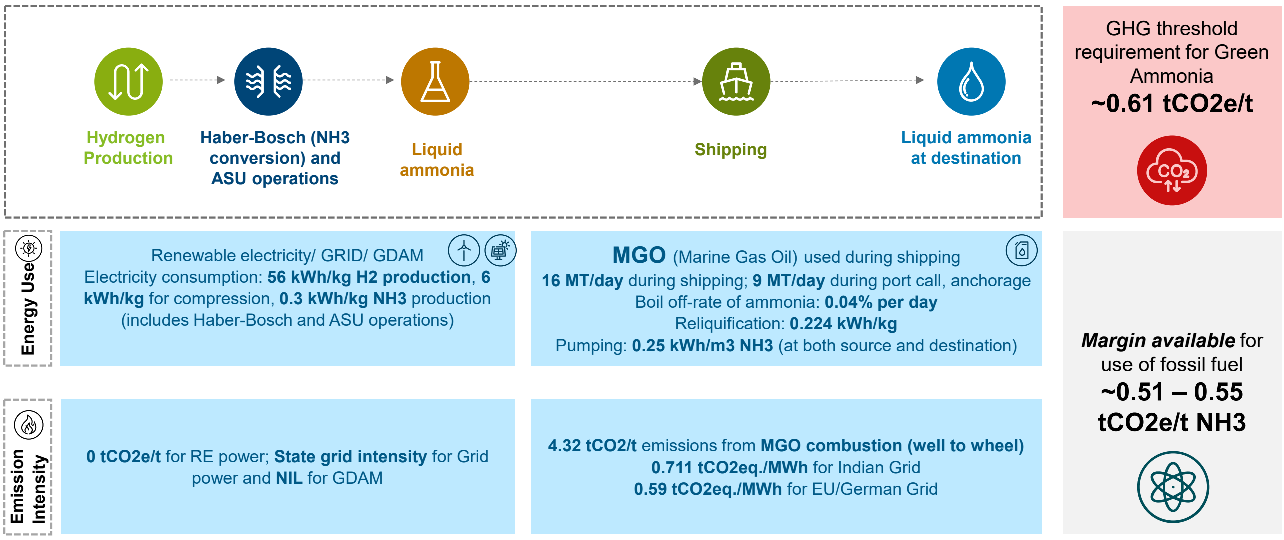


Figure 24: Emission calculation methodology for GNH3 export from India to EU

Shipping 1 ton of green ammonia from India to Europe through Suez Canal generates 0.08 – 0.09 tons CO2[59]. This includes the well to wheel emissions of MGO as well as the electricity consumed at the ports for pumping the ammonia from to and from the ships at the ports.

As per the available emission margin for green ammonia and the emission intensity for the Indian power grid (0.711 gCO2/kWh), nearly 6.5 - 8% of the electricity from national grid can be utilized for hydrogen electrolysis and ammonia loop operations. However, if emission intensity of regional grids is considered, the permissible limit may vary with regions.

4.1.5 RED II criteria and its applicability across the green ammonia value chain

The sustainability criteria in Delegated Act outlines the requirement for qualifying electricity as green and Article 28 of Delegated Act defines the emissions to be considered for the overall use of fuel. The table below captures the entire value chain of ammonia production from manufacturing of equipment till the end use of the product and the applicability of RED II delegated acts on each of them.

Sl.	Particular in green hydrogen value chain	CO2 emissions to be accounted as per RED II	Sustainability criteria for green electricity as per RED II
Equipment manufacturing			
1.	Manufacturing of any equipment required for GH2/ GNH3 production	Not applicable	Not applicable
2.	Transport of Components	Not applicable	Not applicable
3.	Installation of any equipment required for GH2/ GNH3 production	Not applicable	Not applicable
4.	Business travel & Employee Commuting	Not applicable	Not applicable
Power Production			
5.	RE generation	Applicable. Considered as zero.	Applicable: Additionality, temporal and geographical correlation
6.	Transmission and distribution	Applicable. Considered as zero.	Not applicable.
Water			

[59] Considering a shipping vessel of 40,000 MT capacity

Sl.	Particular in green hydrogen value chain	CO2 emissions to be accounted as per RED II	Sustainability criteria for green electricity as per RED II
7.	Seawater desalination	Accounted; ~2 kWh/KL of salted water, translating to 31 kWh/ton of ammonia	Not applicable as it doesn't contribute to the calorific value of GH2
8.	Water transport (pumping)	Accounted. Insignificant power consumption per ton of ammonia (included in overall BOP power consumption)	Not applicable as it doesn't contribute to the calorific value of GH2
9.	Final purification and filtration on site	Accounted. Included in overall BOP consumption.	Not applicable as it doesn't contribute to the calorific value of GH2
10.	Steam production	No steam production is accounted for green ammonia production	Not applicable
Electrolysis			
11.	Electrolysis process	Accounted. Consumes 52 kWh/kg of GH2 production. In addition, 4 – 4.5 kWh will be consumed for BOP system, gas purification, drying and cooling	Applicable. Note: Electricity is an input that contributes to the Lower Heating Value (LHV) of Hydrogen
12.	Gas purification, drying and cooling	Accounted. Included in the BOP consumption	Not applicable as it doesn't contribute to the calorific value of GH2
13.	Compression and storage	Accounted. Consumes 6 kWh/kg of GH2 storage	Not applicable as it doesn't contribute to the calorific value of GH2
Ammonia production			
14.	Air Separation Unit (ASU) for Nitrogen Production	Accounted. Consumes ~200 kWh/Ton of Ammonia	
15.	Ammonia synthesis loop	Accounted. Consumes 200 kWh/Ton of Ammonia; this includes H2 and N2 compressor	Not applicable.
16.	Local storage of ammonia	Accounted.	
Transport and storage			
17.	Local transport of hydrogen/ammonia via pipes, cylinders, tanks in source country	Accounted. Energy consumed for pumping through pipelines GNH3	Not applicable
18.	Storage in ammonia tanks at harbour terminal (pumping, other)	Accounted. Energy consumed for pumping GNH3 on and off ships 0.25 kWh/m³ NH3	Not applicable
19.	Boil off during storage and transportation	Accounted. Reliquefication consumes 0.224 kWh/kg NH3	Not applicable
20.	Boil off losses	Accounted. 0.04% per day of transportation/ shipping	Not applicable
21.	Shipping fuel consumption during sailing	Accounted. 38 MT/day of VLSFO consumed for a 40,000 MT vessel.	Not applicable.
22.	Shipping fuel consumption during anchorage	Accounted. 9 MT/day of VLSFO consumed for a 40,000 MT vessel.	Not applicable
23.	Local transport of ammonia via pipes, cylinders, tanks in destination country	Accounted; for pipeline transport, it will only be the electricity requirement for pumping	Not applicable
24.	Decentralized storage	No CO2 emission	
End use			
25.	End use (e.g. combustion, chemical feedstock or fuel cell)	No CO2 emission from Green hydrogen or ammonia consumption	Not applicable.

The European Commission has recently published a Q&A on the implementation of the hydrogen delegated acts[60].

> **Must all energy consumption used by a hydrogen production facility be of renewable origin to produce RFNBOs?**
>
> No, not necessarily. Electricity or other forms of energy that are used for other purposes (lighting, safety, balance of system) but do not add to the heating value of the output do not need to be renewable. However, the CO2 content of this energy source should be taken into account to calculate the greenhouse gas emissions savings achieved by the RFNBO. Similarly, electricity consumption that is used to compress transport or further process RFNBOs does not need to be renewable, unless it is used to add energy value to the RFNBO.

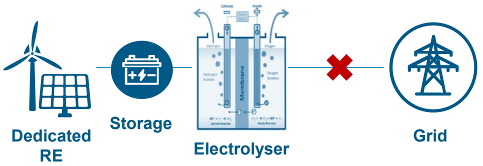
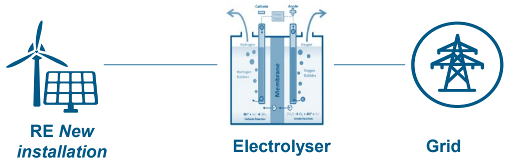
Keeping this in view, the electricity consumed in balance of system (water purification, desalination, air separation unit, transportation, compression, storage, etc.) can be fulfilled through non-RE sources. However, the emissions from such activities are captured to calculate the overall GHG emissions reduction from the RFNBO.

4.2 Options for green hydrogen/ ammonia production as per RED-II

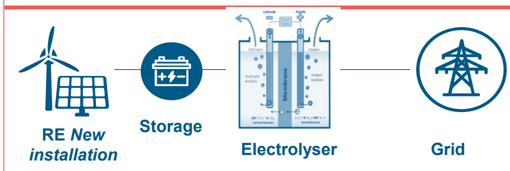
Based on the emission intensity threshold and the criteria of additionality, temporal & geographical correlations, multiple setups for green ammonia production can be configured. The electricity sourcing options range from off-grid electricity production to a combination of off-grid and grid electricity.

The exact sizing of the setup would depend on multiple factors viz. the emission intensity of the state grid in which the facility is located, distance between the source and destination ports, the RE generation profile in the state/ region, and cost of electricity procured from the grid. An illustration of different set-ups is provided below:

Table 23: Options for Green Ammonia production setup

Option	Brief
Electricity Produced Off-grid  	In an off-grid setting, the power for the electrolyser and the ammonia loop must be sourced from a solar-wind hybrid power plant with storage to mitigate the intermittency of RE sources. This is an island solution with no grid connection. The utilization factor of the electrolyser can be varied throughout the day, however, the ammonia loop would need a constant hydrogen feed which can be met by installing hydrogen storage at the electrolyser output.
Co-located RE and grid connection  	With a grid connection, the intermittency from the RE sources can be mitigated through power procurement from the grid. During non-solar hours, the power from grid can be used to ensure constant feed of hydrogen to the ammonia loop. However, a procurement from the grid cannot be beyond the permissible thresholds to meet EU RED guidelines.
Co-located RE and BESS with grid connection	A setup with grid connection, RE power and battery energy storage can also be configured to produce green hydrogen and ammonia. The setup would use grid power as per permissible thresholds and battery storage to mitigate the RE generation intermittency.

[60] European Union. Q&A implementation of hydrogen delegated acts (access here)

Option	Brief
	The capital cost of the setup needs to be optimised to manage the added cost of battery storage. The energy stored in the battery cannot be consumed beyond a month of charging to meet temporal correlation guidelines.

Source: Deloitte analysis

It is critical to analyse the cost of ammonia production with varied production setups. Sizing of RE and BESS will be critical to optimise the landed cost of electricity. A techno-economic scoping is required to evaluate all options and select the most optimum configuration.

5 Techno-economic Scoping for Green Ammonia Production Project

5.1 Methodology

India has inherent advantage of being one of the cheapest RE producer in the world[61]. Green ammonia production cost would depend on the landed cost of RE, electrolyser sizing, hydrogen storage requirements to ensure continuous ammonia loop operations battery installation to mitigate RE intermittency, etc.

The electrolysis process consumes 56 kWh of electricity to produce a kg of hydrogen; additional 6 kWh of electricity is consumed to compress a kg of hydrogen into the storage tanks. The ammonia loop further consumes 0.3 – 0.4 kWh of electricity to produce a kilogram of ammonia. In a **600 kTPA ammonia production** set up with baseload operation of ammonia loop, a constant hydrogen feed of ~12.5 tons per hour (tph) is required. While electrolyser operation can undergo load fluctuation, ammonia loop operation is less flexible due to technological complexities.

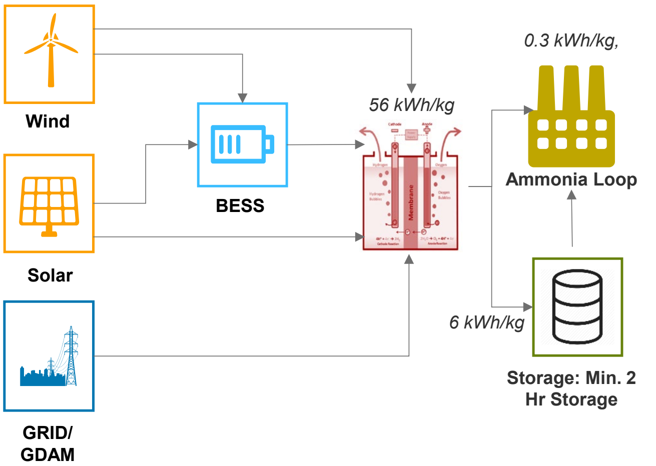


Figure 25: Ammonia production setup and associated energy consumption

It is important to optimise the green ammonia production configuration to minimise the levelised cost of ammonia. **An advanced excel based optimisation tool (using Open Solver) has been developed, which minimises the annual cost of operating the ammonia plant.** The annual cost has two components: (1) the annualised fixed cost of solar, wind, BESS, electrolyser, and hydrogen storage and (2) the operational expenses including power procurement from the grid and GDAM.

Major annual cost elements are tabulated below.

Table 24: Key assumptions for annual cost of ammonia production

Sl.	Particular	Capital expenditure	Annualised fixed cost input
1.	Solar Generation unit	INR 4.5 – 5 Cr/MW	INR 0.59 Cr/MW
2.	Wind Generation unit	INR 7 – 7.5 Cr/MW	INR 0.88 Cr/MW
3.	BESS (2 hours)	INR 3.5 Cr/MW	INR 0.58 Cr/MW
4.	Alkaline electrolyser	INR 5 Cr/MW	INR 0.9 Cr/MW
5.	Hydrogen Storage	INR 8 – 8.5 Cr/ton	INR 0.93 Cr/ton

Other assumptions for the optimisation model are:

- Landed cost of electricity from GDAM is considered in the range of INR 8 – 9/kWh
- Annual escalation of grid tariff is considered as 1.1 – 1.2%[62]. The quantum of electricity that can be procured from the grid depends on the emission intensity of the grid and the emission threshold as per EU norms
- The minimum electrolyser loading is assumed to be 30%.
- Minimum 2 hours of hydrogen storage is assumed for the optimisation model.

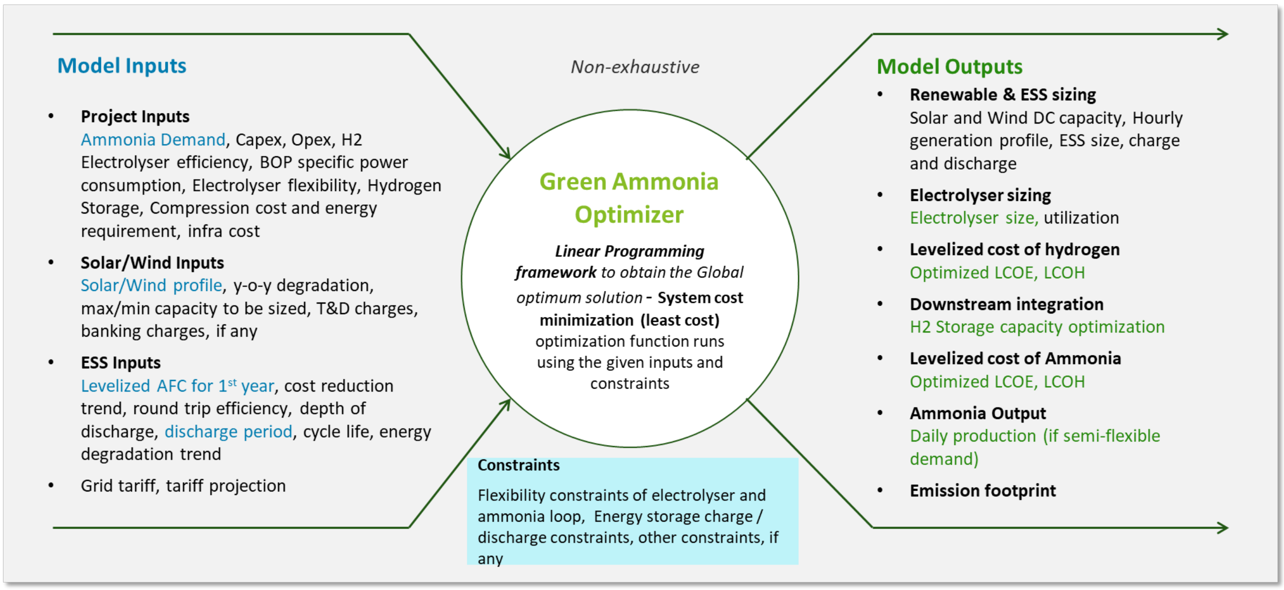
Basis these general assumptions, the objective function of the optimisation model minimises the annualised fixed cost and the operational expenditure, as illustrated below:

$$\boldsymbol{Objective\ function = Min\ (AFC(Solar, Wind, BESS, Electrolyser, Storage\ ) + Opex(Electricity\ from\ grid\ and\ GDAM))}$$

[61] Landed cost of electricity from multiple RE procurement routes has been captured in Chapter 3
[62] The tariffs have been adequately levelised

Why Optimisation is required?

Green ammonia production process is complex with multiple interplays and trade-offs between Variable Renewable Energy, BESS operation, electrolyser sizing and CUF, technical minimum of electrolyser, Hydrogen storage sizing etc. Therefore, a model based approach is critical to optimise the size and loading of an integrated plant. Seasonal Variation of RE generation makes the optimisation function even more complex.



5.2 Permissible grid power procurement for shipping ammonia to European ports

Based on the emission calculation methodology, as elaborated in the earlier section, the available emission threshold would depend on the source and destination ports. The source port decides the state's grid emission intensity[63] and the destination port decides the shipping distance and associated transport related emissions.

The distance between multiple Indian ports and major European ports of Hamburg and Rotterdam are shown below:

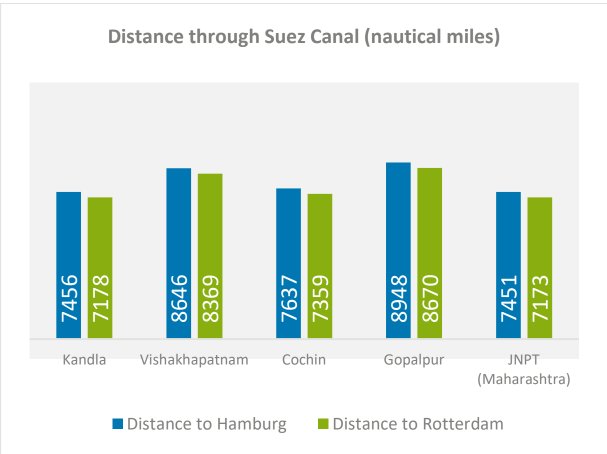


Figure 26: Distance from Indian ports via Suez Canal

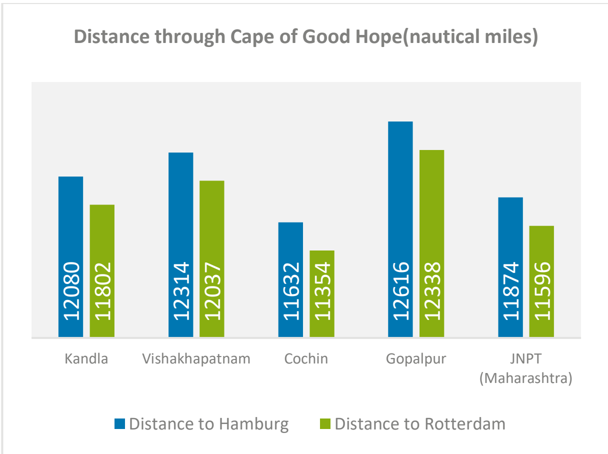


Figure 27: Distance from Indian ports via Cape of Good Hope

Source: Ports.com, Sea-distances.org

Transport related emission from ammonia shipping

Ammonia shipping is usually carried out in vessels of ~40,000 metric tons capacity. These vessels have an average speed of 16 knots and consume nearly 38 MT of marine gas oil (MGO) per day while sailing and 9 MT of MGO during port call and

[63] Considering regional grid emission intensity will be considered

anchorage[64]. MGO is the prime source for the propulsion of the ships, reliquification and the national grids are used for pumping ammonia at the source and destination ports. As per the EU norms, the well to wheel emission intensity for the utilized fuels is considered for the analysis. Based on this, the emission threshold for grid power and the quantum of total electricity that can be procured from grid for ammonia production is evaluated. Shipping emission and allowable grid procurement is captured in the below tables:

Table 25: Shipping emissions and allowable grid power procurement for shipping to Hamburg in a 40,000 MT capacity vessel

Port	Hamburg via Suez canal		Hamburg via 'Cape of Good Hope'	
	Shipping emission (tCO2/tNH3)	Permissible grid power (%)	Shipping emission (tCO2/tNH3)	Permissible grid power (%)
Kandla	0.083	7.35%	0.132	6.66%
Vishakhapatnam	0.095	7.29%	0.135	6.73%
Cochin	0.084	5.86%	0.127	5.38%
Gopalpur	0.099	7.14%	0.138	6.58%
JNPT	0.082	7.22%	0.130	6.56%

Table 26: Shipping emissions and allowable grid power procurement for shipping to Rotterdam in a 40,000 MT capacity vessel

Port	Rotterdam via suez canal		Rotterdam via 'Cape of Good Hope'	
	Shipping emission (tCO2/tNH3)	Permissible grid power (%)	Shipping emission (tCO2/tNH3)	Permissible grid power (%)
Kandla	0.080	7.39%	0.129	6.70%
Vishakhapatnam	0.092	7.33%	0.132	6.77%
Cochin	0.081	5.90%	0.124	5.42%
Gopalpur	0.096	7.18%	0.135	6.63%
JNPT	0.079	7.26%	0.127	6.61%

If regional grid intensity is considered for certification, except Kerala, all other regional grids in India would allow 6.5 – 7.5% grid power procurement along with RE to be emission compliant as per Delegated Act of EU. Therefore, scheduling grid power procurement in low RE time slots could optimise the overall RE and BESS capacity requirement.

5.3 Assumptions for economic assessment of a 600 KTPA Green Ammonia facility

As part of the economic assessment, levelised costs of green hydrogen and green ammonia have been evaluated. Major assumptions are indicated below:

Table 27: LCOA model assumptions

Description	Unit	Assumption
Operation phase assumptions		
Project Life	Years	25
Production Capacity		
Ammonia plant capacity	tonnes / year	600000
Ammonia plant utilization	%	100%
H2 consumed / Kg of Ammonia produced	Kg H2 / Kg Ammonia	0.177
Electrolyser efficiency	%	68%
Electrolyser CUF	%	As per various options (60 – 90%)
Electricity required for BOP - H2 unit only	KWh / Kg H2	4
Hydrogen LHV	KWh / Kg H2	34
Additional electricity required for compression and storing	KWh / Kg H2	6
O&M expenses		

[64] Details regarding vessel sizing and charter costs have been provided in the Chapter on Export Infrastructure

Description	Unit	Assumption
First year O&M expense	% of capital cost	2%
Annual escalation	%	4.0%
Stack lifetime between refurbishes	Years	9
Refurbishment costs	% of capital cost	30.0%
Water usage assumptions		
Water requirement for GH2	Litre / Kg of H2	10
Water requirement for Ammonia	Litre / Kg of NH3	5
Water cost	INR / Litre	0.08
Total electricity required by ammonia unit / Kg of production	KWh / Kg NH3	0.3
Landed cost of electricity (Levelised)	INR / KWh	As per options
Depreciation		
Maximum depreciation (SLM method for book depreciation)	%	100%
Tax depreciation rate (WDV method)	%	15%
Depreciation timeline for refurbishment costs	Years	5
Financing Assumptions		
Capital Structure		
Debt: Equity	ratio	70:30
Return on equity	%	12%
USD to INR exchange rate	INR / USD	80
Exchange Rate Variation	%	0%
Domestic loan details		
Repayment period	Years	10
Interest rate during construction	%	9%
Interest rate post commissioning	%	9%
Loan processing fee	%	0%
Refurbishment loan details		
Repayment period	Years	5
Interest rate	%	10%
Corporate tax rate	%	25.17%
Working Capital Assumptions		
Debtor days	days	30
Creditor days	days	30
Interest on working capital	%	11%

5.3.1 Capital Cost assumptions

The following table presents the estimated capital cost for the Green Ammonia Facility with production capacity of 600,000 tonnes of ammonia per year.

Table 28: Estimated capital costs

Description	Unit	Assumption
Capital cost breakup		
Hydrogen Unit		
Electrolyser	INR Crores / MW	2.5
Balance of Plant Systems	INR Crores / MW	2.5
Hydrogen storage cost	INR Cr/ton	8 – 8.5
Ammonia Unit (600 KTPA)		
Ammonia Loop along with ASU	INR Crores	6000

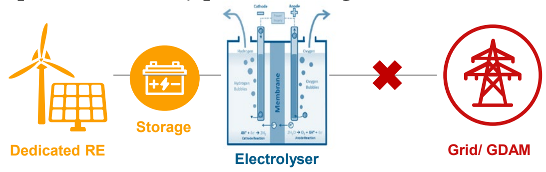
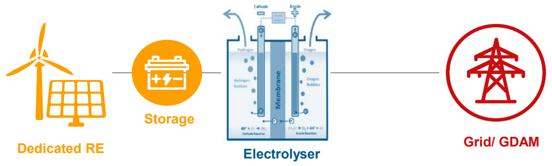
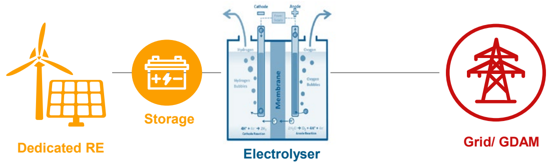
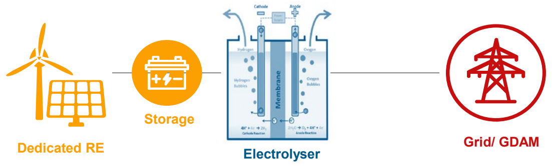
Description	Unit	Assumption
BOP along with Desalination Plant	INR Crores	2400

Note: Infrastructure costs include cost of utilities, sea-water intake etc.

5.4 Production setups for green ammonia production

As per the possible production setups mentioned in Section 4.2, four options/ scenarios have been developed in the Indian scenario for producing green ammonia.

Table 29: Production set-ups for GNH3 production

Production setup	Brief
Option1: Electricity produced off-grid 	• The setup utilizes 100% RE power for electrolyser and ammonia loop operations. • No dependence on grid results in lowest emission intensity product. • RE and BESS systems are assumed to be captive
Option 2: Co-located RE + BESS + Permissible Grid + GDAM 	• Permissible Grid electricity (as per emission thresholds and state emission intensity), RE+BESS and GDAM (Green Day Ahead Market) are utilized for the electrolyser and ammonia operations. • RE and BESS systems are assumed to be captive.
Option 3: Co-located RE + BESS + Optimised Grid + GDAM 	• Optimised Grid electricity (basis optimisation of annual fixed cost) and RE+BESS and GDAM (Green Day Ahead Market) are utilized for the electrolyser and ammonia operations. • Entire production cannot be sent to Europe/ be labelled as green; the quantum of ammonia production attributable to excess grid power consumption than permissible would be termed as grey. • RE and BESS systems are assumed to be captive.
Option 4: High Wind and Solar + BESS + Permissible Grid + GDAM 	• In place of co-located RE capacities, the solar generation from Northern region (Rajasthan profile) and wind generation from Southern region (Tamil Nadu profile) is considered for electrifying the electrolyser and ammonia loop along with permissible grid power (as per emission norms) and GDAM procurement • RE and BESS capacities are assumed to be captive.

For sizing of RE and BESS, monthly average of regional RE generation profiles have been considered unless mentioned otherwise. The RE capacities arrived at from the optimisation tool are AC capacities which are connected at the ISTS level.

5.4.1 Option 1: Electricity produced off-grid

In the off-grid power procurement option, solar and wind power are coupled with battery energy storage to power the electrolyser and the ammonia loop. The BESS installation enables the facility to mitigate the intermittency of RE generation and the hydrogen storage enables the facility to feed the ammonia loop continuously. Even though the system is offgrid, it would utilize the state transmission infrastructure and would be subject to pay state transmission charges as applicable.

The optimal system sizing, landed cost of electricity, cost of ammonia production, and the loading curves for each state has been optimised based on the constraints, regional RE profile and considering a captive RE sourcing arrangement.

5.4.1.1 Gujarat

The optimal system sizing for a 600 ktpa green ammonia set up in an off-grid arrangement is:

Electrolyser capacity (MW)	Solar (MW)	Wind (MW)	H2 Storage (tons)	Electrolyser CUF (%)	BESS 2 hour (MW)	Landed cost of electricity (INR/kWh)	LCOA (USD/t)
1115	1567	1585	87.0	61%	~521	~4.65	~1030

Based on the optimal sizing, the loading pattern of the electrolyser, renewable energy generation and the net outflow from hydrogen storage[65] are as follow.

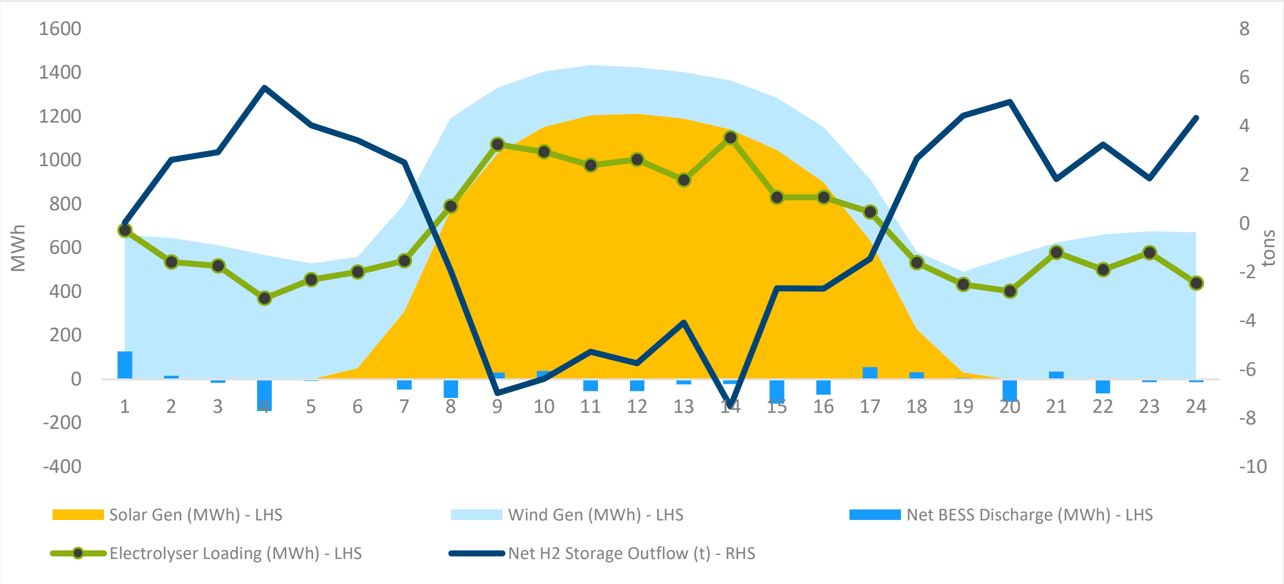


Figure 28: System sizing and average daily loading (24 hours) for Gujarat under Option 1

Key observations:

- In Gujarat, Solar has a better profile than Wind which leads to almost equal sizing for both the technologies
- Solar and Wind has been **oversized by ~3x**, BESS is required to meet the electrolyser power requirement during non-solar hours. **Minimum electrolyser loading of 30%** will be maintained throughout the operation.
- Electrolyser utilization (CUF) is 61% as more utilization will require significantly higher BESS capacity, leading to increase in landed cost of electricity. **Benefit from higher utilisation will be lower than the increase in cost of electricity.**
- During the non-solar hours, the hydrogen storage is being utilized to feed the ammonia loop while the storage is being fed with hydrogen during solar hours.

[65] A positive value indicates that the storage is being utilized to feed the ammonia loop whereas, a negative value indicates that the storage is being filled with the hydrogen being produced by the electrolyser

5.4.1.2 Andhra Pradesh

The optimal system sizing for 600 ktpa green ammonia set up in AP:

Electrolyser capacity (MW)	Solar (MW)	Wind (MW)	H2 Storage (tons)	Electrolyser CUF (%)	BESS 2 hour (MW)	Landed cost of electricity (INR/kWh)	LCOA (USD/t)
947.6	627.0	2557.5	83.5	72%	61.7	5.28	~1080

Based on the optimal sizing, the loading pattern of the electrolyser, renewable energy generation and the net outflow from hydrogen storage are as follow

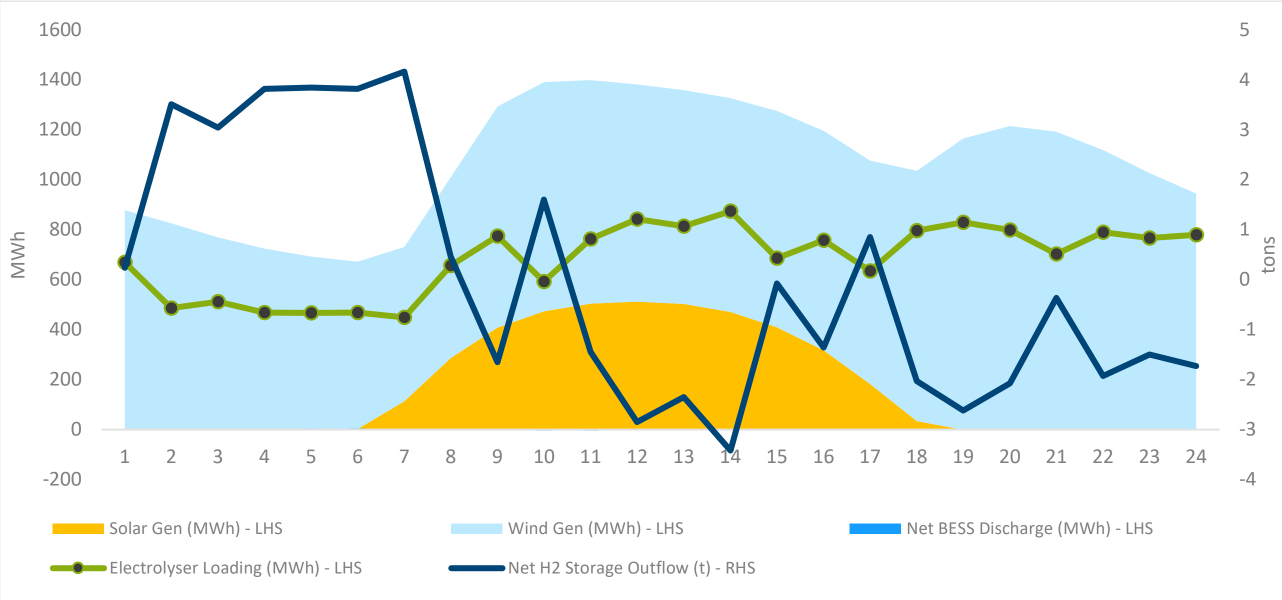


Figure 29: System sizing and average daily loading (24 hours) for Andhra Pradesh under Option 1

Key observations:

- Southern region has a very strong Wind profile which leads to higher sizing compared to solar generation. CUF of Electrolyser is ~72%. However, landed cost is higher than Gujarat because of higher capex of Wind.

5.4.1.3 Kerala

The optimal system sizing for 600 ktpa green ammonia plant:

Electrolyser capacity (MW)	Solar (MW)	Wind (MW)	H2 Storage (tons)	Electrolyser CUF (%)	BESS 2 hour (MW)	Landed cost of electricity (INR/kWh)	LCOA (USD/t)
947.6	627.0	2557.5	83.5	72%	61.7	6.16	~1180

Based on the optimal sizing, the loading pattern of the electrolyser, renewable energy generation and the net outflow from hydrogen storage are as follow:

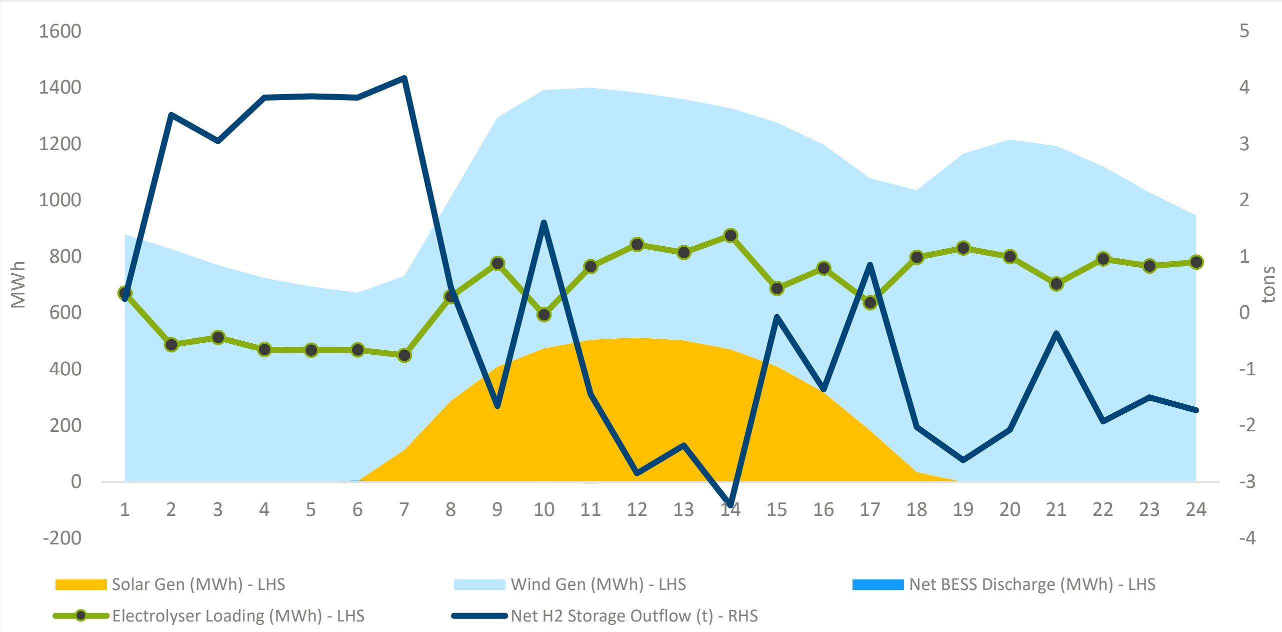


Figure 30: System sizing and average daily loading (24 hours) for Kerala under Option 1

Due to the similar RE generation profiles of Southern region, the sizing for Kerala is similar to that of Andhra Pradesh. However, due to significantly higher transmission charges, the landed cost of electricity in Kerala is higher than Andhra Pradesh.

5.4.1.4 Maharashtra

The optimal system sizing for 600 ktpa green ammonia plant:

Electrolyser capacity (MW)	Solar (MW)	Wind (MW)	H2 Storage (tons)	Electrolyser CUF (%)	BESS 2 hour (MW)	Landed cost of electricity (INR/kWh)	LCOA (USD/t)
1185.0	1814.9	2084.4	80.2	58%	190.4	7.12	~1350

Basis the stated system sizing, the system loading is as follows:

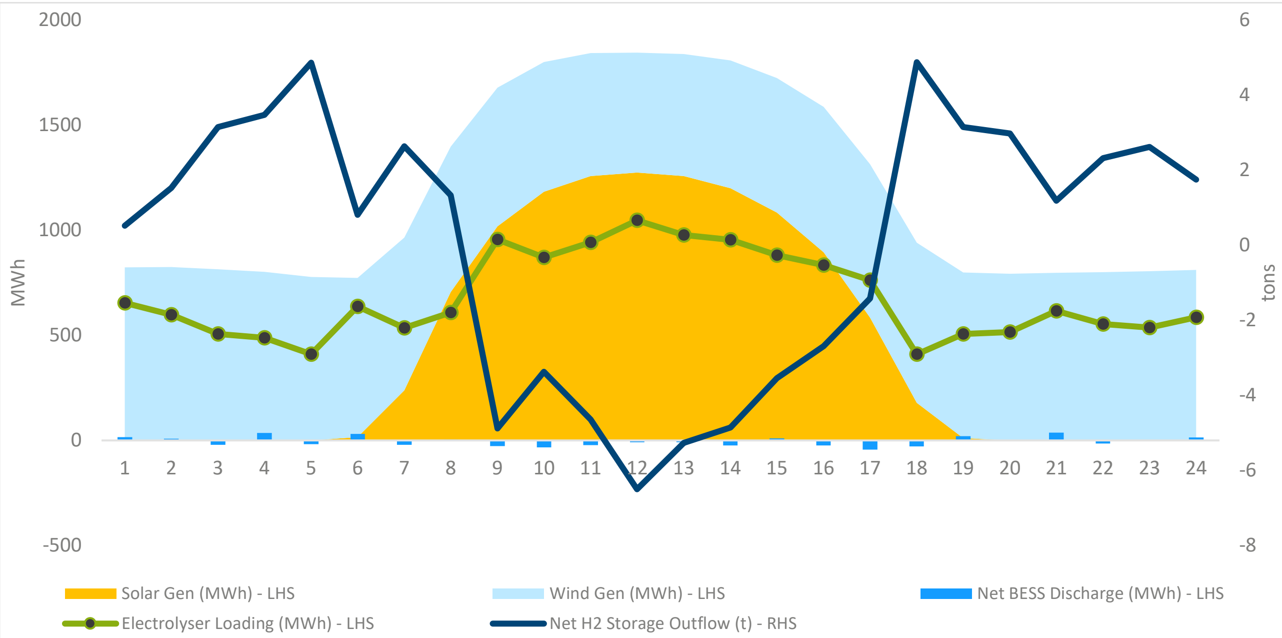


Figure 31: System sizing and average daily loading (24 hours) for Maharashtra under Option 1

Due to the solar and wind profiles of western region, the system needs to oversize both solar and wind capacities. The high transmission charges of the state lead to the highest landed cost of electricity among all the states under consideration.

5.4.1.5 Odisha

The optimal system sizing for shipping the ammonia from Gopalpur to Hamburg are as follows:

Electrolyser capacity (MW)	Solar (MW)	Wind (MW)	H2 Storage (tons)	Electrolyser CUF (%)	BESS 2 hour (MW)	Landed cost of electricity (INR/kWh)	LCOA (USD/t)
1122.2	3062.4	973.5	98.9	61%	2147.7	7.10	~1340

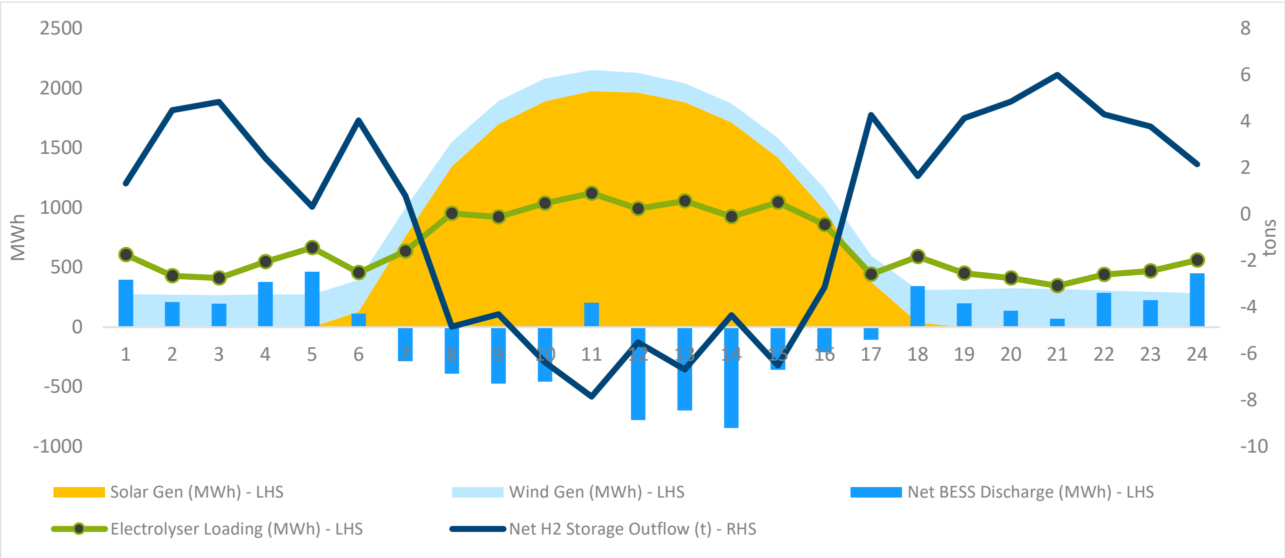


Figure 32: System sizing and average daily loading (24 hours) for Odisha under Option 1

The wind and solar generation profiles of Eastern region has lower CUF in comparison to all other regions in India. Due to this, the RE sizing is dominated by solar power, and BESS requirement as well as overall landed cost is on higher side.

5.4.1.6 Summary of Option 1

For an off-grid electricity production based ammonia production facility, the sizing results are as following:

Table 30: Summary of Option 1

Area	Electrolyser (MW)	Solar (MW)	Wind (MW)	H2 storage (tons)	Electrolyser CUF (%)	BESS (2 hr) (MW)	LCOE (INR/kWh)	LCOA (USD/ton)
Kandla	1115.4	1567.2	1585.9	87.0	61%	521.1	4.65	~1030
Vishakhapatnam	947.6	627.0	2557.5	83.5	72%	61.7	5.28	~1080
Cochin	947.6	627.0	2557.5	83.5	72%	61.7	6.16	~1190
JNPT	1185.0	1814.9	2084.4	80.2	58%	190.4	7.12	~1350
Gopalpur	1122.2	3062.4	973.5	98.9	61%	2147.7	7.10	~1340

Key considerations:

- This optimisation doesn't include any incentive or subsidy in capex or T&D charges
- However, several states have announced support measures which would reduce the cost of development. For example, **~15% capex subsidy would reduce the LCOA by USD 60 – 70/ton and a 30% capex subsidy results in bringing LCOA down by USD 120 – 140/ton**.
- Any subsidy in the transmission charge would further optimise the cost of production – INR 1/kWh (US cents 1.2 per kWh) reduction in landed cost of electricity would reduce **LCOA by ~USD 120/ton**
- No flexibility has been considered in **Ammonia loop operation**

In Option 1, total land requirement for setting up 600 ktpa green ammonia plant would be 9000 – 13000 Acre depending on location and RE profile

Land for RE projects (solar and wind) can be situated anywhere within the state/ region, while land for electrolyser and ammonia units must be within/ nearby the port cities selected.

Table 31: Land requirement for option 1

Port city[66]	Land for Solar capacity (Acres)	Land for Wind capacity (Acres)	Green Ammonia plant (Acre)
Kandla	5485	3965	~100
Vishakhapatnam	2194	6394	
Cochin	2194	6394	
JNPT	6352	5211	
Gopalpur	10718	2434	

[66] The allocation per MW is 3.5 acres for solar, 2.5 acres for wind.

5.4.2 Option 2: Co-located RE + BESS + Permissible Grid + GDAM

Configuration as per option 2 is likely to be the optimum as well as EU compliant. In this configuration:

- With 5 – 8% grid power procurement, requirement of BESS and hydrogen storage are likely to reduce further. Grid will act as natural storage.
- Electrolyser CUF will increase substantially, leading to lower LCOH and LCOA

State wise summary is provided below:

5.4.2.1 Gujarat

Max Grid Power (%)	Grid Power Consumed (%)	Electrolyser capacity (MW)	Solar (MW)	Wind (MW)	H2 Storage (tons)	Electrolyser CUF (%)	BESS 2 hour (MW)	Landed cost of electricity (INR/kWh)	LCOA (USD/t)
7.35%	5.83%	792	894.1	1648.3	24.4	86%	0	4.34	~920

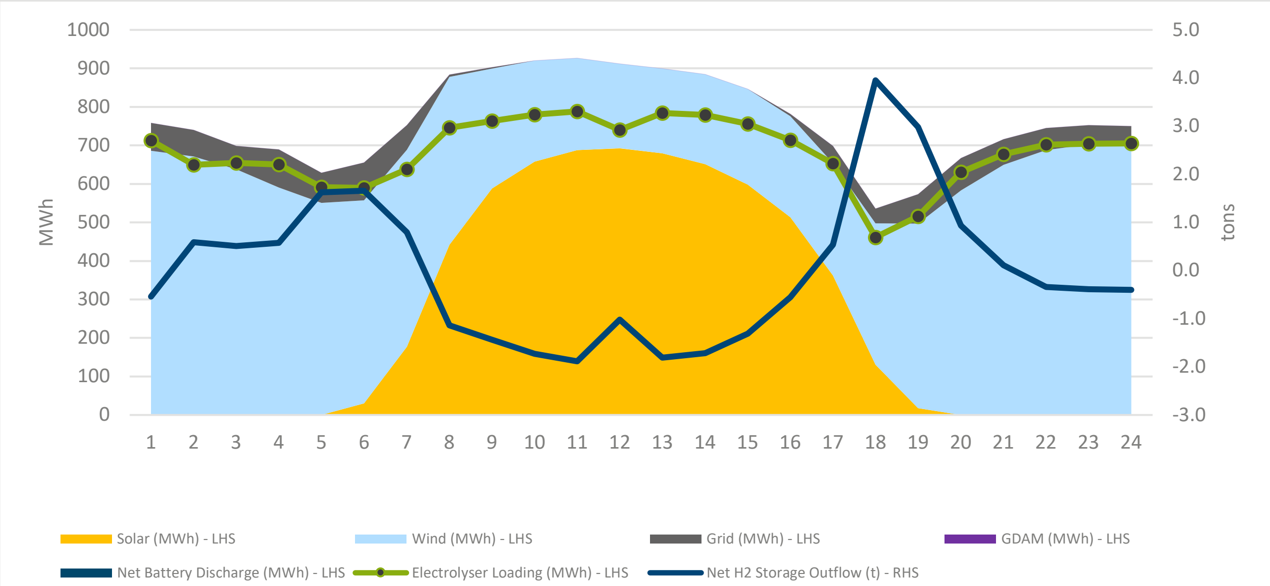


Figure 33: System sizing and average daily loading (24 hours) for Gujarat under Option 2

While the limit of grid procurement is ~7.3%, the model has optimised it to ~5.8% to minimise the system cost by reducing the BESS requirement. In case of Gujarat, Grid HT tariff is higher than the potential RE tariff; therefore, optimisation model will choose to add RE capacity than take it from Grid. No BESS is envisaged as the Grid will act as the natural storage and intermittency will be met by oversizing the wind and solar.

In this option, LCOE and LCOA achieved in Gujarat, without any subsidy, would be INR 4.34/kWh and ~USD 920/ton respectively. Electrolyser size and CUF would be ~790 MW and ~86%.

5.4.2.2 Andhra Pradesh

Max Grid Power (%)	Grid Power Consumed (%)	Electrolyser capacity (MW)	Solar (MW)	Wind (MW)	H2 Storage (tons)	Electrolyser CUF (%)	BESS 2 hour (MW)	Landed cost of electricity (INR/kWh)	LCOA (USD/t)
7.29%	7.29%	881	734.2	1530.7	45.1	78%	0	4.22	930

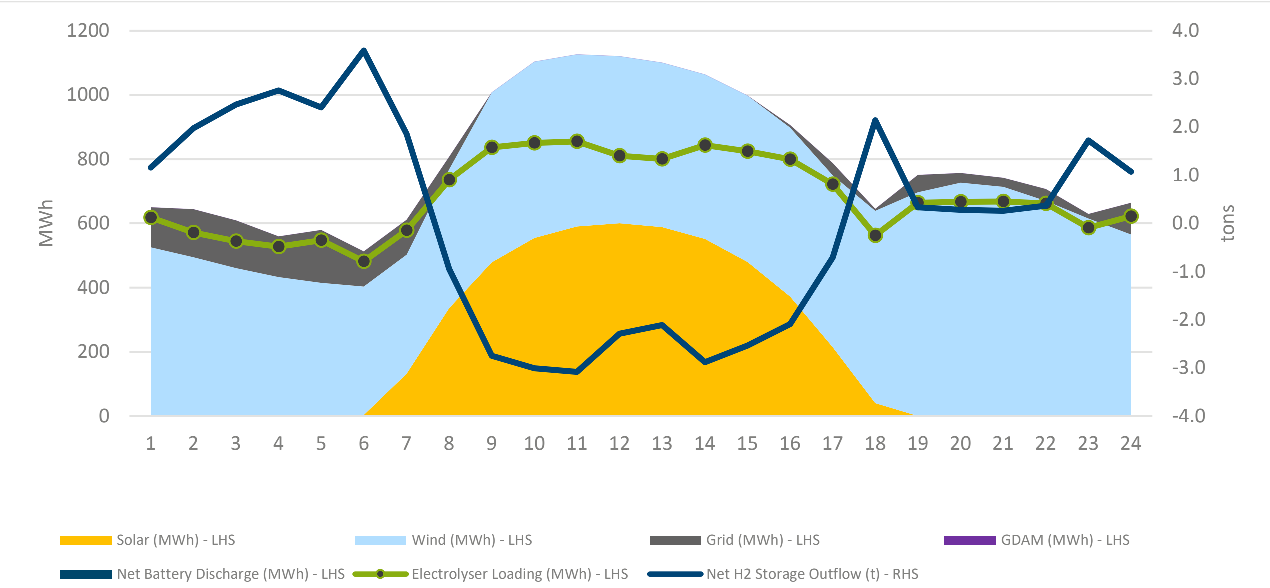


Figure 34: System sizing and average daily loading (24 hours) for Andhra Pradesh under Option 2

The model has considered to source the maximum permissible power from grid (~7.3%) as grid HT power is cheaper than levelised cost of hybrid RE. No BESS is envisaged as the Grid will act as the natural storage and intermittency will be met by oversizing the wind and solar.

In this option, LCOE and LCOA achieved in AP, without any subsidy, would be INR 4.22/kWh and ~USD 930/ton respectively. Electrolyser size and CUF would be ~880 MW and ~78%.

5.4.2.3 Kerala

Max Grid Power (%)	Grid Power Consumed (%)	Electrolyser capacity (MW)	Solar (MW)	Wind (MW)	H2 Storage (tons)	Electrolyser CUF (%)	BESS 2 hour (MW)	Landed cost of electricity (INR/kWh)	LCOA (USD/t)
5.86%	5.86%	913	836.1	1488.8	70.1	75%	0	4.88	~1020

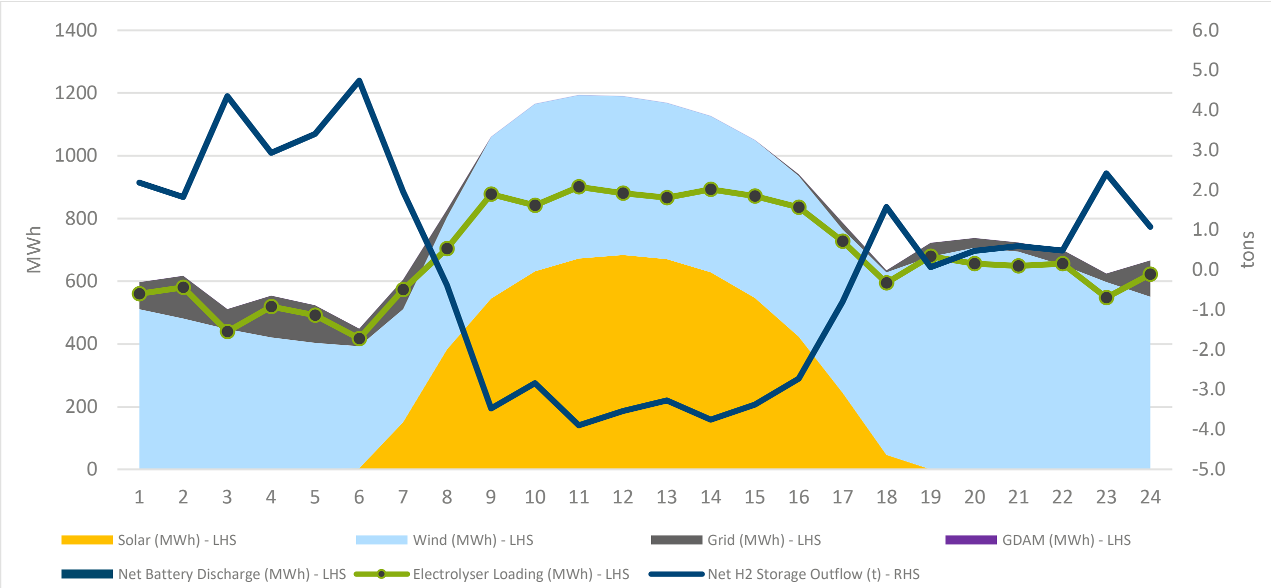


Figure 35: System sizing and average daily loading (24 hours) for Kerala under Option 2

The model has considered to source the maximum permissible power from grid (~5.8%) as grid HT power is cheaper than levelised cost of hybrid RE. No BESS is envisaged as the Grid will act as the natural storage and intermittency will be met by oversizing the wind and solar.

In this option, LCOE and LCOA achieved in Kerala, without any subsidy, would be INR 4.88/kWh and ~USD 1020/ton respectively. Electrolyser size and CUF would be ~910 MW and ~75%.

5.4.2.4 Maharashtra

Max Grid Power (%)	Grid Power Consumed (%)	Electrolyser capacity (MW)	Solar (MW)	Wind (MW)	H2 Storage (tons)	Electrolyser CUF (%)	BESS 2 hour (MW)	Landed cost of electricity (INR/kWh)	LCOA (USD/t)
7.22%	7.22%	784	767.0	1573.5	30.8	87%	0	5.86	1114

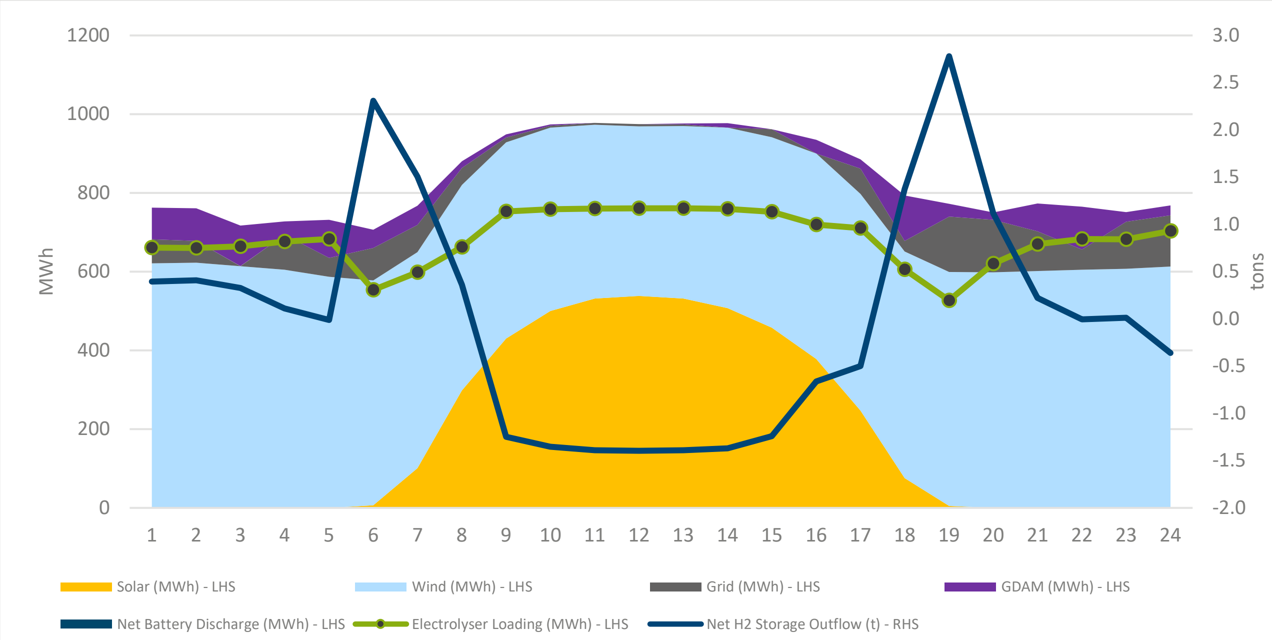


Figure 36: System sizing and average daily loading (24 hours) for Maharashtra under Option 2

The model has considered to source the maximum permissible power from grid (~7.2%) as well as from GDAM to minimise any battery storage requirement and optimise hydrogen storage and electrolyser size. No BESS is envisaged as the Grid will act as the natural storage and intermittency will be met by oversizing the wind and solar.

In this option, LCOE and LCOA achieved in Maharashtra, without any subsidy, would be INR 5.86/kWh and ~USD 1110/ton respectively. Electrolyser size and CUF would be ~780 MW and ~87%.

5.4.2.5 Odisha

Max Grid Power (%)	Grid Power Consumed (%)	Electrolyser capacity (MW)	Solar (MW)	Wind (MW)	H2 Storage (tons)	Electrolyser CUF (%)	BESS 2 hour (MW)	Landed cost of electricity (INR/kWh)	LCOA (USD/t)
7.14%	7.14%	1034	1504.4	1157.7	53.1	66%	0	5.35	1098

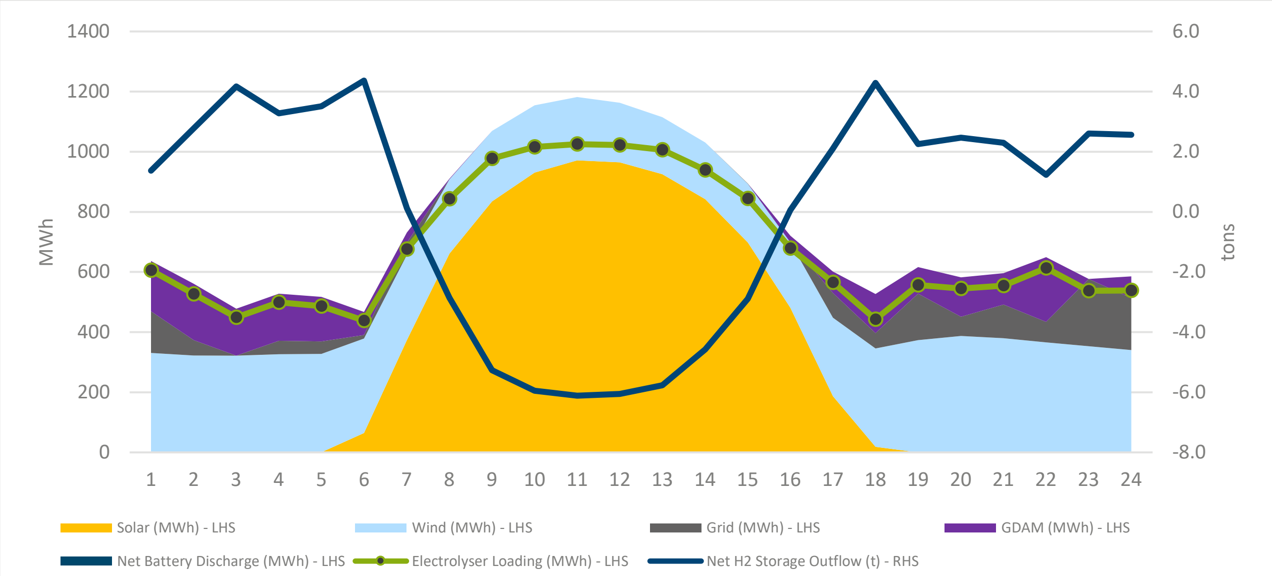


Figure 37: System sizing and average daily loading (24 hours) for Odisha under Option 2

The model has considered to source the maximum permissible power from grid (~7.1%) as well as from GDAM to minimise any battery storage requirement and optimise hydrogen storage and electrolyser size. No BESS is envisaged as the Grid will act as the natural storage and intermittency will be met by oversizing the wind and solar.

In this option, LCOE and LCOA achieved in Odisha, without any subsidy, would be INR 5.35/kWh and ~USD 1100/ton respectively. Electrolyser size and CUF would be ~1030 MW and ~66%.

5.4.2.6 Summary of Option 2

Table 32: Summary of Option 2

Area	Electrolyser (MW)	Solar (MW)	Wind (MW)	H2 storage (tons)	Electrolyser CUF (%)	BESS (2 hr) (MW)	Maximum Grid Power (%)	Grid Power Consumed (%)	LCOE (INR/kWh)	LCOA (USD/t)
Kandla	792	894	1648	24	86%	0	7.35%	5.83%	4.34	924
Vishakhapatnam	881	734	1530	45	78%	0	7.29%	7.29%	4.22	930
Cochin	913	836	1488	70	75%	0	5.86%	5.86%	4.88	1023
JNPT	784	767	1573	30	87%	0	7.22%	7.22%	5.86	1114
Gopalpur	1034	1504	1157	53	66%	0	7.14%	7.14%	5.35	1098

Key considerations:

- This optimisation doesn't include any incentive or subsidy in capex or T&D charges
- However, several states have announced support measures which would reduce the cost of development. For example, **~15% capex subsidy would reduce the LCOA by USD 60 – 70/ton and a 30% capex subsidy results in bringing LCOA down by USD 120 – 140/ton**.
- Any subsidy in the transmission charge would further optimise the cost of production – INR 1/kWh (US cents 1.2 per kWh) reduction in landed cost of electricity would reduce **LCOA by ~USD 120/ton**
- No flexibility has been considered in **Ammonia loop operation**

In Option 1, total land requirement for setting up 600 ktpa green ammonia plant would be 6500 – 8000 Acre depending on location and RE profile

Land for RE projects (solar and wind) can be situated anywhere within the state/ region, while land for electrolyser and ammonia units must be within/ nearby the port cities selected.

Table 33: Land requirement for option 2

Port city[67]	Land for Solar capacity (Acres)	Land for Wind capacity (Acres)	Green Ammonia facility (Acres)
Kandla	3129	4121	~100
Vishakhapatnam	2570	3827	
Cochin	2926	3722	
JNPT	2684	3934	
Gopalpur	5265	2894	

[67] The allocation per MW is 3.5 acres for solar, 2.5 acres for wind.

5.4.3 Option 3: Co-located RE + BESS + Optimised Grid + GDAM

In option 3, Grid power sourcing is kept unconstrained. Therefore, Grid power may go beyond the permissible limit, and the entire ammonia capacity will not be considered as "Green Ammonia" as per EU regulations. In this option,

- Electrolyser CUF will increase further
- LCOA will be optimised further; however, this will be a blended price for grey and green ammonia due to higher consumption of grid power.

Summary of each state is provided below:

5.4.3.1 Gujarat

Grid Power (%)	Electrolyser capacity (MW)	Solar (MW)	Wind (MW)	H2 Storage (tons)	Electrolyser CUF (%)	BESS 2 hour (MW)	Landed cost of electricity (INR/kWh)	LCOA (USD/t)
5.83%	792	894.1	1648.3	24.4	86%	0	4.34	~920

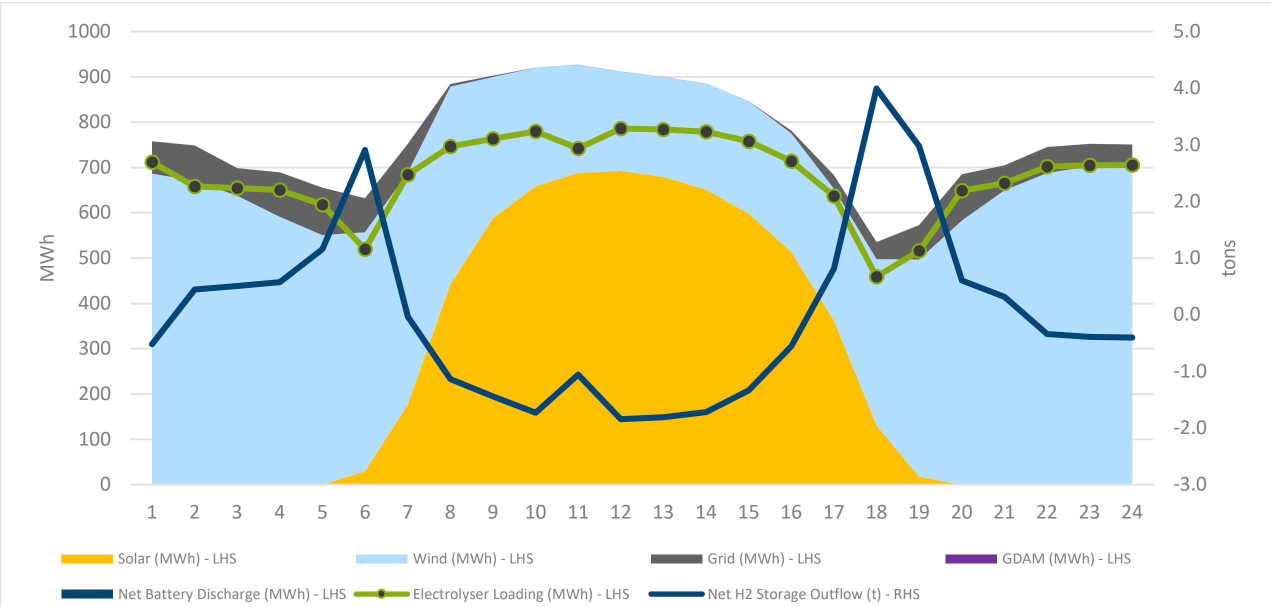


Figure 38: System sizing and average daily loading (24 hours) for Gujarat under Option 3

In Gujarat, Grid power will likely to be limited to ~5.83% as RE is cheaper than grid power. No BESS is envisaged as the Grid will act as the natural storage and intermittency will be met by oversizing the wind and solar.

In this option, LCOE and LCOA achieved in Gujarat, without any subsidy, would be INR 4.34/kWh and ~USD 920/ton respectively. Electrolyser size and CUF would be ~790 MW and ~86%.

5.4.3.2 Andhra Pradesh

Grid Power (%)	Electrolyser capacity (MW)	Solar (MW)	Wind (MW)	H2 Storage (tons)	Electrolyser CUF (%)	BESS 2 hour (MW)	Landed cost of electricity (INR/kWh)	LCOA (USD/t)
14.80%	796	597.7	1386.1	31.6	86%	0	4.31	922

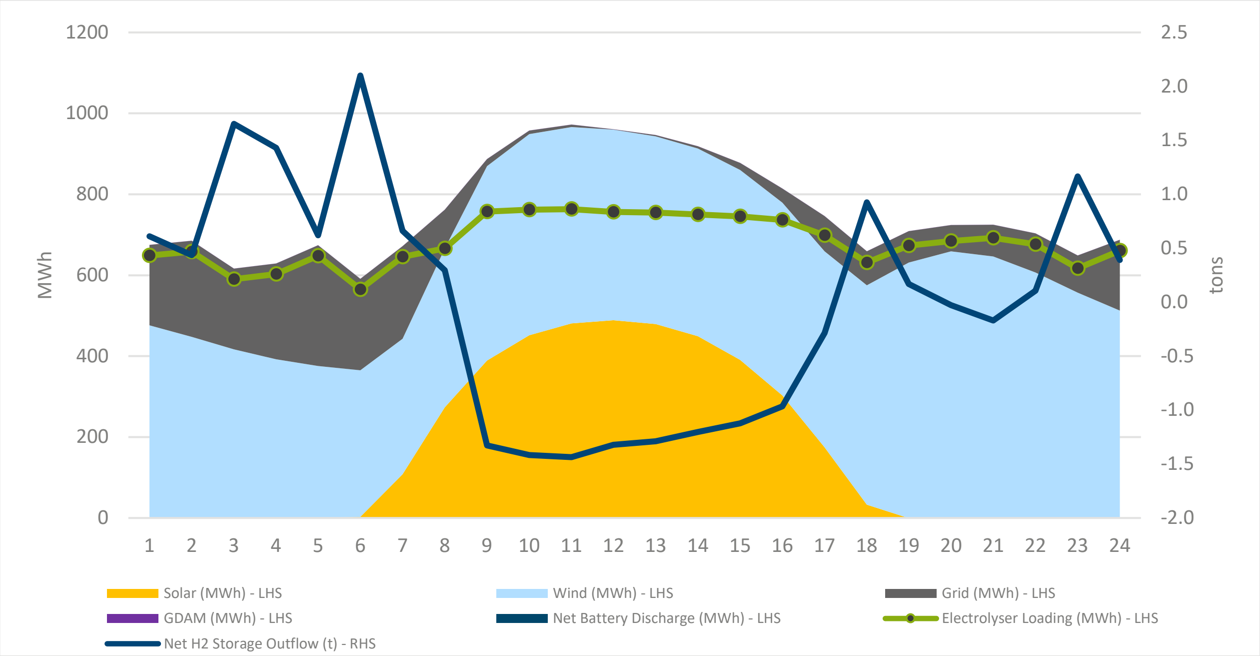


Figure 39: System sizing and average daily loading (24 hours) for Andhra Pradesh under Option 3

In case of AP, with profile from Southern region, sourcing of grid power may be increased to further optimise the system configuration. While significant improvement is not expected in LCOA from Option 2, this may reduce the upfront capex required for RE as well as electrolyser. Grid power will be sourced in the low wind periods.

In this option, LCOE and LCOA achieved in Andhra Pradesh, without any subsidy, would be INR 4.31/kWh and ~USD 920/ton respectively. Electrolyser size and CUF would be ~800 MW and ~86%.

5.4.3.3 Kerala

Grid Power (%)	Electrolyser capacity (MW)	Solar (MW)	Wind (MW)	H2 Storage (tons)	Electrolyser CUF (%)	BESS 2 hour (MW)	Landed cost of electricity (INR/kWh)	LCOA (USD/t)
13.41%	811	609.2	1422.1	27.9	84%	0	4.93	1002

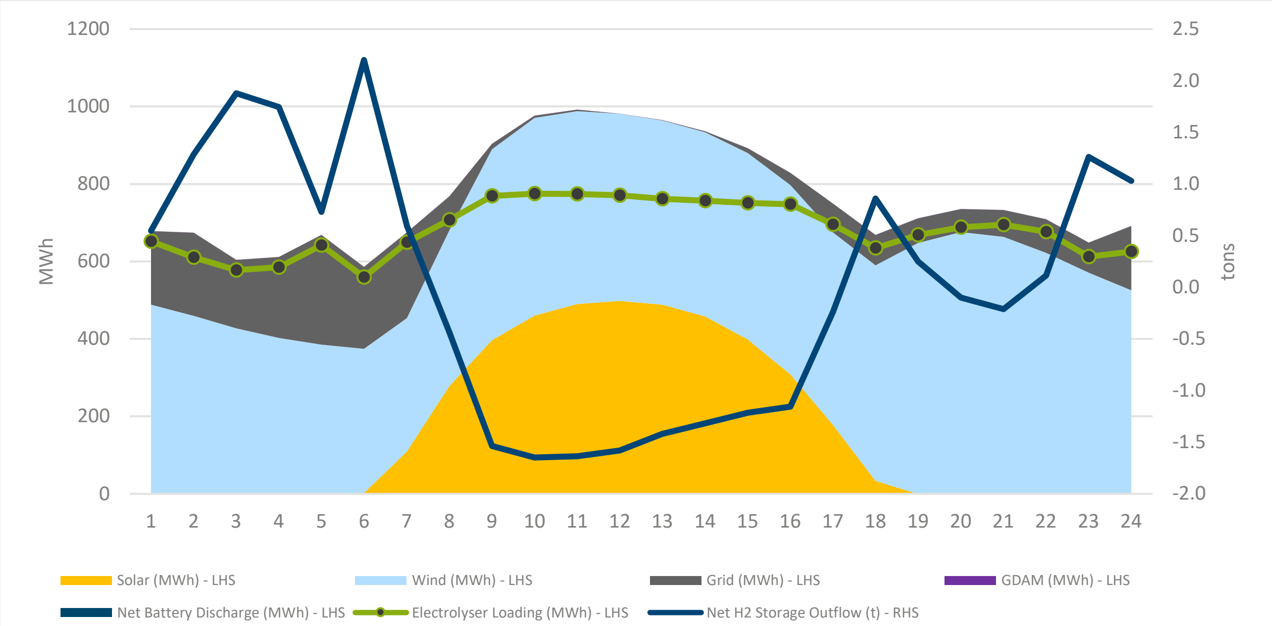


Figure 40: System sizing and average daily loading (24 hours) for Kerala under Option 3

Likewise AP, for Kerala also, sourcing of grid power may be increased to further optimise the system configuration. While significant improvement is not expected in LCOA from Option 2, this may reduce the upfront capex required for RE as well as electrolyser. Grid power will be sourced in the low wind periods.

In this option, LCOE and LCOA achieved in Kerala, without any subsidy, would be INR 4.93/kWh and ~USD 1000/ton respectively. Electrolyser size and CUF would be ~810 MW and ~84%.

5.4.3.4 Maharashtra

Grid Power (%)	Electrolyser capacity (MW)	Solar (MW)	Wind (MW)	H2 Storage (tons)	Electrolyser CUF (%)	BESS 2 hour (MW)	Landed cost of electricity (INR/kWh)	LCOA (USD/t)
12.87%	779	757.9	1581.6	30.1	88%	0	5.86	1113

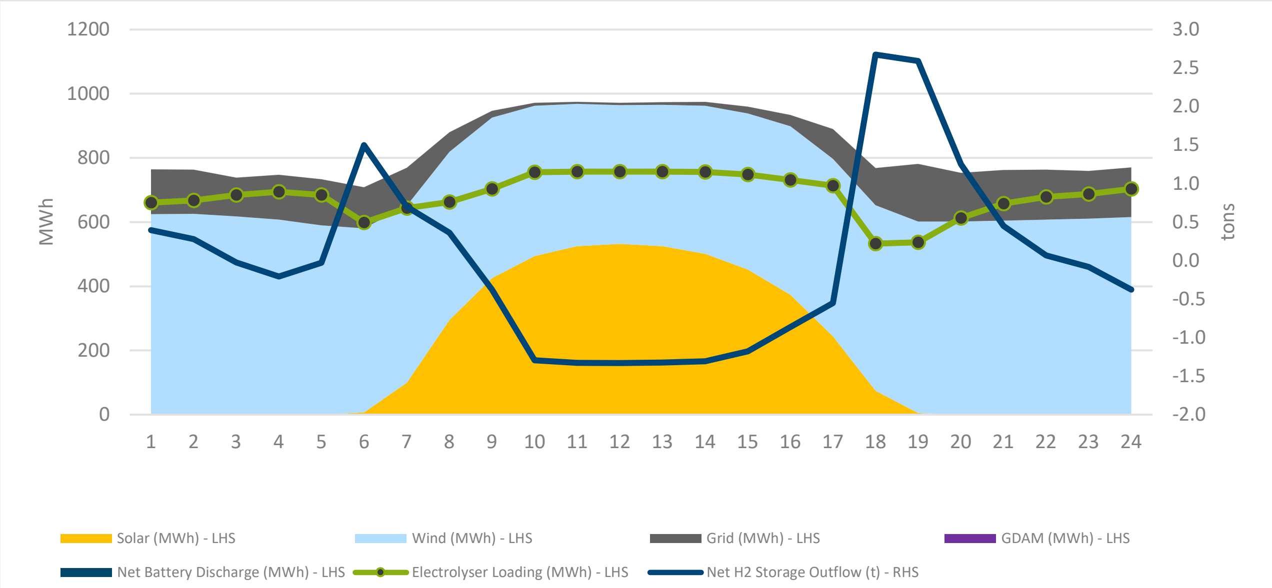


Figure 41: System sizing and average daily loading (24 hours) for Maharashtra under Option 3

In case of Maharashtra also, sourcing of grid power may be increased to further optimise the system configuration.

In this option, LCOE and LCOA achieved in Maharashtra, without any subsidy, would be INR 5.86/kWh and ~USD 1110/ton respectively. Electrolyser size and CUF would be ~780 MW and ~88%.

5.4.3.5 Odisha

Grid Power (%)	Electrolyser capacity (MW)	Solar (MW)	Wind (MW)	H2 Storage (tons)	Electrolyser CUF (%)	BESS 2 hour (MW)	Landed cost of electricity (INR/kWh)	LCOA (USD/t)
25.27%	750	964.0	1347.4	24.4	91%	0	5.52	1065

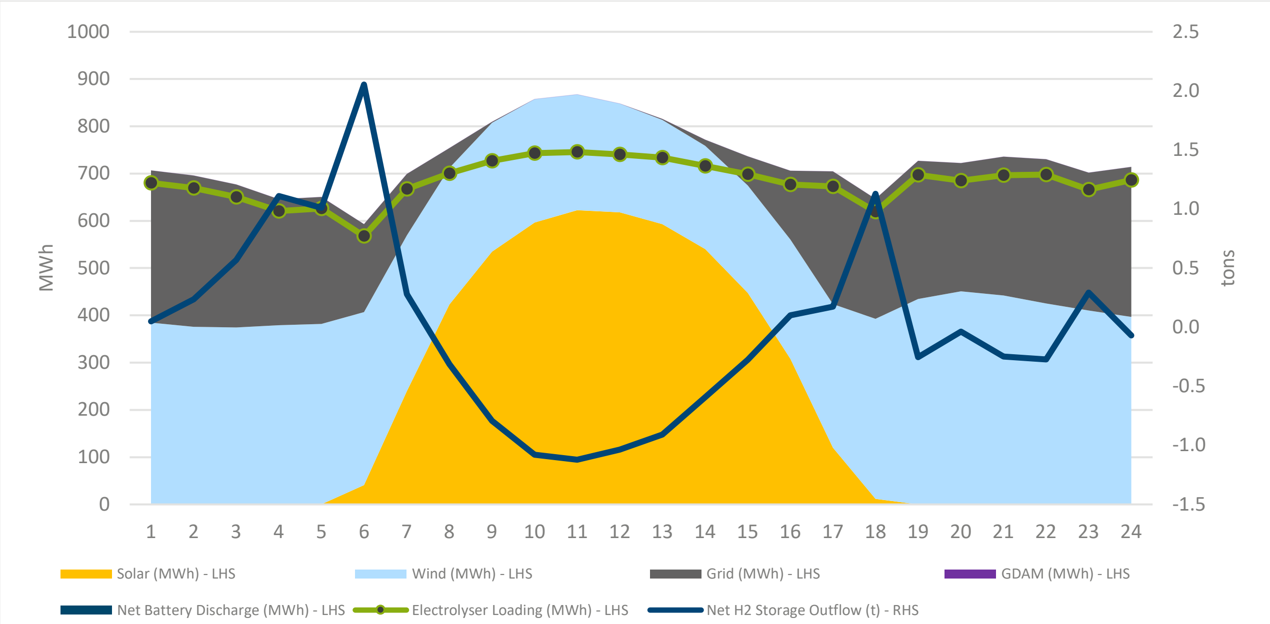


Figure 42: System sizing and average daily loading (24 hours) for Odisha under Option 3

In Odisha, sourcing of grid power is likely to be maximum amongst all states due to low CUF of solar and wind potential in the eastern region.

In this option, LCOE and LCOA achieved in Odisha, without any subsidy, would be INR 5.52/kWh and ~USD 1065/ton respectively. Electrolyser size and CUF would be ~750 MW and ~91%.

5.4.3.6 Summary of Option 3

Table 34: Summary of Option 3

Area	Electrolyser (MW)	Solar (MW)	Wind (MW)	H2 storage (tons)	Electrolyser CUF (%)	BESS (2 hr) (MW)	Grid Power (%)	LCOE (INR/kWh)	LCOA (USD/t)
Kandla	792	894.1	1648.3	24.4	86%	0	5.83%	4.34	924
Vishakhapatnam	796	597.7	1386.1	31.6	86%	0	14.8%	4.31	922
Cochin	811	609.2	1422.1	27.9	84%	0	13.41%	4.93	1000
JNPT	779	757.9	1581.6	30.1	88%	0	12.87%	5.86	1110
Gopalpur	750	964.0	1347.4	24.4	91%	0	25.27%	5.52	1065

Key considerations:

- This optimisation doesn't include any incentive or subsidy in capex or T&D charges
- However, several states have announced support measures which would reduce the cost of development. For example, **~15% capex subsidy would reduce the LCOA by USD 60 – 70/ton and a 30% capex subsidy results in bringing LCOA down by USD 120 – 140/ton**.
- Any subsidy in the transmission charge would further optimise the cost of production – INR 1/kWh (US cents 1.2 per kWh) reduction in landed cost of electricity would reduce **LCOA by ~USD 120/ton**
- No flexibility has been considered in **Ammonia loop operation**

In Option 3, total land requirement for setting up 600 ktpa green ammonia plant would be 5500 – 7500 Acre depending on location and RE profile.

Table 35: Land requirement for option 3

Port city[68]	Land for Solar capacity (Acres)	Land for Wind capacity (Acres)	Green Ammonia facility (Acres)
Kandla	3129	4121	~100
Vishakhapatnam	2092	3465	
Cochin	2132	3555	
JNPT	2653	3954	
Gopalpur	3374	3369	

[68] The allocation per MW is 3.5 acres for solar, 2.5 acres for wind.

5.4.4 Option 4: High Wind and Solar + BESS + Permissible Grid + GDAM

This option is likely to be the most practical and cost-effective option to produce green ammonia. Barring a few regions, the strong presence of both solar and wind generation profiles is not available across all regions in India. Keeping it in view, a simulation has been run for all the identified locations to understand the sizing requirement with best solar and wind profile available in India. However, this would attract additional cost of transmission system (STU charge). **The solar profile of Northern India (Rajasthan) and Wind profile of Southern India (Tamil Nadu) have been been considered for modelling the results**. The sizing, electrolyser loading, utilization, and landed cost of electricity for the facility for all states have been covered in this scenario.

5.4.4.1 Gujarat

Grid Power (%)	Grid Power Consumed (%)	Electrolyser capacity (MW)	Solar (MW)	Wind (MW)	H2 Storage (tons)	Electrolyser CUF (%)	BESS 2 hour (MW)	Landed cost of electricity (INR/kWh)	LCOA (USD/t)
7.35%	7.35%	901	823.2	1469.0	55.8	76%	0	4.06	916

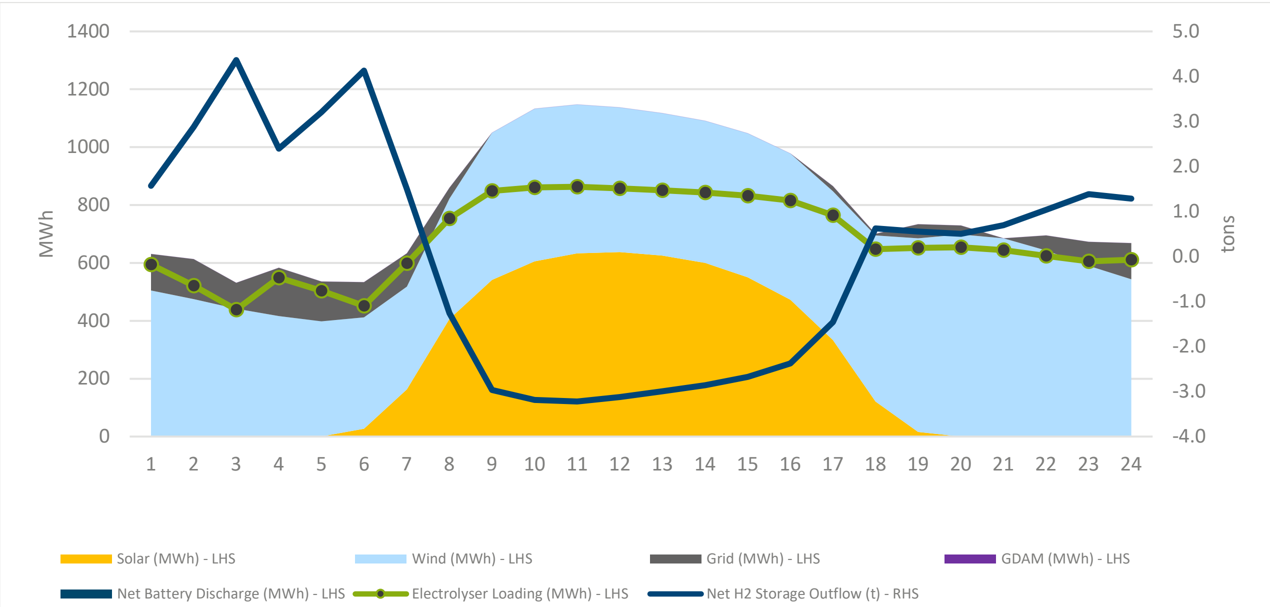


Figure 43: System sizing and average daily loading (24 hours) for Gujarat under Option 4

The model optimises the system cost by sourcing up to 7.3% grid power in the non-solar periods.

In this option, LCOE and LCOA achieved in Gujarat, without any subsidy, would be INR 4.06/kWh and ~USD 916/ton respectively. Electrolyser size and CUF would be ~900 MW and ~76%.

5.4.4.2 *Andhra Pradesh*

Grid Power (%)	Grid Power Consumed (%)	Electrolyser capacity (MW)	Solar (MW)	Wind (MW)	H2 Storage (tons)	Electrolyser CUF (%)	BESS 2 hour (MW)	Landed cost of electricity (INR/kWh)	LCOA (USD/t)
7.29%	7.29%	860	742.9	1462.8	42.4	79%	0	4.31	936

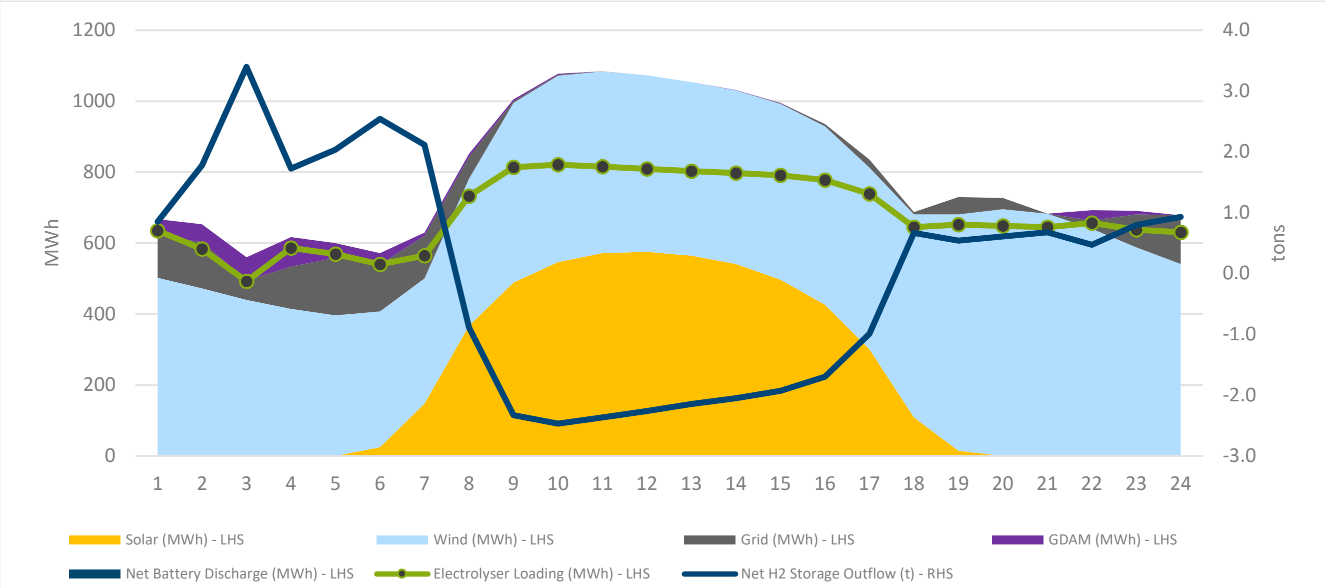


Figure 44: System sizing and average daily loading (24 hours) for Andhra Pradesh under Option 4

The model optimises the system cost by sourcing up to 7.3% grid power in the non-solar periods.

In this option, LCOE and LCOA achieved in AP, without any subsidy, would be INR 4.31/kWh and ~USD 936/ton respectively. Electrolyser size and CUF would be ~860 MW and ~79%.

5.4.4.3 Kerala

Grid Power (%)	Grid Power Consumed (%)	Electrolyser capacity (MW)	Solar (MW)	Wind (MW)	H2 Storage (tons)	Electrolyser CUF (%)	BESS 2 hour (MW)	Landed cost of electricity (INR/kWh)	LCOA (USD/t)
5.86%	5.86%	903	825.6	1466.9	56.0	76%	0	4.95	1027

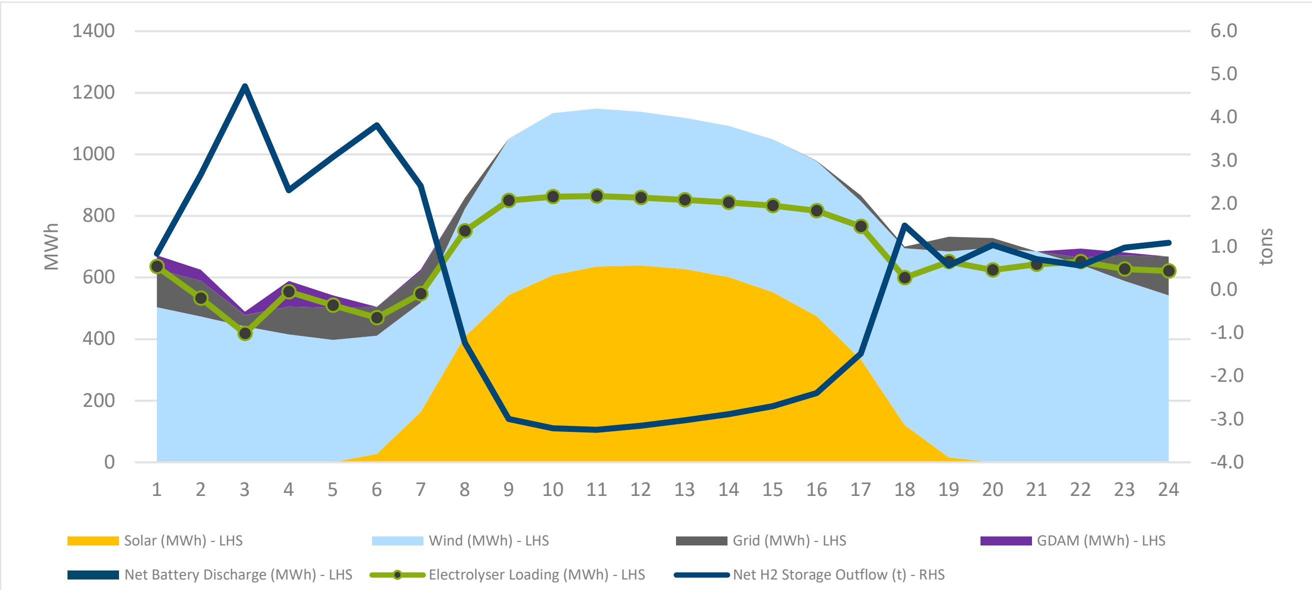


Figure 45: System sizing and average daily loading (24 hours) for Kerala under Option 4

The model optimises the system cost by sourcing up to 5.8% grid power in the non-solar periods.

In this option, LCOE and LCOA achieved in Kerala, without any subsidy, would be INR 4.90/kWh and ~USD 1007/ton respectively. Electrolyser size and CUF would be ~900 MW and ~76%.

5.4.4.4 Maharashtra

Grid Power (%)	Grid Power Consumed (%)	Electrolyser capacity (MW)	Solar (MW)	Wind (MW)	H2 Storage (tons)	Electrolyser CUF (%)	BESS 2 hour (MW)	Landed cost of electricity (INR/kWh)	LCOA (USD/t)
7.22%	6.80%	905	866.6	1459.4	61.5	75%	0	5.13	1051

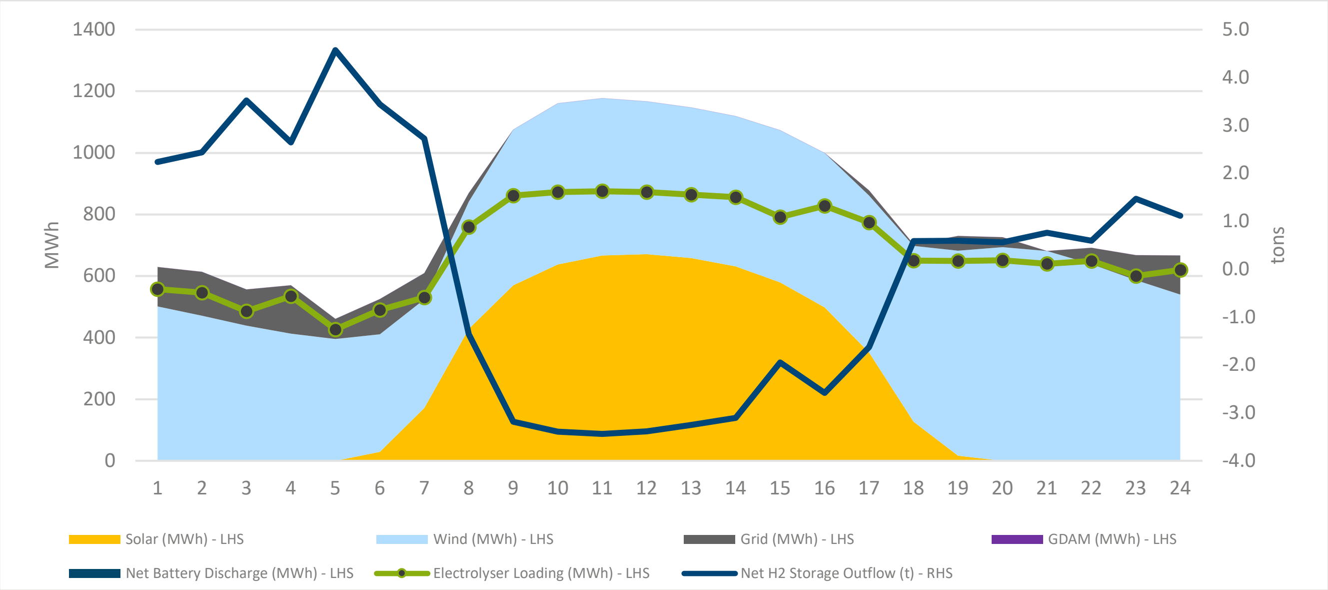


Figure 46: System sizing and average daily loading (24 hours) for Maharashtra under Option 4

The model optimises the system cost by sourcing up to 7.2% grid power in the non-solar periods.

In this option, LCOE and LCOA achieved in Maharashtra, without any subsidy, would be INR 5.13/kWh and ~USD 1051/ton respectively. Electrolyser size and CUF would be ~905 MW and ~75%.

5.4.4.5 *Odisha*

Grid Power (%)	Grid Power Consumed (%)	Electrolyser capacity (MW)	Solar (MW)	Wind (MW)	H2 Storage (tons)	Electrolyser CUF (%)	BESS 2 hour (MW)	Landed cost of electricity (INR/kWh)	LCOA (USD/t)
7.14%	7.14%	860	725.9	1463.7	42.5	79%	0	4.28	933

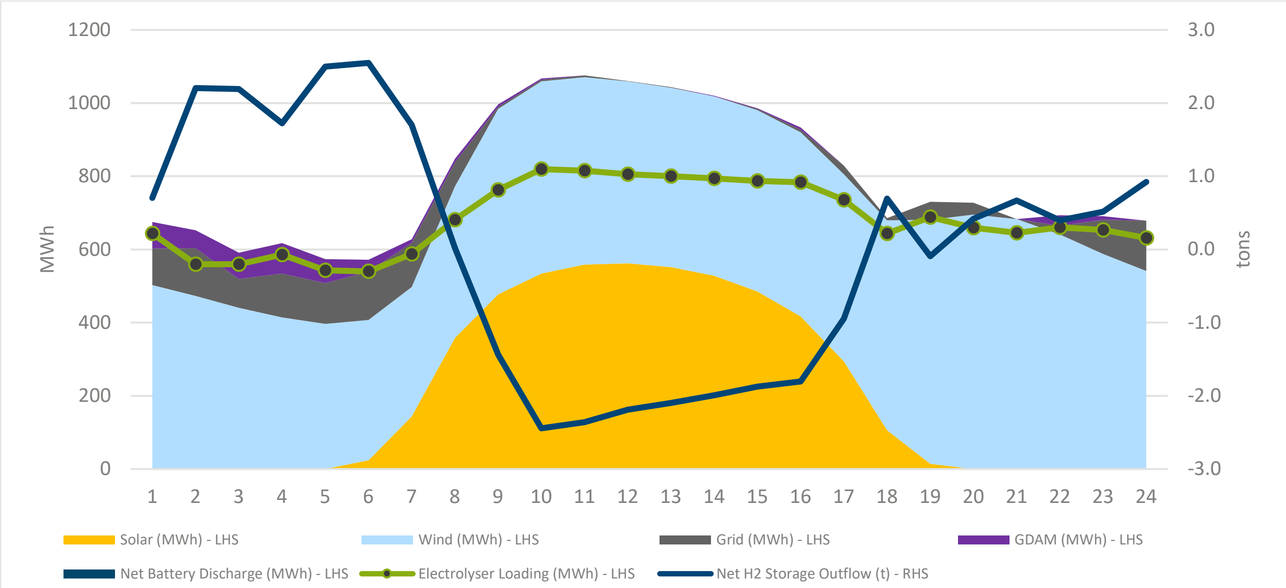


Figure 47: System sizing and average daily loading (24 hours) for Odisha under Option 4

The model optimises the system cost by sourcing up to 7.1% grid power in the non-solar periods.

In this option, LCOE and LCOA achieved in Gujarat, without any subsidy, would be INR 4.28/kWh and ~USD 930/ton respectively. Electrolyser size and CUF would be ~860 MW and ~79%.

5.4.4.6 Summary of Option 4

Table 36: Summary of Option 4

Port	Electrolyser (MW)	Solar (MW)	Wind (MW)	H2 storage (tons)	Electrolyser CUF (%)	BESS (2 hr) (MW)	Grid Power (%)	LCOE (INR/kWh)	LCOA (USD/t)
Kandla	901	823.2	1469.0	55.8	76%	0	7.35%	4.06	916
Vishakhapatnam	860	742.9	1462.8	42.4	79%	0	7.29%	4.31	936
Cochin	903	825.6	1466.9	56.0	76%	0	5.86%	4.95	1027
JNPT	905	866.6	1459.4	61.5	75%	0	7.22%	5.13	1051
Gopalpur	860	725.9	1463.7	42.5	79%	0	7.14%	4.28	933

This is the most optimised option where best solar and wind profiles can be utilized. However, despite use of good solar and wind profiles, there will be regional cost difference due to difference in cost of grid power and state transmission charge (STU). Some of the major considerations of this optimisation exercise are:

- This optimisation doesn't include any incentive or subsidy in capex or T&D charges
- However, several states have announced support measures which would reduce the cost of development. For example, **~15% capex subsidy would reduce the LCOA by USD 60 – 70/ton and a 30% capex subsidy results in bringing LCOA down by USD 120 – 140/ton**.
- Any subsidy in the transmission charge would further optimise the cost of production – INR 1/kWh (US cents 1.2 per kWh) reduction in landed cost of electricity would reduce **LCOA by ~USD 120/ton**
- No flexibility has been considered in **Ammonia loop operation**

In Option 4, total land requirement for setting up 600 ktpa green ammonia plant would be 6200 – 6500 Acre.

Table 37: Land requirement for option 3

Port city[69]	Land for Solar capacity (Acres)	Land for Wind capacity (Acres)	Green Ammonia facility (Acres)
Kandla	2881	3672	~100
Vishakhapatnam	2600	3657	
Cochin	2889	3667	
JNPT	3033	3649	
Gopalpur	2541	3659	

[69] The allocation per MW is 3.5 acres for solar, 2.5 acres for wind.

5.4.5 Comparison of various states

Table 38: Comparison of States

State	LCOA (USD/ton)				Remark
	Option - 1	Option - 2	Option - 3	Option -4	
Gujarat	1030	924	924	916	Gujarat is one of the most sought after state with respect to resource availability, port infrastructure, state level policies and ease of doing business. The state has one of the best solar and wind potential in the country. Also, in order to serve European market, Gujarat ports are better placed than other ports.
Andhra Pradesh	1080	930	922	936	Southern region also has reasonably good solar and wind profile. AP also ranks good in ease of doing business, has good port infrastructure and lower industrial tariff.
Kerala	1190	1023	1000	1027	Wind and solar profile in these regions are not the best in country and low wind periods call for either deployment of battery storage or sourcing of power from grid. Grid power as well as transmission charges are higher in these states.
Maharashtra	1350	1114	1110	1051	
Odisha	1340	1098	1065	933	

Key observations:

- **Option 1** (Off-grid island solution) is the highest cost (LCOA) option for all states due to large scale requirement of energy storage.
- **Option 2** (with permissible grid sourcing) optimises the LCOA by 10 – 20%, depending on regional grid tariff, by minimising the requirement of battery storage.
- **Option 3** (no constraint on sourcing of grid power) could offer incremental benefits over Option 2; however, acceptance of hydrogen in EU with emission footprint higher than the threshold indicated in RED II could be a challenge. In addition, grey ammonia market is not likely to pay a premium for a low carbon ammonia
- **Option 4** (Best RE profile and permissible grid sourcing) is the most logical and practical option for any green ammonia developer. However, this may attract additional state specific transmission charge.

Gujarat and AP are two most preferred states for setting up Green Ammonia facility. However, there may be tailor made incentives on capex, electricity cost and provision of common infrastructure. Selection of the right state should be done based on the real impact on LCOA from the state specific incentives.

Most preferred option is Option 4, which will use best RE profile and source grid power within permissible limit.

5.5 Cost of production in green ammonia in major supply hubs

Cost of production of green ammonia in major supply hubs primarily depends on levelised cost of renewable electricity and amount of subsidy offered towards hydrogen production. Key region-specific assumptions are captured below:

Table 39: Region specific assumptions for Capex (USD/t), LCOE and subsidy support

Region	Capex (USD/Ton)	LCOE (US cents/kWh)	LCOA (USD/T)	Subsidy/Support offered (USD/T)
India	~2700	5.5 – 6.0	860 - 920	Total $2.4 billion subsidy announced and auctions have taken place
MENA	~2700	4.5 – 5.0	720 - 750	NIL
Australia	3000 - 3200	6.0 – 6.5	900 - 950	NIL
Chile	~2700	4.0 – 4.5	750 - 800	NIL
USA	3000 - 3200	6.0 – 6.5	500 - 550	540 (production tax credit of $3/kg of green hydrogen)
Remark	Based on current capex; USA and Australia are likely to have 10 – 15% higher EPC cost	Based on tariff discovered in various regions, normalized for 75% CUF in 2030		While India and few MENA countries have announced support scheme, exact disbursement is undisclosed. USA, through Inflation Reduction Act, will be offering production tax credit towards green hydrogen production

Source: Deloitte analysis

It is important to note that USA has the lowest cost of production due to generous tax credit offered by the federal government. Apart from USA, MENA region is expected to be the second-best destination for developers due to low cost of electricity, followed by Chile, India and Australia.

Table 40: Electricity tariff in different regions

Region	Discovered tariff (2023)
India	$40 - 70/MWh for RTC bids $30/MWh for plain vanilla solar
Middle East[70]	$11 – 25/MWh for plain vanilla solar
Chile[71]	$35 – 38/MWh for hybrid RE $13/MWh for plain vanilla solar
Australia	No instances of auction

Source: Deloitte analysis

[70] https://www.pv-magazine.com/2021/06/25/strong-growth-predicted-for-middle-eastern-solar-pv/

[71] https://www.bnamericas.com/en/news/chile-awards-777gwhy-in-first-supply-auction-of-2022

5.6 Technology assessment

Technology assessment is done based on basic sizing and specification. A detailed assessment should be carried out by the developer during Pre-FEED and FEED stages.

5.6.1 Introduction of the technology and scheme

- Ammonia is produced via the Haber-Bosch process, which converts hydrogen and nitrogen into ammonia. Ammonia production is an energy-hungry process, requiring temperatures around 500 °C and at pressures up to about 20 MPa. To produce a ton of ammonia, an average of 30GJ of energy is consumed.
- Nitrogen is produced via an air separation unit (ASU). Most ASUs installed onsite facilities have the capability to produce oxygen, nitrogen and argon although they can be specialised to just produce one of the gases. At large scale facilities, cryogenic separation is considered as the most economic air separation process. The Industrial Gas producers (Linde, Air Liquide, Air Products) are key providers ASU technology.
- The nitrogen and hydrogen are then reacted in the ammonia synthesis process. This involves both being compressed at a high pressure within a reactor in the presence of a catalyst (normally Iron Oxide). The ammonia is then cooled, and other impurities / gases removed from the mixture.
- Green ammonia is completely carbon free when produced entirely with renewable energy based electrolysis.. One of the key differences between green ammonia and alternative forms is the process used to produce hydrogen. Grey and Blue ammonia make use of conventional steam methane reforming to extract hydrogen from natural gas. Green ammonia, on the other hand is produced using (green) hydrogen sourced from the electrolysis of water. Nitrogen is still sourced from the Air via ASUs and the Haber Bosch process used to synthesize ammonia.
- To produce green hydrogen, water is split into oxygen and hydrogen using renewable electricity, typically wind or solar.

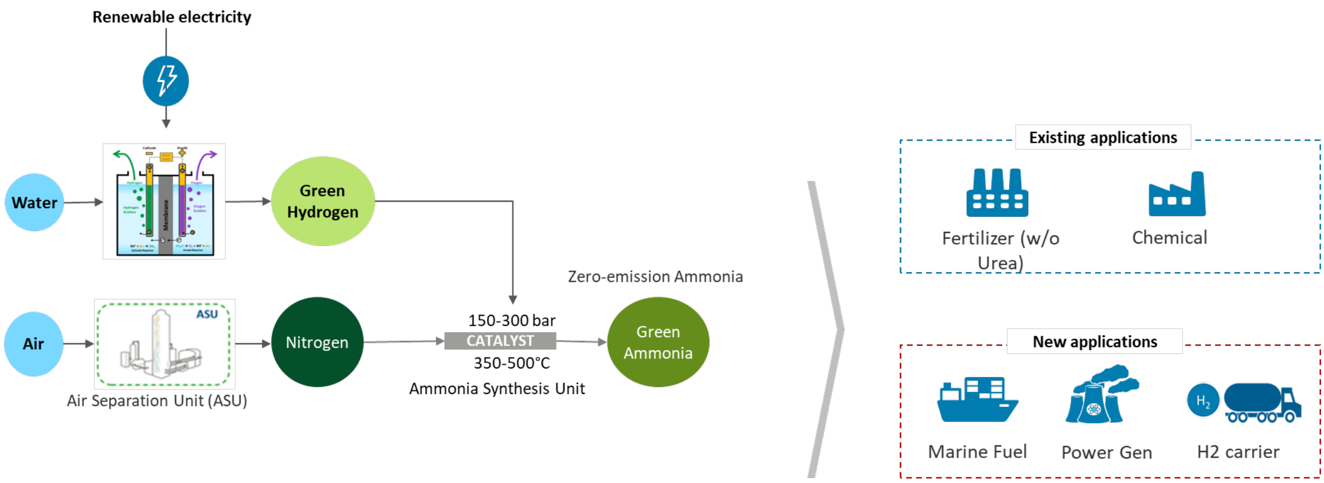


Figure 48: Green ammonia production setup

5.6.2 Overview and scope of the proposed project

The proposed capacity of the Ammonia plant in this analysis and report is 600 KTPA. This will be a green ammonia project where hydrogen will be produced through water electrolysis, powered by Renewable energy. Detail sizing and specification of the project is illustrated below:

Table 41: Key parameters for 600 kTPA green ammonia production facility

S. N.	Key Parameters	Option -4
1	Green Ammonia Plant Capacity	600 KTPA/ 1700 TPD
2	Green Hydrogen Production capacity	110 KTPA/300 TPD

2	Electrolyser capacity	850 – 900 MW
3	Renewable power capacity	Solar: 800 MW Wind: 1450 MW
4	Hydrogen Storage	~50 MT
5	Air Separation Package	60,000 Nm^3/hr
6	Desalination Plant	Raw water: 20 MLD DM water: 6 MLD
7	Ammonia Storage Tank/s and Associated BOG system	40,000 MT (one vessel size)
8	**Land Requirement:** **Process Plant (including Hydrogen Plant- Electrolyser, Ammonia Plant and Associated Facilities)**	**100 Acre**

5.6.3 Technology Selection for Hydrogen and Ammonia plant

The Selection of the main technologies for the green ammonia project is based on available technology maturity, technical performance, and market availability of those technologies.

5.6.3.1 *Hydrogen Generation System (Electrolyser Unit)*

Electrolysis is the process of splitting water into hydrogen and oxygen using electricity. This reaction takes place in a unit called an electrolyser. Electrolyser consists of an anode and a cathode separated by an electrolyte which acts as an electrical insulator and ionic conductor.

Water electrolysis technologies can be classified according to the applied electrolyte. The main water electrolysis technologies are Alkaline Electrolysis (AEL), Proton Exchange Membrane Electrolysis (PEMEL), Solid Oxide Electrolysis (SOEL) and Anion Exchange Membrane Electrolysis (AEMEL).

Globally two technologies are relatively mature – alkaline and PEM; alkaline is more prevalent but PEM is bridging the gap.

A. Alkaline electrolysis technology

Alkaline electrolysis technology is the most prevalent technology at present and also the most mature. According to the IEA, alkaline electrolysis has been adopted by the chlor-alkali industry since 1950s, and hence globally there is adequate workforce skill available. This involves electrolysis of water using liquid alkaline electrolyte (typically lye or 30% potassium hydroxide solution – KOH) and a porous diaphragm. The main benefit of this technology is its liquid electrocatalyst, which negates the need for costly metal materials. Alkaline electrolysis cells can be configured in large stacks and are known for their long-term stability and lifetime. However, the issue faced with alkaline technology is low pressure of operations which leads to requirement of compression for generated hydrogen as well as long ramp-up times which is relatively unsuitable for operations with intermittent renewable power. Thus, **alkaline cells maybe highly suitable for RTC power projects where issue of power variability is eliminated.**

However, significant R&D is in progress to address both of the above issues. OEMs are increasingly focusing on high pressure alkaline electrolyser as well as reduction in ramp-up times.

B. Proton Exchange Membrane (PEM) electrolysis

Proton Exchange Membrane (PEM) electrolysis is the electrolysis of water in a cell equipped with a solid polymer electrolyte (SPE) that is responsible for the conduction of protons, separation of product gases, and electrical insulation of the electrodes. PEM has the advantages of smaller footprint than alkaline (takes around one-third of space as alkaline). PEM is suited more for RE intermittency vs alkaline and since PEM operates at higher pressure, there is no need for hydrogen compression. However, PEM efficiency levels are lower than alkaline and **is costlier than alkaline electrolysers** due to

- Use of costly rare earth materials. The cathode and anode of PEM stack are created by depositing platinum or Iridium on either side of a relatively costly NAFION membrane

- The extraction process of these metals are relatively emission intensive
- The porous transport layer (PTL) is built using titanium which is costly as well. In contrast, alkaline uses nickel which is widely available and of lower cost.

The presence of precious metals makes PEM costlier by about 40-50% than alkaline electrolysers. Currently, Chinese alkaline electrolysers are the lowest cost (USD 300/kW)[72] due to higher scale, mature/developed electrolyser ecosystem and also relatively low labour costs compared to developed countries. Other electrolyser technologies are also undergoing significant R&D work, mainly solid oxide electrolyser cell (SOEC) and anion exchange membrane (AEM) . These technologies are mostly in demonstration phase and are not commercially ready yet.

Based on the technological assessment, market maturity, economics and global references, it is suggested to adopt alkaline electrolyser technology for the proposed integrated project

Output purity: Electrolyser package shall be designed to produce hydrogen with below mentioned specifications.

Purity	: > 99.999 % (vol.)
Oxygen content	: < 2 ppm
Dew point	: ≤ (-) 71 °C @ atm

Loading of electrolyser: Electrolyser shall be operated throughout the day in a varied loading, with minimum loading fixed at 30%. The optimisation of Ammonia production yield depends on the operation of the Electrolyser utilising varying levels of RE. Hydrogen generated from Electrolyser unit shall be supplied to Ammonia plant and any excess amount to Hydrogen Storage tank.

Power requirement for Hydrogen generation: Water electrolysis is an energy intensive process. Lower heating value of hydrogen is 34 kWh/kg; therefore with 65% of electrolyser efficiency will require 52 kWh of electricity to produce 1 kg of hydrogen. Additionally, 2-3 kWh of electricity is required for the balance of plant systems. For compression into storage tank, 5 -6 kWh electricity would be required per kg of hydrogen.

5.6.3.2 Hydrogen Storage

Hydrogen is a lightweight molecule, which results in low energy density for pure hydrogen at room temperature. It needs to be compressed to store at room temperature. Hydrogen can be stored as a compressed gas, liquid, or as a part of a chemical structure. Below are different types of hydrogen storage:

A. Compressed Gas Storage

a. Tubular Cascade/ Skids:

Type I pressure tubes are used in cascade skids. Generally, each cascade skids consist of 6 to 8 nos. of tubes. Tubes are made of metals like carbon steel and low alloy steel, and they are mostly used in industry and are available in market with water volume of 2- 3 m^3.

Figure 49: Hydrogen Tube Cascade/ Skid storage

b. Underground Storage Vessel:

Hydrogen can be stored in pressure vessel in a purposely built underground cavity. The advantage of this technology is low capex compared to other high pressure storage technologies. However, it is not yet commercialized for large

[72] As reported by Bloomberg NEF

scale application, and design is largely dependent on project location geotechnical data.

c. Spherical/Bullet Storage:

Hydrogen tanks that are available in the market are mostly cylindrical. Although this common tank geometry offers good utilisation of the installation space, the potential for weight reduction has been limited. For physical reasons, the required wall thickness in the cylindrical area of the tanks is twice as high as in the spherical area. Thus, the spherical design has potential in terms of material and cost savings.

Figure 50: Hydrogen spherical storage (representative image)

d. Mounded Bullets Storage:

The concept of mounded storage came into prominence after the Mexico City Gas disaster in November 1984, where 16000 m^3 of LPG was stored in 6 spheres and 48 horizontal vessels. Mounded storage usually stores combustible liquids under atmosphere and liquefied gases under high pressure in horizontal cylindrical vessels placed near ground level and covered with suitable backfill. The vessels shall be installed above the highest known ground water table; the soil cover usually protrudes above grade as an earth mound, hence the term "mounded storage".

Figure 51: Mounded bullet storage (representative image)

B. Liquid Storage

a. Hydrogen Liquefaction:

Storing hydrogen in the liquid form requires approximately 6 – 12 kWh/kg-H2 energy which is higher than that needed for high-pressure hydrogen gas compression. Hydrogen liquefaction temperature is -253 deg C and the process of liquefaction is energy intensive. In addition, supply chain system of liquid hydrogen is yet to evolve.

C. Solid State storage (as chemical structure)

a. Metal Hydrides Storage:

Hydrogen can be chemically stored by absorbing or reacting with other chemical compounds such as metals or "organic substances." Metal hydrides are one of the most common types of hydrogen chemical storage that can store hydrogen at high densities that can exceed that of liquid hydrogen. The challenges of storing hydrogen in a chemical form are mostly relative to the hydrogenation and dehydrogenation processes considering high temperature and pressure requirements which might be an obstacle to their application in large-scale energy storage applications.

Based on safety, technical maturity, and market availability, the preferred hydrogen storage type is Mounded Bullet Storage. Mounded Bullet Storage has additional safety associated with it when compared to the other above-ground storage options. The purpose of mound is to protect the vessel against external events such as radiation in case of fire, flying objects and sabotage, and hence the thickness of the cover should be 1.0 m in general. The advantages of mounded storage are:

- Very low possibility of "Boiling Liquid Expanding Vapour Explosion". As in case of early fire, flame impingement or bullet heating, the mound surrounding the bullets will protect the vessel.
- The vessel is protected against heat radiation from a nearby fire, pressure wave originating from an explosion, impact by flying object and sabotage.
- It satisfies environmental and aesthetic requirements.
- It results in reduced site area due to less stringent inter-spacing requirements.
- The safety distance to the site boundary can be reduced considerably.
- Extensive water deluge systems are not required.

Hydrogen will be generated using renewable solar PV and wind power during renewable hours and Ammonia loop will operate continuously for 24 hours a day. So, enough hydrogen to be generated during renewable hours, to meet low/non-renewable hours hydrogen requirement of Ammonia loop. Excess hydrogen generated will be stored in the above-ground hydrogen tank and be supplied to ammonia synthesis loop in the non-renewable hours. Storage tank size will be optimised as per optimised RE and electrolyser sizing.

In the proposed integrated facility, Hydrogen storage capacity will be ~50 MT, as per Option 4. Also, additional ~6 kWh of electricity will be required for compressing and storing per kg of hydrogen.

5.6.3.3 Air Separation Unit (Nitrogen Generation System)

Two primary methodologies exist for the separation of nitrogen from atmospheric air: Cryogenic and Non-Cryogenic processes. In both approaches, atmospheric air is subjected to compression, with subsequent elimination of compression-generated heat. Cooling is achieved through the utilization of heat exchangers. The differentiating factor between these methods becomes apparent in the cooling phase.

Within the Cryogenic process, impurities are separated via temperature swing adsorption (TSA). The cooled air from this process is then directed to a cold box, consisting of a combination of heat exchangers and a distillation column. On the other hand, the non-Cryogenic process involves the removal of hydrocarbons, particulates, and other contaminants through the implementation of carbon towers, filters, and mist eliminators. Subsequently, the processed air undergoes pressure swing adsorption (PSA).

The main advantages of cryogenic and non-cryogenic (adsorption, chemical process, and polymeric membrane) technologies are discussed below:

Table 42: Merits of Nitrogen Generation System Technology

Technology	Status	Economic Range (Nm^3/hr)	Product Quality Vol. (%)	Start-up Time
Adsorption (non-cryogenic)	Mature	Up-to 1500	95	**min**
Chemical	Developing		99	**hours**
Membrane	Semi Mature	Up-to 600	99	**min**
Cryogenic	**Mature**	**> 2000**	**99.9**	**hours**

Cryogenic process is ideal for high volume gases and for better nitrogen purity. While non-cryogenic systems are commercialized for small scales, low flowrate, and medium purity.

Based on the above conclusion and global experiences, cryogenic technology is selected for proposed project.

5.6.3.4 Green Ammonia Production unit

Ammonia plant shall be designed to produce green ammonia using Haber-Bosch process. Basic Design Engineering Package and proprietary equipment for this plant shall be supplied by a renowned Ammonia Licensor.

Liquid ammonia produced from ammonia plant shall have following specifications:

Purity	:	> 99.8 % (wt.)
Water	:	< 0.2 % (wt.)
Oil	:	5 ppm

The unit shall be comprising of the following sections:

a. Synthesis Gas Compression

Synthesis gas (H_2 & N_2 in the ratio of 3:1) at the pressure of 16 - 25 Bar (a) shall be compressed in a multi-stage centrifugal compressor. Recycled gas from synthesis loop shall also be added to the make-up syngas. This mixed syngas shall be compressed to loop operating pressure.

b. Ammonia Synthesis Loop

Ammonia shall be produced in a fixed-bed Ammonia Synthesis Converter. Each bed will be fixed with Iron promoted synthesis catalyst. Make-up & recycled gas from the syngas compressor will be preheated by heat exchanger (Converter Feed/ converter product Exchanger) before feeding it to the converter.

Following chemical reaction over Fe based catalyst takes place in the ammonia converter:

$$N_2 + 3\ H_2 = 2\ NH_3\ (\Delta H = -46.14\ kJ/mole)$$

The formation of ammonia is a reversible and exothermic reaction. The ammonia formation reaction is favoured by high pressure and low temperature. However, the reaction velocity increases with rise in temperature. Thus, optimum temperature and pressure is obtained for maximum ammonia conversion. The pressure and temperature will be based on the design of the licensor.

The converter product gas shall be directed to Ammonia Refrigeration Unit where the product shall be cooled & condensed through a heat exchanger. The liquid ammonia gets separated from the synthesis gas in Ammonia Separator immediately downstream of the exchanger. The remaining vapour from separator, containing ammonia, will be reheated in the chiller, and routed back to the synthesis gas compressor, where it will be mixed with the fresh makeup syngas and compressed in the final stage of the compressor. This loop will continue throughout the process.

c. Ammonia Refrigeration System

A three-stage ammonia refrigeration system will be provided for condensation of the ammonia. This system consists of a multi-stage centrifugal compressor driven by motor along with Refrigerant Intercooler, Condenser, Receiver, and drums.

Production of -33°C cold ammonia liquid product will be accomplished by flashing the liquid ammonia in a flash drum. The product ammonia will then be pumped by the Cold Ammonia pump and sent to the ammonia storage tank.

d. Steam generation through waste heat recovery

The medium pressure steam is generated by recovering waste heat from ammonia converter in series of exchanger, which shall be used for power generation in Steam Turbine-Generator. This captive power shall be utilized within the plant.

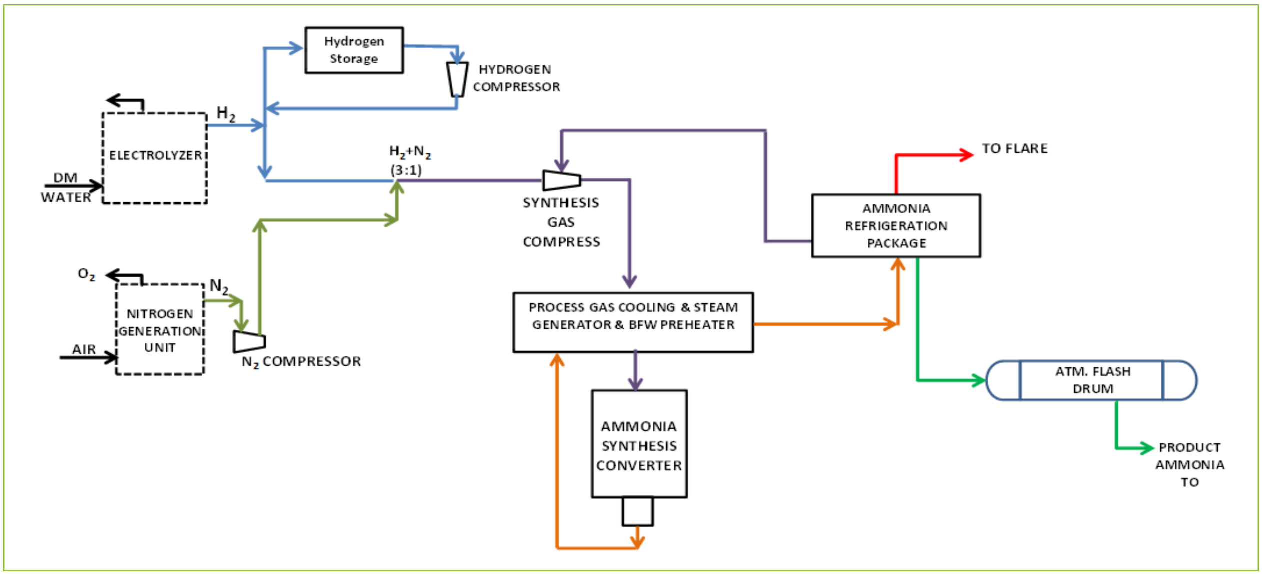


Figure 52: Conceptual Diagram of Ammonia Synthesis Unit

Note: Representative image

e. Liquid Ammonia Storage System and BOG System

Product liquid ammonia (-33°C) from ammonia generation plant shall be sent to atmospheric ammonia storage tank (double wall and double integrity type). Ammonia storage tanks shall be provided with compressors and associated refrigeration system to handle flashing and Boil-off gas (BOG) to minimise the ammonia vapour loss.

The tank consists of cup inside with outer shell insulated from outside. The annulus between the cup and outer tank normally consists of ammonia vapour. The roof is bare and painted outside. Suspended deck with insulation is provided inside tank. The outer tank shell is designed for full strength to hold liquid ammonia at (-)33°C for double safety. The outside of the tank is insulated with rigid polyurethane insulation foamed in-situ (PUF) and covered with aluminium cladding. The bottom has foam glass , which is a load bearing insulation. The cup is covered with suspended deck with resin bonded glass wool insulation.

The tank will be equipped with two pilot operated pressure relief valves and two vacuum relief valves to safeguard the tank against overpressure or vacuum. Isolation valves will provided with suitable mechanical interlock. The tank will rest on elevated foundation slab supported on concrete columns to permit free air passage below the tank. The tank will be provided with a ladder for going inside the cup. A staircase tower with platform leading to tank top will be provided for approach to the nozzles, on the roof.

Table 43: Ammonia storage tank system

Parameter	Description
Storage Tank capacity	2x30,000 MT (50% higher than the capacity of LGC)
No of storage tank	2
Type	Double Wall, Double Integrity, Cup-In-Tank
Operating temperature	-33 deg C
Operating pressure	225 to 1100 mmWC

The tank shall be provided with necessary instruments like float type level indicator, DP type level indicator, temperature indicator, interspaced level indicator and pressure recorder.

One no flare system will be provided for venting / flaring ammonia vapour and maintain tank pressure in case of an emergency like power failure or / and compressors failure. It consists of two pilot burners and an integrated gas seal to deter the flame flash back. It will also be provided with a flame front ignition panel to enable lighting of the pilots from ground level. Fuel gas (LPG) & N2 will be provided for operating the Flare. The vent gases are released through a riser pipe.

Basic Fire-fighting system consisting of fire water tanks and pumping system, fire hydrant and monitor system, manual water spray / water curtain system and portable fire extinguishers shall be provided around the storage facility.

Compressor system with required design shall be provided to maintain the pressure inside the tank during loading and unloading processes.

f. Ammonia Unloading and Transport System

The design of facility for ammonia unloading & transportation shall include Ammonia transfer pump, Metering Station, Inland piping, etc. to off-taker ship.

The process of the ammonia synthesis in the said project shall be based on commercially proven Haber-Bosch loop by a well renowned Licensor (e.g. KBR, Topsoe etc.). The selection of the Licensor will be based on the performance parameters such as loop efficiency, specific energy consumption, operation flexibilities, Proven track records, economics etc.

5.6.3.5 DM Water System

Production of green hydrogen requires ultrapure DM water. The rate of DM water flow will depend on the electrolyser rating. In the proposed project, the requirement of DM water is ~ 6 MLD.

The process from raw water to DM water can be divided into two steps:

- Pretreatment of raw water
- Polishing to ultrapure water

The role of the pretreatment system is to make the raw water suitable as a feed source for the polishing system. This means bringing the water to a state where it resembles city water quality. The type of pretreatment system depends on the source of water as each will come with their own challenges. Groundwater contains dissolved redox active species such as iron and manganese that can precipitate in and clog the polishing system. These can be effectively removed using aeration and sand filtration. For treated wastewater the primary concern is particles, organics, and microorganisms. Here ultrafiltration in combination with UV can be used to bring the water to a suitable quality. Seawater primarily requires removal of salts, but also particles and dormant microorganisms. Using standardized reverse osmosis (RO) desalination is sufficient.

Once the raw water has been pretreated, we will address the following issues to turn it into ultrapure quality:

- Content of ions – conductivity
- Hardness
- TOC
- Silica
- Gasses

To remove the bulk of the ionic load RO is used. The membrane blocks ions, molecules and particles and will therefore also remove organics (TOC) and silica. To reach sufficiently low concentrations it is often necessary to employ a double pass RO system, where the permeate from the first RO process is filtered again in a secondary RO system. For the RO system to operate properly, the water must first be conditioned to avoid scaling and damage to the membranes. If there is free chlorine in the water, this must be removed using active carbon, to avoid oxidation of the selective layer of the membrane. Hardness due to ions such as Ca and Mg can cause scaling and limit the recovery rate. This can be handled by either using a softener that will exchange multivalent ions with Na or by dosing in an antiscalant that will stop the scaling process. RO membranes do not stop dissolved gasses such as CO_2. These must therefore be removed with a dedicated process. For a chemical free option, a membrane degasser can be installed after the RO membrane. Alternatively, lye can be does in front of the membranes to convert CO_2 to bicarbonate ions that can be removed with the RO system. To reach the very low conductivities required by many electrolysers, it is necessary with a final deionization. Here either a mixed bed filter or an electrodeionization (EDI) unit can be used. These processes will take any remaining ions and exchange them for H+ and OH- ions. The mixed bed must be regenerated or exchanged once spent while the EDI can operate continuously due to a self-regenerating design. Often the two deionization technologies will be employed together with the mixed bed placed as a "police filter" after the EDI.

5.6.3.6 Associated Utilities, Offsites, and Balance of Plant (BoP)

Following Balance of Plant (BOP) systems will be considered for the integrated facilities:

A. Cooling and Raw Water System

The total cooling water requirement is estimated as ~20 MLD for the integrated facility. The cooling water system shall consist of:

- Induced draft cooling tower (counter current)
- Circulation pump
- Chemical dosing skid
- Side stream filter

Cooling tower will be designed for approach 4°C and range of 10°C with wet bulb temperature of 29°C. Cooling tower circulation pumps will supply cooling water to various consumers located in hydrogen plant, ammonia plant and offsite and utility. Suspended solid from cooling water will be removed in side stream filter through cooling water discharge header. Cooling Tower blow down and side stream filter backwash will be transferred to Effluent Treatment Plant (ETP).

The project is located on the coast of Bay of Bengal or Arabian Sea. Hence, it is proposed to utilize desalinated sea water for overall plant's cooling water and raw water requirement. Developer will conduct a study to identify sea water intake and outfall location based on dispersion of brine/ reject water from the process complex.

Sea Water Intake System if desalination plant is proposed:

The Sea Water Intake System may consist of the following major components:

- Offshore Intake head
- Buried offshore gravity main (pipeline) from Offshore intake head to onshore intake pump house.
- The Onshore intake pump house will be suitably located based on elevation difference between Offshore intake head and plant location
- Onshore pumping main (pipeline) to convey sea water from onshore pump house to Desalination plant.

The brine/reject water from the plant will be discharged into the sea in line with environmental regulations. The proposed outfall system for the plant will consist of a pumping/gravity main (pipeline) with suitable diffuser arrangement designed to disperse the saline water in line with environmental regulations.

Desalination Package System/Sea water Treatment Unit:

The sea water will be pumped from the sea water intake area to the desalination package, which is a part of the main process plant area. The pumped sea water from intake area shall be fed to the pre-treatment facility. The pre-treated water will be then desalinated in membrane-based Sea Water Reverse Osmosis (SWRO) unit.

The desalination system will be used to produce low salt water from seawater. Low salt water will mainly be used for Raw water for following usage:

- Feed to Potable water generation package
- Utility/Service water
- Cooling water make-up
- Fire water storage tank filling/make-up

The SWRO permeate shall be stored in raw water cum fire water tank. The raw water cum fire water tank shall be sized adequately to hold fire water reserve and two days service water requirement of the plant.

Potable water will be stored in a potable water storage tank sized to hold one day's requirement of the plant. Potable water shall meet the Indian guidelines.

B. Instrument Air Facilities

Instrument Air package comprising of Air Compressor, Dryer, and Receiver shall cater Instrument Air and Service Air requirement of the green ammonia complex. The quality of the air is important to ensure that instrumentation will function properly and reliably. Instrument Air shall have Dew Point of - 40°C, dust, and oil free. Plant Air shall have Dew Point of -10°C, dust, and oil free.

C. Firefighting and Safety System

Firefighting system including firewater storage, pumps etc. shall be considered, which will be adequate to meet the requirement of proposed plant. Provision will be made for firewater ring and other fire & safety equipment. Following components shall be designed and developed during detailed engineering.

- Fire Hydrant System
- Water Monitor (outdoor)
- Fire Hose Cabinet (Outdoor & Indoor)
- Branch Pipe with Nozzles
- Fire Hose
- Hose Reel Assembly
- Alarm Valve Assembly
- Deluge Valve Assembly
- Sprinkler Bulb
- Spray Nozzle
- Water Curtain Nozzle
- High expansion Foam Concentrate Bladder Tank with Foam
- Portable Fire Extinguishers- Dry Chemical Type/ Foam Type/ Carbon dioxide Type
- Fire Buckets
- Fire Beater
- Fire Hook
- Fire & Gas Detection System
- Cleaning agent

D. Vent System

Vent system will be designed and categorized as hazardous vents, non-hazardous vents, as illustrated below:

- **Hazardous vents:** Ammonia, Hydrogen & SynGas vapours shall be sent to a closed system such as a flare system.
- **Non-Hazardous vents:** Steam, oxygen & nitrogen shall be sent to an atmospheric safe location.

The vent system will include following systems, which will be considered during the design stage:

- **De-Pressurization Systems**: Emergency depressurizing systems shall be provided, in addition to pressure relief devices, for the Hydrogen Storage Area, and actuated via operator action at the plant control room. The system shall generally be designed in accordance with API RP521.
- **Flaring Systems**: A common flare system will be considered for disposal of gaseous Hydrogen & Ammonia in the complex. Ammonia and Hydrogen related relief from pressure relief valves outlet, blowdown valves outlet, depressurization valve outlet shall be routed to the flare header connected with the high-pressure (HP) flare system. A separate LP flare system shall be considered for ammonia storage tanks and associated BOG system. Flare design shall be done considering low temperature release of Ammonia vapours.
- **Open Vents:** Oxygen along with minimal amount of hydrogen from the Gas Lye treater / separator section of the Electrolyser Plant is vented to a safe location. On a daily basis, impure hydrogen with oxygen from the gas-lye treater/separator section of electrolyser plant shall be vented to a safe location. Similarly Steam and Nitrogen from the pressure relief valves and vents in the Ammonia Plant area & Nitrogen Generation Plant is vented to an atmospheric safe location.

The venting of toxic or hazardous vapours will be routed to safe location (as determined by dispersion analysis). All vent pipes containing flammable substances will be provided with an in-line flame arrestor. A dispersion study will be performed to ensure that the correct distance is employed for the "safe location". All equipment or instruments requiring vents to atmosphere will be individually vented away from any walkways or ladders.

E. Drain System

Continuous/intermittent discharge in the form of blowdown or cleaning is expected from Electrolyser system and the Ammonia Generation Unit. Other utility packages are also expected to have continuous/intermittent discharges. These effluents will flow to the Effluent Treatment Plant through a adequately designed drainage system.

a. Hazardous drain system

- Hazardous liquid draining is not envisaged for any process fluids in this plant other than for chemicals & fuel for Emergency Diesel Generator (EDG).
- Chemical waste generated from chemical dosing facility (phosphate, oxygen scavenger, etc), from sea/ground water treatment plant shall be sent to neutralizing pit.
- Wastewater from laboratory will be collected and sent to neutralization pit. This wastewater along with other neutralized waste from the plant will be sent to the ETP.
- Similarly, Drains from EDG containing small amounts of Diesel/Oil shall be collected into a pit separately. This shall be transferred to the ETP using Portable pump as an when required.

b. Non-Hazardous Service

- Non-hazardous drains for fluids such as line drains, wash water, lube oil, etc, shall be collected and sent to effluent treatment plant. Oily waste shall be collected separately and not allowed to mix with other non-hazardous waste. The steam condensate shall be routed to the DM Water Plant for reuse after necessary treatment.
- Floor wash drains (Oily water / waste) generated in various buildings / areas (Workshop, Pump house etc.) shall be collected in a pit at the respective areas and shall be transferred to ETP using portable pump as an when required.
- Fire water from transformer area in case of fire shall be collected in a burnt oil pit near the transformer area and the same shall be transferred to ETP for treatment using Portable pump as an when required.

F. Effluent Treatment Plant (ETP)

Effluent Treatment Plant will be designed with following considerations:

- Spillages and floor wash generated in the process units shall be collected in a pit at the respective areas and shall be transferred to ETP using portable pump as an when required.
- In case of rainfall, storm water of entire plant for first 15 minutes shall be routed to ETP because of chemical contamination. After 15 minutes, rainwater shall be routed to storm water drainage.
- Various types of wastewater(s) as described below from the plant will be segregated and transferred to effluent treatment plant for treatment. Treated wastewater shall be disposed-off to sea or any other suitable location and solid waste shall be disposed-off from the plant premises by trucks. Oily waste will be collected in barrels and shall be periodically disposed in suitable location.

Various types of waste generated in the plant are detailed below:

- **Normal Wastewater (containing suspended solids):** Normal wastewater constitutes the following: backwash waste from filters in sea water treatment plant, and clear water from oil water separator provided to treat oily wastewater.
- **Chemical wastewater:** The chemical wastewater shall be received from the Electrolyser, cooling tower and sea water treatment plant. Typically, this water contains small amount (i.e., ppm level) chemicals. The chemicals waste will be diluted within the ETP and be disposed-off to sea.
- **Oily wastewater:** Floor wash drains and fire water from transformer areas in case of fire are the sources of oily wastewater in the plant, which will be collected and treated in the ETP.
- **Abnormal wastewater:** Electrolyte from the Electrolyser will be drained once in four years. Presence of vanadium in the electrolyte makes it impossible to be discharged directly to ETP. A separate pit to neutralize Vanadium into Ferrous vanadate by neutralizing V^+ with $FeSO_4^-$ will be provided. This will be then disposed of from the plant by means of trucks.

G. Electrical Distribution System

The electrical distribution scheme for the project is categories into following segments and briefed in the following sub-sections:

- Energy Management System (EMS)
- Renewable Energy Generation
- Battery Energy Storage System (BESS)
- GRID

Energy Management System (EMS)

The core components of this project comprise the Energy Management System (EMS) and the Smart Metering System. Within the Main Control Room (MCR), the EMS plays a central role by integrating functions such as the Power Plant Controller, Automatic Generation Control, and demand management. Its primary mission is to efficiently distribute the accessible power generated by Renewable Energy (RE) Generators to Electrolysers, thus optimising hydrogen production in line with available RE Power. Working in tandem with the Smart Metering System, the EMS collects data from various sources, including the incoming supply from the Grid, RE Generation, Electrolysers, Battery Energy Storage Systems (BESS), and the Water System, to ensure effective operation.

Following are the key functions of Energy management system:

- Maintain Energy balance between generation and consumption of the complex by controlling RE Generators, Electrolyser, BESS.
- Maintain grid voltage and frequency during steady state condition
- Manage start-up sequence of Electrolysers.
- Maximize the utilization of available solar energy for hydrogen production.
- Regulate ramp-up and ramp-down of Electrolysers.
- Regulate ramp-up of Inverters post cloud condition to maintain grid voltage and frequency within permissible limit.
- Manage shutdown sequence of Electrolysers.
- Regulate Active and reactive power flow at the point of interconnection.
- Manage reactive power requirement of the complex.

Battery Energy Storage System (BESS) for steady state supply of RE

The operation of Electrolysers relies entirely on variable solar input, posing challenges in aligning generation with consumption, particularly in the monsoon seasons. Compounding this issue, the ramp rates of PV inverters and Alkaline Electrolysers differ, leading to a discrepancy between PV generation and Electrolyser consumption even during steady-state conditions.

In this context, Battery Energy Storage Systems (BESS) assume a critical role in both steady-state and transient operations. They effectively mitigate voltage and frequency fluctuations, serving as a primary response mechanism against disturbances, whether in steady-state scenarios or during transient events. By ensuring grid stability and facilitating seamless solar generation without power exchange, BESS proves instrumental in maintaining system integrity. For this project, BESS will be integrated with the solar power plant to provide steady state supply to electrolyser for 12 hours.

Furthermore, the Sea Water Intake, Desalination, and DM Plant functions are designed for continuous operation throughout the day. Therefore, BESS becomes essential in compensating for any shortfall for the renewable energy.

GRID connection:

The project will establish a grid connection at voltage levels of 132kV. This connection will serve as a fundamental reference for daytime operations of Solar Inverters and to ensure the continuous functioning of the Ammonia Loop and balance of plant system during nighttime power requirements.

5.7 Execution plan for a 600 KTPA plant

Implementation of project would involve several activities, of which some are pre-project activities and others are related to physical execution of the project. The total project including offsite facilities will be executed on EPC basis with the help of reputed EPC contractor who will provide services for detailed engineering, procurement, construction and supervision of pre-commissioning & commissioning activities. License, know-how and basic engineering already obtained from reputed process licensors, such as KBR, Topsoe for Ammonia loop.

5.7.1 Pre-project activities

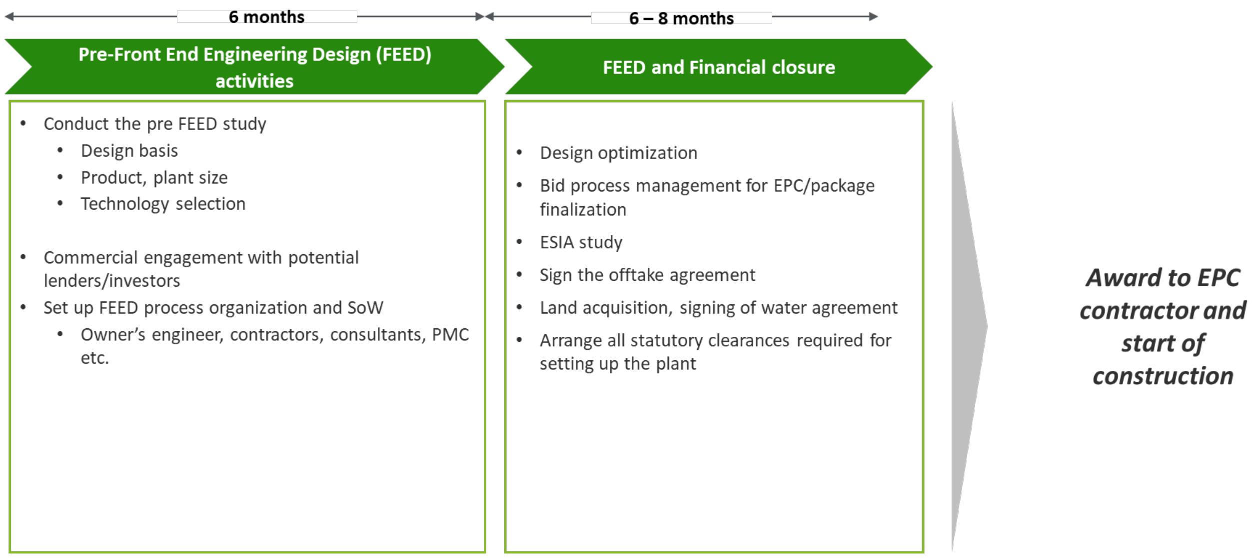
The pre-project activities shall be completed before the physical execution of the project. Key pre-project activities are:

- Approval of the project by competent authority.
- Preparation of Environment Impact Assessment (EIA) study and clearance by Central Pollution Control Boards (MoEF).
- Soil investigation work for ascertaining soil characteristics of the area identified within the present boundary
- Selection of EPC contractor
- Appointment of Owner's Project Management team/Project Management Consultant.
- Mobilization of resources for construction facilities.
- Firming up of arrangement for supply of raw materials from concerned agency.
- Drawing up of a project implementation plan based on a network of activities

5.7.2 Project execution plan

All the pre-project activities mentioned above shall be completed before the zero date of the project. A 600 KTPA project is expected to be completed by 30 months. Detail plan of the project is illustrated below.

Pre-FEED and FEED will require 12 – 14 months before start of construction.



Execution plan is illustrated below:

		Execution schedule for Integrated Ammonia Plant (Months)																													
Sl No	**Activity**	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
1	**Pre-FEED and DPR preparation**																														
2	**EC and other statutory approval, including connectivity for transmission**																														
3	**Selection of engineering firm, completion of basic and detailed engineering**																														
4	**Floating of RFP, selection of OEM and Equipment order**																														
5	**H2 plant construction and commissioning**																														
6	**Other auxiliary systems, including cooling tower and civil work**																														
7	**Ammonia plant, including Civil work**																														
8	**Combined trials , full load tests, Performance guarantee tests**																														
9	**Commercial Operation**																														

EPC contractor will be responsible for carrying out Detailed Engineering of all facilities inside the complex and construction of the plant within budget, quality, Safety and given schedule. Developer and a PMC team will overview/monitor the performance of EPC contractor. Commissioning and guarantee test will be the responsibility of the licensor for the main plants and OEM of hydrogen electrolyser.

6 Key risks and mitigation plans

While ammonia production is an established process, developing hydrogen projects comes with various risks. To ensure successful project development, it's crucial to identify and mitigate these risks effectively. In addition to project development risks, there are risks associated with business and evolving regulations. Here's an overview of major risks associated with the development of the integrated green ammonia project:

Table 44: Risk mitigation plans

Risk	Description	Mitigation measures
Technical and Safety Risks	• Hydrogen is highly flammable and can be challenging to handle safely, leading to potential accidents and infrastructure damage	Employ rigorous safety protocols, invest in advanced leak detection systems, and implement robust emergency response plans. Additionally, use advanced materials and designs for hydrogen storage and transportation infrastructure to minimise risks
Offtake risk	• Green H2/NH3 merchant market is not established. Still, cost of green NH3 is much higher than fossil-based NH3. Therefore, limited voluntary purchase interest from consumers due to this unfavorable economics. • Developers prefer a long term offtake contract (>10 years), while off takers prefer short term contract (2-3 years) • All the above lead to unpredictable cash flow for the developers	Negotiate long term contract with consumers
Technology risk	• Green hydrogen is nascent technology; while certain technologies are mature (e.g. alkaline electrolysis), experience on commercial scale deployment is limited	Select OEM with proven experience and good pedigree
Operational risk	• Non-performance of hydrogen process and equipment (e.g., load factors, conversion efficiency, leakage) poses significant operational risk. • Limited availability of historical data makes it difficult to predict performance.	Train O&M officials by the OEM and in the initial year, outsource the annual maintenance contract to the OEM
Counterparty default risk	• Default of the buying counterparty on its obligations (disappearance, questioning of contract) • Default of the electricity supplier and the equipment supplier	Deploy suitable payment security mechanism Sign multiple small contracts to diversify default risk
Construction risk	• Non-performance of contractor	Incorporation of completion guarantees, due diligence on previous records, contractor evaluation etc.
Regulatory risk to export to EU	• Regulatory regime in EU is evolving and may undergo significant changes in future to accelerate the fight against climate change. • Potential risks may arise due to stringent certification process, change in emission threshold and other sustainability criteria	Offtake contracts should be negotiated to protect exporter by passing through any commercial impact arising out of changes in regulatory provisions to importer.
Legal risk	• Legal risks pertaining to contractual provisions, such as guarantees of payment, penalties, termination, liabilities – direct, indirect, consequential, Change-in-law, Force Majeure, etc.	The exporter should focus on following mitigation measures: • List all legal requirements to be fulfilled by the exporter including implications of various laws in specific member states

Risk	Description	Mitigation measures
	• Risk related to compliance of State specific legal provisions, e.g., German civil code • Any other legal or regulatory obligation derived from entering the contract for the supply of Green Ammonia/related derivatives	• Identify protection available to exporter/supplier in the event of changes in regulatory or legal framework which are introduced in future. • Draft the potential implications of all laws prevailing in EU member states
Taxation	• Prevalence of wide range of complex taxation provisions in the EU member states may lead to adverse commercial impact on the exporter	**Optimise the indirect taxation and duties prevalent in EU states, with focus on** *Value Added Tax (VAT)* • Assess VAT registration requirements, tax declaration and record keeping obligations • Identify potential to optimise VAT balancing, and explore how to claim import VAT as an offset for payable VAT etc. *Energy Product Taxation* • Assess if Green NH3/related derivatives apply to formalisms under Energy Product Taxation (part of the mineral oil / fuel act). • Establish the requirements (if so) for special tax warehouse status, special license requirements, need for guarantees and so forth • Define beneficiary energy taxation of "green" energy product vs. conventional energy product (which constitutes the "incentive" so lower tax rate provides a better competitive situation) *Customs Duties in the EU* • Identify applicable customs duties and tariffs for exporting green ammonia to EU countries from non-EU countries? • Develop a detailed mapping of how the import process works • Establish requirements to act as import as customs declarant, options for customs representation for the DDP scenario • Estimate the import duty burden occurring with the importation of goods, i.e. customs duties and import VAT **The exporter also need to answer following aspects related to indirect taxation:** • Are there any specific tax incentives or exemptions available for exporting green ammonia • How does the value-added tax (VAT) or goods and services tax (GST) apply to the export of green ammonia? • Are there any specific regulations or tax requirements related to the transportation and shipping of green ammonia, such as fuel taxes or environmental levies?

Risk	Description	Mitigation measures
		• Do any tax treaties or agreements exist between the non-EU country and the EU countries that may impact the taxation of green ammonia exports? • Are there any reporting or documentation requirements for exporting green ammonia, such as the need for customs declarations or specific tax forms? • vAre there any environmental or carbon pricing mechanisms in place that may impact the taxation of green ammonia exports? • Are there any specific tax implications related to the sale or distribution of green ammonia within the EU countries, such as local taxes or regional levies? • Are there any restrictions or limitations on the quantity of green ammonia that can be exported, which may have tax implications? • What are the potential penalties or consequences for non-compliance with tax regulations related to exporting green ammonia to EU countries? **Optimising Direct Taxes (Corporate Taxes) across EU and India** • Analyse if storage & sale may trigger establishment and therefore corporate tax and

7 Export Infrastructure

7.1 Summary of export infrastructure needed

At the load port, storage tanks for refrigerated ammonia may be established if direct pipelines connectivity from processing plant to the port berth is not feasible. The ammonia storage tanks are double integrity type atmospheric pressure storage tanks for safety purpose. Liquid ammonia is stored in these tanks at – 33°C temperature by refrigeration system. The pressure within the storage tank may get affected because of the heat ingress from the surroundings through the insulation into the tanks. HT compressors may be needed to be installed as a part of re-liquefaction plant to maintain the pressure in the tank during ship loading and also to maintain tank pressure even without any receipt of ammonia[73,74].

The storage tanks may be provided with necessary instruments like float type level indicator, DP type level indicator, temperature indicator, interspaced level indicator and pressure recorder. The tanks may be provided with suitable numbers of safety valves for protecting the tank from overpressure and vacuum. The tanks may be equipped with two pilot operated pressure relief valves and two vacuum relief valves to safeguard the tanks against overpressure or vacuum. Isolation valves may be provided with suitable mechanical interlocks. A quick closing valve in pump suction line may have an interlock to close on high liquid level in annulus as compared to cup level. This valve may also be provided with local/remote push buttons for closing in case of any emergency. A flare system may also be needed for venting / flaring ammonia vapour and for maintaining tank pressure in case of any emergency like power failure, etc.

Before loading of liquid ammonia for shipment it may be necessary to pre-cool ammonia loading line, by circulating cold ammonia through it. By pre-cooling ammonia-loading line, the temperature of ammonia loading line at marine loading arm end may reach to ~ – 30°C. After pre-cooling the loading line, loading of green ammonia on ships may be carried out using deepwell cargo pumps. Pumps may be provided with an auto circulation minimum flow bypass valve for protection of pump. Before ship loading, the marine loading arm is connected to the manifold of ship and ship loading may be carried out at an agreed loading rate. To maintain the tank pressure and temperature during ship loading; the refrigeration system for ammonia storage tanks is operated. Emergency Power supply to maintain ammonia tanks pressure during power failure may also be made available.

Various other facilities like raw water storage, fire water system, instrument air compressors, metering station, pipe rack, D.G. set may also be needed. Ammonia gas burning facility may also be provided which will not allow any escape of ammonia gas to atmosphere during extreme emergency. Gas detectors may also be provided at different locations.

7.2 Overview of available suitable infrastructure in India

There are 12 ports in India which are reported to be handling ammonia imports in bulk volumes[75]. These ports are in Kandla, Sikka, Dahej, Mormugao, Mangalore, Cochin, Haldia, Paradip, Visakhapatnam, Kakinada, Ennore and Tuticorin. The port users bringing ammonia shipments primarily evacuate ammonia through direct transfer via dedicated pipelines to their respective storage facilities located in their plants or storages in port based tanks for transfer via barges/road tankers.

As per Maritime Amrit Kaal Vision 2047[76], deepening of marine infrastructure at ports is being given priority. The ports in Kandla, Tuticorin and Paradip are planned to have draft in the range of 18 - 23 meters by 2030. Further, ports in Mangalore and Cochin are planned to have draft in the range of 20 - 23 meters by 2047.

[73] Ammonia terminal
[74] Ammonia export terminal
[75] DNV
[76] Maritime Amrit Kaal Vision 2047

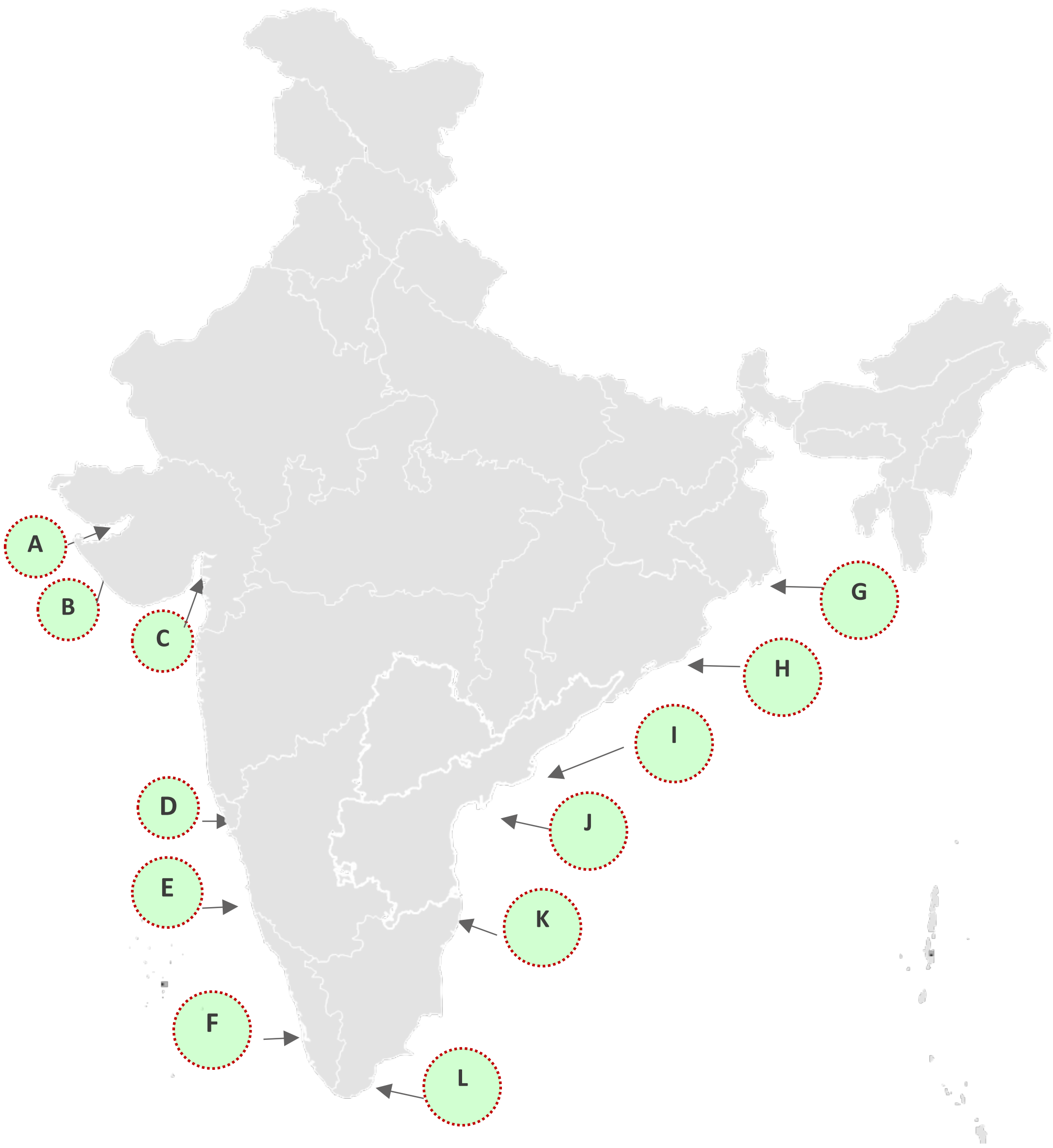


Figure 53: Locations of ammonia imports handling ports in India[77]

Note: Map not drawn to scale

A - Kandla	B - Sikka	C- Dahej	D - Mormugao	E- Mangalore	F- Cochin
G- Haldia	H- Paradip	I- Visakhapatnam	J- Kakinada	K- Ennore	L- Tuticorin

Ports listed above have been handling ammonia cargo import volumes in bulk. They have the necessary marine infrastructure needed to handle ships which are being used for export/imports of ammonia. With dedicated cargo handling infrastructure comprising of dedicated pipelines from ammonia storage tanks located at the production plant to the dedicated marine loading arms units which may be set up at the respective port's berth, seaborne exports of green ammonia may prove to be a techno-economically viable option. It is further relevant to highlight that all the ports are giving priority to handling green cargo. Therefore opportunity of handling 0.6 MMTPA of green ammonia cargo shipments would invite interest from all the above

[77] DNV

listed ports. Further, with increasing focus on deepening the ports marine facilities; the port's cargo handling capacity also increases. This shall make it a viable proposition for all major ports to attract the proposed 0.6 MMTPA green ammonia cargo volumes. Besides, all major ports handle imports of liquefied gases cargoes at one or multiple berths. The ports will be incentivized to increase cargo handling volumes of liquefied gases by requisite planning of their respective berths' occupancy. Besides, the reported capacity utilizations of the major ports for FY 2022-23 is as follows: Visakhapatnam: 55%, Kandla 51.5%, Ennore: 47.8%, Paradip: 46.7%, Cochin: 44.9%, Mangalore :38%, Tuticorin : 34.1%, Mormugao :27.3%. Therefore, it can be reasonably concluded that all the above mentioned major ports may consider the additional 0.6MMTPA green ammonia cargo volumes a viable opportunity for increasing their cargo throughput volumes.

A summarized view of the ammonia handling berths at the respective ports is shared below.

For port in Tuticorin, permissible vessel draft at the ammonia handling berth is reported to be 13 m and permissible vessel's LOA of 228 m. The same berth also handles ships bringing LPG cargo. Further, while the installed capacity of the Port is 111.5 MMTPA; quantity of cargo handled by Port was 41.4 MMTPA in FY 2023-24.

For ammonia handling berth of port in Mangalore, permissible vessel draft is 9.5 m and permissible LOA of vessel is 223 m. Besides, LPG cargo berths available at the port have draft availability of upto 14 m. Further, the reported installed cargo handling capacity of the Port is 108.96 MMTPA; quantity of cargo handled by Port was 45.7 MMT in FY 2023-24.

For ammonia handling berth of port in Kandla, permissible vessel draft is 10.7 m and permissible LOA of vessel is 223 m. Besides, LPG cargo berth available at the port have draft availability of upto 10.6 m and can handle vessels with LOA of 215 m. Further, while the installed capacity of the Port is 267.1 MMTPA; quantity of cargo handled by Port was 137.6 MMT in FY 2022-23.

For Mormugao port, the permissible vessel draft at ammonia handling berth is 13 m and permissible LOA of vessel is 300 m. LPG cargo traffic is not reported to have been handled at Mormugao over the last 5 years. Further, while the installed capacity of the Port is 63.4 MMTPA; quantity of cargo handled by Port in FY 2022-23 was 17.3 MMT.

For ammonia handling berth of port in Cochin, permissible vessel draft is reported to be 9.1 m with permissible LOA of vessel is 170 m. Besides, LPG cargo berth available at the port have draft availability of upto 13 m and can handle vessels with LOA of 230 m Further, while the installed capacity of the Port is 78.6 MMTPA; quantity of cargo handled by Port in FY 2022-23 was 35.3 MMT.

For ammonia handling berth of port in Ennore, permissible vessel draft is reported to be 13.5 m with permissible LOA of 300 m. The same berth also handles ships carrying LPG cargo. Further, while the installed capacity of the Port is 91 MMTPA; quantity of cargo handled by Port in FY 2022-23 was 43.5 MMT.

For ammonia handling berth of port in Visakhapatnam, permissible vessel draft is 10.1 m and permissible LOA is 200 m. Besides, LPG cargo berths available at the port have draft availability of 14 m and permissible LOA of 230 m. Further, the reported installed cargo handling capacity of the Port is 134.2 MMTPA; quantity of cargo handled by Port is 73.8 MMT in FY 2022-23.

For the 2 ammonia handling berths of port in Paradip, permissible vessel draft is 14.5 m and permissible LOA is 230 m. Besides, a dedicated 5 MMTPA capacity berth for handling green ammonia/hydrogen cargo shipments is being planned by the port. Further, the reported installed cargo handling capacity of the Port is 289.8 MMTPA; quantity of cargo handled by Port was 145.4 MMT in FY 2023-24.

For ammonia handling berth of port in Haldia; permissible vessel draft is 12.2 m and permissible LOA is 236 m. Besides, another LPG cargo berth available at the port also have draft availability of upto 12.2 m. Further, the reported installed cargo handling capacity of the Kolkata Port Authority is 92.8 MMTPA; quantity of cargo handled by Port is 65.7 MMT in FY 2022-23.

Key specifications for ammonia handling berths at other ports are as follows -

- Kakinada: Permissible vessel draft is 11.5 m and permissible LOA is 190 m.
- Sikka: Permissible vessel draft is 10.5 m and permissible LOA is 190 m.
- Dahej: Permissible vessel draft is 13 m and permissible LOA is 225 m.

Basis above, it can be concluded that the berths and related mooring facilities available at the above listed ports are well suited for handling mid-size gas carriers for exports of green ammonia in bulk volumes. As per the reported draft availability at the ports as summarized above, Kakinada and Sikka may not be able to handle Large Gas Carriers. The other named 10 ports offer a viable proposition for handling Large Gas Carriers also. Dedicated cargo loading infrastructure with dedicated cargo pipelines may be needed to be created at the berths for enabling seaborne transportation (exports) of green ammonia from the proposed 0.6 MMTPA green ammonia production facility.

7.3 Techno-economical optimal layout of export infrastructure

Two refrigerated ammonia storage tanks with a capacity of 30,000 MT each may be needed to be set up at the load port if direct pipelines connectivity from processing plant to the port berth is not feasible or if leasing of land at port premises is feasible. The total storage capacity of the tanks may be considered 50% larger than the average cargo carrying capacity of LGCs i.e. 40,000 MT. Medium Gas Carriers in service are in in dimensions of ~165m -195m LOA and upto ~11.5m draft. Large Gas Carriers in service are in dimensions of ~195m-220 m LOA and upto ~12.5m draft. As a norm the charterers articulate the availability of draft and of the berth while seeking interests from shipping companies for carrying cargo between the respective load port and the discharge port.

A dedicated pipe rack comprising of Liquid Green Ammonia line, Liquid Green Ammonia Pressurizing line, Green Ammonia drain line, Purge line and Instrument air line may be needed to be set up between the ammonia storage tanks and the port berth. The cargo carrying pipelines may be connected with dedicated marine loading arms installed at the berth. On the port berth, the marine loading arms may be accompanied with gauge panels for temperature, pressure and flow rate. Hydraulic panels and firefighting infrastructure may be needed to be in place. The estimated capital expenditure for setting up export bound liquified green ammonia cargo transfer facilities at an existing berth as per below illustration is ~$ 4- 5 mn. This estimates exclude development cost of greenfield jetty, land lease cost in port, etc. The cost of pipelines and storage tanks may be pro-rata added at rates for pipelines estimated for the on-shore liquid ammonia storage at the production facility. Operating expenses for the ammonia handling facilities at the port's berth could add to an estimated ~$ 0.3-0.4 mn annually.

For illustration purposes, a visual representation of the layout for export infrastructure is shown in below figure.

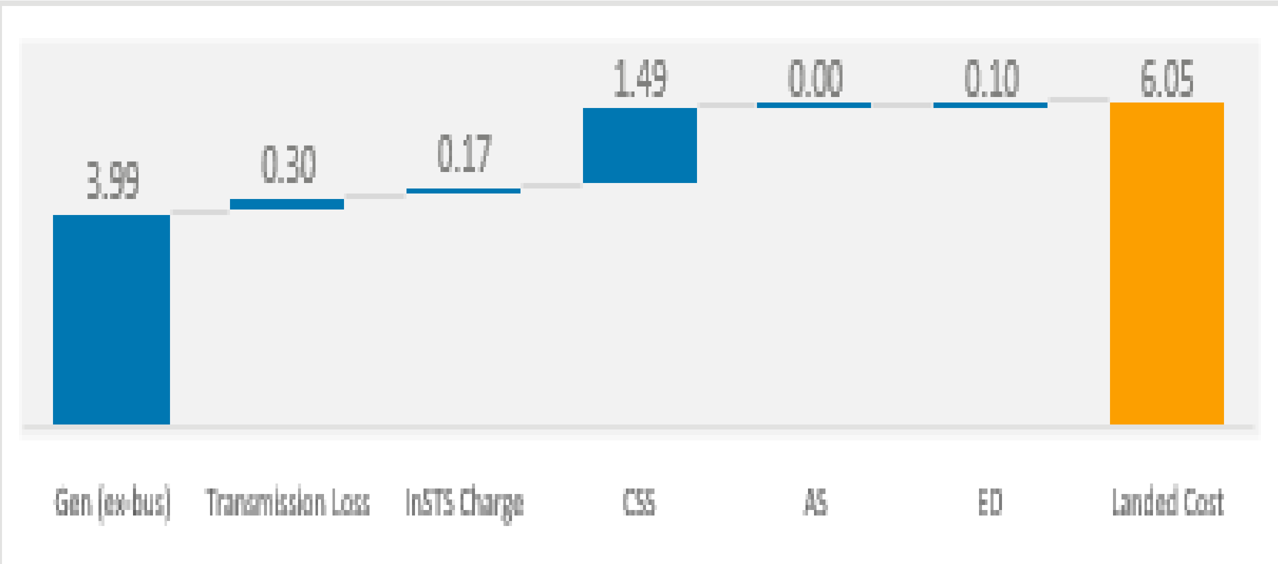


Figure 54: Illustration of layout for export infrastructure

7.4 Investigation of green ammonia filling stations/(un-) loading arm specifications

Two marine loading arms to enable loading of green ammonia into vessels calling upon the port may be needed to be set up at the port's berth. The marine loading arm to be placed into service may be needed to comply with the design, fabrication, material, inspection, and testing requirements as outlined in OCIMF "Design and Construction Specification for Marine Loading Arms"[78]. The manufacturer's certification that the OCIMF standards have been adhered to may be permanently marked on the loading arm or recorded elsewhere at the facility with the loading arm. For exports infrastructure, unidirectional marine loading arms may be preferred over bi-directional marine loading arms. If envisage to import/unload also; bi-directional marine loading arms could be considered which fulfil OCIMF compliances.

[78]OCIMF

The marine loading arm used for transferring ammonia may have a means of being drained or closed before being disconnected after transfer operations are completed. Marine loading arms may also need to be fitted with quick disconnect couplers and emergency quick release systems. Out-of-limit, balance and the approach of out-of-limit alarms may be located at or near the marine loading arm console. Pressure gauges and hydraulic drive cylinders may need to be mounted. Grounding, bonding, electrical installations, control circuits, motor controllers, remote control system, etc. may need to comply with the requirements as stipulated in OCIMF. Besides being OCIMF compliant; the marine loading arm specifications for illustration purpose may include diameter : 12"-16", flow rate : 1,200-2,000 m3/hour and temperature range : +20 °C to – 45°C.

Key EU codes and standards wrt marine loading arms are as listed below :

1. OCIMF 'Design and Construction Specifications for Marine Loading Arms' [79]
2. International Safety Guide for Oil Tankers and Terminal (ISGOTT) [80]
3. ATEX Directive 94/9/EC (Equipment Directive) [81]
4. PED 97/23/EC (Pressure Equipment Directive) [82]
5. EN 1474:2009 European standards for marine transfer systems [83]
6. ISO 28460 [84]

The following aspects of the port and ships may be needed to be considered when determining the loading arm maximum allowable extension limits:

1. Vessel sizes and manifold locations
2. Lowest-low water level (datum)
3. Highest-high water level
4. Maximum vessel surge and sway
    - Maximum width of fendering system

A few key design features of marine loading arms as per OCIMF are listed below:

1. Electrohydraulic control system
2. Fully counterbalanced
3. Emergency Release System
4. Hydraulic Quick Connect/Disconnect Coupler (QC/DC)
5. Wireless remote control system
6. Nitrogen purge
7. Vapour recovery
8. Cargo stripping system
9. Heat tracing/insulation
    - Constant position monitoring

7.5 Analysis of safety aspects for exporting green ammonia via seaborne transport

Possible risks that can occur during seaborne transport of green ammonia may be attributed to non-compliance to the safety protocols during cargo operations, marine accident or failures in structural integrity of cargo tanks and pipelines. The ship management companies therefore are required to adhere to the safe working practices as outlined in the International Safety Guide for Oil Tankers and Terminals (ISGOTT) [85], Society of International Gas Tankers and Terminals Operators (SIGTTO)

---

[79] OCIMF
[80] ISGOTT
[81] ATEX Directive 94/9/EC
[82] PED 97/23/EC
[83] EN 1474:2009 European standards for marine transfer systems
[84] ISO 28460
[85] OCIMF

[86], International Code for the construction and equipments of ships carrying liquefied gases in Bulk (IGC Code)[87], Safety of Life at Seas (SOLAS) [88] and International Maritime organization (IMO) [89].

IMO's International Code for the construction and equipment of ships carrying Liquified Gases in Bulk (IGC Code) provides standards for safe carriage of liquefied gases in such ships including design and construction features that minimise risk to crew, ship and environment. Additional Rules and Regulations of the Classification Society & of Flag State; SIGTTO Manifolds Recommendations for Liquefied Gas Carriers, SIGTTO Ship to Ship Transfer Guide for Petroleum, Chemicals and Liquefied gases; OCIMF Mooring Equipment Guidelines, SIGTTO Recommendations for cargo sampling system are also enforced for ammonia sea borne transport. It is a prerequisite for all shipowners to ensure compliance with the above rules and regulations. Any breach in compliance to the above rules and regulations leads to penalties and liability for bearing consequential losses, etc.

The safety aspects for exporting green ammonia via seaborne transport may need to also consider mitigating effects of any possible liquid and gaseous ammonia fuel leakages and spills and their consequences during the ship operations. The risk prone areas on board ships include storage tanks, tank hold spaces, tank connection space, fuel preparation rooms, bunkering stations, spaces containing liquid or gaseous ammonia piping and vent mast. A few key safety hazards during seaborne transportation of ammonia with the mitigation measures that may be pursued are as listed below.

(A) Risk : Non-compliance to safety protocols during ship loading and unloading, cargo changeover (i.e. changing from LPG to ammonia)

Mitigation: Regular training of seafarers w.r.t. Standard Operating Procedures (SOPs) for cargo operations, flushing and draining systems, etc.

(B) Risk: Severe collision or stranding that could lead to cargo tank damage and uncontrolled release of ammonia

Mitigation: Compliance to traffic separation schemes may be ensured, spill containment systems may be placed on board the vessels, remote stations for monitoring operations, etc. to be included, dedicated hazardous zones and required safety zones to be marked onboard vessels. Possible safety hazards that could arise from uncontrolled release of ammonia may include the accumulation of ammonia vapours in spaces containing a potential source of ammonia release and their spreading over the ship's spaces through non-gastight openings, the spreading of ammonia vapours from the vent mast outlet on open decks and their possible recirculation to accommodation through openings and ventilation inlets, etc.

(C) Risk: Operating personnel come in contact with ammonia vapours

Mitigation: Operating personnel may adopt safe working practices and ensure wearing Personal Protective Equipments (PPE). Emergency showers and eyewash may be made available at convenient locations, Gas sensors and alarms may be regularly checked. Suitable gas tight protective equipment including eye protection of recognized national or international standard is to be worn for protection of crew members engaged in maintenance and operations on board vessels carrying ammonia.

(D) Risk: Breach in ammonia tank and associated piping

Mitigation: Dry drip tray (with a drain leading to enclosed tank), foam/dry chemical powder spill mitigation system may be placed onboard, ammonia release mitigation system may be adopted, quick disconnect couplings and breakaway devices may be regularly inspected. Monitoring and safety system functions with local audible and visual alarms at the manned control stations on board vessels may be periodically checked.

(E) Risk: Cargo comes in contact with parts containing Cu, Zn or alloys

Mitigation: Compliance to IGC Code for ships structural aspects to be ensued, Ammonia test for stress corrosion resistance as outlined in ISO 6957:1988 may be performed as per IACS. Materials for ammonia cargo containment and ammonia fuel piping get directly exposed to ammonia during normal operations and therefore may need to be resistant to the corrosive actions and environmentally assisted cracking associated with ammonia service. Mercury, cadmium, copper, zinc or alloys of these materials may not be used as materials of construction for fuel tanks and associated pipelines, valves, fittings and other items of equipments which normally in direct contact with the ammonia liquid or vapour. Components of rubber or plastic materials that are likely to deteriorate if exposed to ammonia may not be used.

[86]SIGTTO
[87]IGC Code
[88]SOLAS
[89]IMO

A few of the periodic inspections /surveys that have been recommended by Classification societies and IGC Code are as listed below which if complied could help in enabling a safe seaborne transport of green ammonia.

a) Functional testing of water screens above access doors for fuel preparation room.
b) Functional testing of gas evacuation system for fuel preparation room.
c) Functional testing of alarms for monitoring and safety functions.
d) Functional testing of eyewash and decontamination showers.
e) Operational testing of fuel treatment or vent control systems utilizing water scrubbing or treatment systems.
f) Operational testing of associated exhaust after treatment systems.
g) Testing of portable gas detectors for ammonia.
h) Testing of fixed gas detection for ammonia.
i) Testing of gas detection:
   i. where the auxiliary heat exchange circuits are likely to contain ammonia in abnormal conditions as a result of a component failure
   ii. at crankcase breather, or under piston space
   iii. where the engine auxiliary systems are likely to contain ammonia in abnormal conditions as a result of a component failure
j) Examination of toxic areas and ventilation intakes including gas detection system for ammonia.
k) Examination of all other personnel safety and PPE specific to ammonia.

7.6 Green shipping

For deep sea shipping with significant amounts of fuel to be bunkered for ships [90], 2 modes of bunkering clean ammonia may be feasible. In 1st option, green Ammonia as bunker can be supplied using marine loading arms set up at the port berth for ships that can be brought alongside for bunkering. In 2nd option, green ammonia may be filled in bunker supply vessels for bunkering ammonia powered ships located at alternate port berths/offshore locations. Green ammonia may be filled in bunker supply vessels from the marine loading arms. The bunker supply vessels are usually owned or taken on a long-term lease by the fuel producers.

Requirements of green ammonia fuelling may include getting a green ammonia bunkering license from the port of operations, ensuring availability of green ammonia bunker supply vessels permissible for plying in coastal trade and committing to availability of green ammonia bunkering capacity.

IACS member firms[91] have assessed that in future the green ammonia for bunkering may be stored under pressure or refrigerated and ammonia may not always be available in the temperature and pressure range that a ship can handle. Four different possible combinations of bunkering vessels have been assessed with pressurized tanks or semi-refrigerated tanks and similar arrangements in the ship to be bunkered.

According to them, in a scenario wherein the bunkering vessel and the ship to be bunkered have pressurized tanks, bunkering vessel may need to transfer green ammonia using general transfer pumps. The vapour return system from ship taking bunkers to the bunkering vessel may also be needed. In the 2nd scenario; semi-refrigerated tanks in the bunkering vessel and a pressurized tank in the ship to be bunkered, bunkering vessel may transfer green ammonia using installed heater (sea water heated system) and booster pump. Further vapour return system from ship taking bunkers to the bunkering vessel may be needed. Also re-liquefaction system on bunkering vessel may be needed to handle high pressure vapour return.

In an alternate scenario wherein pressurized tanks are on the bunkering vessel and a semi-refrigerated tank in the ship to be bunkered, the bunkering vessel may need liquefaction plant to reduce pressure by lowering temperature. Vapour return system from ship taking bunkers to the bunkering vessel may be needed. Bunkering vessel may also need a compressor to increase pressure of vapour return. In the last scenario; wherein semi-refrigerated tanks exist for both the bunkering vessel and the ship to be bunkered, bunkering vessel may need cooling arrangement. Vapour return system from ship taking bunkers to the bunkering may also be needed.

As per the IACS member firm's assessments; ammonia supply vessels having semi-refrigerated ammonia tanks shall provide larger capacity than those supply vessels which have pressurized ammonia tanks. As per them, ammonia bunker supply vessels having semi refrigerated tanks offer greater flexibility when bunkering ships with semi-refrigerated fuel tanks and owing to a limited cost premium. Summary of the above analysis is tabulated below.

[90] Recommendations for Design and Operation of Ammonia-Fuelled Vessels Based on Multi-disciplinary Risk Analysis
[91] DNV - White Paper on Ammonia As A Marine Fuel

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Bunkering vessel	Pressurized tanks	Semi-refrigerated tanks	Pressurized tanks	Semi-refrigerated tanks
Ship to be bunkered	Pressurized tanks	Pressurized tanks	Semi-refrigerated tanks	Semi-refrigerated tanks
Green ammonia transfer arrangements	Bunkering vessel transfers green ammonia using general transfer pumps. Vapor return system from ship taking bunkers to the bunkering vessel will be needed.	Bunkering vessel transfers green ammonia using installed heater (sea water heated system) and booster pump. Vapor return system from ship taking bunkers to the bunkering vessel will be needed. Re-liquefaction system on bunkering vessel is needed to handle high pressure vapor return.	Bunkering vessel will need liquefaction plant to reduce pressure by lowering temperature. Vapor return system from ship taking bunkers to the bunkering vessel will be needed. Compressor on bunkering vessel is needed to increase pressure of vapor return.	Bunkering vessel may need cooling arrangement. Vapor return system from ship taking bunkers to the bunkering vessel will be needed.

Semi-refrigerated green ammonia bunkering vessels provide larger capacity and flexibility vis-à-vis pressurized green ammonia bunkering vessels.

Figure 55: Possible scenarios in green shipping

7.7 Options and costs for seaborne transport of green ammonia from India to Europe

According to various research reports [92,93,94,95,96], anhydrous ammonia as a global commodity is distributed using Gas Carrier (ships) across oceans. Gas Carriers equipped with insulated tanks at temperatures between -42 °C and -33 °C and near atmospheric pressures are typically used for overseas ammonia transport. These types of ships are capable of transporting either LPG or ammonia and are labelled as refrigerated (full- or semi-refrigerated) LPG carriers. Fully pressurized vessels are used to transport ammonia over short distances at pressures of up to 20 bar;, However, due to their large pressures these tanks are very heavy, and hence they have small cargo capacities. Fully refrigerated vessels have 15,000 to 85,000 m^3 capacity and are used to transport ammonia over long distances by sea. These Gas Carriers transport ammonia at -33 °C with an on-board refrigeration system, working in the same way as a land-based refrigeration storage tank.

Currently, ships within the range of 25,000-60,000 m^3 (17,000 and 42,000 tons) are used for ammonia transportation, whereas ships larger than 60,000 m^3 in size are mostly employed for LPG transportation. Ships smaller than 20,000 m^3 in size are mainly used for local, seaside, and short transportation of both LPG and ammonia. Most ammonia is currently shipped long distances via Medium Gas Carriers (MGCs) and Large Gas Carriers (LGCs). Medium Gas Carriers in service are in in dimensions of ~165m -195m LOA and upto ~11.5m draft. Large Gas Carriers in service are in in dimensions of ~195m-220 m LOA and upto ~12.5m draft. MGCs with 25,000 -50,000 m^3 cargo carrying capacity are, in general, more economical over shorter distances. On the contrary, LGCs with 50,000 -70,000 m^3 cargo carrying capacity are, in general, more economical over longer distances. MGCs are by far the more popular vessel type currently used to transport ammonia, with more vessels in operation. There are 140 MGCs in operation globally. In comparison, 20 LGCs currently in operations globally.

A few relevant market insights[97,98] on the subject are as listed below

a. 114 unique vessels (with a cumulative 2.5 Million DWT) were deployed for shipping ammonia over last 2 years
b. Cumulative ammonia carrying capacity of the unique vessels deployed in CY 2023 and in CY 2022 add to 1.9 MMT
c. 200 LPG tankers in operation with typical storage capacity of ≥ 40,000 MT are capable of carrying ammonia at full refrigeration

[92] Clarksons
[93] Wartsila
[94] Hydrogen Insight
[95] Hydrogen Insight
[96] Hydrogen Europe
[97] Hydrogen Insight
[98] Hydrogen Insight

d. 1,200 LPG tankers could also become suitable for carrying ammonia shipments
e. Existing fleet of more than 600 LNG vessels could also handle ammonia post retrofitting cargo handling system and reliquefication plant
f. 20 Large Gas Carriers (LGCs) and 140 Medium Gas Carriers (MGCs) currently in service
g. Amongst 579 newbuilding ship orders in progress during 2023; 322 will have ammonia ready propulsion system
h. 4 ammonia fueled gas carrier shipbuilding orders placed in 2023 with deliveries commencing from 2026 onwards
i. 19 Very Large Ammonia Carriers (~13 m draft) newbuilding ships orderbook of 88,000/93,000 CBM each with deliveries commencing from 2026 onwards.

Transport costs for Gas Carriers depend on charter rates, distance travelled, fuel consumption, port charges, and tariffs. Charter rates and availability of Gas Carriers are linked to LPG market demand because ammonia can be transported in the same vessels as LPG. LPG markets tend to be seasonal, with high demand in winter (when it is used for heating) and lower demand in summer. Baltic gas indices for transporting LPG can be used as an indicator for current market rates, and in turn these rates can be used as an indicator for current ammonia shipping rates.

Shipping ammonia using gas carriers is primarily executed by time chartering of vessels though voyage chartering of gas carriers is also in vogue. In time chartering mode; a ship is employed for a certain period of time. Long term chartering tenure is generally for 1 year to 2 years (1 year +1 year). Short term chartering options for 1/3/6 months are also available. Ship is hired at a daily rate by charterer. The charterer bears voyage expenses and the shipowner bears responsibility of crewing, technical and operations management of ship. The charterer has freedom to select trade routes and cargoes as permissible for the respective chartered vessel. In voyage charter, ship is employed for a single voyage from a load port to discharge cargo at specified port in agreed area . The shipowner is paid fixed freight per ton of cargo or lump sum. Shipowner incurs all shipping costs as well as additional voyage expenses depending upon the contracting terms. For fixed cargo volumes requiring multiple voyages, voyage charter agreement is generally not preferred.

The charter hire rate per day for a 1 month time charter[99] of an average MGC is reported to be between 54,333-30,000 USD/day for the calendar year 2023. The charter hire rate per day for a 1 month time charter of an average LGC is reported to be between 66,667-33,000 USD/day for the calendar year 2023. On considering a 1 year time charter hire for MGCs[100], charter hire rate per day of an average MGC is reported to be between 28,500-23,700 USD/day for the calendar year 2023. Owing to a small number of LGCs, their 1 year time charter is not reported.

For illustration purposes, seaborne transport costs of exports of green ammonia between Kandla (India) to Hamburg (Germany) and Paradip (India) to KrK (Croatia)have been estimated as tabulated below.

Table 45: Illustration of seaborne transport costs of exports of green ammonia from India to Europe

Load port to load port		**USD**		**USD per Metric Tonne ($/MT)**	
		LGC	MGC	LGC	MGC
Paradip(East Coast India) to KrK (Europe)	Via Suez Canal (43 days)	$ 2.9 mn -$ 2.4 mn	$ 2.5mn - $ 2.1 mn	$ 73 – $ 59	$ 108 – $ 91
	Via Cape of Good Hope (85 days)	$ 5.0 mn - $ 3.9 mn	$ 4.4mn - $ 3.6 mn	$126- $ 96	$ 190 – $ 154
Kandla(West Coast India) to Hamburg (Europe)	Via Suez Canal (49 days)	$ 3.4 mn -$ 2.8 mn	$ 2.9mn - $ 2.4 mn	$ 85 – $ 69	$ 125 – $ 105
	Via Cape of Good Hope (80 days)	$ 4.8 mn - $ 3.7 mn	$ 4.2mn - $ 3.4 mn	$121- $ 93	$ 182 – $ 148

The above estimates are based on parcel size of 23,000 MT & TCE range of CY 2023 ($ 28,500 - $ 23,700) for MGC for 1 year time charter. For LGCs, estimates are based on parcel size of 40,000 MT & TCE range of CY 2023 ($ 35,000 - $ 26,400) for LGC for 1 year time charter. It may be noted that liquefied gas carriers carrying ammonia are currently not allowed to use ammonia as fuel due to its toxicity subject to approval from Flag Administration[101].The VLSFO price range for CY 2023 of $ 675 - $ 525 per MT and MGO price range for CY 2023 of $ 1,200 - $ 800 per MT have been considered for estimates. Considering parcel size of 23,000 MT for MGC shipments and parcel size of 40,000 MT for LGC shipments; Suez canal dues

[99] Fearnleys
[100] Danish Ship Finance
[101] Hydrogen Insight

for round trip are estimated to add upto 10.9 USD/MT for LGC and 14.8 USD/MT for MGC. On same lines, load port costs at Kandla add upto 4.9 USD/MT for LGC and 5.2 USD/MT for MGC. Load port costs at Paradip are estimated to add upto 2 USD/MT for LGC and 2.2 USD/MT for MGC. As per prevalent norm of adopting CFR for ammonia ocean transportation, the discharge port costs, taxes, duties and levies (if any) are not considered in illustrations for shipping costs.

In the above scenario the return voyage may likely not be carrying any liquified cargo from EU. However, with active chartering desk the same vessel on return voyage may be aligned for bringing liquified gases (ammonia, propane and butane) import from Middle East or North Africa's (eg. Nigeria) energy rich countries towards India. On the contrary, if a LGC vessel is chartered for laden passage only; it may lead to savings of $ 0.5-1.0 mn per LGC shipment via Suez Canal and $ 0.8-1.5 Mn per LGC shipment via Cape of Good Hope. For a scenario wherein a MGC vessel is chartered for laden passage only; it may lead to savings of $ 0.5-0.9 mn per MGC shipment via Suez Canal and $ 0.8-1.4 Mn per MGC shipment via Cape of Good Hope. These estimations are based on the reported TCE range of CY 2023 ($ 54,333 – $ 30,000) for MGC and TCE range of CY 2023 ($ 66,667 - $ 33,334) for LGC for a laden voyage.

Owing to the views on demand offtake volumes (shipment parcel sizes) from the proposed 0.6 MMTPA facility, it may be apt to consider the fleet of Mid-Size Gas Carriers (MGCs) or Large Gas Carriers (LGCs) as preferred mode of seaborne transport. Given the production capacity of 0.6 MMTPA of production plant; ammonia produced can be loaded and exported to Europe once every ~ 14 days if MGC shipments are opted or once every ~ 24 days if LGC shipments are opted. Hence, 26 shipments in MGCs with each shipment having 23,000 MT parcel size for each shipment or 15 shipments in LGCs (with 40,000 MT parcel size for each shipment) may be needed for 100% exports of 0.6 MMTPA green ammonia produced from the proposed facility.

8 Annexure

8.1 List of RE projects along with discovered tariff, awarded since 2017

RE Type	Closing Date/ Award Date	Developer	Tariff(INR/KWh)	Capacity(MW)	Total Capacity (MW)	Tender Issuer
Solar	1-Jan-17	ACME	2.97	250	750	MPSECL
Wind	1-Feb-17	Inox	2.97	250	750	MPSECL
Solar	1-Feb-17	Rays Power	4.4	100	236	TANGEDCO
Solar	1-Apr-17	Solitaire	3.15	250	250	NTPC
Solar	1-May-17	ACME	2.44	200	500	SECI
Solar	1-May-17	Avaada	2.62	100	250	SECI
Solar	26-Sep-17	NLC	3.47	709	1500	TANGEDCO
Wind	4-Oct-17	ReNew	2.64	250	1000	SECI
Solar	1-Dec-17	Hero Futures	2.47	300	500	SECI
Wind	21-Dec-17	Sprng	2.43	198	425	GUVNL
Solar	22-Dec-17	Azure	2.48	200	250	SECI
Wind	13-Feb-18	Torrent	2.44	500	2000	SECI
Wind	6-Mar-18	Adani	2.85	75	500	MSEDCL
Wind	5-Apr-18	Sprng	2.51	300	1985	SECI
Solar	1-May-18	Mahoba	2.71	200	1000	SECI
Solar	10-May-18	Sprng	2.72	250	750	SECI
Solar	18-May-18	Softbank	2.82	200	200	SECI
Solar	2-Jul-18	ACME	2.44	600	2300	SECI
Solar	16-Jul-18	Softbank	2.7	250	750	SECI
Wind	1-Aug-18	Sprng	2.77	200	1200	NTPC
Solar	3-Aug-18	ACME	2.44	600	600	SECI
Solar	21-Aug-18	Aditya Birla	2.79	75	75	GRIDCO
Solar	17-Sep-18	Girija	2.44	300	500	GUVNL
Wind	25-Sep-18	Adani	2.76	300	1200	SECI
Solar	3-Dec-18	NTPC	3.02	85	550	UPNEDA
Wind	5-Dec-18	Softbank	2.67	450	840	SECI
Solar	21-Dec-18	Softbank	2.84	250	700	GUVNL
Solar	22-Jan-19	ACME	2.74	300	1000	MSEDCL
Wind	15-Feb-19	Ostro	2.82	300	1200	SECI
Wind	15-Feb-19	Betam Wind	2.79	200	480	SECI
Solar	19-Feb-19	UPC Renewable	2.55	50	500	GUVNL
Solar	1-Mar-19	Fortum	2.48	250	750	SECI
Solar	1-May-19	Engie	2.65	200	600	GUVNL
Solar	13-May-19	Tata Power	2.75	200	250	GUVNL
Wind	14-May-19	Anisha	2.8	40	745	GUVNL
Hybrid	27-May-19	Adani	2.69	600	720	SECI
Hybrid	27-May-19	Adani	2.69	600	720	SECI
Solar	30-May-19	Ayana	2.54	300	1200	SECI
Solar	19-Jun-19	Hero Futures	2.5	250	680	SECI
Solar	9-Aug-19	GRT	2.53	140	470	SECI
Solar	1-Sep-19	TBEA	2.63	300	300	NTPC
Solar PSU	26-Sep-19	NTPC	3.5	769	922	SECI
Wind	30-Sep-19	CLP	2.83	251	441	SECI

RE Type	Closing Date/ Award Date	Developer	Tariff(INR/KWh)	Capacity(MW)	Total Capacity (MW)	Tender Issuer
Solar	31-Oct-19	ReNew	2.71	300	960	SECI
Solar PSU	6-Jan-20	NTPC	3.5	923	1104	SECI
Solar Mfg	17-Jan-20	Adani	2.92	2000	3000	SECI
Peak	31-Jan-20	ReNew	6.85	300	1050	SECI
Peak	31-Jan-20	Greenko	6.12	900	1050	SECI
BESS	31-Jan-20	Greenko	2.7	900	1200	SECI
Solar	27-Feb-20	Softbank	2.5	600	1200	SECI
Solar	18-Mar-20	Vena	2.61	40	350	GUVNL
Solar	16-Apr-20	Softbank	2.55	600	1200	SECI
RTC	8-May-20	ReNew	2.9	400	400	SECI
Solar	1-Jun-20	Solarpack	2.36	300	2000	SECI
Solar	6-Aug-20	O2	2.43	400	1170	NTPC
Solar	13-Aug-20	Vena	2.78	100	700	GUVNL
Hybrid	14-Sep-20	Vena	2.99	160	970	SECI
Solar	12-Nov-20	Tata Power	2.97	110	200	KSEB
Solar	23-Nov-20	Sembcorp	2	400	1070	SECI
Solar	19-Dec-20	NTPC	1.99	200	500	GUVNL
Hybrid	23-Dec-20	Adani	2.41	600	1200	SECI
Solar	18-Feb-21	Torrent	2.22	150	300	Torrent Power Solar
Solar	19-Feb-21	Rising Sun	2.25	190	190	NTPC
Solar	22-Feb-21	Torrent Power	2.22	150	300	Torrent Power
Wind	15-Mar-21	Adani	2.77	300	1200	SECI Tranche X
Solar	24-Mar-21	Coal India	2.2	100	500	GUVNL Tranche XII
Solar	24-Mar-21	NTPC	2.2	150	500	GUVNL Tranche XII
Solar	24-Mar-21	Spmg	2.2	120	500	GUVNL Tranche XII
Solar	3-May-21	TPREL	2.51	250	250	MSEDCL 250 MW Solar
Solar	15-May-21	SJVN	2.73	100	100	GUVNL Phase X
Solar	7-Jul-21	ACME	2.42	300	500	MSEDCL-Phase VI
Hybrid	9-Jul-21	TPREL	2.62	300	500	MSEDCL Hybrid
Hybrid	23-Aug-21	NLC	2.34	150	1200	SECI Tranche IV
Hybrid	23-Aug-21	Azure	2.35	150	1200	SECI Tranche IV
Wind	2-Sep-21	ReNew	2.69	300	1200	SECI Tranche XI
RTC	14-Oct-21	Hindustan Thermal	3.01	250	2500	SECI RTC II
Solar	2-Feb-22	Ayana	2.36	300	600	SECI ISTS X
Solar	4-Feb-22	Ayana	2.35	300	600	SECI ISTS X
Solar	4-Feb-22	Fortum	2.36	300	600	SECI ISTS X
Solar	2-Mar-22	ReNew	2.33	100	250	PSPCL
Solar	16-Mar-22	SJVN	2.29	100	500	GUVNL Phase XIII
Hybrid	5-May-22	TPREL	2.53	600	1200	SECI Tranche V
Floating Solar	7-May-22	AMP Energy	3.21	100	100	RUMSL E-Phase I
Floating Solar	7-May-22	NHDC	3.22	100	100	RUMSL D-Phase I
Solar	10-Jun-22	Aditya Birla	2.3	300	500	GUVNL Phase XIV
BESS	20-Jul-22	Hero Futures	11.25	10	10	KSEB
BESS	26-Aug-22	JSW	1083500	500	500	SECI ESS I (500/1000)
Solar	19-Sep-22	Blupine	2.49	120	750	GUVNL Phase XVI

RE Type	Closing Date/ Award Date	Developer	Tariff(INR/KWh)	Capacity(MW)	Total Capacity (MW)	Tender Issuer
Floating Solar	11-Nov-22	NTPC	3.69	100	100	RUMSL B-Phase II
Floating Solar	11-Nov-22	SJVN	3.7	100	100	RUMSL C-Phase II
Solar	2-Dec-22	Solar Arise	2.9	100	500	MSEDCL Phase IX
ESS	8-Dec-22	Greenko	2792308	500	500	NTPC 500/3000
Peak	12-Dec-22	Ayana	9	150	250	MSEDCL Felxible
Wind	22-Dec-22	SJVN	2.9	100	1200	SECI Tranche XIII
PSP	20-Mar-23	Greenko	4.5	700	1000	PCKL 1GW PSP
PSP	20-Mar-23	JSW	4.5	300	1000	PCKL 1GW PSP
RTC	5-Apr-23	Sprng	3.99	100	1000	REMCL 1000 MW RTC
Peak	12-Apr-23	Blupine	6.68	100	1200	RUVNL Solar+ESS
Peak	12-Apr-23	AMP Energy	4.64	100	1200	SECI Tranche-VI
Solar	13-Apr-23	SAEL	2.87	100	500	MSEDCL Tranche-X
Solar	4-May-23	Blupine	2.61	150	1000	RUVNL 1000 MW Solar
Hybrid	10-May-23	AMP Energy	3.07	150	150	CESC 150 MW Hybrid
Solar	1-Jul-23	KPI Energy	2.7	100	800	GUVNL Ph XVII-GSECL II
Solar	21-Jul-23	Eden	2.6	300	2000	SECI Phase XI
Solar	6-Nov-23	Engie	2.52	300	3000	NHPC
Wind	17-Nov-23	Juniper	3.58	50	150	RECPDCL

The discovered tariff would depend on CUF, which varies from project to project. Normally, CUF is required to be met by the developer on an annualised basis, meeting several other RFP criteria simultaneously.

Deutsche Gesellschaft für
Internationale Zusammenarbeit (GIZ) GmbH

Registered offices
Bonn and Eschborn, Germany

Friedrich-Ebert-Allee 32 + 36
53113 Bonn, Deutschland
T +49 228 44 60-0
F +49 228 44 60-17 66

E info@giz.de
I www.giz.de

Dag-Hammarskjöld-Weg 1-5
65760 Eschborn, Deutschland
T +49 61 96 79-0
F +49 61 96 79-11 15

The International Hydrogen Ramp-up Programme (H2Uppp) of the German Federal Ministry for Economic Affairs and Climate Action (BMWK) promotes projects and market development for green hydrogen in selected developing and emerging countries as part of the National Hydrogen Strategy.