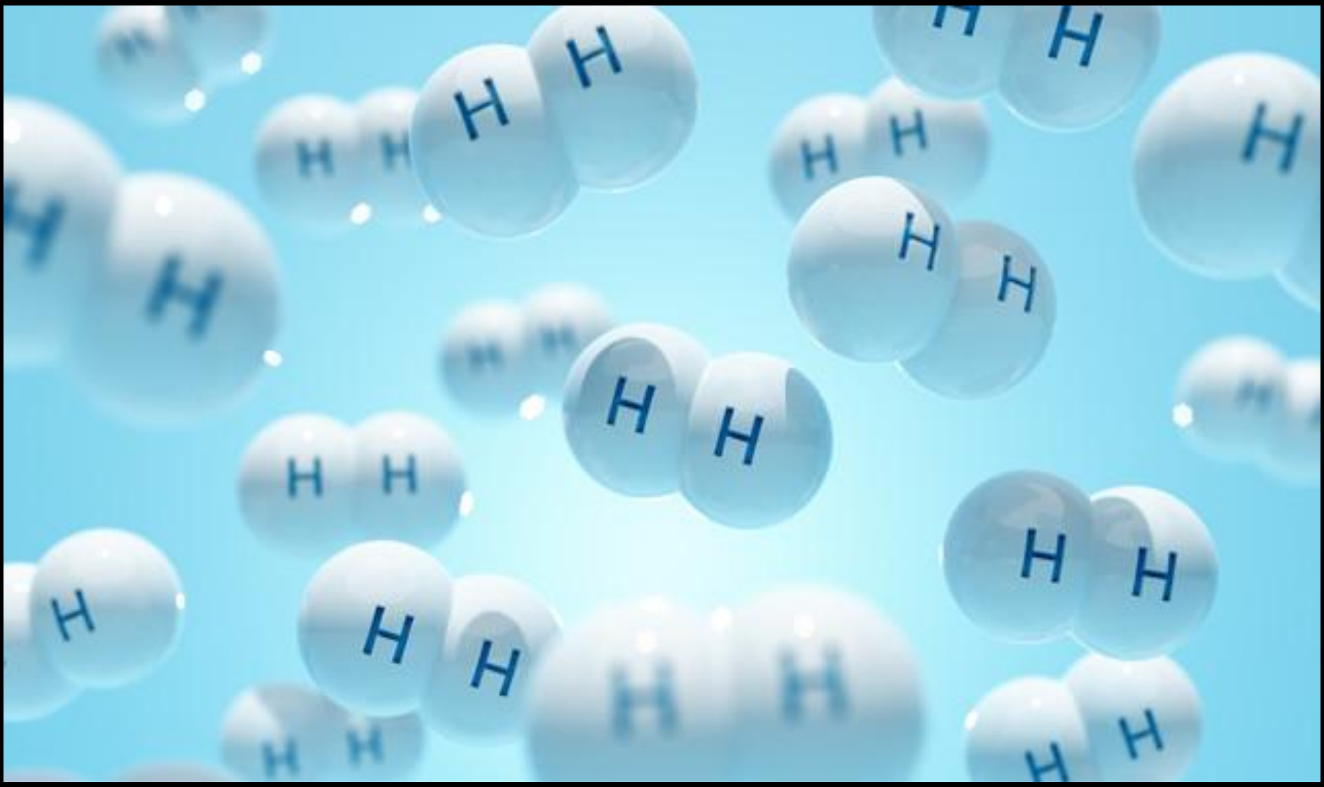

Pathways for Transmission of Hydrogen in Natural Gas Pipelines and City Gas Distribution Network

Annexure to Final Report

19 June 2025

Submitted by:

ICF Consulting India Pvt. Ltd.

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Table of Contents

List of Tables

List of Figures

Annexure A- Supply and Demand Assessment

A1- Sector-Wise Hydrogen Demand Projections

This section presents the demand projections for various industries, including Iron & steel, CGD, ammonia, refineries, transport and large Industries.

A1.1 Refinery

The refining industry is a major consumer of hydrogen, with an estimated global demand of around 41 MMT (2022[1]). Most of the hydrogen demand in refineries is met through on-site production using steam methane reforming (SMR) to produce hydrogen. Additionally, the remaining hydrogen demand is fulfilled by other refinery processes such as catalytic naphtha reforming and steam cracking.

Hydrogen is a crucial component in refineries and is employed in several ways. One of its primary uses is in hydrotreaters, where it reacts with impurities like sulphur and nitrogen in the presence of metal catalysts and heat, reducing the sulphur content of refined products. The by-products of this process, namely hydrogen sulphide and ammonia gas, are subsequently removed. Another application of hydrogen in refineries is in hydrocrackers, where it is used to convert heavy, long-chain gases into lighter products such as gasoline and diesel. Additionally, hydrogen is utilized as a fuel for heating requirements within the refinery, making it a versatile and essential component in the refining process.
In order to evaluate the consumption of hydrogen within a refinery, it is crucial to consider the three primary processes that could typically consume hydrogen in a refinery.

1) **Hydrotreater**: The demand for hydrogen in a refinery is directly linked to the sulphur content of refined products, which is regulated by EURO standards since 2005. The requirement of lower sulphur content in the refined products leads to a higher demand for hydrogen in the hydrotreater process.
2) **Hydrocracker**: This unit in a refinery employs hydrogen gas to convert heavy gas oil into lighter distillates by breaking down long hydrocarbon chains. The feedstock used in this process is light vacuum gas oil, and the resulting products are light and middle distillates, including but not limited to gasoline, diesel, kerosene, LPG, and jet fuel.
3) **As Fuel for Heating**: Refineries use various fuels for direct heating, including natural gas, furnace oil, and others. As the cost of producing hydrogen decreases, it may become a more attractive option for heating in refineries, potentially increasing demand for hydrogen in this sector. The hydrogen demand in a refinery was estimated by considering its use inside the hydrotreater and hydrocracker units.

Hydrogen Demand - Methodology

The existing refinery capacity in India is close to 254 million metric tons per annum(MMTPA)[2].
Hydrogen is generated through the following processes:

- Hydrogen is generated as a by-product of the reforming process by Catalytic Reforming Unit (CRU). This internally produced hydrogen as a by-product typically averages around 30% of the hydrogen consumption in the refinery (based on data provided by IOCL during stakeholder interactions for IOCL refineries).
- Hydrogen is produced through Hydrogen Generation Unit (HGU) that uses the Steam Methane Reforming (SMR) of natural gas and naphtha to meet the hydrogen requirement in refineries.

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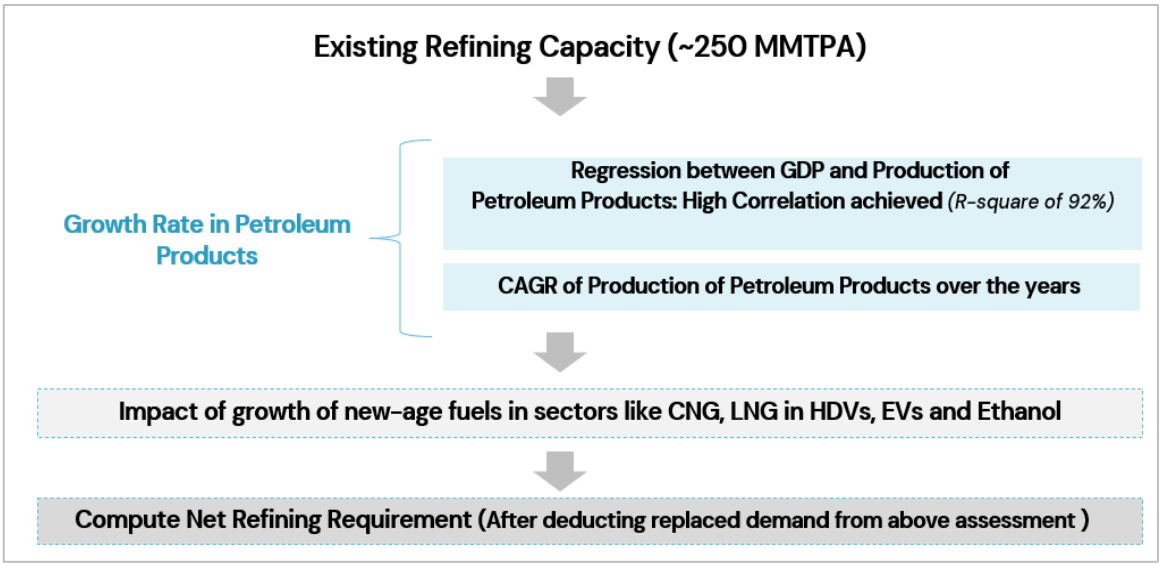
[1] https://iea.blob.core.windows.net/assets/c5bc75b1-9e4d-460d-90566e8e626a11c4/GlobalHydrogenReview2022.pdf

[2] https://ppac.gov.in/infrastructure/installed-refinery-capacity

ICF used its propriety model to forecast net refining requirements. Our methodology for forecasting refinery capacity to 2040 is shown below:

Figure 1: Methodology for forecasting net refining requirement



<u>Short-term demand forecast (Till 2028)</u>

ICF used information shared by CHT and public information available for expansion/new refinery capacity announced to forecast refinery capacity by 2028. Some of the key new refinery capacity and expansions include:

- Greenfield refinery set-up for Barmer refinery and Nagapattinam refinery
- Expansion of Visakhapatnam refinery, Panipat refinery, Barauni refinery, Koyali refinery, Mumbai refinery, Bina refinery, MRPL refinery and Numaligarh refinery.

<u>Key Assumptions for forecasting refinery capacity</u>

To carry out the assessment of the net refining capacity, 3 scenarios were considered under which different assumptions were taken for the computation. The 3 scenarios are defined as follows:

1. Optimistic Scenario: Rapid growth of petroleum products amid rising economy and standards of living, clubbed with limited adoption of new age fuels.

2. Realistic Scenario: Growth of petroleum products and hydrogen driven by existing fuel usage trends and norms across the sectors.
3. Conservative Scenario: Stricter emission norms across sectors due to climate change leading to reduced demand of petroleum products.

Below table lists out all the assumptions taken to forecast refinery growth till 2040.

Table 1: Key assumptions for forecasting net refining capacity.

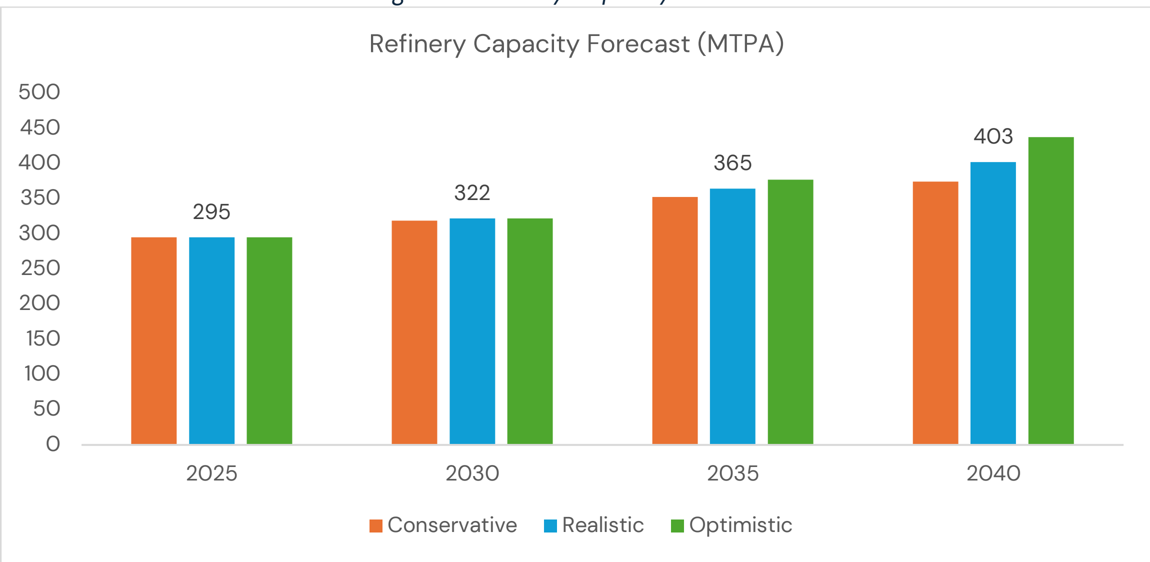
Divers	Conservative scenario	Realistic scenario	Optimistic scenario
GDP growth rate and impact on POL consumption	GDP will slow down to 5% by 2030 from 6.3% in FY 2024. Factor of 0.95 is used to reflect improving energy efficiency of the economy	GDP forecast between 6.3% to 7.3% till 2025 and then decrease to 5% by 2040. Petroleum products forecast dependent on historical regression analysis	GDP forecast between 6.3% to 7.3% till 2025 and then decrease to 6% by 2040. Petroleum products forecast dependent on historical regression analysis

Impact of CNG	CNG forecast based on ICF's natural gas model - optimistic scenario (detailed in CGD blending)	CNG forecast based on ICF's natural gas model - realistic scenario (detailed in CGD blending)	CNG forecast based on ICF's natural gas model - conservative scenario (detailed in CGD blending)
Impact of EVs and FCEVs	10% penetration of FCEVs Annual EV sales for passenger vehicles to reach out 3 million in 2040	5.5% penetration of FCEVs Annual EV sales for passenger vehicles to reach out 2.6 million in 2040 (based on bloombergNEF report and ICF model)	3% penetration of FCEVs Annual EV sales for passenger vehicles to reach out 1.5 million in 2040
Impact of Ethanol Blending	20% ethanol blending by 2030 and then increase to 25% by 2040	20% ethanol blending by 2035 and remains flat	20% ethanol blending by 2040

Demand forecast – Net Refining Capacity

Based on the above assumptions and various scenarios considered, total demand from Petroleum products continues to grow despite a gradual shift towards the cleaner fuels – the total refinery capacity might reach ~400 MTPA by the year 2040. In comparison, IEA India Energy Outlook 2021, forecast refinery capacity to reach 382 MMTPA by 2040.

Figure 2: Refinery Capacity Forecast



<u>**Hydrogen Demand (Fuel)**</u>

Typically, the total fuel and feedstock consumption in a refinery is around ~10[3]% by weight of crude oil processed. Refineries use fuel oil, fuel gas, naphtha and natural gas as fuels to produce refined products. The energy mix of natural gas and fuel oil/naphtha changes as price of natural gas changes against these commodities. Blending of natural gas with hydrogen may be an option for usage of hydrogen as fuel in refinery.

The key processes where natural gas may be used as fuel in refineries are:

- Fuel for process and utility heaters, replacing fuel oil and fuel gas.

[3] Energy Statistics India 2023 | Ministry of Statistics and Program Implementation | Government Of India (mospi.gov.in)

- Fuel for gas turbines, replacing naphtha.
- Fuel for hydrogen generation units, replacing gas and naphtha.

The hydrogen demand as fuel will depend on following factors:

- Cost parity between natural gas and hydrogen as fuel. Based on ICF pricing model, green hydrogen will not achieve cost parity against natural gas by 2040.
- Technical limitations of use of hydrogen in various process. Typically, gas turbines and furnaces will have technical limitations for using hydrogen as fuel in refineries. Literature review suggests gas turbines may only allow 1-2% hydrogen blending with natural gas by volumes.

Thus, based on above discussions, ICF do not forecast any fuel demand for hydrogen in refineries by 2040.

Hydrogen demand (feedstock):

Post the computation of net refining requirement, an average hydrogen requirement across refineries was assumed to forecast the total hydrogen demand for the refinery sector. The overall average hydrogen requirement across refineries in India is ~9,000 - 10,000 Tonnes/MMT refinery capacity (based on stakeholder interactions and data provided by IOCL). An analysis of the installed HGU capacities across IOCL refineries provides an idea on the average refinery requirement met by an HGU unit, which averages ~70% for the total requirement for the IOCL plants (~7000 Tonnes/MMT refinery capacity). The rest of the hydrogen demand is supplied by CRU, where hydrogen is the by-product of the process.
The table below (Table 2.1) illustrates hydrogen demand from CRU and HGU as provided by IOCL for its refineries. While the demand for hydrogen depends on each of the refinery capacity and its configuration, we see an approximate demand of 10,000 Tonnes/MMT of the refinery capacity.

Table 2: Installed HGU Capacity for IOCL refineries

Refinery	HGU Name Plate Capacity (KTPA) (as on 1.3.2023)	Refinery capacity (MTPA)	Hydrogen production in HGU (TPA) (FY 23)	Hydrogen production in CRU + Others (TPA) (FY 23)	Total hydrogen consumption (TPA) (FY 23)
Digboi	7	0.65	6340	1456	7796
Guwahati	12	1	10200	0	10200
BGR	30	2.7	22500	4000	26500
Barauni	HGU- 1:34 HGU- 2:20 Tot-54	6	32500	18400	50900
Gujarat	HGU- 1:38 HGU- 2:11 HGU 3/4: 2x72.5 **Tot- 194**	13.7	86100	37200	123300
Haldia	HGU- 1:15 HGU- 2:90 **Tot-105**	8	84000	3280	87280
Mathura	HGU- 1:34 HGU- 2:60 **Tot**-94	8	55600	19600	75200
Panipat & PNC	HGU- 1:38 HGU-2/3: 2x70 HGU- 4:44 **Tot-266**	15	118137	46301	164438
Paradip	HGU-1:72.8 HGU (new) :60 **Tot-132.8**	15	71300	68732	140032
IOC-Total	**894.8**	**70.05**	**486677**	**198969**	**685646**

There are key uncertainties that will impact hydrogen demand for the refinery sector. These include:

- Level of sulphur content in the crude: As refinery use sour crude, it will require more hydrogen to remove the sulphur content.
- Integration of petrochemical plants: In an integrated petrochemical complex, hydrogen generated from CRU will be utilized in petrochemical plant and thus creating higher requirement of hydrogen from HGU/externally sourced hydrogen.

Based on the above analysis, hydrogen requirements for refineries will increase from 3.85 Million Tonnes Per Annum (MTPA) to 4.38 Million Tonnes Per Annum (MTPA) by 2040. Out of this, the requirement for external hydrogen (from HGU) will be around 2.69 MTPA to 3.06 MTPA by 2040.

Figure 3: Total Hydrogen Consumption in refineries (as Feedstock)

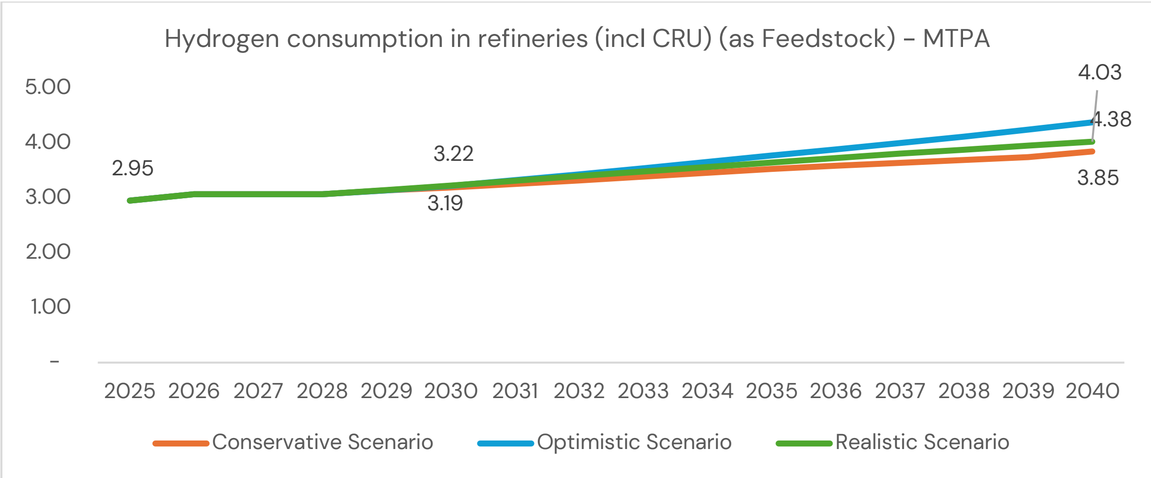
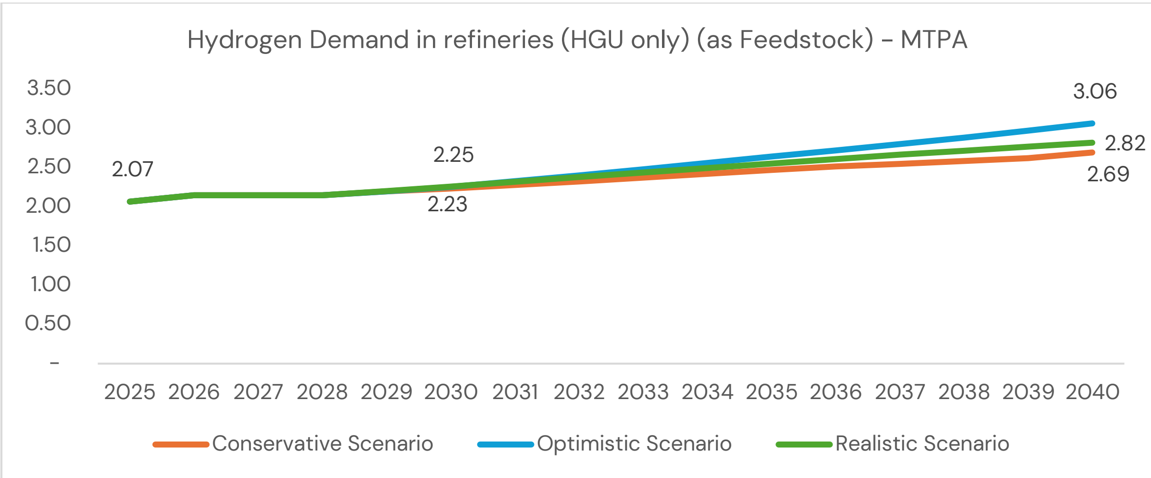


Figure 4: Total Hydrogen Demand in refineries (as Feedstock)



State-wise hydrogen demand

Based on current installed capacity of refineries and their location, we forecasted hydrogen demand for the refinery for the snapshot years

Table 3- State wise hydrogen demand for refineries (both CRU + HGU)

States	2025	2030	2035	2040
Andhra Pradesh	0.07	0.08	0.09	0.10
Assam	0.09	0.10	0.12	0.13
Bihar	0.05	0.06	0.06	0.07
Gujarat	1.25	1.37	1.55	1.71

Haryana	0.21	0.23	0.26	0.29
Karnataka	0.16	0.18	0.20	0.22
Kerala	0.16	0.18	0.20	0.22
Madhya Pradesh	0.13	0.14	0.16	0.18
Maharashtra	0.14	0.16	0.18	0.19
Odisha	0.07	0.08	0.09	0.10
Punjab	0.08	0.09	0.10	0.12
Rajasthan	0.10	0.10	0.13	0.14
Tamil Nadu	0.21	0.23	0.26	0.29
Uttar Pradesh	0.09	0.10	0.11	0.12
West Bengal	0.10	0.11	0.13	0.14
	2.95	**3.21**	**3.65**	**4.03**

The table below shows the state-wise demand of the hydrogen demand from external source such as HGU for the snapshot years.

Table 4 - State wise hydrogen demand for refineries (only HGU)

States	2025	2030	2035	2040
Andhra Pradesh	0.05	0.06	0.06	0.07
Assam	0.07	0.07	0.08	0.09
Bihar	0.04	0.04	0.05	0.05
Gujarat	0.88	0.96	1.08	1.20
Haryana	0.15	0.16	0.19	0.20
Karnataka	0.11	0.13	0.14	0.16
Kerala	0.11	0.12	0.14	0.16
Madhya Pradesh	0.09	0.10	0.11	0.13
Maharashtra	0.10	0.11	0.12	0.14
Odisha	0.05	0.05	0.06	0.07
Punjab	0.06	0.06	0.07	0.08
Rajasthan	0.07	0.07	0.09	0.10
Tamil Nadu	0.15	0.16	0.18	0.20
Uttar Pradesh	0.06	0.07	0.08	0.09
West Bengal	0.07	0.08	0.09	0.10
	2.07	**2.25**	**2.55**	**2.82**

Green hydrogen demand for refineries

The adoption of green hydrogen in refineries will be driven by following factors:

- *Green hydrogen consumption obligation (GHCO)*: The draft memorandum circulated on National Green Hydrogen Mission (NGHM) on October 2021 identified GHCO commitments for refinery with a view that 100% of hydrogen needs for refinery will be provided by green hydrogen by 2035.This required refinery to meet 10% of hydrogen demand through green hydrogen in 2024 and will reach 100% of green hydrogen by 2035. These GHCO obligations were not present in the final document.
- *Cost parity with grey hydrogen*: As per ICF model, cost of green hydrogen will remain high compared with grey hydrogen produced from SMR. As per ICF model, the cost parity between grey hydrogen and green hydrogen will be achieved by 2035.

Thus, in our base case we have assumed that refineries will achieve 50% of the GHCO [4]obligations by 2040. The table below illustrates GHCO requirements for refinery.

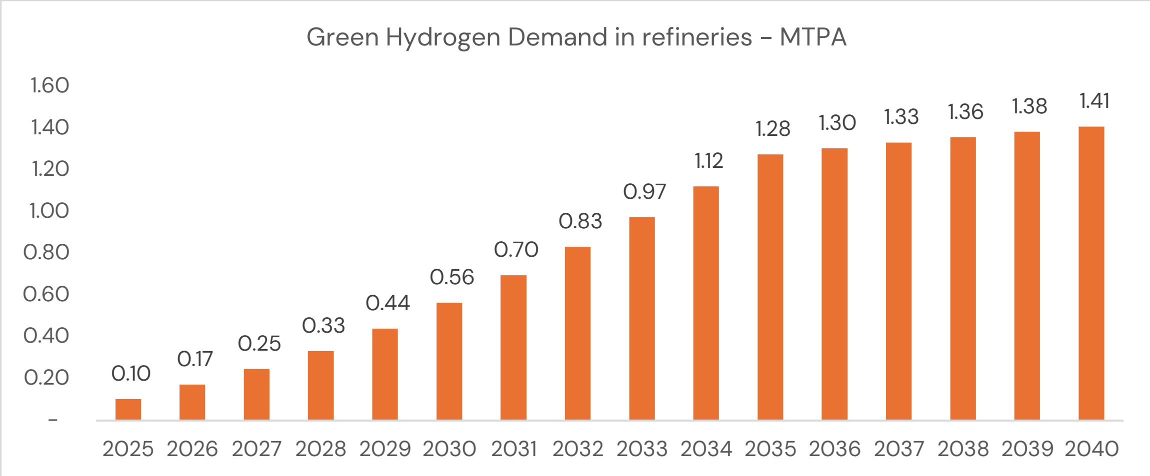
[4] Draft National Green Hydrogen Mission Document Draft Version dated 27 October 2021

Table 5 – GHCO obligations and ICF assumptions for green hydrogen trajectory in refineries

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
GHCO for refining	5%	10%	16%	23%	31%	40%	50%	60%	70%	80%	90%	100%	100%	100%	100%	100%	100%	100%
ICF Case	0%	0%	5%	8%	12%	16%	20%	25%	30%	35%	40%	45%	50%	50%	50%	50%	50%	50%

The figure below shows green hydrogen demand for refinery to reach 1 MTPA by 2033 and 1.5 MTPA by 2040.

Figure 5: Green Hydrogen Demand in refineries (as Feedstock)



A1.2 Ammonia

Ammonia plays a key role in ensuring universal food security and nutrition requirement for crops and is a critical chemical feedstock in several industrial applications. As the global demand for ammonia increases with population growth, decarbonizing ammonia becomes critical to reduce emissions in the chemicals sector. Demand for ammonia is also expected to grow in a decarbonized world as an energy carrier, with use cases emerging in shipping, power generation, and as a hydrogen carrier. It becomes critical therefore, that as the demand for ammonia grows, the process to manufacture ammonia moves away from relying heavily on fossil fuel and towards cleaner energy sources.

The launch of the National Hydrogen Mission is an indicator that the government has started to take concrete steps towards meeting its climate targets and making India a green hydrogen hub. This is expected to help in meeting the target of production of 5 million tonnes[5] of green hydrogen by 2030 and the related development of renewable energy capacity.

Hydrogen and ammonia have further been envisaged to be the future fuels as a substitute for fossil fuels. Production of green hydrogen and green ammonia using renewable energy is one of the major requirements towards environmentally sustainable energy security of the nation. Government of India is taking various measures to facilitate the transition from fossil fuel / fossil fuel-based feed stock to green hydrogen / green ammonia.

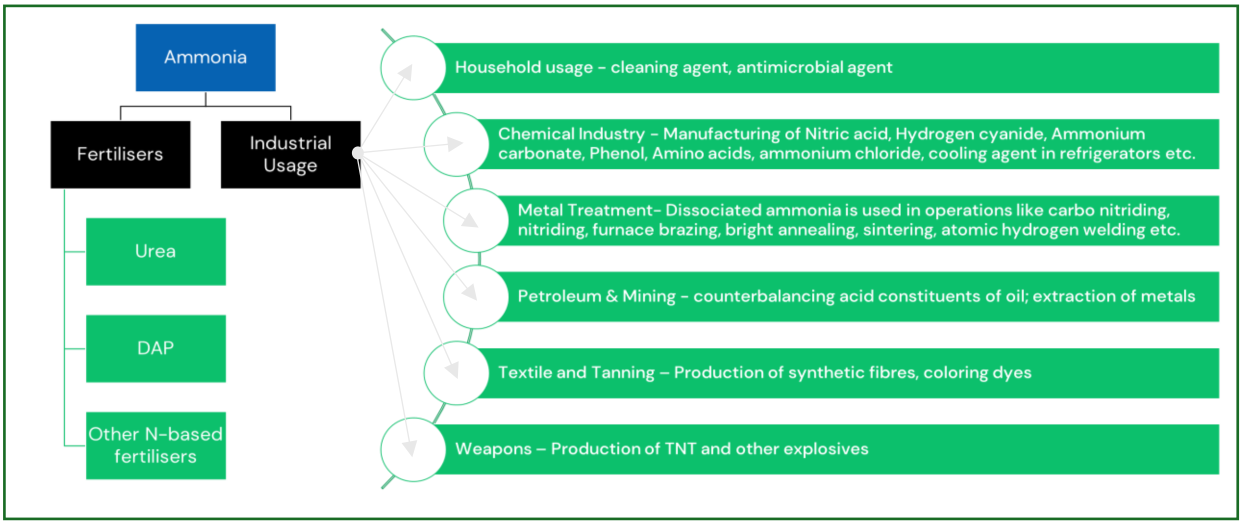
A snapshot of the policy notification issued by Ministry of Power (MoP) as outlined by the Press Information Bureau is provided below:

- *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.*

[5] https://pib.gov.in/PressReleasePage.aspx?PRID=1799067

- *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 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 storage for this purpose shall be provided by the respective port authorities at applicable charges.*

Figure 6: Ammonia Usage in Various Industries



The policy draws a roadmap for possible integration of clean fuel in the existing system. This will reduce dependence on fossil fuel and reduce crude oil imports. Subsequently, the plan is for our country to emerge as an export Hub for green hydrogen and green ammonia.

Ammonia Usage

Ammonia finds its usage majorly in the fertilizer Industry and for other industrial purposes. The demand of ammonia in India has risen from 15.5 MTPA in 2016[6] to 19.3 MTPA in 2022[7] [8].

Although ammonia has multiple usage in other industries, the majority is being utilized in the fertilizer Industry only. Based on FY 2022 data, total ammonia demand for the fertilizer sector 17.9 MTPA, that is almost

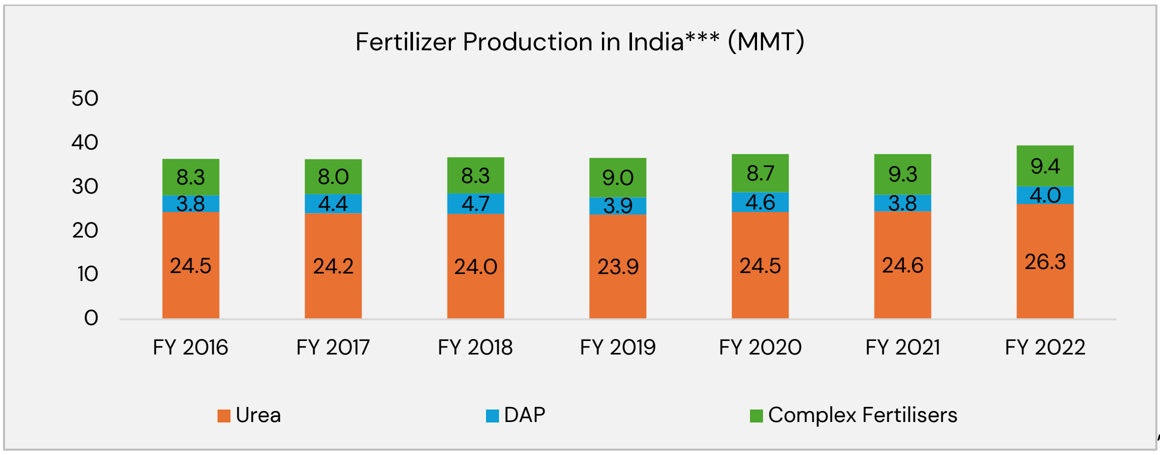
[6] https://gpca.org.ae/wp-content/uploads/2018/03/Changes-in-Indias-Natural-Gas-Market-and-Implications-for-the-Fertilizer-Industry.pdf
[7] https://www.expertmarketresearch.com/reports/indian-ammonia-market#:~:text=The%20Indian%20ammonia%20market%20size,of%20nearly%209.27%20million%20tons – Figures for 2020 are approximate

[8] https://www.ammoniaenergy.org/articles/india-a-future-ammonia-energy-giant/

91% of total demand for ammonia in India.

Thus, the fertilizer industry is driving the major demand of ammonia in the country.

Figure 7: Fertiliser Production in India

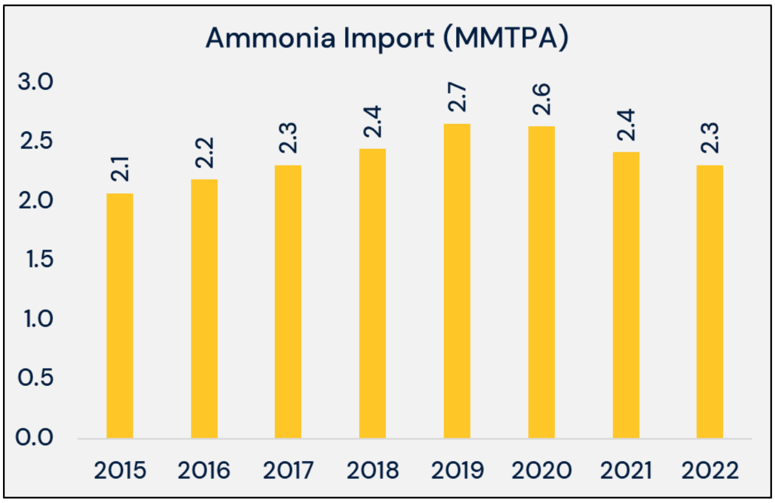


Looking at the historical data, following trends may be observed:

- Urea production in India remained flat from year FY 2016 to FY 2021 with significant jump in FY 2022 due to revival of Urea projects.
- DAP demand remains fairly stable around 4 MTPA with cost economics driving changes in DAP production in India.
- Complex NPK fertilizer has slowly increased in the last 3 years to reflect an increase in capacity from 8.7 MTPA to 9.4 MTPA.

The ammonia imports (for manufacturing DAP and complex NPK fertilizer) remains around 3.4-2.7 in last five years.

Figure 8: Ammonia Import in India



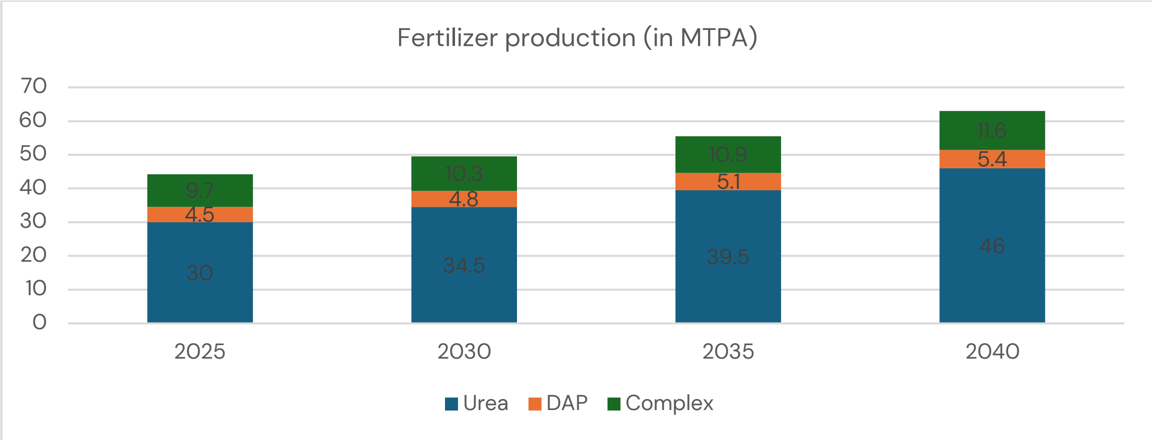
Fertilizer demand projection

ICF used its propriety fertilizer model to forecast demand of fertilizer (urea and non-urea nitrogenous fertilizers) till 2040. Some of the key assumptions are:

- Till 2030, urea production will be driven by announced projects for revival or expansion. Post 2030, urea demand will grow linked to population growth. The import of urea will decrease from 15% from 2025 to zero by 2035.
- DAP production and complex NPK fertilizers will grow at rate of 1.2% based on historical data.

The graph below shows our forecast of nitrogenous fertilizers (Urea and Non-Urea) till 2040

Figure 9: Fertilizer Production in MTPA

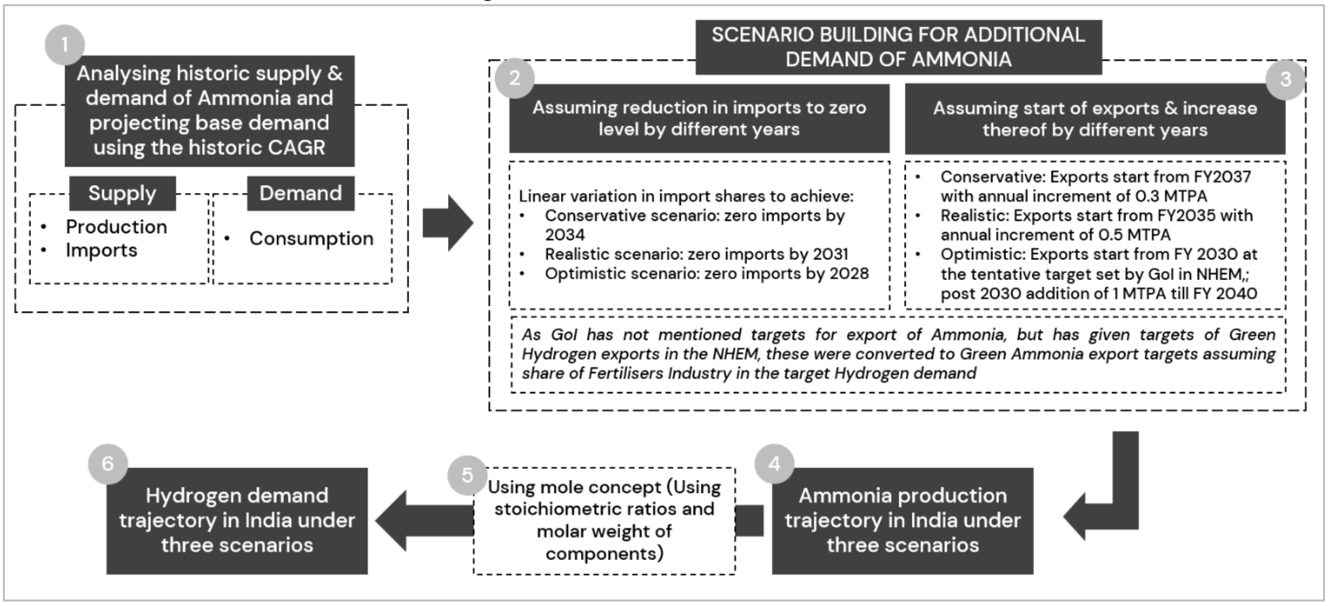


Ammonia Demand Projection

The unconstrained demand projection for ammonia and subsequently hydrogen has been done considering various scenarios of imports and exports. The base domestic consumption demand has been projected linearly based on historic numbers. The imports were then reduced to the level of zero in all the scenarios using different trajectories in the respective scenarios. Subsequently, once the imports become zero, the exports have been started, again using different trajectories in different scenarios. These scenarios have been elaborated in the coming sections.

Further, while calculating the demand of hydrogen from the projected production demand of stoichiometric ratios and molar weight of the components.

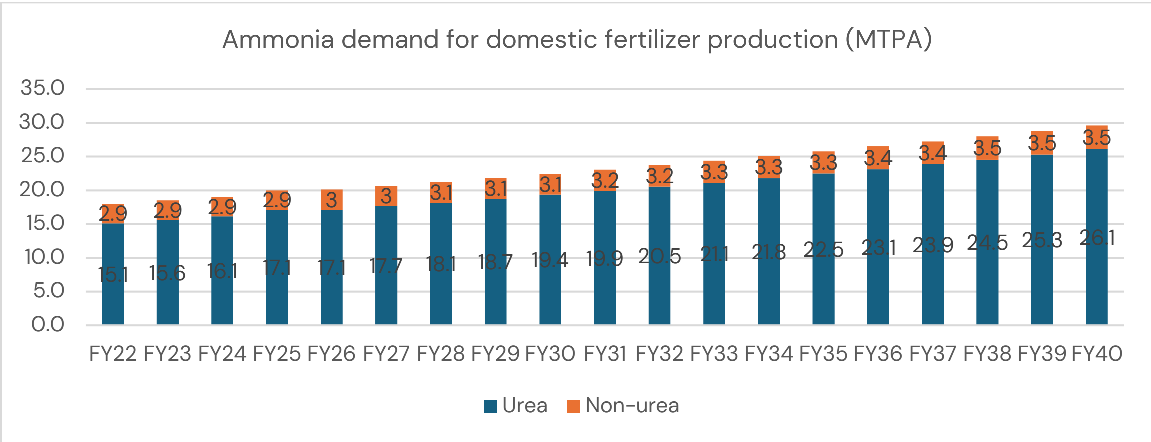
Figure 10: Ammonia demand model



Ammonia Demand

As discussed above, the overall ammonia demand for domestic usage in the context of India has been projected considering the historic rate of increase of ammonia demand in India. This has been done considering the fact that ammonia demand in the fertilizer industry has become stagnant to some extent over the years and the industrial sector has shown significant growth in recent years and has started to build its base in the overall ammonia demand of the country.

Figure 11: Ammonia demand projection in India for domestic usage



The above graph depicts the total domestic ammonia production and imported ammonia in India. The imported ammonia is utilized for producing fertilizers including DAP and NPKs, whereas Urea is directly imported for urea-based fertilizers. The analysis does not include imported direct fertilizers (Urea or non-urea) in India.

It can be observed that the demand of ammonia in domestic usage is increasing from 18 MTPA in FY 2022 to 29.6 MTPA in FY 2040.

Further, while much of the current dependence of ammonia has been on imports, with the push on green ammonia as well as the expansion plans of the current ammonia plants and the govt. of India planning to build India as an export hub of green ammonia, the projection of unconstrained ammonia demand in the context of India has been done considering various scenarios of production, import and export.

The key assumptions for three scenarios as shown in chart above is summarized below:

Table 6: Ammonia Demand Scenarios

Driver	Conservative scenario	Realistic scenario	Optimistic scenario
Import target	Ammonia imports to be zero by 2034	Ammonia imports to be zero by 2031	Ammonia imports to be zero by 2028
Export target	Ammonia export start from FY 2037 with 0.3 MMT per year	Ammonia export start from FY 2035 with 0.5 MMT per year	Ammonia export start from FY 2030 with 0.5 MMT per year

Based on the above scenarios, ammonia demand projected for India is presented in the below figures:

Figure 12: Ammonia Production Requirement – Realistic Scenario

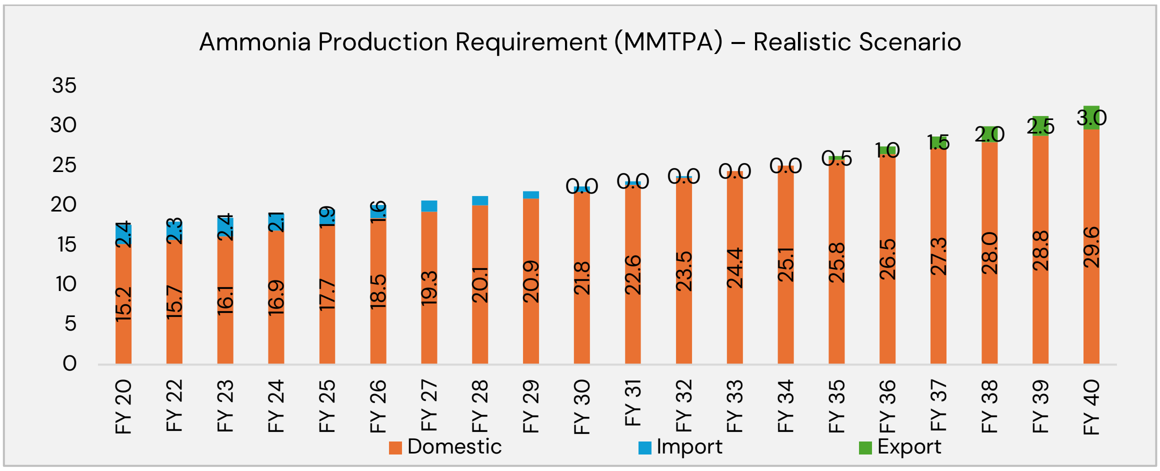


Figure 13: Ammonia Production Requirement – Conservative Scenario

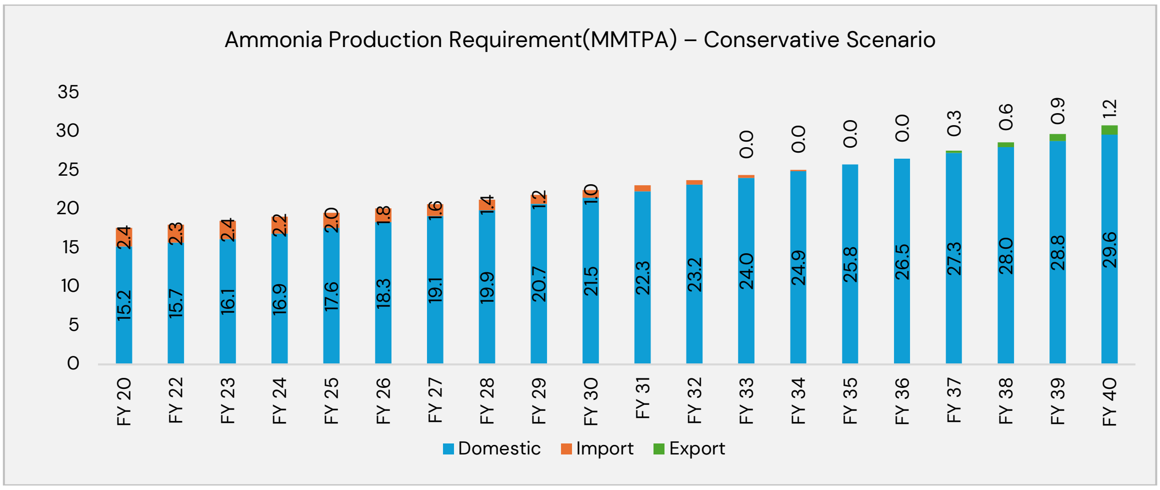
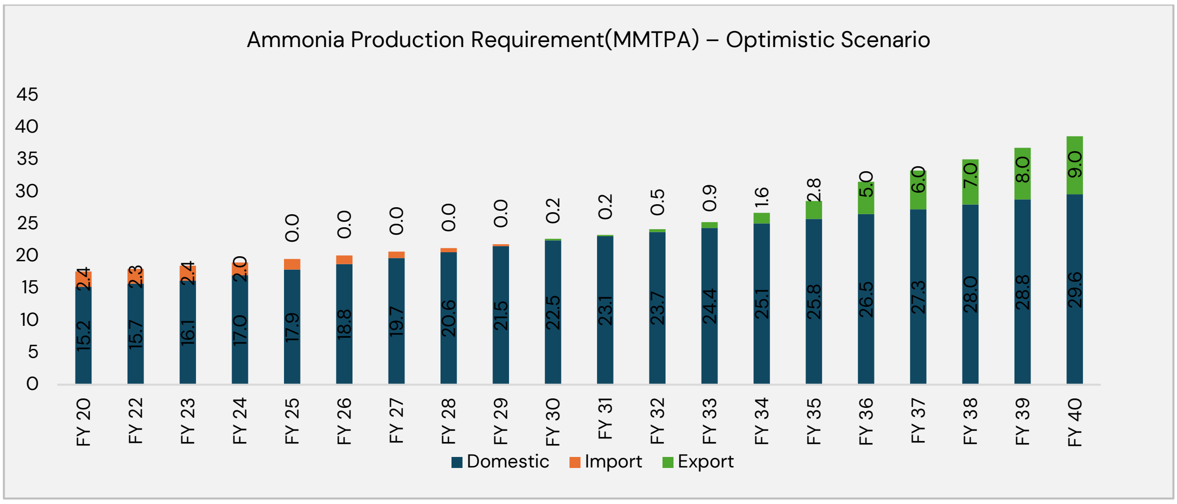


Figure 14: Ammonia Production Requirement – Optimistic Scenario



In the conservative scenario, the overall ammonia production in the country is expected to grow to ~31 MTPA in FY 2040 whereas the same is expected to grow to ~33 MTPA and ~39 MTPA in the realistic and optimistic scenario respectively.

The export demand is playing a major role in the optimistic scenario (government push scenario) wherein it is expected to grow up to 9 MTPA whereas the same is limited to 3 MTPA and 1.2 MTPA in the realistic and conservative scenarios respectively.

Hydrogen Demand from Ammonia demand

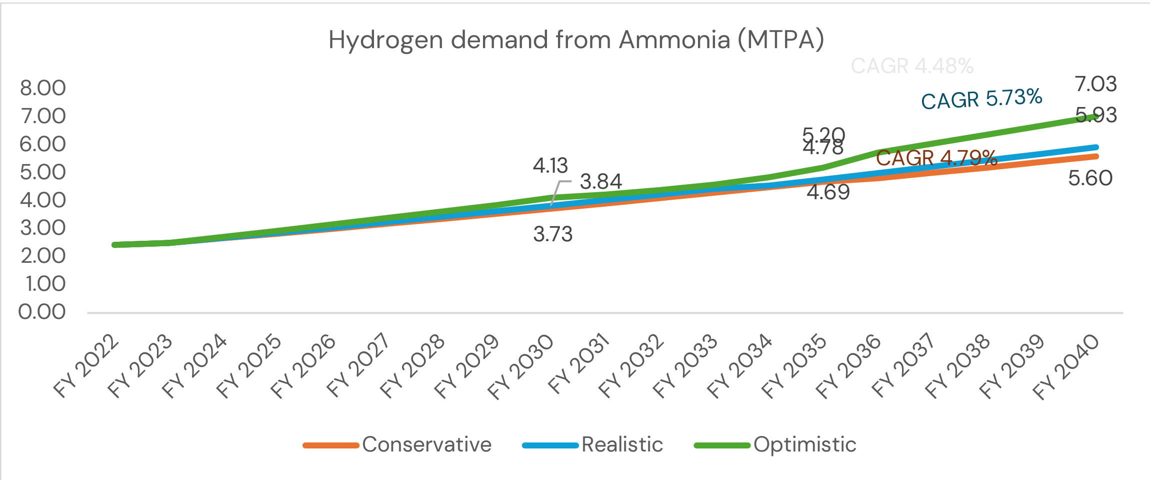
As discussed above, mole concept has been used to project the potential demand of hydrogen based on expected Ammonia demand. The stoichiometric ratios and molar weight of components have been used to identify the quantum of hydrogen requirement in all the three scenarios.

$2NH_3$ --à $N_2 + 3H_2$

The above chemical reaction has been used to calculate the quantum of hydrogen required. Given that the atomic weight of nitrogen is 14u and hydrogen is 1u, a total of 34u of ammonia is required to generate 6u of hydrogen and vice-versa. Further, a yield of ~97% has been considered for the Haeber Bosch process. Overall, hydrogen required will be around 177 kg per tonne of ammonia.

With the help of above approach, the hydrogen requirement in each of the scenarios of ammonia demand is calculated and presented in figure below:

Figure 15: Hydrogen Demand from Ammonia



The hydrogen demand from ammonia production is expected to vary between 5.6 MTPA to 7.03 MTPA in 2040 based on different scenarios. The growth rate also varies from 4.79% in conservative scenario to 5.73% in optimistic scenario. The major driver which has led to the gap between conservative and optimistic scenario is the quantum of export of ammonia in the respective scenarios.

Based on current installation of urea and non-urea fertilizers, we forecasted state wise demand for ammonia sector as shown in the table below:

Table 7 Ammonia Demand- State wise

States	2025	2030	2035	2040
Andhra Pradesh	0.14	0.18	0.22	0.26
Assam	0.12	0.16	0.20	0.24
Bihar	0.11	0.15	0.19	0.22
Goa	0.04	0.05	0.06	0.07
Gujarat	0.38	0.50	0.62	0.73
Haryana	0.05	0.06	0.08	0.09
Jharkhand	0.11	0.15	0.19	0.22
Karnataka	0.03	0.05	0.06	0.07
Kerala	0.07	0.09	0.12	0.14

Madhya Pradesh	0.22	0.29	0.36	0.42
Maharashtra	0.25	0.33	0.41	0.48
Odisha	0.11	0.15	0.19	0.22
Punjab	0.09	0.12	0.15	0.17
Rajasthan	0.33	0.44	0.55	0.64
Tamil Nadu	0.10	0.13	0.16	0.19
Telangana	0.11	0.15	0.19	0.22
Uttar Pradesh	0.80	1.05	1.30	1.52
West Bengal	0.26	0.34	0.42	0.50
	3.34	**4.38**	**5.46**	**6.39**

<u>Green hydrogen in fertilizer</u>

Although hydrogen has a great potential in fertilizer sector, the role of green hydrogen will depend on cost economics of green hydrogen against grey hydrogen, government policies as well as technology changes needed. In our base case for green hydrogen, we assume that:

- Current ammonia imports for manufacturing DAP/NPK fertilizer will be replaced by green ammonia.
- After cost parity is achieved, 100% of additional capacity will be met through green ammonia for non-urea fertilizer.
- We do not envisage any green ammonia plant for urea fertilizer due to potential constraints on CO2 availability.
- All exports of ammonia will be based on green ammonia and no SMR plant will be set up for ammonia exports.

The figure below shows green ammonia requirements in our base case (for realistic case of ammonia demand)

Figure 16: Green ammonia demand for domestic consumption and exports

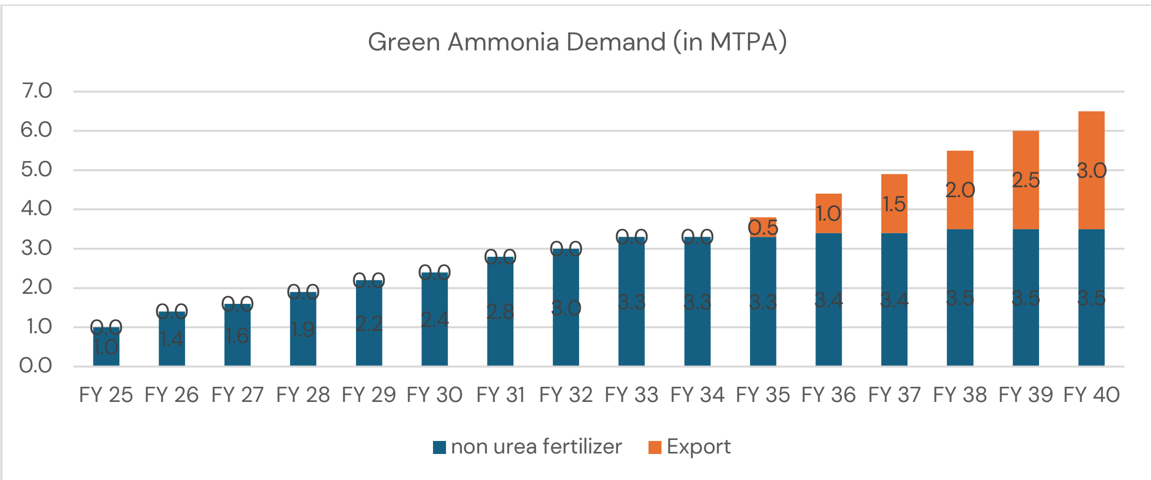
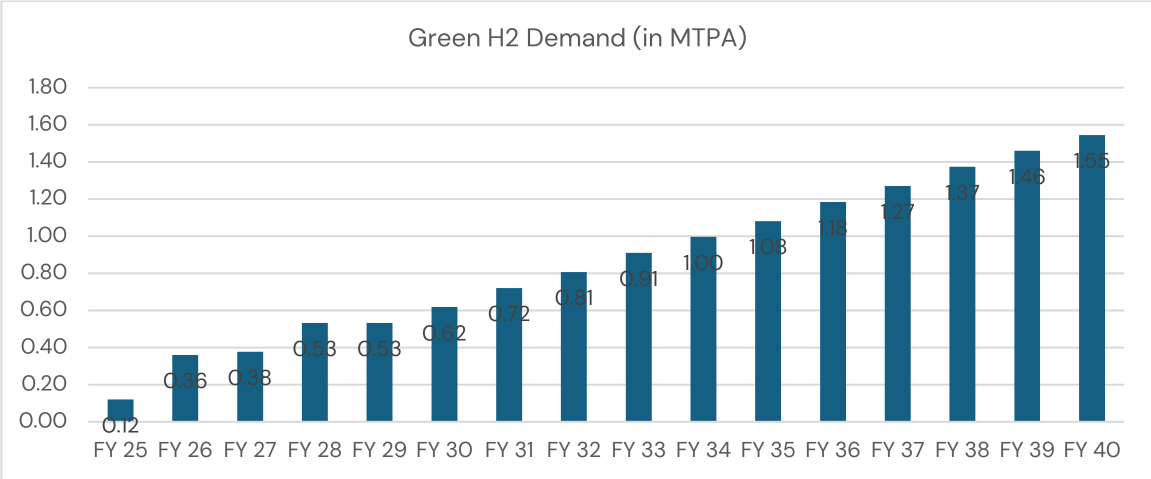


Figure 17: Green hydrogen demand for domestic consumption and exports



A1.3 CGD Blending

The focus of this discussion is on the blending of hydrogen in the City Gas Distribution (CGD) network in India. It is worth noting that the CGD network in India is spread across the country. The initial step towards utilizing hydrogen in the CGD network involves the blending of hydrogen with natural gas. However, the blending of hydrogen in the CGD network is currently limited by the type of pipeline material used and the restrictions posed by the end-use applications.

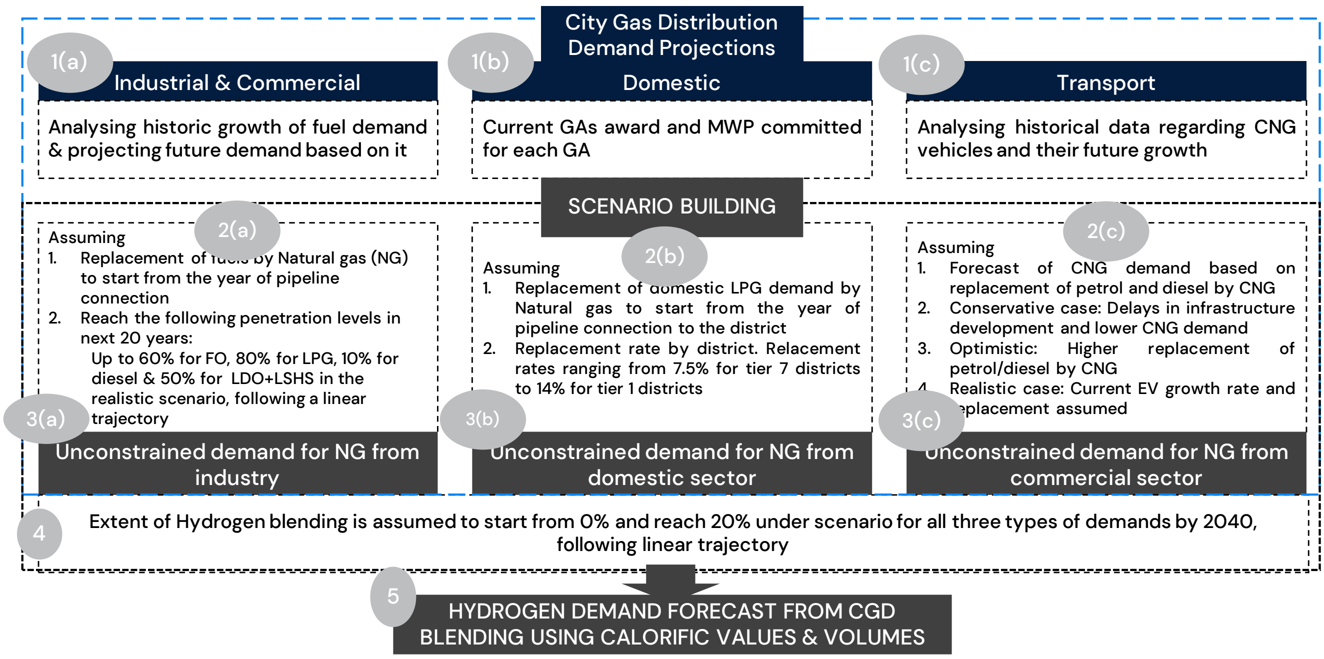
Technical studies are presently underway to determine the extent to which hydrogen blending can be carried out in the Indian city gas pipeline network, based on the type of steel used. The outcome of these studies, along with the results of the pilot projects, will determine the future expected percentage of hydrogen blending in the Indian CGD network.

Literature review suggests that the end-use limitations of hydrogen blending are 10%-20% for industrial applications, without any technological augmentation, and 30% for commercial and industrial applications. However, in a practical application, the current pilot project being conducted by GAIL in M.P. has observed a blending rate of around 2%, which is raised to 5% by bypassing the CNG refilling stations.

CGD demand analysis

The projection for CGD demand has been conducted for three sectors, namely industrial, domestic, and commercial. The basic methodology employed for unconstrained demand analysis involves an analysis of historic fuel demand, followed by the replacement of LPG demand with natural gas. Finally, hydrogen demand is forecasted using calorific value and volumes.

Figure 18: Methodology for unconstrained demand analysis



Assumptions made under these three scenarios have been summarized in table below:

Table 8: Key Assumptions for CGD demand forecast

Scenario	Optimistic	Conservative	Realistic
Definition	CGD shows higher growth rate for all sectors due to replacement of FO and LSHS for environmental concerns (Industrial, commercial, transport and residential)	Higher penetration of EVs and no replacement of FO by natural gas.	CGD shows historical growth rate for all sectors (Industrial, commercial, transport and residential)
Blending location	**Blending at City Gate Station.**	**Blending at City Gate Station.**	**Blending at City Gate Station.**
Infrastructure upgradation	Pipeline material limitation: old burners may need to be tested for hydrogen safety and may need to be replaced (Network components – like compressors, valves, flow may need to be changed)	No infrastructure upgradation required	Bypassing CNG stations in the gas network or using higher hydrogen blend as per CNG pilot projects
Penetration rate by 2040:	**Industrial sector**: • 80% Bulk LPG • 80% FO • 15% Bulk Diesel • 60% LDO +LSHS **Commercial sector** • 60% commercial LPG **Residential sector** • 10% to 18% domestic LPG replacement based on Tier of the district. **Transport sector** • Cars – 20% • Commercial cars – 40% • Auto -45% • LCV – 10% • Buses – 25%	**Industrial sector**: • 45% Bulk LPG • 30% FO • 7% Bulk Diesel • 30% LDO +LSHS **Commercial sector** • 30% commercial LPG **Residential sector** • Only meet MWP and then remains flat. **Transport sector** • Cars – 15% • Commercial cars – 20% • Auto -25% • LCV– 10% • Buses – 15%	**Industrial sector**: • 80% Bulk LPG • 60% FO • 10% Bulk Diesel • 50% LDO +LSHS **Commercial sector** • 50% commercial LPG **Residential sector** • 7.5% to 14% domestic LPG replacement based on Tier of the district. **Transport sector** • Cars – 15% • Commercial cars – 30% • Auto -35% • LCV– 10% • Buses – 20%

Natural gas demand forecast

The table below summarizes natural gas demand for all three cases across four segments.

Table 9: Natural gas demand in CGD sector (in mmscmd) (conservative, optimistic and realistic scenarios)

Industrial	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Conservative	13	14	15	16	16	17	18	19	19	20	21	21	22	23	24	24	25	26
Realistic	14	15	16	17	18	19	20	21	21	22	23	24	24	25	26	27	28	28
Opportunistic	15	16	17	19	20	21	22	23	24	25	26	27	28	29	30	31	32	32

Commercial	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Conservative	1	1	1	2	2	2	3	3	4	4	5	5	6	7	8	9	10	12
Realistic	1	1	2	2	3	3	4	5	5	6	6	7	8	9	10	12	14	16
Opportunistic	2	2	3	3	4	4	5	6	7	7	8	9	10	11	13	15	17	19

Residential	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Conservative	4	4	5	6	6	7	8	9	10	11	12	14	15	16	19	22	25	29
Realistic	5	6	7	8	9	10	11	13	14	15	17	18	20	22	26	30	35	40
Opportunistic	6	7	9	10	12	13	15	16	18	20	21	23	25	28	33	38	44	51

Transport	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Conservative	18	21	23	25	28	30	33	35	37	39	41	44	46	48	51	53	56	59
Realistic	19	22	26	29	33	37	41	46	50	54	58	62	67	72	78	84	90	96
Opportunistic	20	24	27	32	36	41	46	51	56	61	66	72	78	85	91	99	107	115

Total	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Conservative	**37**	**40**	**44**	**48**	**52**	**57**	**62**	**66**	**70**	**75**	**79**	**84**	**88**	**94**	**101**	**108**	**116**	**125**
Realistic	**39**	**45**	**51**	**57**	**63**	**70**	**77**	**84**	**90**	**97**	**104**	**111**	**119**	**129**	**140**	**152**	**166**	**181**
Opportunistic	**42**	**49**	**56**	**63**	**71**	**79**	**87**	**96**	**104**	**112**	**121**	**130**	**140**	**152**	**166**	**182**	**199**	**218**

H2 blending in CGD network

Transport sector

Most of the research has sought to identify the hydrogen mix at which optimized reduction of NOX, CO, CO2 and unburned hydrocarbon emissions can be obtained while limiting engine redesign and maintenance. The broad consensus is that 20% is the optimum blend for meeting these purposes.

Key limitation for HCNG blending comes from BIS 14590 - H2 limit (2%) in CNG Cylinder.

A few studies that demonstrated the same are:

NREL used an optimization strategy using a balanced scorecard of emissions, engine performance and total costs, and it judged 20-23% hydrogen by volume to be the optimum blend range.

Trials in Montreal (the Euro-Quebec project) and Vancouver (Cummins-Westport Inc.) showed that the use of HCNG blend (20% H2 by volume) led to significant reduction in emissions.

We have assumed that blending of hydrogen in transport sector will achieve 20% by volume by 2040.

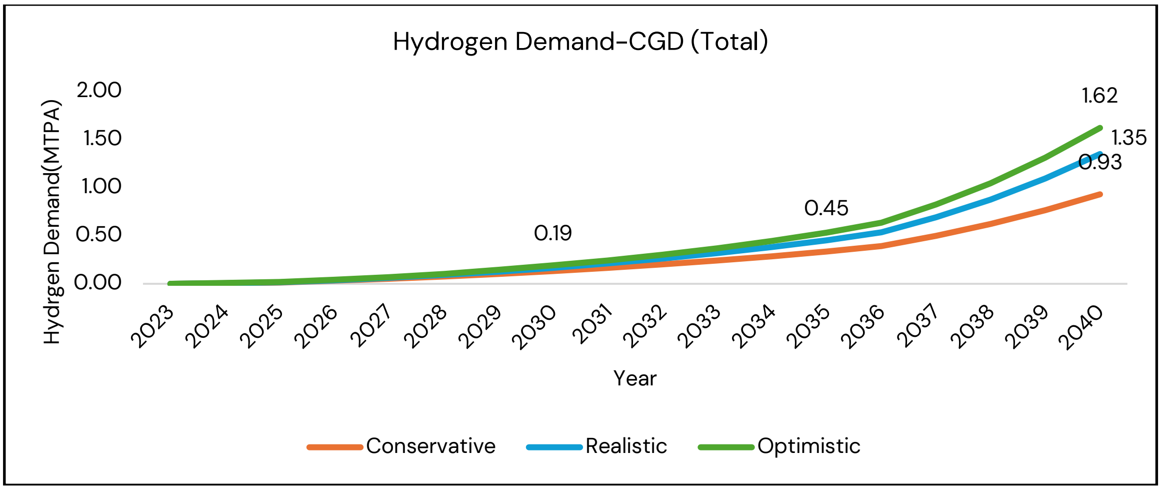
Residential, industrial and commercial sector

The literature review suggests that residential, commercial and industrial may allow 10% of H2 blending without significant changes in the infrastructure. Blending limits of 10-20% would require some changes in infrastructure (repurposing of infrastructure). For our analysis we have assumed blending of 20% by 2040.

The results of demand projection for H2 in CGD blending are summarized below:

- 2030: H2 demand varies from 0.13 MTPA to 0.17 MTPA
- 2040: H2 demand varies from 0.93 to 1.62 MTPA

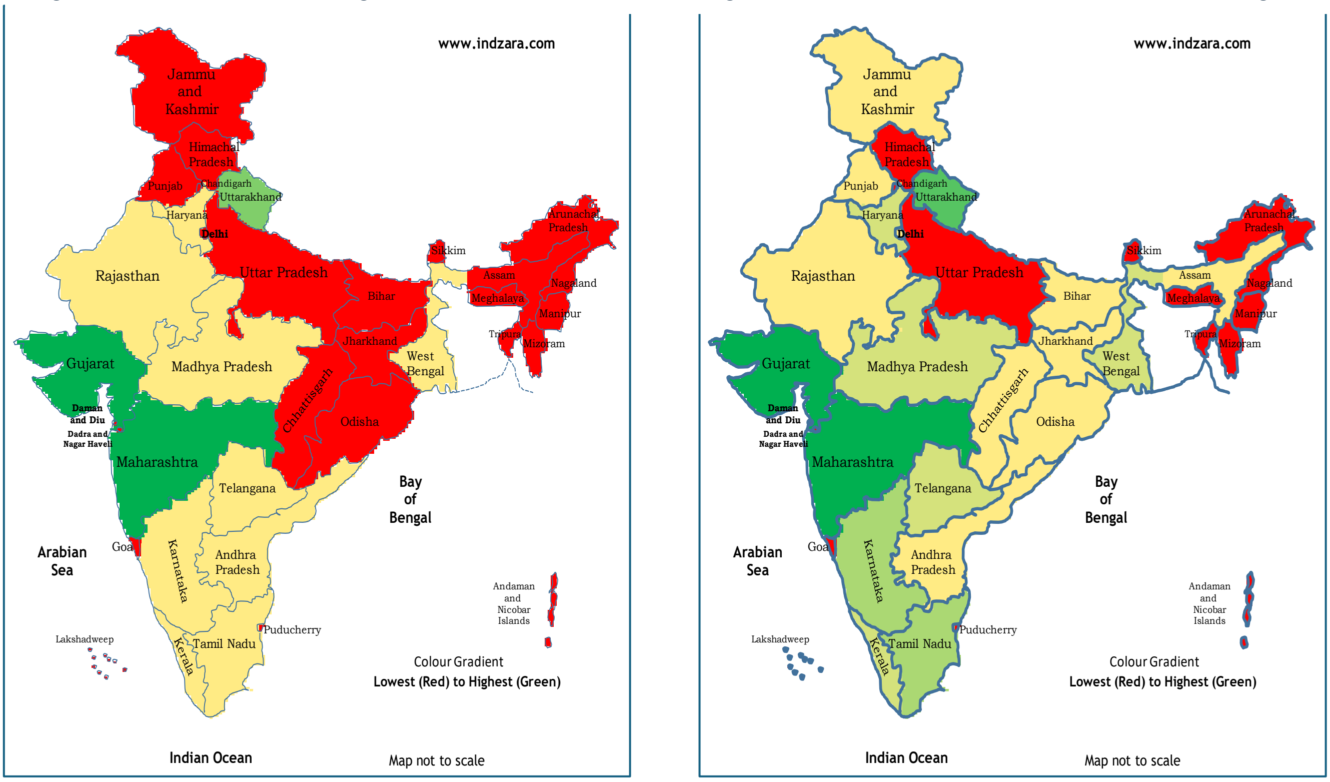
Figure 19: Hydrogen Demand (MTPA) (CGD – Total)



In conclusion, the projections for hydrogen production indicate a potential increase in demand in the CGD blending sector in the future.

The following heat map shows CGD blending demand in different states for the snapshot year 2030 and 2035. This is based on district wise natural gas demand and blending ratio at different snapshot year.

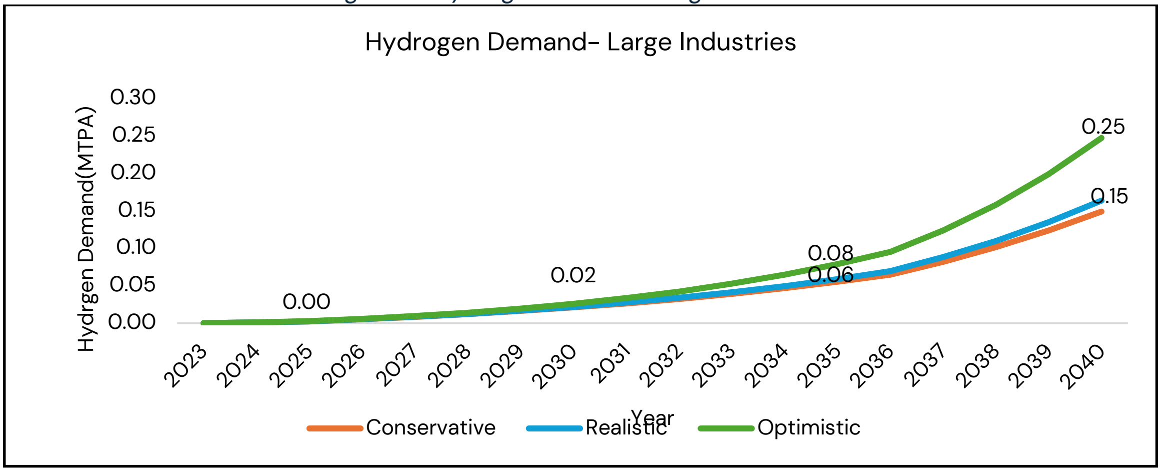
Figure 20: Heat map of hydrogen demand due to CGD blending for the snapshot year 2030 (left) and 2035 (right)



Large industries (blending)

This section estimates demand of large industries (> 50,000 scmd) not included within the CGD blending framework. It centers on the computation of natural gas demand for the glass, ceramic, and alumina sectors, using historical CAGR as a foundational metric. Three distinct scenarios are formed: the conservative, realistic, and optimistic. The realistic scenario is founded on historical CAGR trends, while the conservative scenario postulates a 10% reduction in CAGR compared to the realistic counterpart, and the optimistic scenario assumes a 10% increase in CAGR relative to the realistic baseline. Subsequently, following the determination of natural gas demand under each scenario, the analysis proceeds to evaluate hydrogen demand. Hydrogen demand estimation is done assuming hydrogen blend possibility with natural gas. Hydrogen demand estimation uses the same blending assumptions as employed in the CGD blending analysis. Figure below shows the hydrogen demand estimation for large industries in three scenarios:

Figure 21: Hydrogen Demand-Large Industries

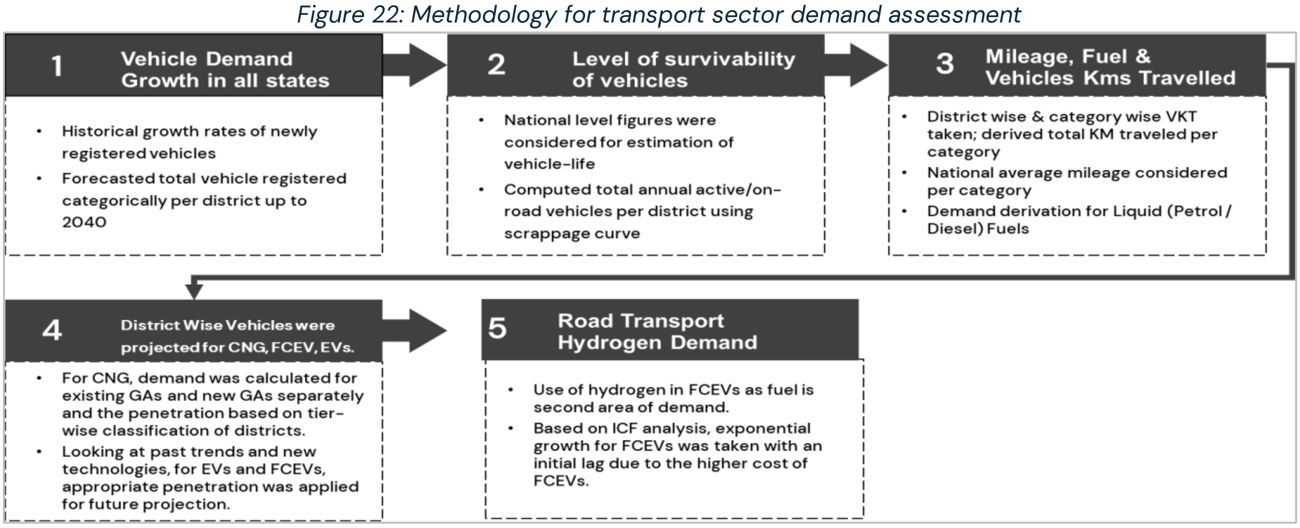


Green hydrogen demand for blending (CGD and large industries): Since, the reason to blend hydrogen with natural gas to be used as a fuel is to decarbonize the gas sector. Hence, the demand for hydrogen for blending (CGD and large industries) will be supplied by green hydrogen. Moreover, in the early years, due to lower blending limits , the impact of blending on end user pricing will be limited and hence there will be support for end user to offtake blended natural gas.

A1.4 Transport sector

India's Ministry of New and Renewable Energy (MNRE) has been supporting various hydrogen projects in academic institutions, research organizations, and industry for development. There has also been establishment of two hydrogen refueling stations at the Indian Oil R&D center in Faridabad and the National Institute of Solar Energy in Gurugram. In February 2020, MNRE partnered with NTPC Ltd., an Indian energy conglomerate, to propose the launch of a pilot fuel cell bus project. A hydrogen fuel cell bus was also launched in 2019 in India by Tata Motors in collaboration with the Indian Space Research Organization (ISRO) and Indian Oil (IOCL). The general methodology adopted for demand analysis is displayed in the following flow chart.

Figure 22: Methodology for transport sector demand assessment



Optimistic, conservative, and realistic scenarios were created to showcase the various possibilities of hydrogen demand in the sector.

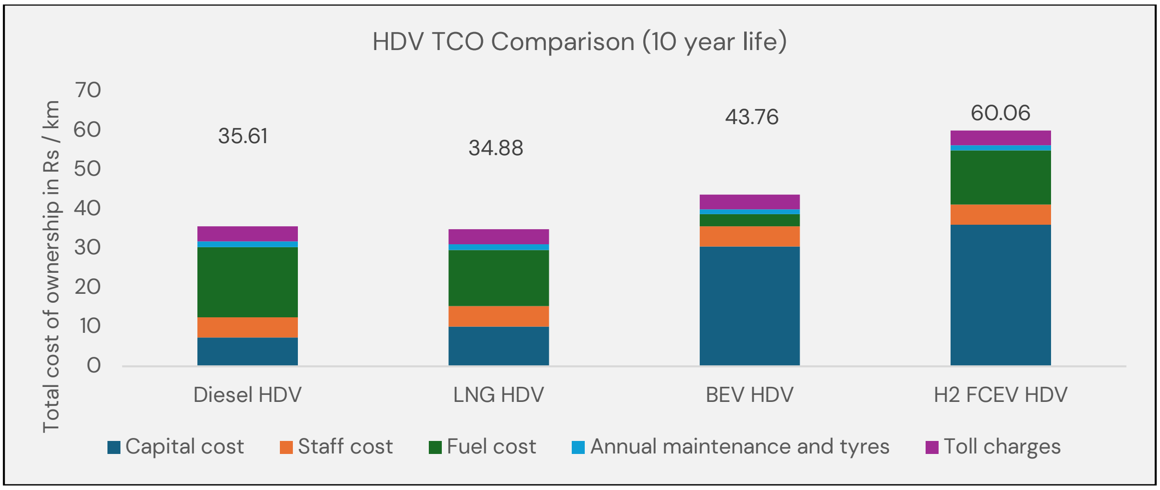
Hydrogen demand from FCEVs

Hydrogen fuel cell electric vehicles (FCEVs) are a type of zero-emission vehicle that use hydrogen to generate electricity for the vehicle's electric motor. FCEVs offer several benefits over traditional gasoline-powered vehicles, including longer driving ranges, and lower emissions. In addition, hydrogen fuel can be produced from a variety of renewable sources, making FCEVs a potentially more sustainable transportation option. Despite these advantages, FCEVs remain a relatively niche market due to the high cost and limited availability of hydrogen fuel infrastructure. However, as the technology continues to mature and infrastructure expands, FCEVs may become a more viable transportation option for consumers.

Considering that hydrogen technology has not yet matured significantly, the demand analysis would present a better picture of the possible hydrogen demand in the coming years. Even though hydrogen vehicles are coming up across the world, they are available at a substantial price premium to diesel alternatives. Hence, it is necessary to consider this aspect to estimate the hydrogen demand in FCEVs.

ICF conducted TCO comparison for HDVs of different fuel options. The comparison is shown in the following chart:

Figure 23: HDV TCO Comparison (10-year life)



It can be observed that FCEV is not cost competitive at the current prices of technology and fuel. Further, the higher capital costs form a key deterrent for FCEV adoption.

A comprehensive literature review of global studies was conducted to understand the global perception on cost parity of FCEVs.

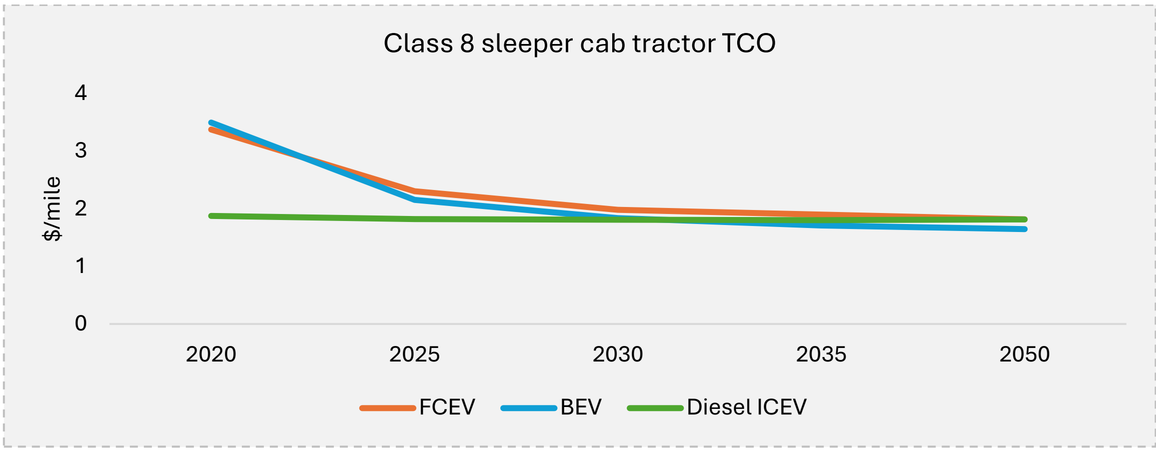
According to NREL, hydrogen FCEVs tend to become cost-competitive for long-haul (>500-mile) heavy trucks by 2035. A study by California Air Resources Board presents that FCEV cost parity is not possible before 2030. According to a recent ICCT Report, hydrogen fuel subsidies would likely be necessary to make fuel cell electric trucks financially viable for truck operators at least until 2035. It also estimates that TCO gap between FCEV and diesel truck will be ~+30% by 2030 in France.

Table 10: TCO Gap b/w fuel cell and Diesel tractor-trailer for trucks purchased in 2030 without policy intervention according to ICCT

Country	TCO Gap in 2030
Germany	+32%
Italy	+30%
Spain	+21%

According to a report by Argonne National Laboratory, the breakeven for per mile cost of a FCEV HDV with diesel truck comes even beyond 2040. The chart is shown below:

Figure 24: Class 8 Sleeper Cab Tractor TCO



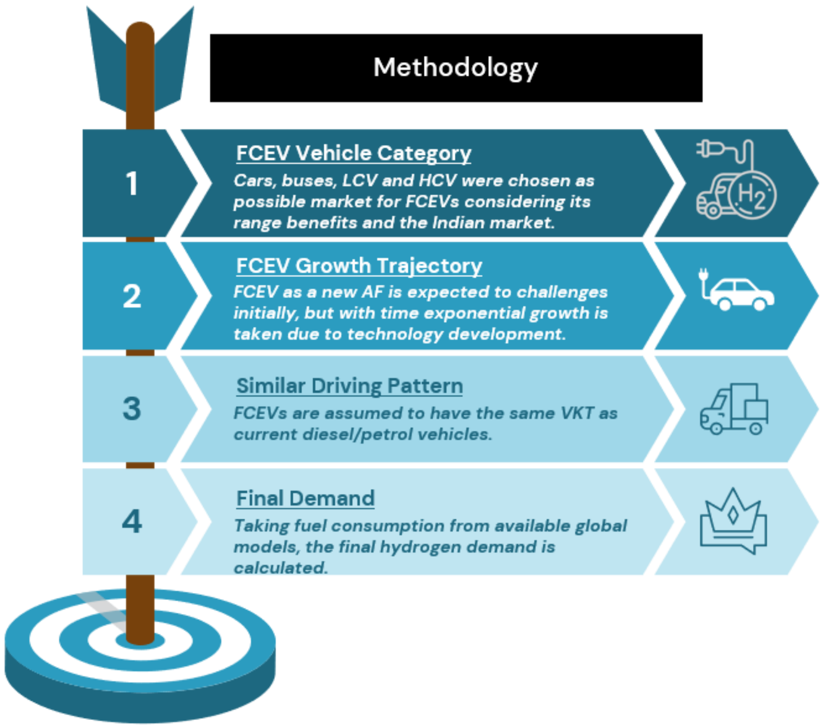
Cost parity for BEVs, is estimated to be achieved b/w 2022-2035, which will give BEV adoption an advantage over FCEVs.

Therefore, through this analysis, it was concluded that FCEVs are not cost competitive currently and are expected to reach cost parity globally beyond 2035.

FCEVs being new and having higher costs, are expected to face similar initial challenges as that of EV due to the market perception of alternative fuel vehicles. TCO studies show, that to promote FCEVs over EVs, focus needs to be on capitalizing on the technical benefits of FCEVs such as longer range, less refuel time. These benefits are extremely important for long range transport.

To estimate the hydrogen demand from this segment the following methodology was utilized:

Figure 25: Hydrogen Demand Methodology for FCEVs



<u>Key Assumptions for forecasting hydrogen demand for FCEVs</u>

For forecasting the hydrogen demand for FCEVs, 3 scenarios were considered based on different trajectories for FCEVs penetration in on-road buses, LCVs and HCVs. These vehicle categories have been considered since the FCEVs gain advantage over BEVs for long range heavy duty transportation.
The 3 scenarios are defined as follows:

Table 11 - Scenarios for the hydrogen demand In FCEVs

Scenario	Optimistic	Conservative	Realistic
Definition	Studying the adoption of EVs and challenges faced by it, realistic scenario for FCEVs was developed. Optimistic and conservative scenarios were developed to cover all range of possibilities.		
Assumption	Scenario for 10% penetration of FCEVs in on-road Buses, LCVs & HCVs by 2040 No penetration of FCEVs in other category of on-road vehicles (Two-wheelers, Three-wheelers/Autos)	Scenario for 3% penetration of FCEVs in on-road Buses, LCVs & HCVs by 2040 No penetration of FCEVs in other category of on-road vehicles (Two-wheelers, Three-wheelers/Autos)	Scenario for 5.5% penetration of FCEVs in on-road Buses, LCVs & HCVs by 2040 No penetration of FCEVs in other category of on-road vehicles (Two-wheelers, Three-wheelers/Autos)

Table 12 – Trajectory for penetration rate of FCEVs in Buses, LCVs & HCVs[9]

	2030	2035	2040
Realistic	0.26%	1.02%	5.50%
Optimistic	0.91%	3.01%	10.00%
Conservative	0.27%	0.90%	3.00%

The demand for FCEVs is based on the detailed ICF's transport model. The transport model is ICF's comprehensive proprietary model, which estimates future fuel demand for different types of vehicles till 2040. The major assumptions & intermediate analysis for forecasting hydrogen demand in FCEVs till 2040 are as follows:

1. **Percentage of Fuel (Petrol & Diesel) Consumption in Transport Sector (State-Wise)** -

Table 13: % Fuel Consumption in Transport Sector

State_Wise_Diesel Consumption	%
Transport Sector	
Andhra Pradesh	74%
Assam	78%
Bihar	55%
Delhi	72%
Gujarat	85%
Haryana	65%
Karnataka	76%
Kerala	76%
Madhya Pradesh	68%
Maharashtra	87%
Orissa	82%
Punjab	53%
Rajasthan	77%
Tamil Nadu	78%
Uttar Pradesh	56%
West Bengal	81%

[9] These penetration percentages for FCEVs across vehicle categories have been assumed based on the inputs from the stakeholder consultations & the breadth of possible FCEV penetration expressed by them

Non- Trasport Sector	26%

This is based on ICF's analysis and input data from PPAC on fuel usage across states & transport sector. This analysis coupled with the district-wise primary fuel (Diesel & petrol) consumption data, is used to estimate the fuel consumption across transport sector in each district in the country.

2. Percentage of Fuel (Petrol & Diesel) Consumption Category-Wise[10] :

Table 14: % Fuel consumption Category- Wise

Sub Category Diesel Consumption	
Three wheelers Passengers/Goods	7%
Buses	8%
HCV/LCV	33%
Cars & UV Commercial	10%
Cars & UV Private	15%
Non transport	27%
Total	100%

Sub Category Petrol Consumption	
Cars	34%
UV	2%
Two wheelers	61%
Three wheelers	3%
Total	100%

3. Growth Rate of New Vehicles (State-Wise & Category-Wise) : State-wise category-wise growth of new vehicles has been assumed based historical growth rate of vehicles & country-wide stakeholder consultation with transport departments conducted for the creation & updation of the ICF's transport model.

4. Assumptions for growth of CNG vehicles & Ethanol blending :

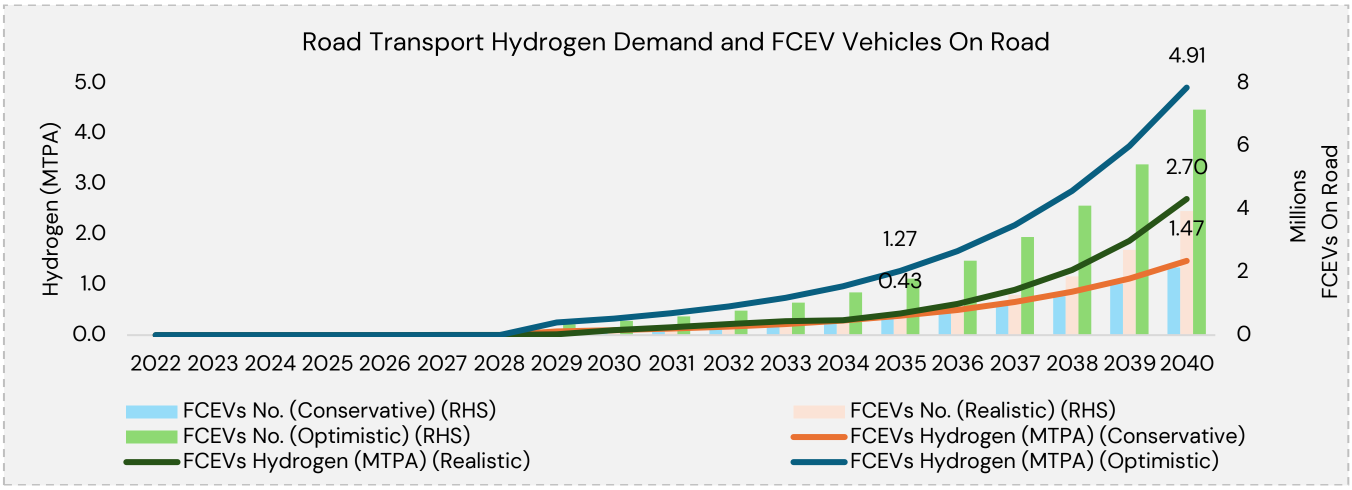
Table 15: Assumptions for Growth of CNG vehicles & Ethanol blending

Divers	Conservative scenario	Realistic scenario	Optimistic scenario
Impact of CNG	CNG forecast based on ICF's natural gas model - optimistic scenario (detailed in CGD blending)	CNG forecast based on ICF's natural gas model - realistic scenario (detailed in CGD blending)	CNG forecast based on ICF's natural gas model - conservative scenario (detailed in CGD blending)
Impact of EVs and FCEVs	10% penetration of FCEVs Annual EV sales for passenger vehicles to reach out 3 million in 2040	5.5% penetration of FCEVs Annual EV sales for passenger vehicles to reach out 2.6 million in 2040 (based on bloombergNEF report and ICF model)	3% penetration of FCEVs Annual EV sales for passenger vehicles to reach out 1.5 million in 2040
Impact of Ethanol Blending	20% ethanol blending by 2030 and then increase to 25% by 2040	20% ethanol blending by 2035 and remains flat	20% ethanol blending by 2040

The following chart depicts the hydrogen demand projection for the three scenarios till 2040:

10 http://ppac.org.in/WriteReadData/Reports/201411110329450069740AllIndiaStudyonSectoralDemandofDiesel.pdf

Figure 26: Road Transport Hydrogen Demand and FCEV Vehicles on Road



Key takeaways from the hydrogen demand projection:

1. Even by achieving only *~5.5% penetration* of on road vehicles in chosen vehicle categories by 2040, the FCEV hydrogen demand could reach *~2.7 MTPA*.

2. With *10% penetration* of on road vehicles by 2040, FCEV can present hydrogen demand of *~5 MTPA*.

Green hydrogen demand for FCEVs: Since, the reason for shifting to FCEVs from the conventional transport (fossil fuel based) is to decarbonize the transport sector. Thus, except for pilot projects, the hydrogen demand from FCEVs is expected to be green hydrogen only.

A1.5 Chemicals: Methanol and Hydrogen Peroxide

Hydrogen is an important element in the chemical industry, particularly in the production of methanol and hydrogen peroxide. Methanol, also known as wood alcohol, is a clear, colorless liquid that is used as a solvent, a fuel, and a chemical intermediate in the synthesis of other chemicals. It is produced through the reaction of carbon monoxide and hydrogen, with the hydrogen providing the necessary reactivity to produce methanol. Hydrogen peroxide, on the other hand, is a chemical compound with the formula H2O2. It is a pale blue liquid that is used as a bleaching agent, an oxidizer, and a disinfectant.

However, there are some challenges with utilizing green hydrogen that need to be addressed. One of the main challenges is the cost of producing green hydrogen, which is currently higher compared to other fossil fuels. However, as the demand for clean and renewable energy sources increases, the cost of producing green hydrogen is likely to decrease. Another challenge is the transportation and storage of hydrogen, which requires specialized infrastructure and equipment due to its high flammability.

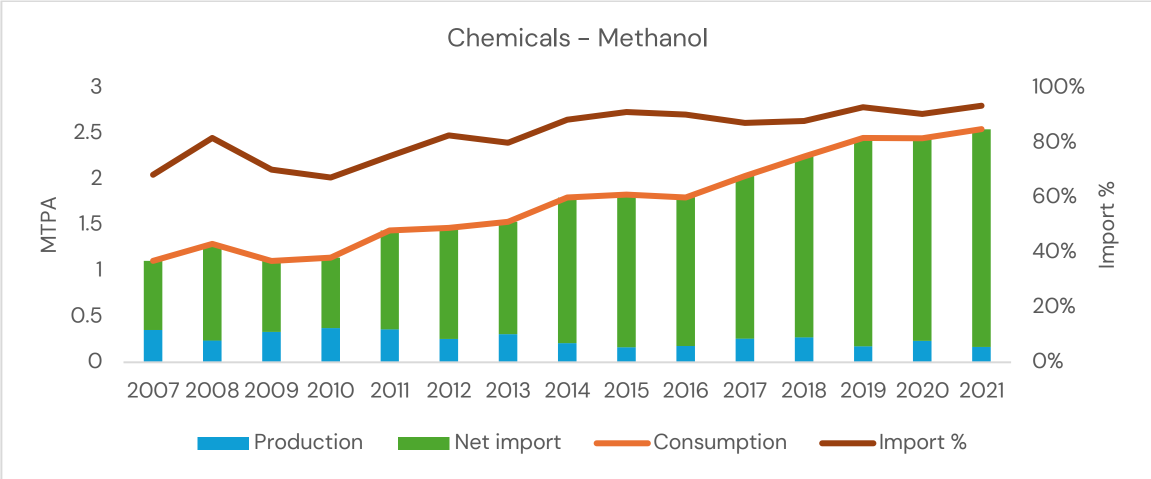
Major demand for hydrogen from the chemicals sector is expected to come from methanol alone, with minor contribution from hydrogen peroxide. Through analysis it was found that based on the current chemical production data for different chemicals, a major share of demand for hydrogen can be expected from these two chemicals alone, and hence focus has been kept on methanol and hydrogen peroxide. Even according to the global hydrogen demand assessments conducted by IEA, a major chunk of hydrogen demand comes from methanol alone.

Demand Analysis

Methanol

Analysis was conducted to study methanol consumption, production and import in India over the past decade.

Figure 27: Chemicals: Methanol



It was observed that import meets 90% of the methanol demand in India. This has continued to be the case as domestically produced methanol (from natural gas) is not competitive with the imported methanol, largely from the gulf where natural gas is abundantly available at very low prices. If domestic methanol prices could be brought down, there is a significant demand that can be tapped.

Based on govt. push for reducing import dependency, and targets set by NITI Aayog under methanol economy, the following scenarios were developed. [11]

Table 16: Growth and import assumption under each scenario

Scenario	Optimistic	Conservative	Realistic
Growth Assumption	**8.5%** Assuming Methanol Blending taken up significantly	**~6%** Assuming Past growth trend continues with no additional growth.	**7.5%** Assuming growth starts to pick up and slight blending is achieved.
Import Assumption	Assuming methanol imports reduce to 10% by 2040.	Assuming methanol imports reduce to 70% by 2040.	Assuming methanol imports reduce to 30% by 2040.

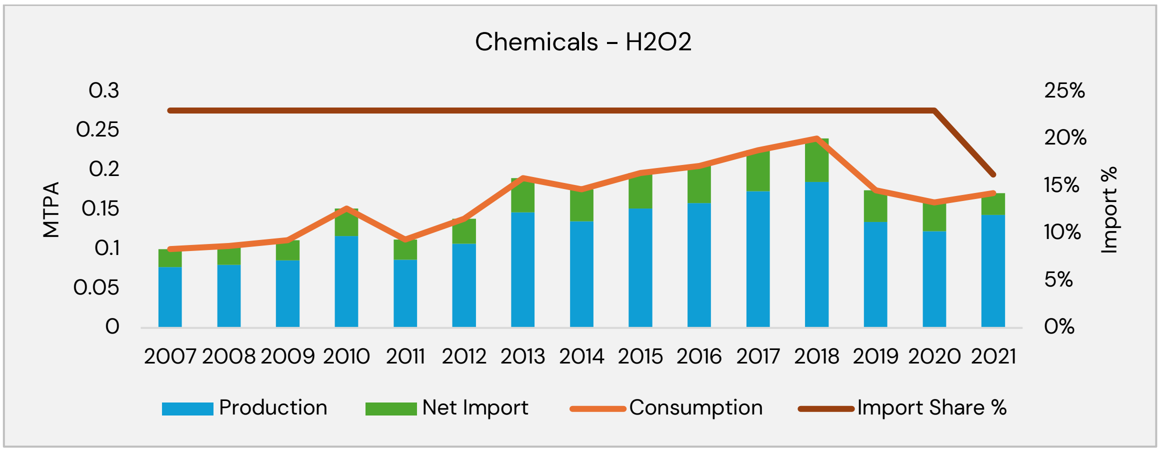
urther, the H2 demand for methanol production has been calculated by taking factor for hydrogen consumption per kg of methanol production as per IEA.

Hydrogen Peroxide

Similar analysis on consumption, production and import of hydrogen peroxide was conducted as shown below:

[11] The growth rate have been assumed based on the stakeholder inputs & the sector analysis as per NITI Aayog's reports - https://www.niti.gov.in/sites/default/files/2023-02/DDG_2023-24_0.pdf

Figure 28: Chemicals: H2O2



The import percentage for hydrogen peroxide has remained constant throughout the years. Barring the most recent years, hydrogen peroxide consumption has grown at an average CAGR of ~6%. Hydrogen peroxide is quite versatile in the industry and finds demand in a diverse group of sectors.

Looking at the growth trajectory of hydrogen peroxide consumption, along with growth of its demand sectors, the following scenarios were considered[12]:

Table 17: Growth Assumption for Hydrogen peroxide

Scenario	Optimistic	Conservative	Realistic
Assumption	Assuming H_2O_2 finds greater utilization across sectors, with considerable growth in its demand sectors.	Assuming past growth is replicated in the future.	Assuming the growth is led by the growth of pulp & paper industry, as it has prominent demand for H_2O_2.
Growth	Growth – 10%	Growth – 5%	Growth – 7%

The hydrogen peroxide synthesis reaction is given below:

H_2O_2 Synthesis Reaction

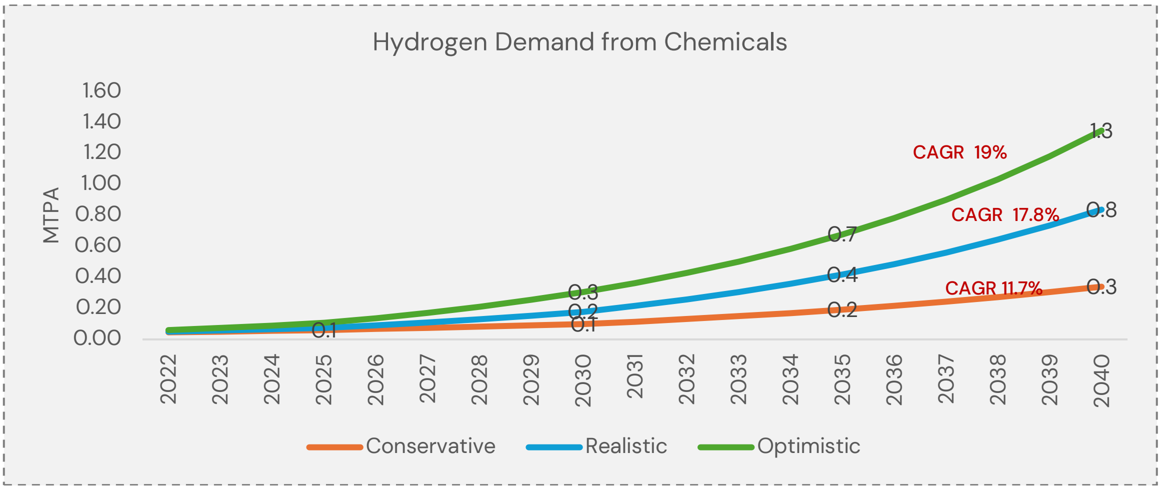
$$O_2 + H_2 \rightarrow H_2O_2$$

Using the chemical synthesis reaction, hydrogen requirement per kg of H2O2 produced was computed, which is then used to find the unconstrained demand.

Demand Results

12 The growth rate have been assumed based on the stakeholder inputs

Figure 29: Hydrogen Demand from Chemicals (MTPA)



Demand for hydrogen in chemicals ranges between 0.3 MTPA in the conservative scenario, to ~1.4 MTPA in the optimistic scenario.

The state-wise capacity is envisaged to be come-up in the states that currently have major capacities for methanol production (major demand driver in chemicals) and have associated supply chain set-up. The broad state-wise demand of chemical sector in India is likely to be distributed as follows (MTPA):

Table 18 State-wise demand of chemical sector

States	2025	2030	2035	2040
Gujarat	0.04	0.08	0.17	0.34
Maharashtra	0.03	0.06	0.12	0.24
Assam	0.03	0.06	0.11	0.23

Green hydrogen demand for Chemical sector: For understanding the potential demand of green hydrogen in the chemical sector, the cost economics of the green hydrogen vis-a-vis alternatives needs to be assessed. Since, in absence of any government mandated green hydrogen consumption targets the usage of green hydrogen in the sector is likely to be driven by cost economics.

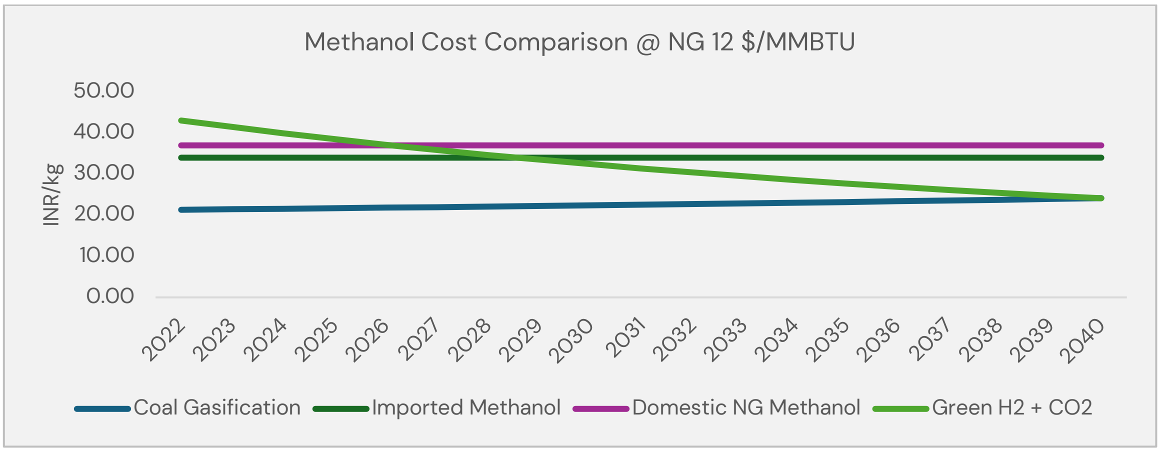
In the case of methanol, pricing of methanol produced from different alternatives i.e. imported methanol, Natural gas based domestic production, coal gasification, & green hydrogen has been considered. While, for hydrogen peroxide, the price of different types of hydrogen is considered based on ICF's hydrogen cost dynamics model.

Since, over the past decade, imported methanol prices have been lower than domestic methanol price. Hence to increase domestic production, NITI Aayog along with the Ministry of coal have proposed coal gasification route for the production of methanol. According to NITI Aayog and the National Coal Gasification Mission document, the price of methanol from coal is expected to be between Rs 22 – 25 per kg.

The cost chart for methanol price based on production process is given below:[13]

[13] ICF Research & analysis, NITI ayog, Coal Gasification document

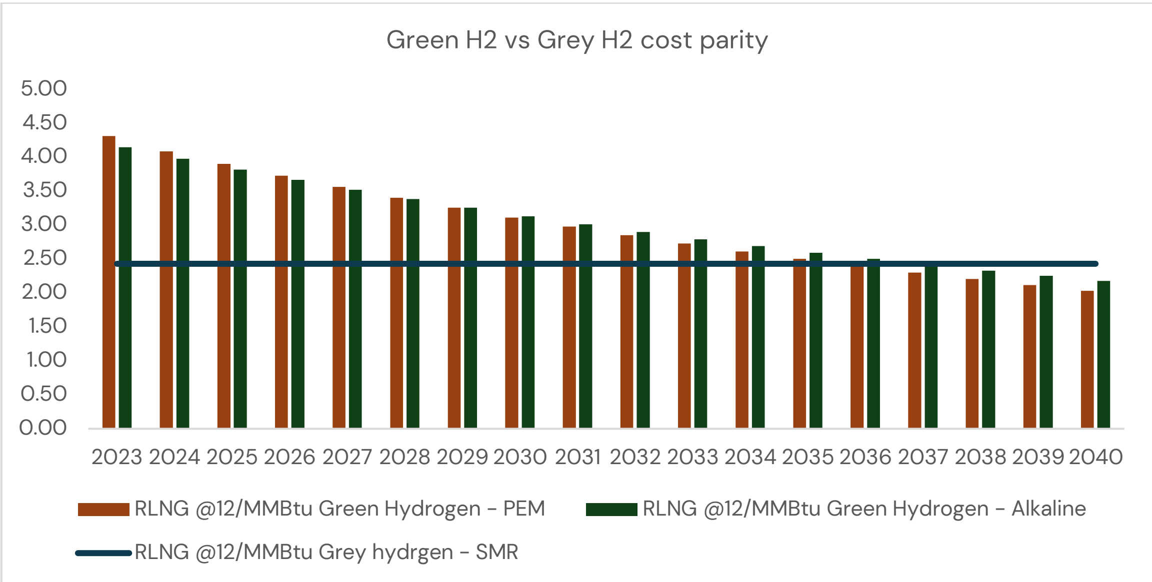
Figure 30: Methanol cost comparison (NG Price- 12 USD/MMBtu)



At NG 12 $/MMBTU, the domestic and imported methanol costs are significantly higher than methanol from coal gasification, and hence the coal gasification route offers a method for increasing domestic production of methanol. In the long-term methanol from green hydrogen will become the cheapest option. Methanol from green hydrogen + CO2 will take over a decade to achieve cost parity.

The following graph showcases the expected cost comparison of grey hydrogen with green hydrogen for RLNG @$12/MMBTU :

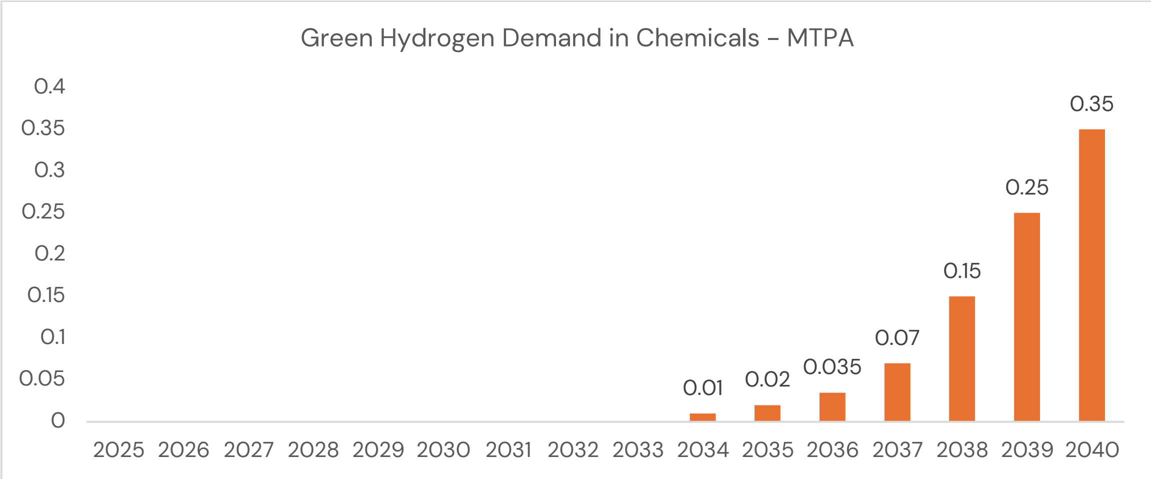
Figure 31: Green H2 vs Grey H2 cost parity



Based on the cost environment, the cheapest type of hydrogen will be used for H2O2 synthesis. Grey hydrogen is preferred at first, but after green hydrogen achieves cost parity around 2034-2036, it becomes the preferred choice of industry. Hence, for hydrogen peroxide, green hydrogen will be adopted around 2034 -2036.

Thus, in absence of government mandated green hydrogen consumption mandates, the likely proportion of green hydrogen in the demand for chemicals is likely to be as follows:

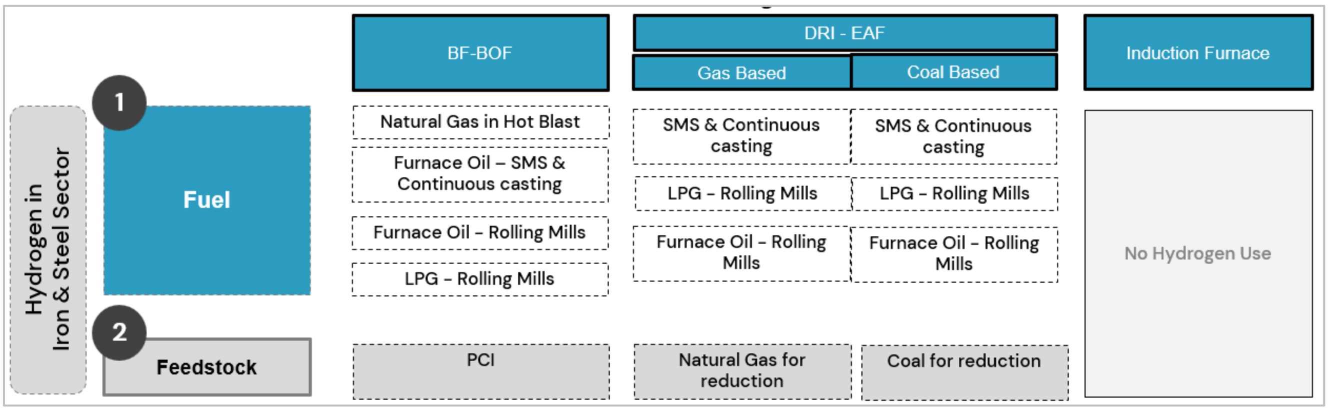
Figure 32: Green Hydrogen Demand- Chemical(MTPA)



A1.6 Iron & Steel

India is a major player in the global steel production market, ranking as the world's second-largest producer of crude steel during the January-December 2019 period, with a provisional production of 111.25 million tons. This represents a growth rate of 1.8% compared to the previous year's corresponding period. Additionally, India holds the title of the largest producer of Direct Reduced Iron (DRI) or sponge iron worldwide, with a production of 36.86 million tonnes during the same period, showing a growth rate of 7.7% over the corresponding period of the previous year. In the iron & steel sector, hydrogen has the potential to replace furnace oil, natural gas, and LPG as a fuel in basic oxygen furnace and electric arc furnace-based sub processes. Additionally, it can be used as a reducing agent instead of natural gas and coal in these processes. Hydrogen can also be used as a fuel in rolling mills, continuous casting, and hot blast, but it is not used in induction furnaces. A detailed overview of the possible usage of hydrogen in the iron & steel sector is shown in figure below, which depicts the production technologies and the potential use of hydrogen in these technologies.

Figure 33: Production technologies used in iron & steel sector and possible uses of hydrogen



Demand analysis

Feasibility of shifting to green Hydrogen

- Current Usage: Coal is currently a primary fuel source for Blast Furnace-Basic Oxygen Furnace (BF-BOF) plants in the steel industry. This traditional method has significant carbon emissions associated with it.

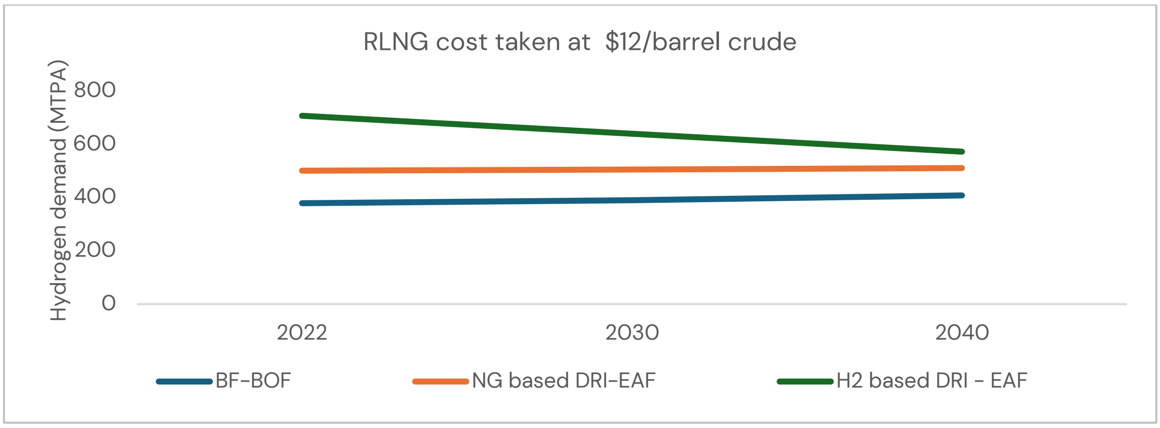
- Capital Expenditure: Transitioning from coal to hydrogen-based processes would indeed require substantial capital expenditure. This is because it involves retrofitting or building new infrastructure, including hydrogen production facilities and modified furnaces.
- Cost-Intensive Option: Converting coal-based BF-BOF plants to hydrogen-based ones is a cost-intensive option. However, it's essential to consider the long-term benefits, including reduced carbon emissions and compliance with environmental regulations.

Natural Gas to Hydrogen:

- Cost of Green Hydrogen: The cost of green hydrogen is currently expected to be higher than that of natural gas, at least until 2040.
- Carbon Taxation and Incentives: Without carbon taxation or incentives for green steel production, it's challenging to bridge the cost gap between natural gas and green hydrogen. Government policies and incentives are crucial to encourage steel manufacturers to adopt hydrogen-based processes. Subsidies, tax credits, and regulatory frameworks can make green hydrogen more economically viable

Thus, the critical driver of iron & steel industry to shift to green hydrogen is the decarbonisation of the steel sector. Currently, the cost economics of iron & steel sector dictates a significant premium (Atleast 35-40% higher than NG based DRI & atleast ~70-80% premium over coal based DRI[14]) for using green hydrogen rather using natural gas or coal. The cost difference is likely to reduce in future, however, till 2040 the green hydrogen based DRI is likely to be more expensive than coal or gas based DRI at RLNG cost $12/barrel of crude.

Figure 34: Feasibility of shifting to Green Hydrogen: NG cost taken at 12% of $/barrel crude



In the context of shifting the iron and steel industry to hydrogen-based production, it's essential to recognize that this transition is a long-term sustainability goal. While the initial costs and cost disparities with natural gas are challenges, government support through incentives, regulatory approvals, and carbon pricing mechanisms can facilitate this shift. Over time, the environmental benefits and potential for improved market competitiveness can make hydrogen-based steel production an economically viable and sustainable choice. This transition is essential to reducing greenhouse gas emissions and aligning with global climate goals.

The demand of hydrogen in the iron & steel sector is limited by affordability of high-cost steel and existing infrastructure. Thus, based on the cost dynamics it is less likely that the initial demand of green steel will be driven by domestic consumption, rather, it is expected that the initial demand of green steel would be driven by the export market.

[14] ICFs cost model for steel sector

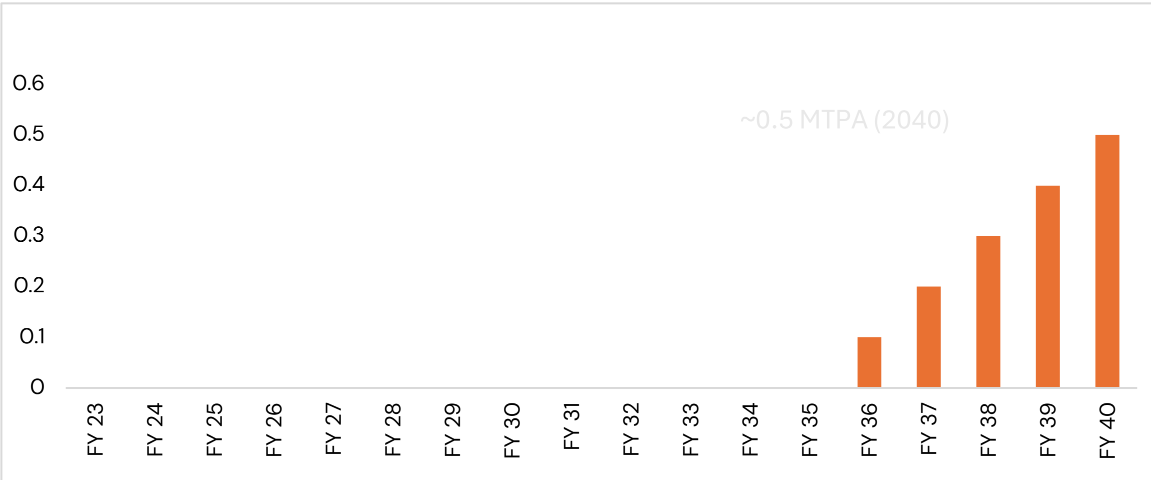
Thus, demand of iron & steel sector from green steel exports has been envisaged in this analysis till 2040. Three cases have been created based on stakeholder consultations for this sector 1) Case 1: Conservative Scenario 2) Case 2: Realistic Scenario 3) Case 3: Optimistic Scenario. Figure below shows the key assumptions made in this study.

Figure 35: Iron & Steel sector Demand – Key Assumptions

	Case 1	Case 2	Case 3
Iron & Steel	A ~ 10 MTPA green steel capacity is set-up by 2040 for export in India	Aspirational target to set up at least 20 MTPA green steel capacity for export in India as per NITI Aayog - is reached by 2040	Aspirational target to set up at least 20 MTPA green steel capacity for export in India - as per NITI Aayog - is reached by 2035; further capacity installation expected at similar pace

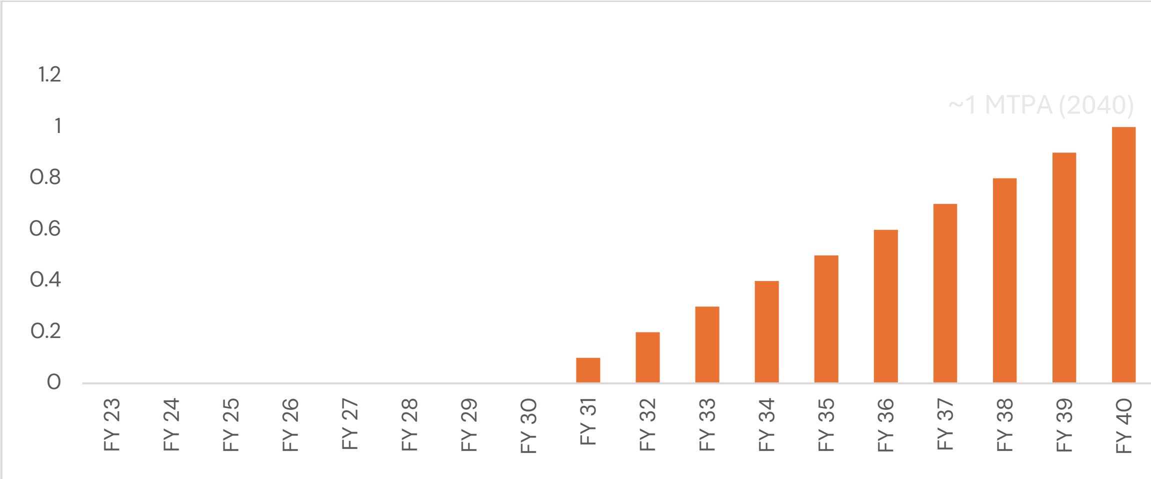
In the conservative scenario, it is assumed that the green steel capacity (based on green hydrogen) starts operating post 2035 and reaches a cumulative installed capacity of 10 MTPA of green steel by 2040. Thus, the green hydrogen demand is estimated to be around 0.5 MTPA by 2040 in the conservative scenario. Figure below shows the results of the conservative scenario.

Figure 36: Conservative Scenario: Hydrogen Demand in Iron & Steel sector (MTPA)



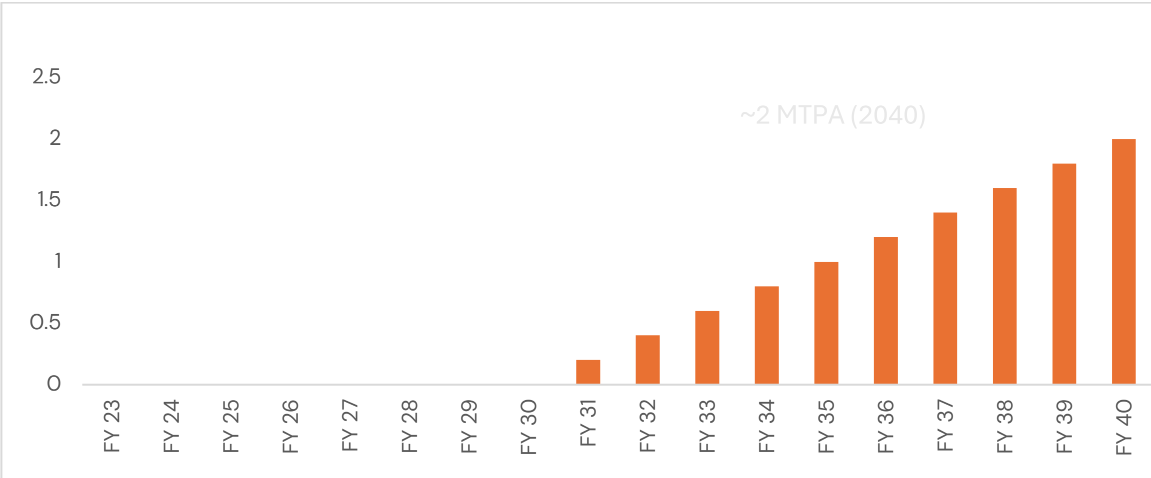
In realistic scenario, it is assumed that the green steel capacity (based on green hydrogen) starts operating post 2030 and reaches a cumulative installed capacity of 20 MTPA of green steel by 2040, as per the aspirational target set by NITI Aayog for green steel export capacity in India. Thus, the green hydrogen demand is estimated to be around 1 MTPA by 2040 in the realistic scenario. Figure below shows the results of the realistic scenario.

Figure 37: Realistic Scenario Hydrogen Demand in Iron & Steel sector (MTPA)



In the optimistic scenario, the green hydrogen demand is estimated to be around 2 MTPA by 2040. It is worth noting that NITI Aayog has set a target to establish at least 20 MTPA green steel capacity for export in India. In this scenario, it is assumed that the NITI Aayog's target is met by 2040. Figure below summarizes the results of the optimistic scenario.

Figure 38: Optimistic Scenario: Hydrogen Demand in Iron & Steel sector (MTPA)



The state-wise green steel capacity is likely to come up in the states near the ports which are currently exporting steel (incl. Kakinada, Paradeep & Mumbai port). Thus, the steel capacity is envisaged to be set up in Maharashtra Odisha & Andhra Pradesh.

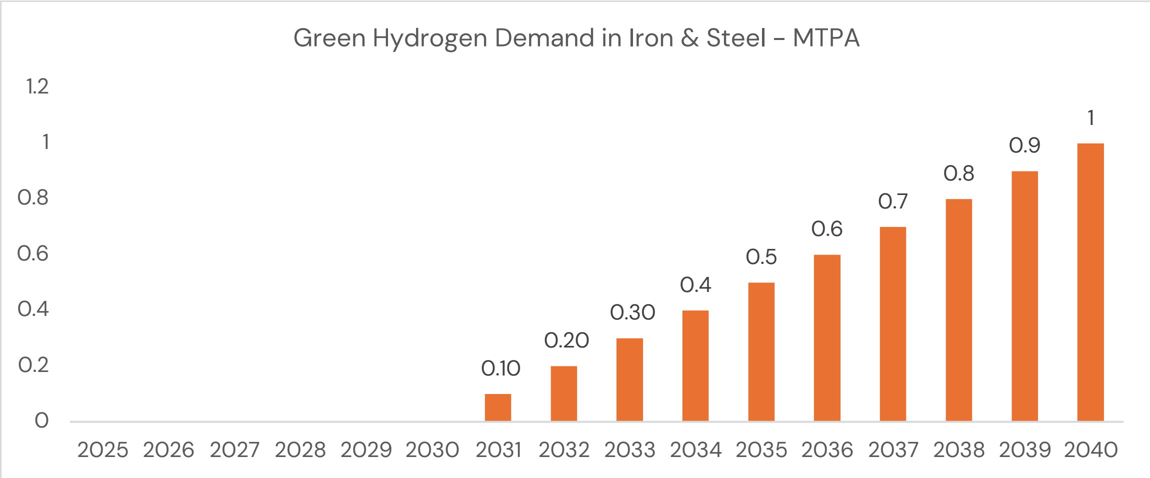
The broad state-wise demand of chemical sector in India is likely to be distributed as follows (MTPA):

Table 19 State wise demand of Chemical sector-India

States	2031	2035	2040
Maharashtra	0.03	0.17	0.33
Odisha	0.03	0.17	0.33
Andhra Pradesh	0.03	0.17	0.33

Green hydrogen demand for Iron & steel sector: Since, the reason for shifting to hydrogen from conventional fuel i.e coal & natural has in the iron & steel sector is to decarbonize the sector. Thus, except for pilot projects, the hydrogen demand from FCEVs is expected to be green hydrogen only.

Figure 39: Green hydrogen demand for iron & steel sector



A2- Green hydrogen production potential

To understand the potential of green hydrogen production across India, an analysis of the availability of key resources required for green hydrogen production has been conducted. The key resources required for an electrolysis based green hydrogen plant are water & renewable electricity. Thus, this section aims to analyze the potential for green hydrogen production across India based on the expected availability of these resources.

Green Hydrogen (via Electrolysis)

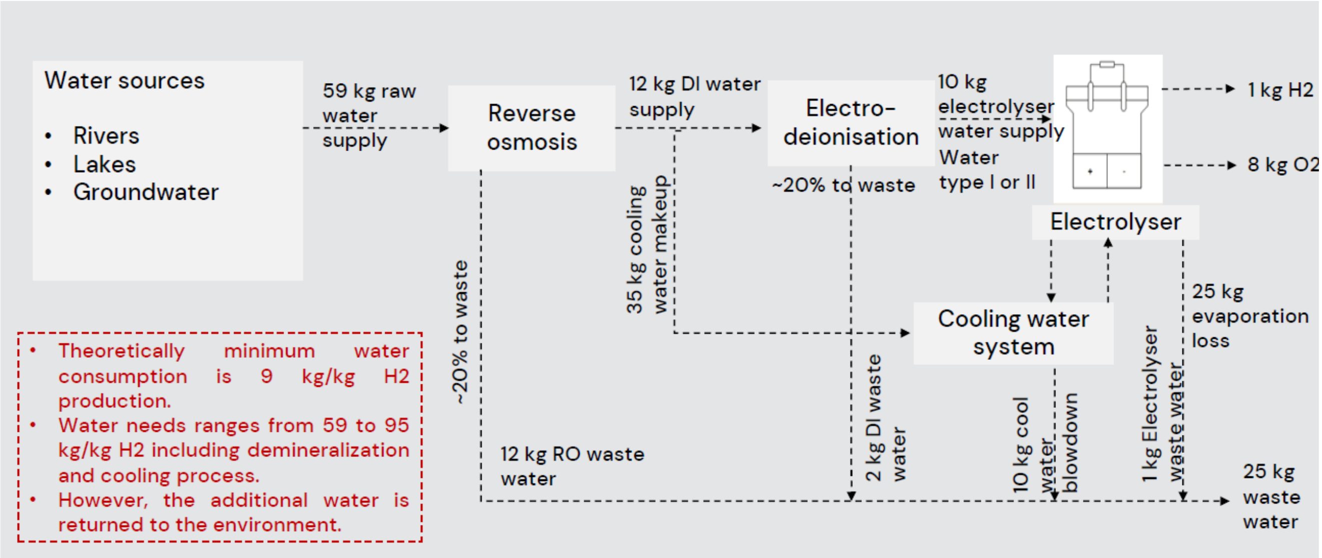
A2.1 Water availability

The production of green hydrogen via electrolysis involves drawing water from various sources, such as rivers and lakes. This water is then subjected to a reverse osmosis and de-ionization system to produce de-ionized water, which is subsequently fed into an electrolyser to generate hydrogen. Ideally, a minimum of 9 kg of water is required per kg of hydrogen produced, but the actual water consumption can range from 59 to 95 kg[15] per kg of hydrogen, accounting for the demineralization and cooling processes. However, any

[15] https://www.brendandagg.com/documents/NAYLOR-2022-IWA-Full-Paper.pdf

additional water utilized during the process is returned to the environment. Figure 3.1 provides a detailed illustration of the hydrogen production process from water.

Figure 40: Hydrogen generation process



Currently, there are three major sources of water available for hydrogen production, namely ground, surface, and saline water. Groundwater is often polluted by dissolved solids, and the treatment required depends on the water's composition. Reverse osmosis is a commonly used treatment option that can eliminate some ions, but it can lead to water losses of 15-25%.

Surface water, on the other hand, is polluted by suspended solids (TSS) and organic pollution measured by biochemical oxygen demand (BOD). The treatment required includes fine screening, coagulation/filtration, and reverse osmosis. While fine screening and coagulation/filtration cause negligible water loss, reverse osmosis can result in water loss. Saline water, which has a high salinity level of 36-37%, is also a significant source of water pollution. Fine screening and reverse osmosis are common treatment operations required for saline water, with a water loss of 35-40%. Table 3.1 provides an overview of the water supply treatments needed for the three sources of water.

Table 20 - Water supply cost for various sources of water[16]

Source of water	Main water pollutants	Treatment operations needed
Ground water	Dissolved solids	Depend on composition of water. May be necessary to remove some ions which can be also ensured via Reverse Osmosis (15-25% water loss).
Surface water	Suspended solids (TSS), Biochemical Oxygen Demand (used as a surrogate of the degree of organic pollution of water)	Fine screening (negligible water loss), coagulation/filtration (negligible water loss), reverse osmosis
Saline water	Salinity 36-37 %	Fine screening (negligible water loss), reverse osmosis (35-40% water loss).

The consumption of water during hydrogen production is minimized when deionized water is used as the source of water. However, if ground or surface water is utilized, the water consumption can be significantly reduced from 59 kg/kg of hydrogen to 18 kg/kg of hydrogen by using an air-cooled electrolyzer instead of a water-cooled one.

Considering the Indian perspective of water usage, the water requirement for producing green hydrogen by 2040 is projected to be less than 0.05% of the total annual surface water resource potential in India. Table-3.2 illustrates the water requirements for hydrogen production.

[16] file:///C:/Users/56236/Downloads/SimoesCatarinoEtal_WaterUseForH2Production_PreprintFeb2021.pdf

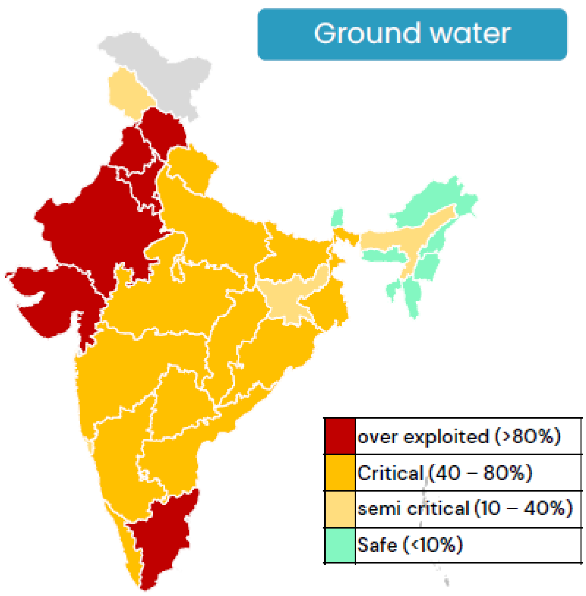
Table 21 -Water requirements to produce hydrogen[17]

Parameters	Source of water	Kg/kg of H2	Water demand for 17 MTPA hydrogen demand by 2040
Minimum water consumption for hydrogen production	Deionised water	9 - 15	0.15 – 0.25 BCM
Water consumption including demineralisation and water cooled electrolyser	Ground water/Surface water	59 - 98	~1 – 1.67 BCM
Water consumption including demineralisation and air cooled electrolyser	Ground water/Surface water	18 - 30	~0.3 -0.5 BCM

Water stress level maps

Taking into consideration the availability of groundwater in India, it is observed that in certain states, such as Delhi, Haryana, Punjab, Rajasthan, Himachal Pradesh, and Tamil Nadu, groundwater is excessively exploited due to high extraction rates. In contrast, only the northeastern states, except Assam, have a safe level of groundwater, while the rest of India faces a critical or semi-critical level of groundwater availability.
As of 2017, the net amount of groundwater available for future utilization is estimated to be 173.25 billion cubic meters (bcm). Figure 3.2 illustrates trends in the usage of groundwater.

Figure 41: Groundwater trend in India

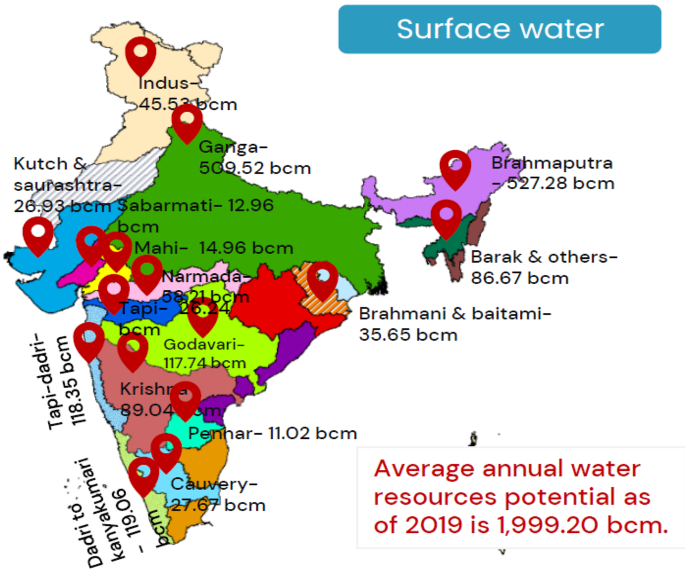


India's surface water is primarily contributed by three major rivers: Brahmaputra, Ganga, and Godavari, which provide 527.28 billion cubic meters (bcm), 509.52 bcm, and 117.74 bcm of water, respectively. As of 2019, the average annual water resource potential of India is estimated to be 1,999.20 bcm[18], indicating that these rivers contribute a substantial amount to the overall surface water availability. The illustration in Figure 3.3 provides a comprehensive overview of the surface water potential of different rivers in India, highlighting their relative contributions to India's water resources.

[17] https://energypost.eu/hydrogen-production-in-2050-how-much-water-will-74ej-need/#:~:text=Looking%20at%20hydrogen%20production%2C%20the,30.2%20according%20to%20%5B1%5D.
https://www.statista.com/statistics/1111839/india-water-demand-by-sector/

[18] http://cwc.gov.in/sites/default/files/reassessment-water-availability-volume-ii-november18.pdf

Figure 42: Surface water availability of India

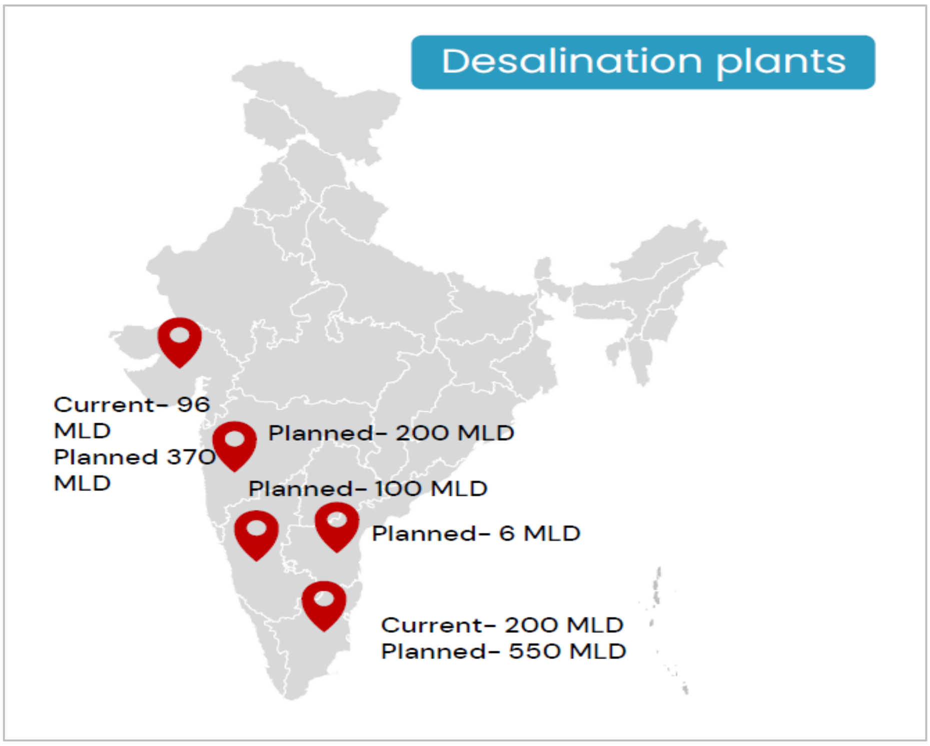


As rivers flow through multiple states, inter-state disputes have arisen over water usage, particularly concerning rivers such as Krishna, Godavari, Narmada, and Cauvery. The dispute over the Krishna river is currently active among Maharashtra, Andhra Pradesh, and Karnataka, while the Godavari dispute is active among Maharashtra, Andhra Pradesh, Karnataka, Madhya Pradesh, and Odisha. The major disputes over water usage between the different states that share the same river system are as follows:

- Krishna (MH, AP & KN)
- Godavari (MH, AP, KN, MP & OD)
- Narmada (RJ, MP, GJ & MH)
- Cauvery (Kerala, KN, TN & Pondicherry)
- Vansadhara (AP & OD)
- Mahadayi (Goa, KN & MH)

In terms of state-owned desalination plants, Tamil Nadu and Gujarat currently have the highest capacity, with 200 MLD and 96 MLD respectively. However, these states have planned to increase their capacity to 550 MLD and 370 MLD, respectively. A 100 MLD desalination plant utilizing reverse osmosis technology has the capability to generate drinking water valued at approximately INR 5.15 billion.
Other states, including Maharashtra, Karnataka, and Andhra Pradesh, have also set targets to increase their desalination capacity. Figure below provides a clear representation of the projected capacity of desalination plants in different states.

Figure 43: Desalination capacity of states



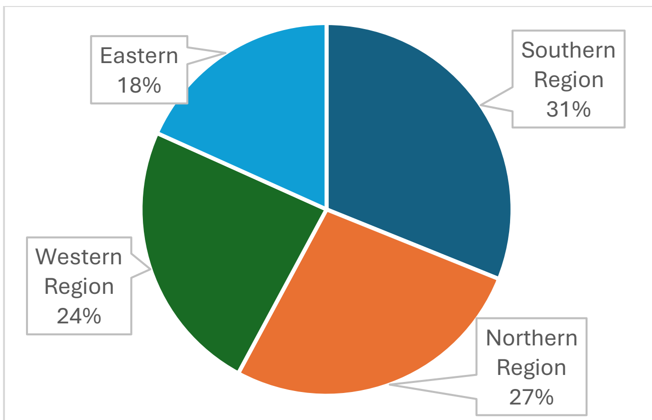
Thus, water availability at an aggregate level is not a major challenge / constraint for assessing the green hydrogen production potential across states.

A2.2 Renewable Energy availability

India's power generation mix is rapidly shifting towards a more significant share of renewable energy. Today India is one of the world's largest producers of renewable energy with over 41% of its installed capacity from renewable energy sources (incl. large hydro). Based on the recent installed capacity report by Central Electricity Authority, this segment sheds light on the renewable energy potential in India.

Southern India leads with the highest share (31%) of installed renewable capacity followed by northern (27%) and western regions (24%).

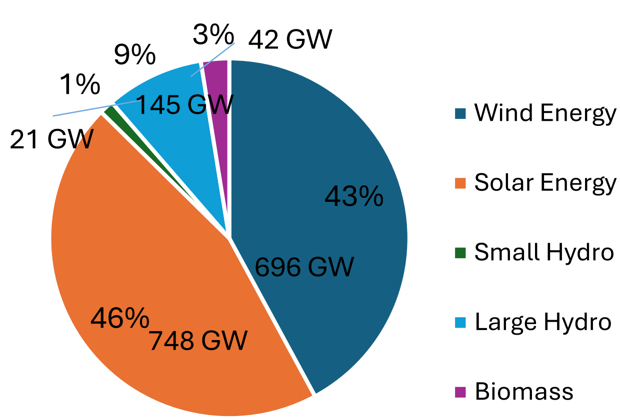
Figure 44: Figure 0.45 Region wise distribution of RE Installed Capacity (%)



Renewable Energy Potential[19]

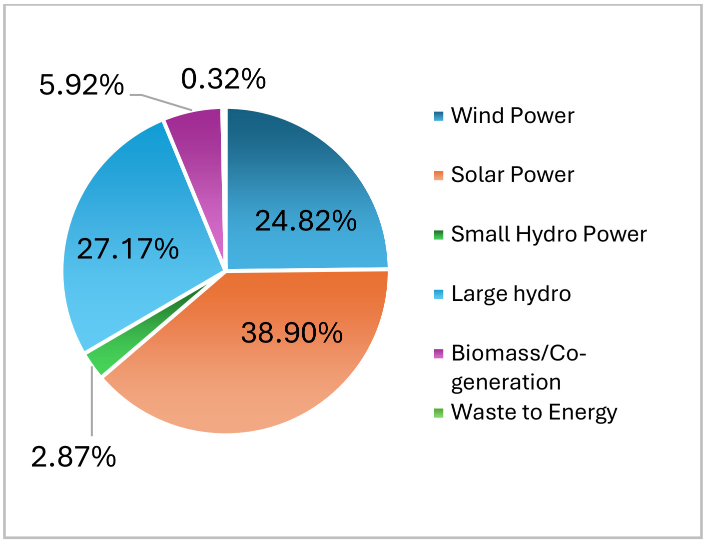
Total potential of renewable energy in India is ~1652 GW which corresponds to ~56 MTPA of Green Hydrogen. Since, already installed RE capacity in India is ~172 GW (without large hydro) and ~217 GW (with large hydro). Thus, the remaining unutilized RE potential is ~1435 GW which corresponds to ~51 MTPA of Green Hydrogen.

Figure 45: RE Installed Capacity (FY 2023)



[19] All renewable capacity potential in this section are based on the MNRE annual report

Figure 46: Total RE potential in India (GW)

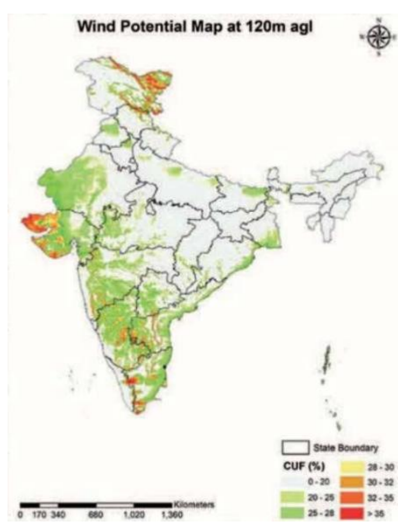


The details of the potential of each type of renewable energy in India is outlined in subsequent sections.

1) Wind Potential[20]

Wind is an intermittent and site-specific source of energy and therefore, an extensive wind resource assessment is essential. For wind resource assessment the National Institute of Wind Energy (NIWE) has installed 967 wind-monitoring stations all over the country and has issued wind potential maps at 50 m, 80 m, 100 m and 120 m above ground level. The latest assessment indicates gross wind power potential of 302.25 GW and 695.50 GW in the country at 100 meter and 120 meters respectively, above ground level. Most of this potential exists in the seven states listed as follows –

Figure 47: Wind Potential in India



[20] All renewable capacity potential are based on the MNRE annual report

Table 22 Wind potential in Indian States

States	Wind Power Potential at 120 mtr agl (GW)
Gujarat	142.56
Rajasthan	127.75
Karnataka	124.15
Maharashtra	98.21
Andhra Pradesh	74.9
Tamil Nadu	68.75
Madhya Pradesh	15.4
Total (7 windy States)	**651.72**
Other States	43.78
All India total	**695.5**

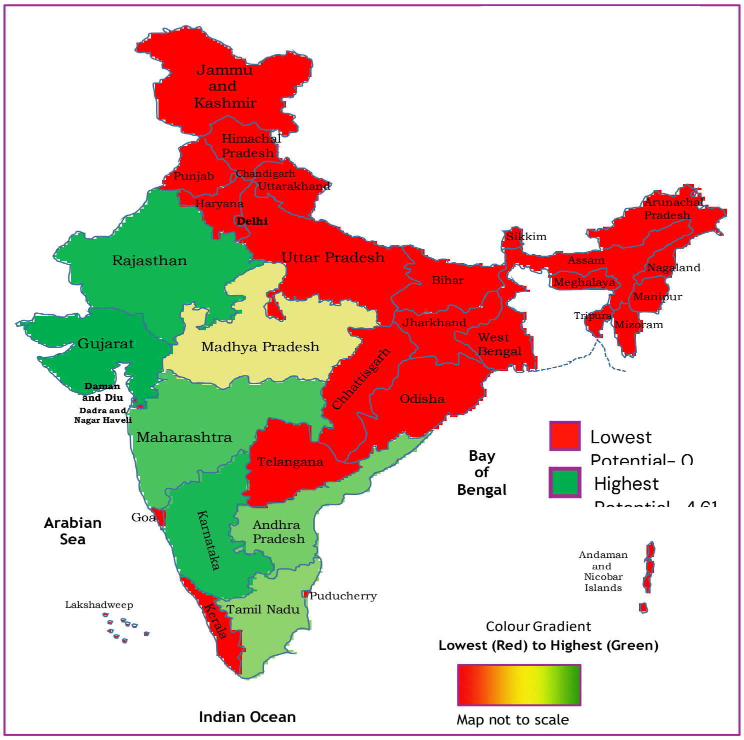
Thus, India's total wind potential has been estimated to ~696 GW, which corresponds to a green hydrogen production potential of 24.65 MTPA[21]. Top six windy states viz. Gujarat (20%), Rajasthan (18%), Karnataka (18%), Maharashtra (14%), Andhra Pradesh (11%) and Tamil Nadu (10%) constitute around 91% of the total wind potential in the country. Out of the total potential of ~696 GW, ~43.75 GW of wind capacity has already been installed in India.[22] Therefore, un-utilized wind capacity potential in India is ~652 GW, which corresponds to 23.10 MTPA of green hydrogen.

Heatmap of India showcasing state-wise distribution of green hydrogen potential from wind power is as follows (higher wind potential states as green and lower wind potential states as red):

[21] Assumptions - : Wind CUF~25 %, Solar CUF~ 23% , Hydro(Small and Large)~42%, 62.5 Kwh electrical energy to produce 1 kg of H2

[22] As on June, 2023

Figure 48: Heat map for Wind potential of Indian States



2) Solar Potential[23]

Based upon availability of land and solar radiation, the potential solar power in the country has been assessed to be around 748 GW which corresponds to a 24.14 MTPA green hydrogen production potential. Around 51% of the contribution comes from four states viz. Rajasthan (19%), J&K (15%), Maharashtra (9%) and Madhya Pradesh (8%). Further, cumulative capacity of ~70 GW of solar power projects have already been installed in the country[24]. Thus, un-utilized solar capacity potential in India is ~678 GW, which corresponds to 21.89 MTPA of green hydrogen.

State-wise details of estimated solar energy potential in the country and the cumulative installed capacity (as on 31.12.2021) are given below –

Table 23 -Solar Potential in Indian States

State/ UT	Solar Potential (GWp)	State/ UT	Solar Potential (GWp)	State/ UT	Solar Potential (GWp)
Andhra Pradesh	38.44	J&K	111.05	Odisha	25.78
Arunachal Pradesh	8.65	Jharkhand	18. 18	Punjab	2.81
Assam	13.76	Karnataka	24.70	Rajasthan	142.31
Bihar	11.20	Kerala	6.11	Sikkim	4.94
Chhattisgarh	18.27	Madhya Pradesh	61.66	Tamil Nadu	17.67

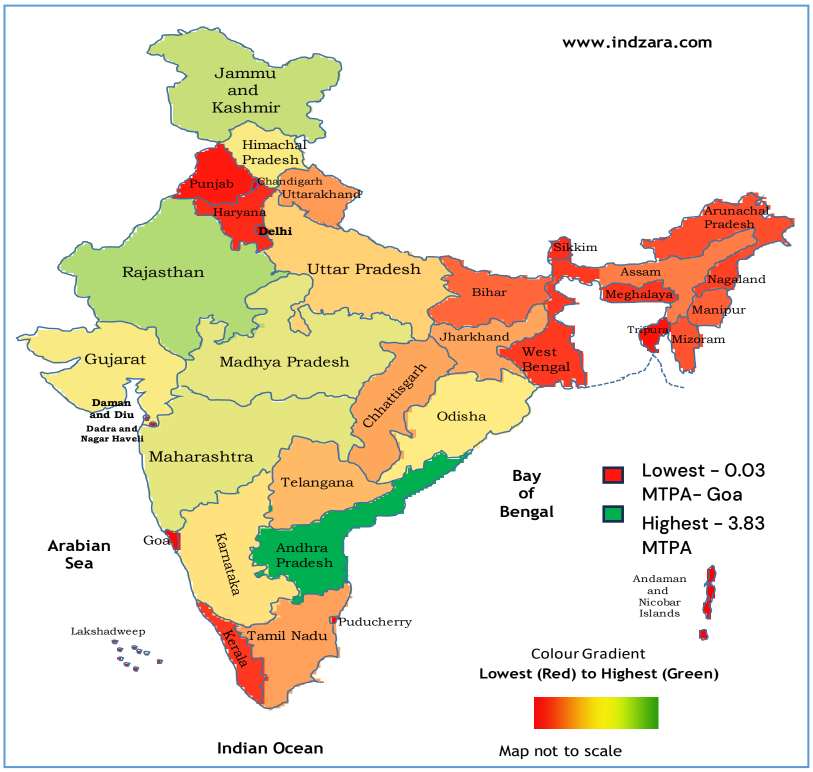
[23] All renewable capacity potential are based on the MNRE annual report

[24] As on June, 2023

Delhi	2.05	Maharashtra	64.32	Telangana	20.41
Goa	0.88	Manipur	10.63	Tripura	2.08
Gujarat	35.77	Meghalaya	5.86	Uttar Pradesh	22.83
Haryana	4.56	Mizoram	9.09	Uttarakhand	16.80
Himachal Pradesh	33.84	Nagaland	7.29	West Bengal	6.26

Heatmap of India showcasing state-wise distribution of green hydrogen potential from solar power is as follows (higher solar potential states as green and lower solar potential states as red):

Figure 49: Heat map for Solar potential of India



3) Small Hydro Potential (SHP)[25]

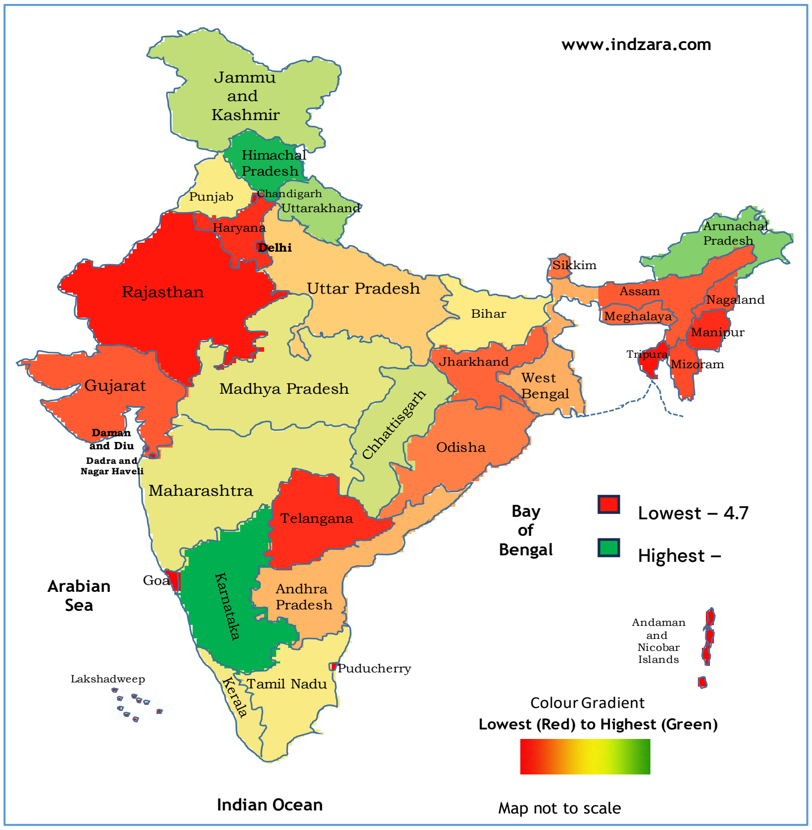
Hydro power plants of 25 MW or below are classified as small hydro plants in India, while those larger than 25 MW are classified as large hydro plants. The estimated potential of small/mini/micro-hydel projects in the country is 21 GW from 7133 sites located in different States of India, which corresponds to a ~1.26 MTPA green hydrogen production potential. Around 52% of the contribution comes from four states viz. Karnataka (18%), Himachal Pradesh (16%), Arunachal Pradesh (10%) and Uttarakhand (8%). Further, through 1150 Small hydro Power projects a cumulative capacity of ~4.9 GW of small hydro power projects have already been

[25] All renewable capacity potential are based on the MNRE annual report

installed in the country and 71 projects of ~0.36 GW at various stages of implementation [26]. Thus, un-utilized small hydro capacity potential is around 15.8 GW, which corresponds to ~0.94 MTPA of green hydrogen. Though, since many of these plants would have smaller capacity, they may be suitable only for hydrogen plants upto a limited size.

Heatmap of India showcasing state-wise distribution of green hydrogen potential from small hydro power is as follows (higher small hydro power potential states as green and lower small hydro power potential states as red):

Figure 50: Heat Map for Small Hydro Potential of Indian States



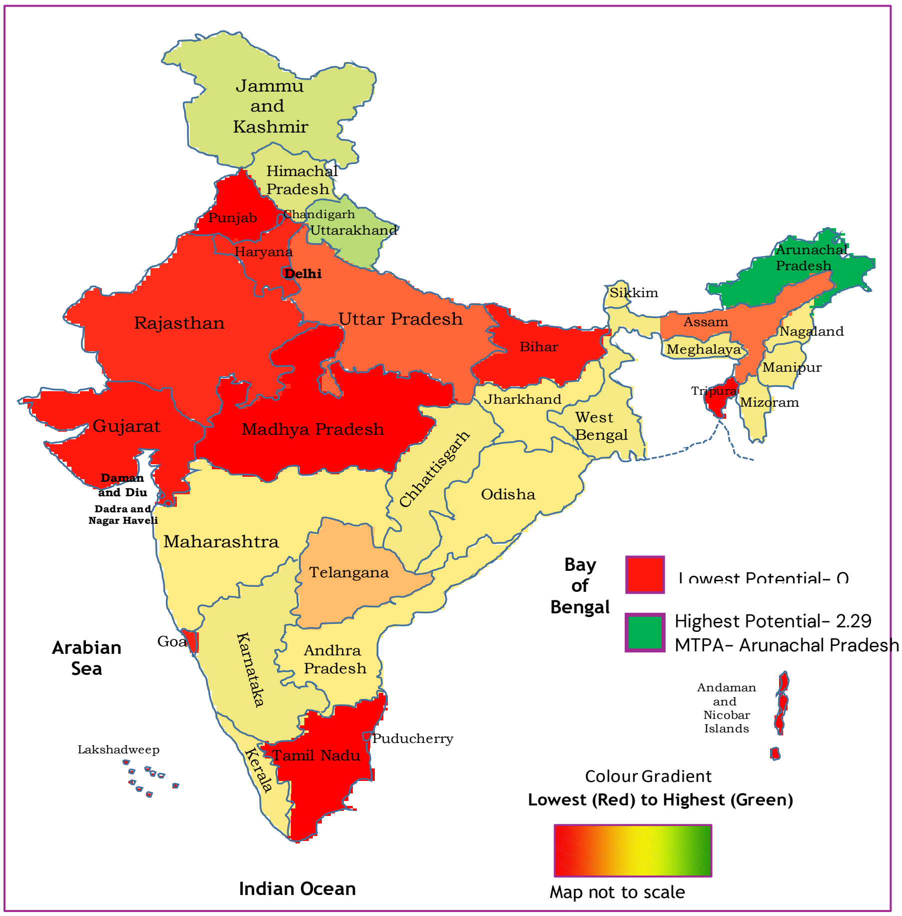
[26] As on December, 2021

4) Large Hydro Potential[27]

The estimated potential of large-hydro projects in the country is ~145 GW which corresponds to ~8.64 MTPA green hydrogen production potential. Around 68% of the contribution comes from four states viz. Arunachal Pradesh (34%), Himachal Pradesh (13%), Uttarakhand (12%) and J&K (8%). A cumulative capacity of ~42 GW of large hydro power projects are already operational in the country & further 15 GW is under-construction[28]. Thus, un-utilized large hydro capacity potential is around 88 GW, which corresponds to ~5.24 MTPA of green hydrogen.

Heatmap of India showcasing higher large hydro potential states as green and lower small hydro potential states as red.

Figure 51: Heat Map for Large Hydro Potential of Indian States



[27] All renewable capacity potential are based on the MNRE annual report

[28] As on 28th Feb, 2023

Annexure B- Technical Assessment

B1- Limitations and specifications of Literature reviews and studies analysed

In the examination of blending limits, multiple studies have been scrutinized. However, these studies are not without limitations. Each study introduces varying blending limits on different components, each with unique specifications and distinct limitations. In terms of specifications, the study titled "The Limitations of Hydrogen Blending in the European Gas Grid" classifies pipelines with pressures greater than 16 bar as transmission lines and those with pressures less than 16 bar as distribution lines. Conversely, the NREL study named "Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues" suggests that the pressure in distribution pipelines ranges from 1 to 5 bar, while in transmission lines, it varies from 42 to 84 bar. A Canada-based study, the "Review of Hydrogen Tolerance of Key Power-to-Gas (P2G) Components and Systems in Canada: Final Report," indicates that distribution pipelines operate within a pressure range of 0.34 bar to 13 bar, and transmission lines range from 13 bar to 103 bar. Another NREL study, "NREL Report - Hydrogen Blending into Natural Gas Pipeline Infrastructure: Review of the State of Technology," specifies that distribution pipelines operate up to 21 bar, and transmission networks operate within the range of 42 to 84 bar. Table 3-7 shows specifications and limitations of studies analyzed.

Concerning the limitations of these studies, it is notable that mitigation measures are often vaguely specified, with generic statements such as "Further research needed" or "System-specific analysis needed." Moreover, several studies lack comprehensive coverage of all aspects. For instance, in "The Limitations of Hydrogen Blending in the European Gas Grid," steel grades are not adequately specified, and the detailed interaction of hydrogen with materials is not thoroughly addressed. Some studies exhibit a singular focus, such as the study "Hydrogen-Enriched Natural Gas as a Domestic Fuel: An Analysis Based on Flash-Back and Blow-Off Limits for Domestic Natural Gas Appliances within the UK," concentrating solely on domestic equipment. Similarly, the study named "Hydrogen Effects on X80 Pipeline Steel in High-Pressure Natural Gas/Hydrogen Mixtures" exclusively examines the interaction of hydrogen with X80 steel grade. In most studies, limitations arise from incomplete descriptions of certain components' issues or the absence of properly specified mitigation measures.

Table 24: Specifications and Limitations of Various Studies

S.NO.	Particular	Alphabet Code	Pressure of DL and TL	Limitations
1.	The limitations of hydrogen blending in the European gas grid	a	TL: > 16 Bar DL: < 16 Bar	Only Word "Steel" is mentioned, while no mention of Grade. Hence Difficult to determine interaction with grade. Not Much detail with respect to interaction of hydrogen with various materials. Mitigation measures are not given for most of the elements of NG pipeline system. (Distribution system, compressor, domestic gas piping, measurement devices, Cavern storage and End-users system (Gas burners, CNG vehicles, Gas Engines, Gas Turbines, power plants and Industrial applications)). Issues are not described for Gas Burners.

2.	Hydrogen Blending Impacts Study	b	Not Specified	Mitigation measures are not given for most of the elements of NG pipeline system. (Household Appliances, IC Engines, underground porous storage, Manufactured vessels, Salt cavern, CNG fuel Tank). For IC Engines and Salt Caverns, issues are not specified. Term " Manufactured vessels" is not specified properly i.e., grade of steel specified, capacity and specification of such vessel. No Discussion on Gas Turbines, compressors, feedstock applications i.e., critical components are not discussed at all.
3.	Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues	**c**	**TL -** Operate at pressures of 600–1,200 psig (42–84 bar) and in some cases up to 2,000 psig (139 bar). **DL-** 0.25–60 psig (1.03–5.15 bar) and sometimes up to 100 psig (8 bar)	This Study focus majorly on Downstream extraction of Hydrogen from blended mixture and measurement devices and domestic appliances. Mitigation measures are not given for Measurement devices. No Discussion on Gas Turbines, compressors, feedstock applications i.e., critical components are not discussed at all. Apart from that no discussion on storage techniques.
4.	Hydrogen-enriched natural gas as a domestic fuel: an analysis based on flash-back and blow-off limits for domestic natural gas appliances within the UK	d	Not Specified	This Study has a very limited focus i.e., focuses on only domestic appliances and that too in region of UK
5.	Review of hydrogen tolerance of key Power-to-Gas (P2G) components and systems in Canada: final report	**e**	**Distribution Pipelines-** (0.34 Bar to 13 Bar) **Transmission Pipeline- (**13 Bar to 103 Bar)	Issues are not specified properly for unmodified steel pipelines, plastic pipelines, salt cavern, CNG vehicles, Steel Tank, Gas Turbines. Mitigation plans are not properly specified for unmodified steel pipelines, plastic pipelines, porous storage, salt cavern, CNG Vehicles, Steel tank and Gas Turbines. End User components i.e., domestic appliances, gas burners, Feedstock applications, boilers etc. are not discussed in detail.
6.	The effects of injecting hydrogen (renewable gases)	f	Not Specified	Issues are not properly specified for residential and commercial appliances, electrical installation, and metering components. Mitigation Plan are not discussed properly for residential and commercial appliances, industrial application, gas turbine, gas engine and electrical installation. End User components i.e., domestic appliances, gas burners, Feedstock applications, boilers etc. are not

				discussed in detail.
7.	Analysis of compression and transport of the methane/hydrogen mixture in existing natural gas pipelines	g	Not Specified	Only general blending limit for entire grid is discussed along with some focus on compressor. No other aspect is discussed in the study.
8.	Utilizing 'Power-to-Gas' Technology for Storing Energy and to Optimize the Synergy between Environmental Obligations and Economical Requirements	h	Not Specified	Mitigation measures and issues are not given for Domestic appliances and CNG vehicles. Blending limit is not given for Gas Turbine, Burners, Boilers, and gas engines. Industrial end users viz. feedstock applications etc. are not discussed.
9.	Clean energy and the hydrogen economy	i	Not Specified	This study gives results on the basis of pilots performed by third party and give blending limit for general appliances.
10.	Transformation of the European natural gas grid into hydrogen	j	Not Specified	▪ Limit is given for each component but issues and mitigation plans are not discussed for any element of natural gas pipeline.
11.	Fuel Cells and Hydrogen Applications for Regions and Cities Vol. 2	k	Not Specified	Study is more focused towards FCEVs and Economics and comment only on general blending limit permissible in entire grid, however, no issues and mitigation plans are discussed.
12.	The Potential to Build Current Natural Gas Infrastructure to Accommodate the Future Conversion to Near-Zero Transportation Technology	**l**	**Transmission Pipeline-** 41.36 Bar to 82.73 Bar **Distribution Pipeline-** 2.06 Bar to 6.89 Bar	Issues and Mitigation Plan are not given for meters and Burner. A limit is given for each component, but issues and mitigation plans are not discussed for any element of the natural gas pipeline.
13.	Hydrogen effects on X80 pipeline steel in high-pressure natural gas/hydrogen mixtures	m	Not Specified	This study doesn't talk about blending, it only talks about hydrogen embrittlement on Steel grade X80.

14.	Admissible hydrogen concentrations in natural gas systems	n	Not Specified	Mitigation plans are not discussed for salt cavern and gas engines. Issues are not discussed vehicle tank, gas turbines. Blending limits are not defined for underground porous storage, salt cavern and gas chromatographs.
15.	Sector Forum Energy Management / Working Group Hydrogen	o	Transmission network- (Around 80 bar) or the gas distribution network (<30 bar for example) differs across Europe.	Mitigation is not discussed for any element of Natural gas pipeline except pressure regulators and valves. Issues is not discussed for any element of Natural gas pipeline except process gas chromatographs. Study focuses on blending limit of entire network, PGC and pressure regulators and valves. No discussion about Gas engines, Turbines, boiler, CNG fuel tank or any other critical component.
16.	Testing Hydrogen admixture for Gas Applications- Impact of hydrogen admixture on combustion processes – Part II: Practice	p	Not Specified	This study focuses on Issues of hydrogen admixing on appliances used in domestic appliances and doesn't talk about blending limit.
17.	Non-combustion related impact of hydrogen admixture - material compatibility	q	Not Specified	This Study only focuses on hydrogen embrittlement i.e., effect of hydrogen on material structure and properties. Blending limits are not discussed.
18.	NREL Report - Hydrogen Blending into Natural Gas Pipeline Infrastructure: Review of the State of Technology	**r**	**Distribution Network (USA)-** Operates up to 20.68 Bar. **Transmission Network (USA)-** 42 to 84 Bar.	This Study focuses on explaining about issues rather than establishing general blending Limits. There are various Disagreement with other literatures viz. It is generalized assessments often vary in their depth of evaluating hydrogen compatibility, leading to conflicting conclusions.
19.	Hydrogen Impact on Downstream installation	s	Low pressure mains (Distribution)- 0.3 Bar Medium pressure mains (Distribution)- 0.07 Bar to 2.1 Bar High pressure and secondary mains (Distribution)- 2.1 Bar to 10.5 Bar Trunk and primary mains (Distribution)- 10.5 Bar to 68.95 Bar	This Study analyse the impact of only 10% Hydrogen.

			Pipeline (Transmission)- More than 10.5 Bar	

B2- Electrolyzer safety Rules

This section will explore some of the electrolzyer safety rules. To ensure safety in electrolyzer systems, it is crucial to minimize external leaks in pressurized hydrogen systems by reducing leak points, performing regular maintenance, using compatible materials, and implementing leak detection with ventilation, pressure, and flow monitoring. For avoiding risks in mixing hydrogen and oxygen, it is necessary to analyze gas mixtures and monitor pressure, flow, and stack temperature. Handling oxygen hazards involves using compatible materials, minimizing ignition mechanisms, and ensuring proper ventilation to prevent oxygen-enriched atmospheres above 23.5%. This comprehensive approach addresses the key risks associated with the operation of electrolyzers. Table shows the electrolyzer safety rules.

Table 25: Electrolyzer safety Rules

S.NO.	Risk	Mitigation
1	External leaks are likely in pressurized H2 systems	Joints and fittings minimized to reduce number of leak points. Regular maintenance and leak checks to keep leaks small. Compatible materials and factor of safety used to prevent hydrogen embrittlement failures. Leak and flame detection along with ventilation, pressure and flow monitoring.
2	Cross-over may result in flammable mixtures on the H2 or O2 side. (More likely at start-up and stack end-of-life)	Stack not operated below the turn down ratio life specified by the manufacturer. On O2 side: H2 sensor within O2/water separator and/or temperature monitoring on recombiner On H2 side: Deoxo equipment with temperature monitoring Note- Recombiners and Deoxo reactors are not capable of mitigating high concentrations and may act as an ignition source
3	Stack rupture or pinhole leaks may enable mixing of H2 and O2 Possible reason for rupture ▪ More likely at the end of life. ▪ Accelerated stack degradation may occur due to poor water quality. ▪ Loss of coolant may lead to overheating.	Gas mixture analysis Pressure and/or flow monitoring. Temperature monitoring for the stack

4	Oxygen hazards are significant while using electrolysis systems. Hazards with O2 ▪ **Material flammability-** All nonmetals are flammable in 100% O2, Metals also become flammable as O2 pressure and % increase. ▪ **Ignition sensitivity-** Energy required for ignition decreases, Materials of construction may ignite via compression heating, particle impact, and others. ▪ Combustion consequence- Higher heat release from fire, Potential to involve otherwise "burn-resistant" materials, Higher overpressure from explosions. **Note**-As O2 P & T increases flammability, ignitability, and damage potential also increase. **Major Risk** If O2 is pressurized, bulk metals may be flammable and ignition more likely	Maximalize compatible materials Minimize ignition mechanisms. Outdoor vent outlets- Free from ignition sources, located at a safe distance from the H2 vent outlet and building air intakes. Indoor applications- Sufficient ventilation provided to prevent oxygen-enriched atmospheres above 23.5%.

B3- Final Workshop

PESO Findings

Background: Utilizing existing natural gas pipelines for blending hydrogen offers a promising avenue to leverage current infrastructure, reduce expenses, and facilitate the shift towards a hydrogen-centric economy.

Key Points regarding hydrogen blending:

- Metallurgical compatibility: Careful assessment and selection of pipeline materials, along with corrosion prevention measures, are crucial to mitigate risks of hydrogen-induced metallurgical issues like embrittlement and cracking.
- Pressure and temperature considerations: Modifications to pipeline systems may be necessary to accommodate the unique characteristics of hydrogen and ensure safe transport, addressing challenges such as diffusion, permeation, and embrittlement at high pressures.
- Blending ratios and impacts: Proper determination of hydrogen and natural gas blending ratios is essential to maintain safe and efficient pipeline operation, considering combustion properties, temperature variations, and operational integrity.
- Regulatory compliance and safety standards: Adherence to specific regulatory requirements and safety standards for hydrogen transportation, including risk assessments and safety measures, is vital to ensure the reliability and safety of repurposed pipelines for hydrogen transport.

Case Study of Blending of 5 % Hydrogen with Natural Gas in PNG network

A. **Gas Composition Analysis:** PESO has thoroughly reviewed the gas composition analysis reports, focusing particularly on the hydrogen dosage in natural gas and the analysis of ethyl mercaptan within the township. Results of that report are summarized below.

- **Hydrogen Dosing:** In the township's PNG network, hydrogen is currently being dosed with natural gas at a concentration of 5%, within an expected range of 4.5% to 5.5%. Analysis of gas samples taken between May and September 2023 revealed hydrogen percentages ranging from 4.5% to 5%. This indicates that the hydrogen concentration across the PNG network in the township falls within the anticipated range of 4.5% to 5%.

- **Ethyl Mercaptan Analysis:** In July 2023, ethyl mercaptan concentration analysis was conducted weekly both at the blending skid and outside it. The desired concentration of ethyl mercaptan for effective odour detection is more than 2 parts per million (PPM). Recorded values of ethyl mercaptan exceeded the specified minimum thresholds at both locations. The distinct odour provided by ethyl mercaptan ensures effective detection of gas leakages, affirming its adequacy in the gas mixture.

- **Summary of gas composition analysis:** The information provided suggests that the management of hydrogen dosing with natural gas and ethyl mercaptan analysis in the Township is being handled effectively. It is crucial to maintain hydrogen concentration within the desired range and to ensure that the ethyl mercaptan concentration is adequate for odour detection. These measures are essential for the safe and efficient operation of the gas distribution network. Regular monitoring and analysis of gas composition play a vital role in ensuring the integrity and safety of the PNG network.

B. **Material Testing, Training, and perception Survey:** PESO has thoroughly reviewed the comprehensive material testing, training initiatives, and a perception survey conducted concerning the blending of hydrogen with natural gas in the PNG network. This thorough examination underscores the commitment to ensuring the safety and efficacy of hydrogen integration within the gas distribution system.

- **Material Testing:** Various analyses including composition analysis, tensile strength testing, corrosion mapping, and macrostructure examination of GI pipes were conducted. Additionally, thickness mapping and macrostructure examination of PE pipes were carried out. Compatibility tests of sealing components and macrostructure analysis of burners were also performed. The findings from these studies revealed no adverse effects on the PNG network due to the blending of 5% hydrogen with natural gas. This indicates that the materials and components utilized in the network are compatible with the blended gas mixture, ensuring its safe integration and operation.
- **Training:** Training sessions were held to educate personnel on the characteristics of both natural gas and hydrogen. Presentations demonstrated flame colors corresponding to various levels of hydrogen blending with natural gas within the pipeline. Additionally, safety aspects concerning the utilization of hydrogen blended with natural gas were thoroughly explained, ensuring that personnel are well-informed about potential risks and requisite precautions.
- **Perception Survey:** A perception survey was undertaken in 25 households to solicit feedback from consumers. The responses received were satisfactory, suggesting that consumers are generally comfortable with the implementation of blended gas in the PNG network. This positive feedback underscores a favorable reception towards the use of blended gas among consumers.

C. **Overall Summary:** In essence, the findings from material testing, training sessions, and the perception survey reflect a meticulously planned and safety-conscious approach to incorporating hydrogen blending with natural gas in the PNG network. The absence of detrimental effects on the network, coupled with favourable consumer feedback and thorough safety training, exemplify the successful assimilation of hydrogen into the natural gas infrastructure. PESO underscores the necessity for sustained monitoring and maintenance to ensure the continued safety and efficacy of the blended gas system.

NTPC and Gujarat Gas Study- Pilot Project on Green Hydrogen Blending in PNG Distribution Network

Project Status: Gujarat Gas Limited (GGL) and NTPC forged an agreement on April 5, 2022. Following approval from the PNGRB on September 19, 2022, for blending 5% v/v of hydrogen, India's inaugural Green Hydrogen Blending Project was commissioned on January 2, 2023. To ensure project integrity, Gujarat Energy Research Management Institute (GERMI) conducted assessments, with reports submitted to the PNGRB. Approval was subsequently obtained in November 2023 to increase hydrogen concentration to 8% v/v. The system has since operated with 8% v/v of hydrogen blending for over three months, marking significant progress towards sustainable energy integration.

Major Objectives and Features: The primary objectives of the project include technical validation, ensuring adherence to safety requirements, assessing the impact of hydrogen blending, and addressing user concerns and perceptions. Notably, the project aims to mitigate approximately 5.5 Tons per Annum (TPA) of CO2 equivalent emissions annually and open a path to substitute LNG imports.

Project Description and Scheme: The project description and status are shown in Table given below.

Table 26: Project Description

S.NO.	Particular	Specification
1	PNG Network	Gujarat Gas Limited Surat GA
2	Blending Level	H2 at 5-20% v/v
3	RE Power	Floating Solar (NTPC Kawas)
4	Household	200 nos.
5	Electrolyzer	PEM (Min 1 nm3 /hr.)
6	H2 storage	13 nm3 (640 WL) at 30 bar(g)
7	H2 blending	Active & Monitor, PID c/v, H2 Analyzer
8	Safety Studies	HAZOP, HAC, QRA, EMERA

Studies Conducted: For the hydrogen generation and blending system, Hazard, and Operability (HAZOP) analysis was conducted by M/s Nachiket Enterprise, while Quantitative Risk Assessment (QRA), Hazardous Area Classification (HAC), and Escape Muster Evacuation and Rescue Analysis (EMERA) were carried out by M/s DNV. In the gas pipeline network, Quantitative Risk Assessment (QRA) was undertaken by M/s Bureau Veritas. These comprehensive analyses were conducted by reputable firms to ensure thorough evaluation and mitigation of potential hazards, thereby enhancing safety protocols within the respective systems.
Testing: Various types of testing were done to ensure safety and determine blending limits.

A. **Performance Testing**- Performance tests were conducted on the Hydrogen Generation System, evaluating parameters such as flow rate, hydrogen purity, and maximum pressure.

Similarly, the blending skid underwent performance testing at varying levels of hydrogen blending 10%, 15%, and 20%. Throughout these tests, the blending skid was isolated, and the PNG system was supplied with 100% Natural Gas through a bypass system. The results of the performance tests were deemed satisfactory, indicating the system's capability to meet operational requirements effectively.

B. **Gas Homogeneity and odorant dilution**- The Gas homogeneity test aimed to ascertain whether hydrogen would separate from natural gas (NG). These tests were conducted monthly on three samples from the blending skid at the highest point, and farthest point within the system, with no separation of hydrogen gas observed. Similarly, the odorant test aimed to assess the Dilution Effect, with testing conducted at each blending level on four samples, once a week. No dilution in the odorant level was observed during the testing, affirming the integrity of the gas mixture throughout the system.

C. **Material Testing (at 5% v/v)-** The purpose of material testing was to assess the composition of materials at different blending levels. Testing was conducted every three months on various components, including Polyethylene, Galvanized pipes, Burners, and Rubber seals. For Galvanized pipes, no variation in composition or tensile test results were observed, and there were no structural discontinuities or adverse effects noted during corrosion mapping. Compatibility tests on rubber seals revealed no adverse effects. Similarly, for burners, no structural discontinuities were found in the macrostructure, and corrosion mapping showed no adverse effects. These findings indicate the robustness and compatibility of the materials used at 5% blending levels.

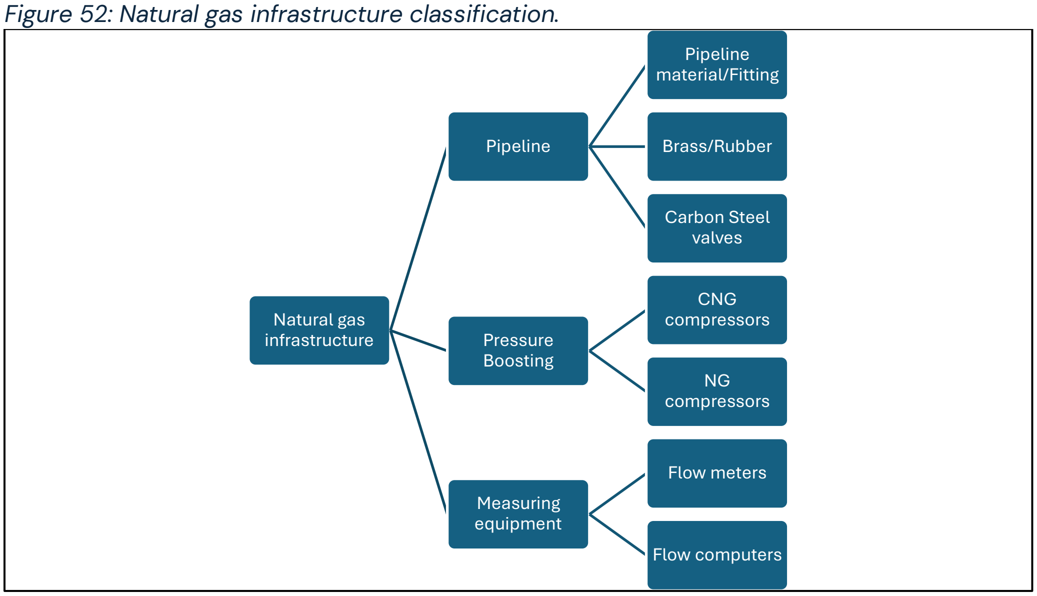
Awareness session and customer participation Survey: Residents of the NTPC township participated in a comprehensive awareness program covering key aspects such as the properties and advantages of natural gas, characteristics of hydrogen gas, and the H2 blending project's objectives. The program also addressed hazards, testing procedures, flame behavior at different blending percentages, dos and don'ts for PNG connections, emergency contacts, and customer service-related information. This initiative aimed to equip residents with essential knowledge for safe and efficient utilization of natural gas and hydrogen blending within their community. Following a customer participation survey, summarized results were obtained alongside corresponding corrective measures. Regarding knowledge about hydrogen gas, it was found that approximately 60% of respondents were already aware, prompting the initiation of awareness sessions as a corrective measure. Satisfaction levels were high regarding heating performance for cooking purposes, while a majority reported no gas flow sound during cooking. Nearly all respondents found the flame visibility in gas appliances to be normal (blue), and all reported adequacy in gas smell. Most respondents demonstrated awareness of actions to take in case of gas leakage, such as turning off the gas supply and opening doors. However, around 50% were found to be aware of emergency contact details, leading to the sharing of a checklist along with emergency contact information. These actions were implemented to address customer concerns and enhance safety awareness, ensuring their satisfaction and preparedness in handling gas-related situations.

Performance at Higher Blending Levels: Following the increase in hydrogen concentration to 8% v/v, a series of assessments were conducted to ensure the continued safety and efficiency of the gas distribution system. Observation of burner flame behavior at domestic and commercial connections revealed no abnormalities. Gas composition analysis during peak flow hours at both domestic and commercial connections indicated that hydrogen levels remained within the acceptable range (7.96% and 7.71%, respectively). Monitoring of odorant concentration and smell at the network's farthest end showed no changes. Scheduled for March 2024 is hydrogen concentration testing at the top and bottom of the testing riser for stagnant line pack, spanning a duration of three months. Chimney stack monitoring at commercial connections was conducted in January 2024, with plans for similar monitoring in March 2024, solely with natural gas combustion, for comparison purposes. Additionally, material testing for pipeline components exposed to the increased hydrogen percentage is slated for March 2024, aligning with the defined frequency of testing post three months of exposure. These assessments aim to ensure the continued safety and reliability of the gas distribution system amidst changes in hydrogen concentration.

GAIL Findings

Infrastructure classification: GAIL initially classified natural gas (NG) infrastructure into three categories viz. pipeline, pressure boosting infrastructure and measuring equipment as follows:

Figure 52: Natural gas infrastructure classification.



Blending Limits: After collecting data from the CGD network and end users, studying relevant literature and international standards, reviewing regulations, consulting with vendors, and considering existing practices and experiences, preliminary limits for safe percentages of hydrogen blending in the CGD networks have been established and shown in the table below.

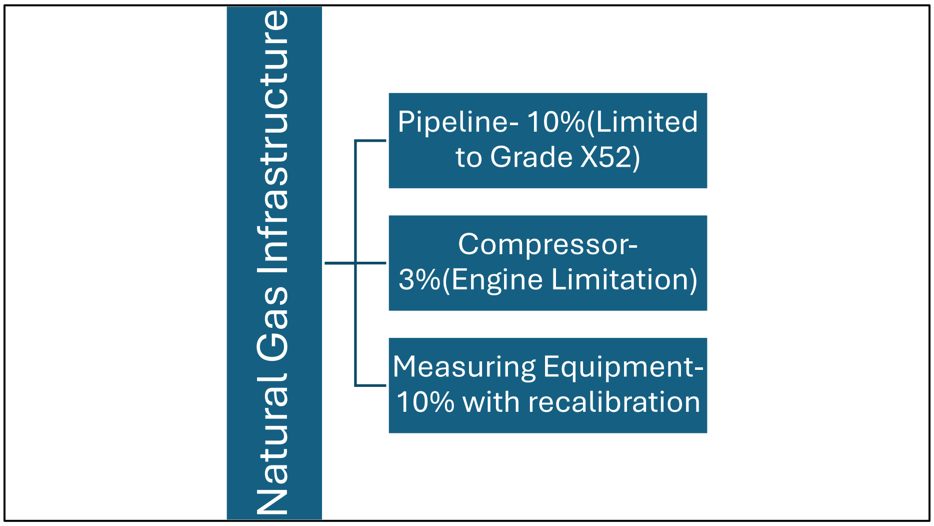
Table 27 Blending limits as per GAIL.

S.NO.	Equipment	Blending Limit
1	Pipeline material/Fitting/Brass/Rubber (Line pipe is limited to only up to Grade X-52.)	10%
2	Carbon Steels Valves	20%
3	Instrumentation equipment*	10%
4	CNG Compressors	25%
5	Engine Drivers	3%
6	Dispenser	3%
7	Domestic Burners	10%
8	Vehicle Engines	3%
9	Electrical Equipment	25%

*Flow meters, EVC and flow computers need to be recalibrated for use in Hydrogen mixed system.

Maximum Blending Percentage: Maximum blending percentage in each component of the natural gas infrastructure is determined by GAIL and results are shown below. However, it is worth noting that hydrogen limit in CNG cylinders is 2% as per IS15490.

Figure 53: Blending limit in each component of NG infrastructure.



Way Forward

- To further knowledge on increasing hydrogen blending percentages in prime movers like engines and turbines, vendors including M/s Siemens, M/s Cummins, and M/s Burckhardt must be contacted for their participation in equipment testing under higher blending percentages. This collaboration aims to gather valuable insights into the feasibility and performance of prime movers operating with increased levels of hydrogen blending.
- To determine the permissible percentage of hydrogen blending in higher-grade pipes, pipe material testing is underway in collaboration with IIT Kanpur, involving two scenarios: soaked samples and in-situ samples. These samples undergo tensile tests, fracture toughness tests, and fatigue crack growth tests. Initial findings from testing a carbon steel (CS) pipe of X 60 grade, soaked in a hydrogen environment at approximately 100 bar for 48 hours revealed no significant changes. Further testing will involve in-situ conditions. Progression of the study will be based on the results obtained from these tests.

B4- Hydrogen Transportation by Road and Rail

In addition to pipelines, hydrogen can also be transported via rail and road. On the road, there are two primary methods for transporting hydrogen. The first method involves transporting compressed hydrogen in its gaseous form using tube trailers. These trailers are equipped with multiple high-pressure cylinders, allowing for the safe and efficient movement of compressed hydrogen gas. The second method entails the use of liquid trailers to transport hydrogen in its liquid state. Liquid hydrogen is stored at extremely low temperatures to maintain its liquid form, requiring specialized insulated containers to prevent vaporization and ensure safety during transit.

For rail transport, the preferred method is to carry liquid hydrogen. This is due to the economic and logistical challenges associated with transporting compressed hydrogen gas by rail. Liquid hydrogen, being denser and more energy-dense than its gaseous counterpart, is more practical and cost-effective for rail transport. Specialized rail cars, designed to maintain the low temperatures necessary for liquid hydrogen, are used to facilitate this mode of transport. These rail cars ensure the hydrogen remains in a liquid state throughout the journey, optimizing both safety and efficiency.

Transportation by Road

Compressed Hydrogen by Tube Trailer: In this case, the evaluation process begins with the assessment of capital expenditure (capex). Capex pertains to the costs associated with acquiring the necessary trucks to transport a specified volume of gas. The cost of a single truck is determined by summing the costs of three primary components: the tube trailer, the truck undercarriage, and the truck cab. Following the capex evaluation, the next step involves determining the number of trucks required to transport the specified volume of gas. This determination is based on several factors, including the speed of the trucks, the time required for loading and unloading, and the number of trips needed to cover the given distance. Number of trips required is evaluated by division of Capacity to transport with capacity of one truck/Tube Trailor. These factors collectively influence the logistical planning and fleet size necessary to achieve the transportation objectives efficiently.

Once the number of trucks needed has been established, the focus shifts to the evaluation of operating expenditure (opex). Opex encompasses ongoing costs associated with the operation of the trucks. A key component of opex is the fuel cost, which is calculated based on the total distance traveled and the mileage of the trucks. In addition to fuel costs, the salary of the driver is included in the opex calculation. The annual cost is then calculated by summing the amortized capex and the total opex. Amortization spreads the capital expenditure over the useful life of the trucks, providing a more accurate representation of annual costs. Finally, to evaluate the transportation cost per unit of volume, the total annual cost is divided by the total volume of gas transported. This calculation provides a clear understanding of the cost efficiency of the transportation process.

Liquid hydrogen by Liquid Trailer: Capital expenditure (capex) is assessed with a particular focus on the costs associated with acquiring the trucks necessary for transporting a specified volume of gas. The cost of a single truck is computed by aggregating the expenses for three key components: the liquid trailer, the truck undercarriage, and the truck cab. Once the cost of a single truck is determined, the next step is to ascertain the requisite number of trucks needed to transport the specified volume of gas. This determination is based on several crucial factors, including the speed of the trucks, the time required for loading and unloading, and the number of trips each truck must complete to cover the given distance. The number of trips required is evaluated by division of Capacity to transport with capacity of one truck/Liquid Trailor. These factors collectively influence the logistical planning and the size of the fleet required to achieve the transportation objectives efficiently and effectively.

Following the thorough evaluation of capex, the focus shifts to the consideration of operational expenditure (opex). Opex encompasses the ongoing costs associated with the operation of the trucks. A key component of opex is the fuel cost, which is contingent upon the total distance traveled by each truck and its mileage. In addition to fuel costs, driver expenses, including salaries and other related costs, are incorporated into the opex calculation.

The annual cost is derived by summing the amortized capex and the total opex expenses. Amortization spreads the capital expenditure over the useful life of the trucks, providing a more accurate representation of the annual costs associated with the transportation operation. Finally, to ascertain the transportation cost per unit of volume, the total annual cost is divided by the total volume of gas transported. This methodology closely mirrors that used for the transportation of compressed hydrogen, with the primary difference being the substitution of a liquid trailer in place of a tube trailer.

Tables shown below represents the Capex and opex assumptions in case of transportation of compressed and liquid hydrogen by road.

Table 28: Capex Assumptions- Hydrogen transportation by Road

S.NO.	Particular	Unit	Value
1	Total Single Truck Cost-Compressed H2	INR Crores	6.71
2	Total Single Truck Cost-Liquid H2	INR Crores	6.26

Table 29: Opex Assumptions- Hydrogen transportation by Road

S.NO.	Particular	Unit	Value
1	Capacity of 1 Tube Trailer Truck-Compressed H2	kg	380
2	Capacity of Liquid Trailer	kg	4000
2	Truck Speed	km/h	24
4	Truck loading/unloading time	h	2
5	Mileage of Trucks	km/liters	3
6	Diesel Cost	INR/liter	89
7	Number of Person per truck	Number	2
8	Driver Salary per month	INR	20000

Transportation by Road

In this analysis, the primary focus is placed on rail units as the key component of capital expenditure (capex). Capex costs are specifically defined by the procurement expenses for these rail units, encompassing all necessary expenditures to acquire the rail units for transportation purposes.

The evaluation of operational expenditure (opex) is rendered straightforward due to the availability of Indian Railways' liquid chemical container facility. Within this facility, charges are determined based on the distance traveled, making the calculation of opex relatively simple and transparent. Essentially, opex in this context is the freight cost incurred for transporting goods using the liquid chemical container facility.

Following the evaluation of both capex and opex, the capex costs are amortized over the useful life of the rail units. This amortization process spreads the initial capital expenditure over a specified period, providing a more accurate representation of the annual costs associated with the rail units. The amortized capex costs are then combined with the opex to determine the total annual cost of transportation. To ascertain the transportation cost per unit of volume, the total annual cost is divided by the total volume of goods transported. The table presented below outlines the assumptions regarding capex and opex.

Table 30: Capex Assumptions- Hydrogen transportation by Rail

S.NO.	Particular	Unit	Value
1	Total Single Rail Unit Cost (Single Bogey Cost)	INR Crores	6.37

Table 31: Opex Assumptions- Hydrogen transportation by Rail

S.NO.	Particular	Unit	Value
1	Capacity of Single Rail Unit	kg	9000
2	Rail loading/unloading time	h	12
3	Rail Freight Charges	INR/Ton/km	2.45

Results:
In order to compare the transportation costs by rail and road, three specific distances are considered: 20 km, 80 km, and 150 km. Beyond these distances, transportation by road becomes impractical due to economic and logistical constraints. Additionally, since railway lines may not be available at certain locations, pipeline transportation becomes a more viable option for distances exceeding 150 km, provided the transported capacities are not too low.
The comparison of transportation costs across these three distances at varying capacities provides a comprehensive understanding of the cost efficiency associated with each mode of transport. Results obtained are summarized below.
20 km Distance (and Variable Capacities)
- Transportation Cost by Road (Tube Trailers): 37.45 INR/kg
- Transportation Cost by Road (Liquid Trailers): 3.35 INR/kg
- Transportation Cost by Rail: 3.33 INR/kg

80 km Distance (and Variable Capacities)
- Transportation Cost by Road (Tube Trailers): 77.71 INR/kg
- Transportation Cost by Road (Liquid Trailers): 6.93 INR/kg
- Transportation Cost by Rail: 3.88 INR/kg

1500 km Distance (and Variable Capacities)
- Transportation Cost by Road (Tube Trailers): 123.38 INR/kg
- Transportation Cost by Road (Liquid Trailers): 11.12 INR/kg
- Transportation Cost by Rail: 4.51 INR/kg

B4- Effect of Hydrogen on various grades of plastic

1. Effect on PE 80/PE 100: The interaction of hydrogen (H_2) with plastic materials is a critical area of study, especially for applications involving the transportation and storage of hydrogen-containing gases. Hydrogen, due to its small molecular size, tends to permeate more readily through plastic materials compared to larger molecules like methane. This characteristic necessitates thorough evaluations to ensure the integrity and safety of plastic pipelines used in such applications.
Work Package-3 of the Natural Hy Project has evaluated permeation losses from polyethylene (PE) pipes, conducting tests on three PE grades: PE 63, PE 80, and PE 100. These tests involved pipes with diameters ranging from 20 mm to 200 mm, subjected to internal pressures between 14.5 psig (1 bar) and 174 psig (12 bars) or higher, and temperatures ranging from 5°C to 25°C. The study utilized pure methane and a hydrogen/methane mixture containing 10% hydrogen to examine the permeation behavior of hydrogen/natural gas compared to natural gas alone. Results indicated that the permeation rate of both methane and hydrogen increases with the internal pressure. Furthermore, it was found that the permeation coefficient of hydrogen is 4 to 5 times greater than that of methane in the hydrogen/methane mixture. This significant difference highlights the increased permeation risk associated with hydrogen in mixed gas applications, emphasizing the need for careful consideration of material selection and operating conditions in such scenarios.

2. Effect on MDPE: GTI's experimental work on medium-density polyethylene (MDPE) has revealed a notable decrease in creep performance when exposed to a 20% hydrogen-methane blend. Creep performance, which refers to the material's ability to withstand prolonged stress without significant deformation, is crucial for the long-term reliability of pipelines. The presence of hydrogen in the methane blend appears to adversely affect the MDPE's structural integrity, leading to reduced performance under sustained pressure. The decreased creep performance associated with the hydrogen-methane blend highlights the need for careful consideration and potentially enhanced material specifications to ensure safety and durability in hydrogen-containing gas distribution systems.

B5- Hydrogen specification for blending and impurity limits in NG.

Hydrogen specification for blending: Once blending limits have been analyzed, it is crucial to determine the purity of hydrogen that must be injected with natural gas (NG) for blending purposes. In this regard, MARCOGAZ, the technical association representing 28 member organizations from 20 European countries within the European natural gas industry, has proposed specific hydrogen specifications for blending purposes. MARCOGAZ has formulated these specifications based on existing regulations in Europe. Firstly, a minimum hydrogen concentration of 98 mol% is required before injection. This level of hydrogen purity aligns with the Type I, Grade A quality defined in ISO 14687, and is consistent with proposals made in BSI PAS4444, DVGW G260, EASEE-gas CBP for hydrogen, and the working draft for the CEN TS. Additionally, regarding trace components, the hydrogen injected into the natural gas grid must meet the values and limits specified in existing European standards (EN 16726 and EN 16723-1) or national specifications and standards on gas quality, except for gross calorific value (GCV), Wobbe Index (WI), relative density, and methane number.

Impurity Limits in Natural Gas: Feedstock applications are highly sensitive to hydrogen blending in natural gas (NG), with a blending limit of 2%. Even before blending, the NG fed into reformers contains impurities. This section outlines the allowable impurity limits in NG used in reformers. In fertilizer plants and refineries, reformers are the major equipment that consume NG and will therefore use blended NG. Based on consultations with a fertilizer plant, the impurity limits for NG in reformers are as follows:

Table 32: Impurity limits in NG fed to reformer.

S.NO.	Element	Quantity Permitted
1	Oxygen	<10 ppm(v)
2	Moisture	<10 ppm(v)
3	Chloride	These elements must be non-detectable i.e., must be between 1ppb and 3ppb.
4	Sulphur	
5	Lead	
6	Arsenic	

Annexure C- Regulatory Assessment

C1- Mapping the regulatory structure for Hydrogen Markets in International Geographies, namely USA, UK, Australia, EU

This Section will describe the regulatory landscape for Hydrogen internationally. It will review the hydrogen value chain from production to end-use in order to identify the key government agencies that have jurisdiction in different areas. The goal is to provide an understanding of the regulatory landscape for hydrogen globally, which may act as a guideline to benchmark the existing legislation in India and identify gaps.

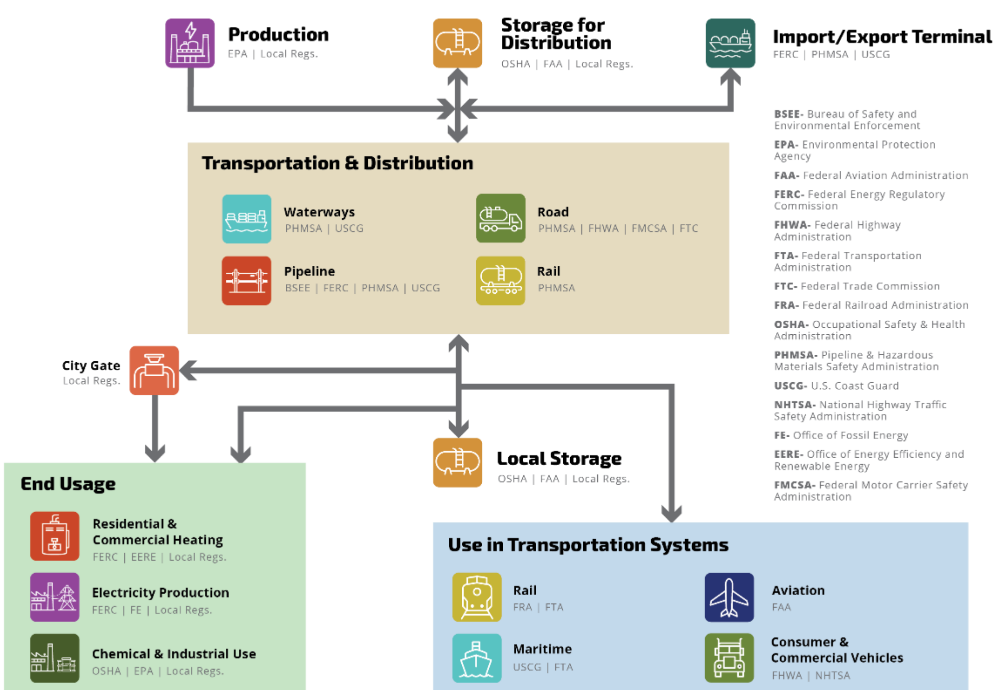
This section examines the regulatory structures for hydrogen in four key geographies: the United States, the United Kingdom, Australia, and European Union. It assesses the different bodies and agencies responsible for hydrogen regulation in each country, as well as the specific regulations in place for each stage of the hydrogen value chain, from production to end use.

C1.1. USA- Regulatory Landscape of the Hydrogen Value Chain

This Section will describe the regulatory landscape for Hydrogen in USA. It will review the hydrogen value chain from production to end-use in order to identify the key government agencies that have jurisdiction in different areas. The goal is to provide a comprehensive overview of the regulatory landscape for hydrogen in the United States.

The diagram below depicts the key regulatory map for hydrogen and its end use application in US.

Figure 54: US regulatory setup for Hydrogen (Source: Sandia National Laboratories)



The figure, based on input across agencies, shows various segments of the hydrogen value chain from production through end-use and lists the agencies that may have jurisdiction in key areas. The regulatory landscape involves a suite of Federal and local regulators who may oversee each segment of the hydrogen value chain.

Summary of Regulations
Based on a DOE-funded report by Sandia National Laboratories, Table 1 (below) shows specific regulatory activities by various agencies. Agencies will work together to regularly update this assessment and to identify and prioritize actions to ensure the U.S. can accelerate the buildout of hydrogen production, delivery, storage, and end-use, while also addressing potential environmental concerns and ensuring equity and justice for overburdened, underserved, and underrepresented individuals and communities.[29]

Table 33: Summary of US Regulatory Structure

<table>
<tr><th rowspan="2">System</th><th rowspan="2">Classification</th><th colspan="3">US Regulatory Structure</th></tr>
<tr><th>Agency</th><th>Regulations</th><th>Summary</th></tr>
<tr><td rowspan="2">Production</td><td rowspan="2">Safety</td><td>Environmental Protection Agency</td><td>40 CFR Part 98</td><td>Requires greenhouse gas reporting by applicable facilities, including related to hydrogen production and other applicable source categories.</td></tr>
<tr><td>DOE</td><td>IJA Sec 40315 (Sec 822 of EPACT-2005)</td><td>Directs DOE to develop a clean hydrogen production standard.</td></tr>
<tr><td>Storage</td><td>–</td><td>FAA</td><td>14 CFR Part 420</td><td>Dictates the separation distance requirements for storage of liquid hydrogen and any incompatible energetic liquids.
Determination of separation distances for compatible energetic liquids.
For liquid hydrogen and hydrazine, a launch site operator must use the “intraline distance to compatible energetic liquids” for the energetic liquid that requires the greater distance under table E-8 of appendix E as the minimum separation distance between compatible energetic liquids.
<table>
<tr><th>Pounds of energetic liquid</th><th>Pounds of energetic liquid</th><th>Public area and intraline distance to incompatible energetic liquids</th><th>Intraline distance to compatible energetic liquids</th><th>Pounds of energetic liquid</th><th>Pounds of energetic liquid</th><th>Public area and intraline distance to incompatible energetic liquids</th><th>Intraline distance to compatible energetic liquids</th></tr>
<tr><td>Over</td><td>Not Over</td><td>Distance in feet</td><td>Distance in feet</td><td>Over</td><td>Not Over</td><td>Distance in feet</td><td>Distance in feet</td></tr>
<tr><td></td><td></td><td></td><td></td><td>60,000</td><td>70,000</td><td>1,200</td><td>130</td></tr>
<tr><td>100</td><td>200</td><td>600</td><td>35</td><td>70,000</td><td>80,000</td><td>1,200</td><td>130</td></tr>
<tr><td>….</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>45,000</td><td>50,000</td><td>1,200</td><td>120</td><td>8,000,000</td><td>9,000,000</td><td>1,800</td><td>305</td></tr>
<tr><td>50,000</td><td>60,000</td><td>1,200</td><td>125</td><td>9,000,000</td><td>10,000,000</td><td>1,800</td><td>310</td></tr>
</table></td></tr>
</table>

[29] U.S. National Clean Hydrogen Strategy and Roadmap (energy.gov)

				Determination of separation distances for incompatible energetic liquids. If intervening barriers prevent mixing, a launch site operator must separate the incompatible energetic liquids by no less than the intraline distance that tables E-7 and E-8 of appendix E
		FERC*	18 CFR Part 157	Issuance of certificates of public convenience and necessity to prospective companies providing energy services or constructing and operating interstate natural gas pipelines and storage facilities.
			40 CFR 144, 146	Authorization to inject hydrogen for the purposes of subsurface storage.
		OSHA	29 CFR Part 1910	Dictates the safety of the structural components and operations of gaseous and liquid hydrogen storage and delivery.
Transport	Pipeline	BSEE	43 USC Chapter 29	Manages compliance programs governing oil, gas, and mineral operations on the Outer Continental Shelf (OCS).
		FERC*	18 CFR Part 1 53, 157, and 284	Applications for authorization to construct, operate, or modify facilities used for the export or import of natural gas. Issuance of certificates of public convenience and necessity to prospective companies providing energy services or constructing and operating interstate natural gas pipelines and storage facilities. Regulation of natural gas transportation in interstate commerce.
		PHMSA	49 CFR Part 192, 195	Prescribes minimum safety requirements for pipeline facilities, pipelines, and the transportation of gas or hazardous liquids within the limits of the outer continental shelf.
		USCG	33 CFR Part 154	Regulations for facilities transferring hazardous materials back and forth from a vessel to a facility.
	Rail	PHMSA	49 USC 5117 and 49 CFR Part 172, 173, 174, 179, 180	Lists and classifies hazardous materials for transportation and prescribes the requirements for papers, markings, labeling, and vehicle placarding. Provides requirements for preparing hazardous materials for shipment as well inspection, testing, and other requirements for transportation of hazardous materials in or on rail cars, including construction & usage instructions for DOT-113A60W tank cars. Gives the authority to authorize a variance that is still at the same safety level, special permit is required to use an alternative fuel that does not have a safety standard.
	Road	FHWA	23 CFR Part 658, 924	Regulates size and weight of trucks and highway safety which includes bridges, tunnels, and other associated elements.
		FMCSA	49 CFR Part 356, 389, 397	Motor carrier routing requirements, general motor carrier safety regulations, and transportation of hazardous materials.
		FTC	16 CFR Part 306	Describes the certification and posting of automotive fuel ratings in commerce.

		PHMSA	49 CFR Part 172, 173, 177, 178, 180	Lists and classifies hazardous materials for transportation, and prescribes requirements for papers, markings, labelling, and vehicle placarding. Provides requirements for preparing hazardous materials for shipment, and inspection, testing, and other requirements for transportation of hazardous materials via public highways (including transportation containers).
	Waterways	PHMSA	49 CFR Part 172, 173, 176, 178, 180	Lists and classifies hazardous materials for transportation and prescribes the requirements for papers, markings, labelling, and vehicle placarding. Provides requirements for preparing hazardous materials for shipment, as well inspection, testing, and other requirements for containers. Requirements for transportation by vessel.
		USCG	33 CFR Part 154, 156 and 46 CFR Part 38, 150, 151, 153, 154	Regulations for transferring hazardous materials back and forth from a vessel to a facility. Transfer of oil or hazardous material on the navigable waters or contiguous zone of the U.S. Requirements for transportation of liquified or compressed flammable gases, including incompatibility of hazardous materials and rules for containers. Regulations for ships and vessels carrying bulk cargo, including bulk liquified gases as cargo, residue, or vapor.
End Usage	Auxiliary Power and Alternative Power Supply	FAA	14 CFR Part 23, 25, 27, 29 Subpart E	Requirements for electrical generating systems including auxiliary and backup power for airplanes and rotorcraft.
		FMCSA	49 CFR Part 390	Regulates additional equipment on commercial vehicles to ensure it does not reduce the overall safety of the vehicle.
		F RA	49 CFR Part 229	Regulations for electrical systems, generators, protection from hazardous gases from exhaust and batteries, and crashworthiness for locomotives.
		USCG	46 CFR Part 1 1 1	Regulations for power supply systems on ships.
	Chemical and Industrial Use	Environmental Protection Agency	40 CFR Part 98	Requires greenhouse gas reporting by applicable facilities, including related to general stationary combustion and other applicable source categories.
		OSHA	29 CFR Part 1910	Dictates the safety of the structural components and operations of gaseous and liquid hydrogen in terms of storage as well as delivery.
	Electricity Production	DOE	10 CFR Part 503, 504	Relates to new baseload powerplants including the use of alternative fuels as a primary energy source.
		Environmental Protection Agency	40 CFR Part 60	Addresses GHG emissions from fossil fuel-fired electric generating units (EGUs).
		FERC*	18 CFR Part 292	Regulations regarding small power production and cogeneration facilities.
	Import/Export Terminals	USCG	33 CFR Part 154, 156	Regulations for self-propelled vessels that contain bulk liquified gases as cargo, cargo residue, or vapor. Transfer of oil or hazardous materials on the navigable waters or contiguous zone of the U.S.

	Transportation Use:			
	Use in Consumer and Commercial Vehicles	FHWA	23 CFR Part 658, 924	Regulates the size and weight of trucks and highway safety which includes bridges, tunnels, and other associated elements.
		NHTSA	49 CFR 571	Provides Federal Motor Vehicle Safety Standards for motor vehicles and motor vehicle equipment.
	Use in Aviation	FAA	14 CFR Part 23,25,26, 27, 29, 33	Provides requirements and airworthiness standards for airplanes and rotorcraft.
	Use in Maritime	FTA	49 USC Chapter 53	Requirements for National Public Transportation Safety Plan for public transportation that receives Federal funding.
		USCG	46 CFR Parts 24196	Regulation of vessel construction for both passenger and cargo applications as well as general fuel requirements based on the flash point of the fuel.
	Use in Rail	F RA	49 CFR Part 229, 238	Locomotive safety design and crashworthiness requirements, including safety requirements for passenger locomotives.
		FTA	49 CFR Part 659, 674	Provides guidance for rail fixed guideway systems and the oversight of safety, including hazard management and safety and security plans and review. Mandates state safety oversight of fixed guideway public transportation systems.

* Application of some of these authorities to hydrogen may require additional legislative or regulatory action (e.g., FERC)

C1.2. UK- Regulatory Landscape of the Hydrogen Value Chain

This section will provide a comprehensive overview of the regulatory landscape for hydrogen in the United Kingdom. It will review the hydrogen value chain from production to end-use in order to identify the key government agencies that have jurisdiction in different areas. It covers the study of the different legislations regulating hydrogen. While there is very little legislation in the UK that specifically relates to hydrogen, it is captured under the definition of "gas" in the Gas Act 1986 and is therefore regulated as part of the gas network.

The UK Regulatory Landscape consists of several government agencies and bodies that have developed regulations for the production, storage, transportation, and end use of hydrogen.

Table 34: Stakeholder Map- UK Regulatory Agencies and Jurisdiction

Regulatory agency / Regulatory Legislation	Jurisdiction
Office of Gas and Electricity Markets (Ofgem)	Ofgem is the economic regulator of the UK gas and electricity markets. It licenses hydrogen gas operators and sets standards for the safe and efficient operation of the gas network.
Health and Safety Executive (HSE)	HSE is responsible for regulating the safety of hydrogen production, storage, and transportation. It publishes guidance and standards for the industry and enforces health and safety law.
Environment Agency (EA)	The EA is responsible for protecting the environment. It regulates hydrogen production and storage facilities to ensure that they do not pollute the land, air, or water
Planning (Hazardous Substances) Act 1990 and Planning (Hazardous Substances) Regulations 2015	To regulate the storage of hydrogen, including a requirement for consent in certain situations
the Dangerous Substances and Explosive Atmosphere Regulations (DSEAR) 2002	To place duties on employers to eliminate or control the risks from explosive atmospheres in the workplace
Pipelines Safety Regulations 1996	Set out requirements for pipeline design, construction, installation, operation, maintenance, and decommissioning, while the Notification of Installations Handling Hazardous Substances Regulations 2002 places restrictions on handling hazardous substances in quantities exceeding a threshold.
The Gas Safety (Management) Regulations 18 (GSMR)	Gas Safety (Management) Regulations (GSMR) 1996 require any transporters of gas, including hydrogen, to submit a safety case to the Health & Safety Executive (HSE) identifying hazards and risks and how they are controlled
The International Carriage of Dangerous Goods by Road (ADR)	Covers transportation of hydrogen by road and set standards for pressure vessels used

Summary of Regulations

The UK's regulatory framework for hydrogen is still in its early stages of development, but there is a growing body of legislation and guidance in place. Table 3 summarizes the regulatory structure in place for Hydrogen in the UK.

Table 35: Summary of UK Regulatory Structure

System	Classification	UK Regulatory Framework		
		Agency	Regulations	Summary

Production	Safety	Planning (Hazardous Substances) Regulations 2015	Schedules 1 and 2	Hydrogen is considered a hazardous substance under the Planning (Hazardous Substances) Regulations 2015. The controlled quantities of hydrogen are also specified as 2 tonnes. Obtaining hazardous substances consent from the relevant authority is required if you are planning to use, store, or handle hydrogen in quantities above the controlled thresholds
			Part 1	Establishes the legal framework for regulating hazardous substances and ensuring that they are handled safely and responsibly. It requires that all applications for hazardous substances consent be recorded in a register, along with any directions or decisions made by the authority or the Secretary of State.
			Part 2, 3, 4	Outlines the procedures for obtaining hazardous substances consent. It sets out the criteria that must be met for an application to be granted. Deals with enforcement and validity of consent
		HSE(Health and Safety Executive)	Dangerous Substances and Explosive Atmospheres Regulations 2002	These regulations provide information on how to handle dangerous substances and prevent explosive atmospheres in the workplace. Protect workers from the risks posed by dangerous substances and explosive atmospheres and require employers to assess and manage these risks in their workplace. Includes risk assessment, elimination or reduction of risks, identification of hazardous contents, and arrangements for dealing with accidents and emergencies
			COMAH-Regulation 10	All operators (it applies to both upper and lower-tier establishments) are required to prepare a major accident prevention policy document (MAPP) and submit it to the CCA
			COMAH-Regulation 18,19,20	Reporting of Major Accidents: Information to be supplied by the operator and actions to be taken following a major accident, Action to be taken by the Central Competent Authority following a major accident, Notifiable incident
		Office of Gas and Electricity Markets (Ofgem)	Gas Act	The Gas Act and energy industry codes do not yet cover other forms of hydrogen. **Applicability to hydrogen** **Hydrogen production is not currently licensed, although there are strict health and safety requirements relating to the fuel**
		The Gas Safety (Management) Regulations18 (GSMR),		Regulates the public gas networks. GSMR restricts hydrogen content in the gas mixture to under 0.1% Various hydrogen innovation projects, including HyNet19 and HyDeploy20, are working with HSE to understand how GSMR can be revised to permit higher levels of hydrogen in the public gas networks, to either 20% or 100%
		EA	The	Obtain a permit from the EA before operating a

		(Environment Agency)	Environmental Permitting (England and Wales) Regulations 2016:	hydrogen production or storage facility
			The Water Environment (Controlled Activities) (England and Wales) Regulations 2010:	These regulations control activities that could pollute water, such as the discharge of wastewater from hydrogen production facilities
			The Air Quality Standards Regulations 2010:	These regulations set limits on the levels of certain pollutants in the air, including nitrogen dioxide and sulphur dioxide. Hydrogen production facilities must comply with these limits
	Internal (usage)	Planning (Hazardous Substances) Regulations 2015	Schedules 1 and 2	Obtaining hazardous substances consent from the relevant authority is required if you are planning to use hydrogen in quantities above 2 tonnes.
Storage		Planning (Hazardous Substances) Regulations 2015	Schedules 1 and 2	Consent is required to store more than two tonnes of hydrogen (67.2MWh) and further consent for over five tonnes (168MWh)
		HSE (Health and Safety Executive)	COMAH-Regulation 23, 24	The competent authority must prohibit the operation or bringing into operation of any storage facility, or any part of storage facility where the measures taken by the operator for the prevention and mitigation of major accidents are seriously deficient The competent authority must identify groups of establishments ("domino groups") where the risk or consequences of a major accident may be increased, and t5ake appropriate measures.
			Dangerous Substances and Explosive Atmospheres 2002 Regulations 9,10	Where a dangerous substance is present at the workplace, the employer shall provide his employees with suitable and sufficient information, instruction and training on the appropriate precautions and actions to be taken by the employee in order to safeguard himself and other employees at the workplace; Identification of hazardous contents of containers and pipes where containers and pipes used at work for dangerous substances are not marked to be done by employer
		Town & Country Planning (Environmental Impact Assessment) Regulations16 or the Infrastructure Planning		An Environmental Impact Assessment (EIA) must be completed in accordance with the said regulations. This impact assessment is required for all storage of 200,000 tonnes or more of

		(Environmental Impact Assessment) Regulations17 (for the local and nationally significant infrastructure planning regimes respectively)		chemical products and production facilities making basic inorganic chemicals (which include hydrogen).
		EA (Environment Agency)	The Environmental Permitting (England and Wales) Regulations 2016:	obtain a permit from the EA before operating a hydrogen production or storage facility
Transportation	Pipeline	Pipelines Safety Regulations 1996	Schedule 2 Reg 18	contains definition and classifications of dangerous fluid A 'major accident hazard pipeline' is one which conveys a dangerous fluid which has the potential to cause a major accident.
			Reg 9	design considerations such as the location of the pipeline, depth of cover, need for supports or anchors, and extra protection at vulnerable locations should be adhered to
			Reg 13	maintain the pipeline to secure its safe operation and to prevent loss of containment.
			Reg 14	Pipelines should be decommissioned in a manner so as not to become a source of danger. Once a pipeline has come to the end of its useful life, it should be either dismantled and removed or left in a safe condition
			Reg 16	The operator shall take reasonable steps to inform people of the existence of the pipeline and its whereabouts, and for major accident hazard pipelines there should be regular contact with owners/occupiers and tenants of the land through which the pipeline passes
			Regulations 19 to 27	defines the pipelines with the potential to cause a major hazard accident which attract the additional duties under these Regulations: emergency shut-down valves, notifications, the preparation of a major accident prevention document, the preparation of emergency procedures and the preparation of an emergency plan by the local authority
			Reg 19	emergency shut-down valves (ESDVs) to be fitted to certain pipelines connected to offshore installations.
		The Gas Safety (Management) Regulations 18 (GSMR),		Regulates the public gas networks. GSMR restricts hydrogen content in the gas mixture to under 0.1% Various hydrogen innovation projects, including HyNet19 and HyDeploy20, are working with HSE to understand how GSMR can be revised to permit higher levels of hydrogen in the public gas networks, to either 20% or 100%. **The Gas Safety (Management) (Amendment)**

				Regulations 2023 (GSMAR)[30] amend the 1996 regulations so that a wider range of gas specification may be injected into a gas network. This is primarily through reducing the lower Wobbe Index limit set out in Schedule 3, with this change coming into force on 6 April 2025.
		HSE (Health and Safety Executive)	Dangerous Substances and Explosive Atmospheres Regulations 2002	DSEAR requires businesses to carry out risk assessment associated with transportation of dangerous substances, including hydrogen.
		Gas Safety (Management) Regulations (GSMR) 1996		any transporters of gas, including hydrogen, to submit a safety case to the Health & Safety Executive (HSE) identifying hazards and risks and how they are controlled.
	Rail Road Waterways	ADR	Carriage of Dangerous Goods and Use of Transportable Pressure Equipment Regulations 2004	Carriage of dangerous goods, including hydrogen, by road and rail and places general duties on everyone with a role in transporting the goods
END USAGE	Hydrogen, motor vehicles	THE EUROPEAN PARLIAMENT	Regulation (EC) No 79/2009 OF THE EUROPEAN PARLIAMENT	This Regulation establishes requirements for the type-approval of motor vehicles regarding hydrogen propulsion and for the type-approval of hydrogen components and hydrogen systems. This Regulation also establishes requirements for the installation of such components and systems
		UN Economic Commission for Europe	ECE/TRANS/ WP.29/2013/41	Review and evaluate analyses and crash tests conducted to examine the risks and identify appropriate mitigating measures for hydrogen-fueled vehicles.

[30] https://www.hse.gov.uk/gas/supply/legislation.htm

C1.3. Australia- Regulatory Landscape of the Hydrogen Value Chain

Australia has the potential to be a major player in the global hydrogen industry, given its abundant renewable energy resources, proximity to key Asian markets, and extensive existing gas export infrastructure. However, the regulatory landscape for hydrogen in Australia is still in its early stages of development. This section will provide an overview of the current regulatory landscape for hydrogen in Australia.

Table 36: Stakeholder Map- Australia Regulatory Agencies and Jurisdiction

Regulatory agency / Regulatory Legislation	Jurisdiction
Comcare	Regulates workplace health and safety obligations, in respect of Commonwealth places and entities
Department of Climate Change, Energy, Environment and Water	Has regulations related to the protection of environment
Clean Energy Regulator	The Clean Energy Regulator is a government body responsible for accelerating carbon abatement for Australia
Australian Energy Market Operator	Applies the National Electricity Law, and National Gas Law as a law of the Commonwealth to offshore areas.
Department of Industry, Science, and Resources	Regulates all components of offshore carbon capture and storage infrastructure, and associated infrastructure, in natural formations within Commonwealth waters
National Transport Commission	model code regarding the transport of dangerous goods transport by road, and rail
Australian Maritime Safety Authority	Regulates pollution from shipping
Department of Home Affairs	Has Security of Critical Infrastructure Act 2018 which creates a range of reporting and security obligations on critical infrastructure for electricity generation infrastructure
Australian Border Force	protects Australia's border and enable legitimate travel and trade.
Department of Agriculture, Fisheries and Forestry	Export Control Act 2020- Regulations on exports
Department of Foreign Affairs and Trade	Fair trade agreements between Australia and other nations

Summary of Regulations

Despite being in its early stages of development, the Australian regulatory landscape for hydrogen is already relatively comprehensive, with regulations in place to cover all aspects of the hydrogen value chain. Table 5 summarizes the existing regulations in place for hydrogen in Australia.[31]

Table 37: Summary of Australia Regulatory Structure

System	Classification	Australia Regulatory Framework: Agency	Regulations	Summary
Production	Safety	Gas Supply (Safety and Network Management) Regulation 2022		A network operator must, when designing, constructing, operating, or extending a gas network or part of a gas network, take into account all relevant standards. Maximum penalty— (a) for a

[31] Commonwealth Hydrogen Regulation - DCCEEW

				corporation—10,000 penalty units, or (b) for an individual—5,000 penalty units.
				Section 10(4)- Requires that a leak test of a gas installation be conducted
				Section 16- A network operator must— (a) implement the safety and operating plan for its gas network lodged with the Secretary under, and (b) not construct, alter, extend, maintain, repair or operate a gas network except in accordance with the safety and operating plan.
		Dangerous Goods Safety (Storage and Handling of Non-explosives) Regulations 2007 (the DGSH Regulations)		Licensing is required for a storage and handling facility exceeding 5,000 litres of hydrogen. Note that this is the total volume (in litres) of all storage and pipework containing hydrogen (i.e. the water capacity). A documented dangerous goods risk assessment is required
		Comcare	Work Health and Safety Act 2011	Regulates workplace health and safety obligations, in respect of Commonwealth places and entities. However, it is noted that all states and territories have similar legislation which establish similar regulatory obligations for operating in their jurisdiction. The obligations established through this regulation go to ensuring the safety of workers and other persons are not put at risk by a business. It also provides obligations regarding a range of specific items, such as emergency plans, hazardous chemicals and atmospheres, and the assessment, determination, and licensing of major hazard facilities.
		Department of Climate Change, Energy, Environment and Water	Recycling and Waste Reduction Act 2020	Regulates the disposal of certain categories of waste by export. Categories may include, but not limited to, glass, plastic, tyres, paper, cardboard, and hazardous waste.
		Clean Energy Regulator	National Greenhouse and Energy Reporting Act 2007	Establishes 2 schemes which regulate greenhouse gas emissions from high emission facilities. The first requires these facilities to report their greenhouse gas emissions. The second requires these facilities to limit their emissions to a suitable level or pay monies.
		Australian Energy Market Operator	Australian Energy Market Act 2004	Applies the National Electricity Law, and National Gas Law as a law of the Commonwealth to offshore areas. The National Electricity Law regulates how companies operate and participate in the competitive generation and retail sectors. It also is responsible for the economic regulation of electricity transmission and distribution networks. The National Gas Law regulates the governance framework and key obligations relating to the access to gas pipelines. This includes the Australian Energy

				Market Operator's role and functions. It also establishes a gas market bulletin board.
	Internal (usage)	National Measurement Act 1960		Regulates how gases and liquids, such as hydrogen or ammonia, are measured for the purposes of trade. The legislative framework achieves this by establishing a mandatory framework, which requires measurement devices for trade, to have pattern approval (design), verification, (initial testing of individual instruments and systems) and in-service accuracy, for the purposes of measuring quantity and composition of gas and liquid.
		Department of Climate Change, Energy, Environment and Water	Industrial Chemicals Act 2019	Regulates registration for businesses that manufacture or import industrial chemicals. Fees and obligations vary based on the value and type of chemical. Common examples of industrial chemicals may include hydrogen, ammonia, industrial cleaners, and lubricants.
Storage		Gas Supply (Safety & Network Management) Regulation 2022		(Safety and design plan for gas networks)- Definition of "gas" For the Act, Dictionary, definition of gas, each of the following is declared to be a gas— (a) hydrogen gas that is not mixed with another gas, (b) a mixture of hydrogen gas and either natural gas or liquefied petroleum gas.
Transportation	**Pipeline**	Petroleum and Gas (Production and Safety) Act 2004	Section 67(2) of the P&G Safety Reg	specifies that the operator of the pipeline must ensure the design, construction, operation, maintenance, and abandonment of the pipeline comply with one of the listed standards. Standards relevant for hydrogen in pipelines will be the AS/NZS 4645 series or the AS/NZS 2885 series. Most hydrogen fuel gas pipelines are defined as operating plant and require a Safety Management System that complies with s675(1) of the P&G Act.
			Section 81 of the P&G Safety Reg	requires the operator of a gas distribution system to ensure the design, construction, operation, maintenance, and abandonment of a gas distribution system complies with the AS/NZS 4645 series. The AS/NZS 4645 series currently excludes mixtures of gases with a hydrogen content in excess of 15% by volume [AS/NZS 4645.1-2018 1.2 (d)].
	Rail	National Transport Commission	Australian Code for the Transport of Dangerous Goods by Road & Rail	Provides a model code regarding the transport of dangerous goods transport by road, and rail. This model law is implemented through legislation in each jurisdiction.
	Road	National Transport Commission	Australian Code for the Transport of Dangerous Goods by Road & Rail	Provides a model code regarding the transport of dangerous goods transport by road, and rail. This model law is implemented through legislation in each jurisdiction.

	Waterways	Australian Maritime Safety Authority	Protection of the Sea (Prevention of Pollution from Ships) Act 1983	Regulates pollution from shipping. This includes general waste management when at sea, incident reporting and post incident clean-up obligations, greenhouse gas emissions and noxious liquids.
End Usage	Electricity Production		Industrial Chemicals Act 2019	Regulates registration for businesses that manufacture or import industrial chemicals. Fees and obligations vary based on the value and type of chemical. Common examples of industrial chemicals may include hydrogen, ammonia, industrial cleaners, and lubricants.
		Clean Energy Regulator	Carbon Credits (Carbon Farming Initiative) Act 2011	Regulation establishes Australia's Carbon Credits incentive scheme. A project proponent will need to apply to register their project under this scheme and satisfy and operate in accordance with a carbon credit methodology established under the Act.
		Clean Energy Regulator	Renewable Energy (Electricity) Act 2000	Regulates the Renewable Energy Target. This is the Commonwealth's incentive scheme for green electricity production.
		Australian Energy Market Operator	Australian Energy Market Act 2004	Applies the National Electricity Law and National Gas Law to offshore areas. The National Electricity Law regulates the economic regulation of electricity transmission and distribution networks. The National Gas Law regulates the governance framework and key obligations relating to the access to gas pipelines, including the Australian Energy Market Operator's role and functions. It also establishes a gas market bulletin board.
		Department of Home Affairs	Security of Critical Infrastructure Act 2018	Creates a range of reporting and security obligations on critical infrastructure for electricity generation infrastructure.
	Export-Import		National Measurement Act 1960	Regulates how gases and liquids, such as hydrogen or ammonia, are measured for the purposes of trade. The legislative framework achieves this by establishing a mandatory framework, which requires measurement devices for trade, to have pattern approval (design), verification, (initial testing of individual instruments and systems) and in-service accuracy, for the purposes of measuring quantity and composition of gas and liquid.
			Industrial Chemicals Act 2019	Regulates registration for businesses that manufacture or import industrial chemicals. Fees and obligations vary based on the value and type of chemical.
		Department of Home Affairs	Maritime Transport and Offshore Facilities Security Act 2003	Establishes security obligations over port facilities for national security purposes. These security obligations may include developing a security plan for approval by the regulator, implementing that security plan and undertaking security assessments.
		Australian Border Force	Customs Tariff Act 1995	Regulates Australia's duty on the import of goods.

		Department of Agriculture, Fisheries and Forestry	Export Control Act 2020	Regulates the export of goods from Australia, including prohibiting and placing conditions on the export of certain goods.
		Free Trade Agreement – Department of Foreign Affairs and Trade	Customs Act 1901 Customs Tariff Act 1995 Customs (Korean Rules of Origin) Regulation 2014 Customs (International Obligations) Regulation 2015	Regulates Australia's requirements for exporting hydrogen and ammonia to South Korea under the Korea-Australia Free Trade Agreement. This free trade agreement is between Australia and Korea.
		Free Trade Agreement – Department of Foreign Affairs and Trade	Customs Act 1901 Customs Tariff Act 1995 Customs (Japanese Rules of Origin) Regulations 2014	Regulates Australia's requirements for exporting hydrogen and ammonia to Singapore under the Singapore-Australia Free Trade Agreement. This free trade agreement is between Australia and Singapore.
		Free Trade Agreement – Department of Foreign Affairs and Trade -	Customs Act 1901 Customs Tariff Act 1995 Customs (Regional Comprehensive Economic Partnership Agreement Rules of Origin) Regulations 2021 Customs Tariff Regulations 2004 – Customs (International Obligations) Regulation 2015	Regulates Australia's requirements for exporting hydrogen and ammonia in respect of the Regional Comprehensive Economic Partnership. This is a free trade agreement between: Australia Brunei China Cambodia Indonesia Korea Japan Laos Malaysia Myanmar New Zealand Philippines Singapore Thailand Vietnam
		Free Trade Agreement – Department of Foreign Affairs and Trade -	Customs Act 1901 Customs Tariff Act 1995 Customs (Trans-Pacific Partnership Rules of Origin) Regulations 2018 Customs Tariff Regulations 2004 – In Particular, Schedule 3 Customs (International Obligations) Regulation 2015	Regulates Australia's requirements for exporting hydrogen and ammonia in respect of Comprehensive and Progressive Agreement for Transpacific Partnership (CPTPP). This is a free trade agreement between: Australia Brunei Darussalam Canada Chile Japan Malaysia Mexico Peru New Zealand

				Singapore Vietnam

C2- Comparative analysis of the Indian Regulatory Framework with the Global Framework for Hydrogen

Current hydrogen regulations in India are in fairly nascent stage. Petroleum and Explosives Safety Organization (PESO) acts as a nodal agency for regulating safety of hazardous substances such as explosives, compressed gases, and petroleum in India, and provides some regulations regarding the safe handling of hydrogen. Explosives Act 1884, Static and Mobile Pressure Vessels (Unfired) Rules, 2015, and Gas Cylinder Rules 2016 form the key legislations that regulate hydrogen in India. The following table provides a comparison of the Indian regulations to international regulations and identifies key gaps that need to be bridged by Indian regulatory agencies to establish a proper hydrogen regulatory framework in India.

Table 38: Comparative Summary of International Regulations

S.NO	VALUE CHAIN	INDIAN REGULATIONS	REGULATIONS IN USA	REGULATIONS IN UK	REGULATIONS IN AUSTRALIA
1.	Production	MNRE Green Hydrogen Definition- After discussions with multiple stakeholders, the Ministry of New & Renewable Energy has 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 CO2 equivalent / Kg H_2 MoEFCC - The Manufacture, Storage and Import of Hazardous Chemical Rules, 1989 (on approvals for industrial activity, of on-site and off-site emergency plans for prevention of major accidents, rules for storage of hazardous substances) CPCB- The Air (Prevention and Control of Pollution) Act, 1981 (General regulations regarding emissions, pollution, air quality control etc) CPCB-The Hazardous and Other Wastes (Management and Transboundary Movement) Rules, 2016 (on waste disposal)	EPA (Regulations regarding environment & greenhouse gas emission) DOE (to develop clean hydrogen production standards)	Planning (Hazardous Substances) Regulations 2015 (safe handling of hazardous substances) Dangerous Substances and Explosive Atmospheres Regulations 2002 (Explosive management in workplace) Office of Gas and Electricity Markets (Ofgem) (strict health and safety requirements) Environment Agency (Environment related rules)	Dangerous Goods Safety (SH) Regulations 2007 (safe handling of hazardous substances) Work Health & Safety Act 2011 (Explosive in workplace) Recycling and Waste Reduction Act 2020 (on waste disposal) National Greenhouse & Energy Reporting Act 2007 (on greenhouse emissions) Australian Energy Market Act 2004 (on electricity and gas markets) Industrial Chemicals Act 2019 (regulations for businesses manufacturing industrial chemicals)

2.	Storage	PESO- Static and Mobile Pressure Vessels (Unfired) Rules, 2016 (on vessels, fittings, valves etc. & certifications) MoEFCC - The Manufacture, Storage and Import of Hazardous Chemical Rules, 1989 (labeling and markings required on containers of hazardous substances)	Federal Energy Regulatory Commission (issue of certificates & Authorization to inject hydrogen for the purposes of subsurface storage) Occupational Safety and Health Administration (safe storage at work)	Planning (Hazardous Substances) Regulations 2015 (safe storage, licenses required over certain qty) DSEAR 2002 (Explosive storage in workplace) COMAH (control operation of storage facilities) EA (Environment Agency) (permit for storage)	Gas Supply (Safety & Network Management) Regulation 2022 (Safety and design plan for gas networks)- Definition of "gas" For the Act, Dictionary, definition of gas, each of the following is declared to be a gas— (a) hydrogen gas that is not mixed with another gas, (b) a mixture of hydrogen gas and either natural gas or liquefied petroleum gas.
3.	Transportation	PESO- Static and Mobile Pressure Vessels (Unfired) Rules, 2016 (rules for vessels for transport) PESO- Gas Cylinder Rules (on transportation via cylinders) MoEFCC - The Manufacture, Storage and Import of Hazardous Chemical Rules, 1989 (on import rules) PNGRB Regulations (Regulates gas network, recommendations on expanding the scope to include hydrogen have been discussed in subsequent sections)	BSEE (transport regulation for outer continental shelf) FERC (regulates import-export transport facilities) Pipeline and Hazardous Materials Safety Administration (Prescribes minimum safety requirements & transport of hazardous materials) US Coast Guard (Regulations for facilities transferring hazardous materials back and forth from a vessel to a facility) Regulations on RAIL, ROAD, WATERWAYS	Pipelines Safety Regulations 1996 (design regulations) The Gas Safety (Management) Regulations 18 (GSMR) 1996 (regulates percentage of hydrogen blending) DSEAR (requires businesses to carry out risk assessment associated with transportation of dangerous substances, including hydrogen) Regulations on RAIL, ROAD, WATERWAYS	Petroleum and Gas (Production and Safety) Act 2004 (Pipeline design and safety) National Transport Commission: Australian Code for the Transport of Dangerous Goods by Road & Rail (provides regulations for road and rail transport) Australian Maritime Safety Authority: Protection of the Sea (Prevention of Pollution from Ships) Act 1983 (regulates transport by waterways)
4.	End Usage	MoEFCC - The Manufacture, Storage and Import of Hazardous Chemical Rules, 1989 (on imports) PESO- Gas Cylinder Rules (on transportation) MoRTH- Automotive Industry Standard (for Hydrogen FCEVs) Other Technical standards (for Fuel cell vehicles, refueling stations etc)	Different regulations for: • Auxiliary Power, Alternative Power Supply • Chemical and Industrial Use • Electricity Production • Import/Export Terminals • Transport use	FCEVs Hydrogen use as fuel	Different regulations for: • Electricity Production • Export-Import

C3- Recommended changes in The PNGRB Regulations

List of Regulations along with links:-

S.No	Name of Regulation	Link
1	Authorizing Entities to Lay, Build, Operate or Expand City or Local Natural Gas Distribution Networks	https://www.pngrb.gov.in/OurRegulation/PNGRB%20Regulations/A.%20CGD%20Network/A.1.%20CGD%20Authorization%20Regulations/CGD%20Auth-Post%20Amendment-30.09.2020.pdf
2	Determination of Transportation Rate for CGD and Transportation Rate for CNG	https://www.pngrb.gov.in/OurRegulation/PNGRB%20Regulations/A.%20CGD%20Network/A.2.%20CGD%20Tariff%20Regulations/CGD%20Tariff-Original%20Reg-23.11.2020.pdf
3	Exclusivity for City or Local Natural Gas Distribution Network	https://www.pngrb.gov.in/OurRegulation/PNGRB%20Regulations/A.%20CGD%20Network/A.3.%20CGD%20Exclusivity%20Regulations/CGD%20Excl-Post%20Amendment-01.01.2015.pdf
4	Technical Standards and Specifications including Safety Standards for City or Local Natural Gas Distribution Networks	https://www.pngrb.gov.in/OurRegulation/PNGRB%20Regulations/A.%20CGD%20Network/A.4.%20CGD%20T4S%20Regulations/CGD%20T4S-Post%20Amendment-15.09.2020.pdf
5	Code of Practice for Quality of Service for City or Local Natural Gas Distribution Networks	https://www.pngrb.gov.in/OurRegulation/PNGRB%20Regulations/A.%20CGD%20Network/A.5.%20CGD%20Service%20Regulations/CGD%20Service-Post%20Amendment-15.03.2018.pdf
6	Access Code for City or Local Natural Gas Distribution Networks	https://www.pngrb.gov.in/OurRegulation/PNGRB%20Regulations/A.%20CGD%20Network/A.6.%20CGD%20Access%20Code%20Regulations/CGD%20Access%20Code-Original%20Reg-23.11.2020.pdf
7	Integrity Management System for City or Local Natural Gas Distribution Networks	https://www.pngrb.gov.in/OurRegulation/PNGRB%20Regulations/A.%20CGD%20Network/A.7.%20CGD%20IMS%20Regulations/CGD%20IMS-Post%20Amendment-23.11.2020.pdf
8	Determining Capacity of City or Local Natural Gas Distribution Network	https://www.pngrb.gov.in/OurRegulation/PNGRB%20Regulations/A.%20CGD%20Network/A.8.%20CGD%20Capacity%20Determination%20Regulations/CGD%20Capacity-Post%20Amendment-30.09.2020.pdf
9	Guiding Principles for Declaring City or Local Natural Gas Distribution Networks as Common Carrier or Contract Carrier	https://www.pngrb.gov.in/OurRegulation/PNGRB%20Regulations/A.%20CGD%20Network/A.9.%20CGD%20Common%20Principles%20Regulations/CGD%20Common%20Carrier-Original%20Reg-30.09.2020.pdf
10	Authorizing Entities to Lay, Build, Operate or Expand Natural Gas Pipelines	https://www.pngrb.gov.in/OurRegulation/pdf/Consolidated-Regulations/GSR340_30.12.2016_final.doc
11	Affiliate Code of Conduct for Entities Engaged in Marketing of Natural Gas and Laying, Building, Operating, or Expanding Natural Gas Pipeline	https://www.pngrb.gov.in/OurRegulation/pdf/Gazette-Regulation/English/GSR540(E)-E.pdf
12	Access Code for Common Carrier or Contract Carrier Natural Gas Pipelines	https://www.pngrb.gov.in/OurRegulation/pdf/Gazette-Regulation/English/GSR541E.pdf
13	Determination of Natural Gas Pipeline Tariff	https://www.pngrb.gov.in/OurRegulation/pdf/Gazette-Regulation/English/GSR807(E)-HE.pdf
14	Guiding Principles for Declaring or Authorizing Natural Gas Pipeline as Common Carrier or Contract Carrier	https://www.pngrb.gov.in/OurRegulation/pdf/Gazette-Regulation/English/GSR273(E)-HE.pdf

15	Technical Standards and Specifications including Safety Standards for Natural Gas Pipelines	https://www.pngrb.gov.in/OurRegulation/pdf/Gazette-Regulation/English/GSR612(E)-E.pdf
16	Determining Capacity of Petroleum, Petroleum Products and Natural Gas Pipeline	https://www.pngrb.gov.in/OurRegulation/pdf/Consolidated-Regulations/F.No.S-A-Admn.doc
17	integrity Management System for Natural Gas Pipelines	https://www.pngrb.gov.in/OurRegulation/pdf/Gazette-Regulation/English/FNoInfra-IM-NGPL-1-2010-E.pdf
18	Imbalance Management Services Regulations	https://www.pngrb.gov.in/OurRegulation/pdf/Gazette-Regulation/English/IMS(E).pdf
19	Emergency Response & Disaster Management Plan (ERDMP) Regulations	https://www.pngrb.gov.in/OurRegulation/pdf/Consolidated-Regulations/GSR39.doc
20	Petroleum And Natural Gas Register	https://www.pngrb.gov.in/OurRegulation/pdf/Consolidated-Regulations/GSR481.doc

C3.1- Regulations in which Amendments have been suggested.

Authorizing Entities to Lay, Build, Operate or Expand City or Local Natural Gas Distribution Networks

Regulation No.	Existing Regulation (Reproduced Verbatim)	Suggested Amendments / Additions
5 - Criteria for selection of entity for expression of interest route	*(1) The Board may carry out a preliminary assessment of the expression of interest with respect to the following, namely: -* *(a) natural gas availability position.* *(b) possible connectivity with an existing or proposed natural gas pipeline for supply of natural gas to the city gate of the proposed CGD network, including LNG supplies by tank trucks or tank wagons and CNG by cascades; and* *(c) any other relevant issue as the Board may consider necessary.....*	Addition of additional assessment point of Hydrogen availability position.
	.... *(6) .....* .... *(b) (iv) entity has an adequate number of technically qualified personnel with experience in construction, pre-commissioning, and commissioning of 6 [hydrocarbon steel pipelines] and also has a credible plan to independently undertake and execute the CGD project on a standalone basis.* *Explanation. - The entity shall have at least*	For projects involving hydrogen blending, it is advised that entities are mandated to have technically qualified persons in case of hydrogen as well. It is suggested that an additional area of expertise be added to the list- *(v) design, execution of*

	three technically qualified personnel on its permanent rolls having experience of not less than 7 [three year] in the following areas, namely: - *(i) right of way acquisition or clearance securing;* *(ii) design and execution of a [hydrocarbon steel pipeline] project.* *(iii)pre-commissioning including hydro-testing and restoration; and* *(iv)safety of [hydrocarbon steel pipeline] and installations;*	*pipelines for blended hydrogen, & safety of such installations*

Determination of Transportation Rate for CGD and Transportation Rate for CNG

Regulation No.	Existing Regulation (Reproduced Verbatim)	Suggested Amendments / Additions	Rationale / Explanation
5	*5. <u>Volumes to be considered in determination of transportation rates</u>:* *(1) The volumes to be used as divisor for the purpose of determination of the unit transportation rate for CGD shall be equal to the actual volume of natural gas (including the volume of natural gas transported by pipelines for CNG) transported in the CGD network during the corresponding period.* *(2) The volumes to be used as divisor for the purpose of determination of the unit transportation rate for CNG shall be equal to actual volume of natural gas compressed as CNG during the corresponding period*	In addition to Natural gas, 'Blended natural gas' also to be considered for the calculations. Therefore, *The volumes to be used as divisor for the purpose of determination of the unit transportation rate for CGD shall be equal to the actual volume of natural gas and blended natural gas (including the volume of natural gas transported by pipelines for CNG and blended natural gas) transported in the CGD network during the corresponding period.* *(2) The volumes to be used as divisor for the purpose of determination of the unit transportation rate for CNG shall be equal to actual volume of blended natural gas and natural gas compressed as CNG during the*	Volume division will change to reflect blending of hydrogen

		corresponding period	

Access code for City or Local Natural Gas Distribution Networks

<table>
<tr><th>Regulation No.</th><th>Existing Regulation (Reproduced Verbatim)</th><th>Suggested Amendments / Additions</th><th>Rationale / Explanation</th></tr>
<tr><td>8 - Gas Parameters</td><td>The authorised entity shall, on a non-discriminatory basis, specify the threshold limits for gas parameters at the entry point, such as the acceptable ranges of pressure, temperature and calorific value and the acceptable threshold limits for other elements in gas, such as carbon dioxide (CO2), nitrogen (N2) and oxygen (O2) in the access arrangement:

Provided that the aforesaid ranges or the threshold limits shall be in conformity with those specified in Schedule-VI. ....</td><td>The threshold limit for gas parameters at the entry point in reference to the acceptable ranges of pressure, temperature and calorific value and the acceptable threshold limits for other elements in gas must also be mentioned for blended natural gas and hydrogen respectively.

The ranges and threshold limits should also be populated in Schedule - VI of the regulation.</td><td>Given the fact that the overall composition of natural gas would be changed when blended with hydrogen, it is advisable that the appropriate ranges and threshold limits are provided by the authorized entity as per the ranges and limits set by the appropriate technical authority and as added in Schedule - VI.</td></tr>
<tr><td>Schedule VI</td><td>Threshold Limit for Gas Parameters on City or Local Natural Gas Distribution Network
<table>
<tr><th>Parameters</th><th>Limit</th></tr>
<tr><td>Hydrocarbons dew pt (Degree Celsius, max.)</td><td>0</td></tr>
<tr><td>Water dew point (Degree Celsius, max)</td><td>0</td></tr>
<tr><td>Hydrogen Sulphide (ppm by wt. max.)</td><td>5</td></tr>
<tr><td>Total Sulphur (ppm by wt. max.)</td><td>10</td></tr>
<tr><td>Carbon dioxide (mole % max.)</td><td>6</td></tr>
<tr><td>Total inerts (mole %)</td><td>8</td></tr>
<tr><td>Temperature (Degree Celsius, max.)</td><td>55</td></tr>
<tr><td>Temperature (Degree Celsius, min.)</td><td>10-20</td></tr>
<tr><td>Oxygen (% mole vol. max.)</td><td>0.2</td></tr>
<tr><td>Wobbe Index for domestic consumers (based on MJ/SCM)</td><td>39-53</td></tr>
</table></td><td>Threshold limits to be modified with respect to hydrogen blended Natural gas</td><td></td></tr>
</table>

Authorizing Entities To Lay, Build, Operate Or Expand Natural Gas Pipelines

Regulation No.	Existing Regulation (Reproduced Verbatim)	Suggested Amendment / Addition
4 - Initiation of proposal through expression of interest route or suo-motu by Board.	(1) *An entity desirous of laying, building, operating or expanding a natural gas pipeline shall submit an expression of interest to the Board in the form of an application at Schedule A along with an application fee as specified under the Petroleum and Natural Gas Regulatory Board (Levy of Fee and Other Charges) Regulations, 2007.*	H2 Blended NG

	(2) *The Board may suo-motu initiate a proposal inviting entities to participate in the process of selection of an entity for laying, building, operating or expanding natural gas pipeline along any route.*	
5 - Criteria for selection of entity for expression of interest route.	*(6) (c) states that to be technically capable of operating and maintaining a natural gas pipeline, an entity must have at least one year of experience or have a joint venture or technical assistance agreement with an experienced party or have adequate qualified personnel and a credible plan to operate independently.* *(6) (d) the entity has agreed to abide by the relevant regulations for technical standards and specifications including safety standards* *(6) (e) the entity has adequate financial strength to execute the proposed natural gas pipeline project and operate and maintain the same and shall meet some financial criterion*	Government to consider if these technical and financial criteria are equally applicable to entities desirous of laying, building, operating or expanding blended/non blended hydrogen pipelines and if not, then separate criteria to be provided. *(6)(c) and (e) to be amended to add blended natural gas along with natural gas.* *c- 'Operating and maintaining a natural gas <u>or blended natural gas pipeline</u> an entity must have at least one year of experience or have a joint venture or technical assistance agreement with an experienced party or have adequate qualified personnel and a credible plan to operate independently.'* *e- the entity has adequate financial strength to execute the proposed natural gas <u>or blended natural gas pipeline</u> project and operate and maintain the same and shall meet some financial criterion*
15- Quality of service	(1) *The entity laying, building, operating or expanding a natural gas pipeline must*	Recommended that quality of service

standards	*comply with the quality of services standards as specified in Schedule F.*	standards is supplemented as appropriate for pipelines transporting blended natural gas

Affiliate Code of Conduct for Entities Engaged in Marketing of Natural Gas and Laying, Building, Operating, or Expanding Natural Gas Pipeline

Similar regulations would be needed for entities engaged in marketing of hydrogen and laying, building, operating or expanding dedicated hydrogen pipelines and pipelines carrying hydrogen blended natural gas.
Government may consider if these existing regulations may be extended to apply to entities engaged in marketing of hydrogen and laying, building, operating or expanding dedicated hydrogen pipelines and pipelines carrying hydrogen blended natural gas.
Or fresh analogous regulations are formulated for such entities.

Determination of Natural Gas Pipeline Tariff

It is recommended that either a separate Schedule is added in the regulation specifying the determination of hydrogen pipeline tariff or amendments are made to provide for inclusion of hydrogen pipelines in Schedule A

Determining Capacity of Petroleum, Petroleum Products and Natural Gas Pipeline

• It is recommended that software package and flow equation are also prepared for hydrogen.
• Further, it is recommended that new constant and variable parameters are specifically defined with respect to Hydrogen.

Integrity Management Systems for Natural Gas Pipelines

Regulation No.	Existing Regulation (Reproduced Verbatim)	Suggested Amendment / Addition
3 - Scope	*These regulations shall cover all the existing and new natural gas transmission pipelines, spur lines, sub-transmission pipelines (STPL) and dedicated pipelines. This includes the associated facilities required for transportation of natural gas through pipelines, that is terminals, intermediate pigging facilities, compressor stations, sectionalizing valves etc.* *The materials and specifications followed shall be in accordance with Petroleum and Natural Gas Regulatory Board (Technical Standards and Specifications including Safety Standards for Natural gas pipeline) Regulations, 2009*	The regulations to be amended to include retrofitted/hydrogen ready pipelines and appropriate Integrity management systems to be in place for the same to account for Hydrogen blended natural gas in addition to Natural gas.

Petroleum And Natural Gas Register

Regulation No.	Existing Regulation (Reproduced Verbatim)	Suggested Amendment / Addition
3 - Contents of the Register	*(1) Register shall be divided into following five parts namely:-* *(a) Part I containing a list of all entities who have been registered for market notified petroleum, petroleum products and natural gas.* *(b) Part II containing a list of all entities who have been registered for establishing and operating LNG terminals or proposing to establish and operate LNG terminals;* *(c) Part III containing a list of all entities who have been registered for establishing storage facility for petroleum, petroleum products or natural gas exceeding such capacity as may be specified by regulations;* *(d) Part IV containing a list of all entities who have been authorized for laying, building, operating or expanding a common carrier or contract carrier pipelines; and* *(e) Part V containing a list of all entities who have been authorized for laying, building, operating or expanding a city or local natural gas distribution network* (2)	The regulations to specify which part or parts of the register would contain lists of entities engaged in marketing hydrogen and establishing and operating hydrogen related infrastructure including storage infrastructure. Parts I, III, and V need amendment to add blended natural gas along with natural gas.

C3.2– Regulations for which Testing is Recommended

Technical Standards and Specifications including Safety Standards for City or Local Natural Gas Distribution Networks

Regulation No.	Existing Regulation (Reproduced Verbatim)	Suggested Amendments / Additions
General	Inclusion of ASME B31.12 throughout the regulations. Currently, these regulations require compliance to ASME B31.8	
5 - Intent	*(b) The continuation of operation of existing CGD network shall be allowed only if it meets the following requirements, namely:- (i) The CGD system downstream of city gate station shall have been tested initially at the time of commissioning in accordance with ASME B 31.8 Chapter IV (with minimum test pressure of 1.4 times of MAOP for steel network and 1.4 time MAOP or 50 PSI whichever is higher for PE network). The entity should have proper records of the same. Such test records shall have been valid for the current operation. Alternatively, if such a record is not available, the entity should produce in service test record of the CGD network having tested at a pressure of 1.1 time of MAOP as per ASME B 31.8*	Given the fact that the overall composition of natural gas would be changed when blended with hydrogen, it is advisable that testing be conducted up to 20% hydrogen blend, to determine if minimum test pressure that has to be maintained needs any change for the operation of CDG Network.
Schedule 1D	*iv) City gate station (CGS): typically comprising of, but not limited to, the following facilities:* *- Filters* *- Separators (if required).* *- Metering facilities.* *- Heater (if required)* *- Pressure reduction skid comprising active and monitor combination with a minimum 50% redundancy with stream discrimination arrangement, including slam shut valve for over and under pressure protection and creep relief valves 1[***].* *- Online odorization equipment designed to minimize fugitive emissions during loading, operation and maintenance.*	Additionally, H2 Blending skid and relevant infrastructure to be included
	Inter distance between various facilities required at CGS shall be as per Table – 1.	Inter distance between facilities to be specified for hydrogen specific facilities as well. It is advisable that testing be conducted for hydrogen blending, to

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<tr><th colspan="8">Table – 1: Inter-distance between Facilities at CGS</th></tr>
<tr><td>Sr. No.</td><td>From/To</td><td>1</td><td>2</td><td>3</td><td>4</td><td>5</td><td>6</td></tr>
<tr><td>1</td><td>Compound Wall</td><td>-</td><td>6</td><td>6</td><td>6</td><td>6</td><td>6</td></tr>
<tr><td>2</td><td>Control Room / Office Building / Store</td><td>6</td><td>-</td><td>12</td><td>12</td><td>2</td><td>15</td></tr>
<tr><td>3</td><td>Pressure Regulation and / or Metering</td><td>6</td><td>12</td><td>-</td><td>2</td><td>12</td><td>15</td></tr>
<tr><td>4</td><td>Odorant System</td><td>6</td><td>12</td><td>2</td><td>-</td><td>12</td><td>15</td></tr>
<tr><td>5</td><td>Electrical Sub Station</td><td>- #</td><td>2</td><td>12</td><td>12</td><td>-</td><td>15</td></tr>
<tr><td>6</td><td>Gas fired heaters</td><td>6</td><td>15</td><td>15</td><td>15</td><td>15</td><td>-</td></tr>
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<td>determine if there is need for amendment or not</td>
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Design Factors for Steel Pipe Construction
<table>
<tr><th colspan="5">Table 2 - Design Factors for Steel Pipe Construction</th></tr>
<tr><td>Facility</td><td colspan="4">Location Class</td></tr>
<tr><td></td><td>1*</td><td>2*</td><td>3*</td><td>4*</td></tr>
<tr><td>Pipelines</td><td>0.72</td><td>0.60</td><td>0.50</td><td>0.40</td></tr>
<tr><td>Crossings of roads, without casing:
(a) Private roads
(b) Unimproved public roads
(c) Roads, highways, or public streets, with hard surface</td><td>

0.72
0.60
0.60</td><td>

0.60
0.60
0.50</td><td>

0.50
0.50
0.50</td><td>

0.40
0.40
0.40</td></tr>
<tr><td>Crossings of roads, with casing:
(a) Private roads
(b) Unimproved public roads
(c) Roads, highways, or public streets, with hard surface and Railway crossings</td><td>

0.72
0.72
0.72</td><td>

0.60
0.60
0.60</td><td>

0.50
0.50
0.50</td><td>

0.40
0.40
0.40</td></tr>
<tr><td>Pipelines on bridges</td><td>0.60</td><td>0.60</td><td>0.50</td><td>0.640</td></tr>
<tr><td>Parallel Encroachment of pipeline on roads and railways
(a) Private roads
(b) Unimproved public roads
(c) Roads, highways, or public streets, with hard surface and Railway crossings</td><td>

0.72
0.72
0.60</td><td>

0.60
0.60
0.60</td><td>

0.50
0.50
0.50</td><td>

0.40
0.40
0.40</td></tr>
<tr><td>Pipeline on bridges</td><td>0.50</td><td>0.50</td><td>0.50</td><td>0.40</td></tr>
<tr><td>River Crossing- open cut [1]</td><td>0.72</td><td>0.60</td><td>0.50</td><td>0.40</td></tr>
<tr><td>Horizontal Direction Drilling (HDD) [1]</td><td>0.72</td><td>0.60</td><td>0.50</td><td>0.40</td></tr>
<tr><td>Compressor station piping</td><td>0.50</td><td>0.50</td><td>0.50</td><td>0.40</td></tr>
<tr><td>Fabricated assemblies</td><td>0.60</td><td>0.60</td><td>0.50</td><td>0.40</td></tr>
</table>
</td>
<td>Testing is required for hydrogen blended Natural gas to check if these design requirements suffice.</td>
</tr>
<tr>
<td>Schedule 1G</td>
<td>ODOURISATION
Natural gas supplied through CGD Network shall have a distinct odour, strong enough to detect its presence in case of leakage.
1[A pre – determined quantity of suitable odorant shall be dosed into the gas stream. The dosing should be such that it is safe for human as well as materials and equipments used in CGD system.]
Odour level tests shall be carried out to recognise the odour imparted by the gas supplier/distribution company. These tests are to be carried out at various defined locations on the</td>
<td>Odour tests to be carried out for blending of hydrogen, and amendments can be made accordingly</td>
</tr>
</table>

	network and at network extreme ends. If odou level falls below the minimum acceptable level same shall have to be intimated to the control room of the gas supplier and accordingly corrective actions are to be taken.	
Annexure I and II	*List of Specifications of Piping Materials used in CGD Network, and List of Specifications for Equipment used in CGD Network*	Inclusion of the following international standards: **ASME B31.12-** Standard on hydrogen piping and pipelines. Contains requirements for piping in gaseous and liquid hydrogen service and pipelines in gaseous hydrogen service. The general requirement section covers materials, brazing, welding, heat treating, forming, testing, inspection, examination, operating and maintenance. The industrial piping section covers requirements for components, design, fabrication, assembly, erection, inspection, examination and testing of piping. *ASME B31.12 includes pipeline systems with hydrogen content over 10%, thus needs to be adopted. For pipelines with hydrogen content under 10%, ASME B31.8* **CGA G-5.4: 2019-** This standard applies to hydrogen piping in the supply system (to the source valve) and to the consumer piping (from the source valve to the point of use) **Other:** **ASME STP PT 006: 2017-** Design Guidelines for Hydrogen Piping and Pipelines

		API 1104- Standard for Welding Pipelines and Related Facilities **UN ECE regulation 110-** to ensure the safety of CNG cylinders and their associated components, including their installation, maintenance, and use in vehicles

Integrity Management System for City or Local Natural Gas Distribution Networks

Testing and HAZOP studies are required for developing and implementing an effective and efficient Integrity Management Plan for hydrogen for providing safe and reliable delivery

Determining Capacity of City or Local Natural Gas Distribution Network

Panhandle equation, which is applicable for NG pipeline, is also valid for H2 blended NG pipeline and pure H2 pipeline in principle but co-efficient of the equations need to be re-worked by analytical methods and same must be tested Experimentally.
An analysis of the modifications done to the capacity equation in the USA has been conducted by ICF.

NOTE: *The Panhandle equation, which is utilized for determining the capacity of natural gas pipelines, can also serve as a method for assessing capacity when hydrogen is blended with natural gas. Furthermore, it can be adapted to calculate the capacity of pipelines transporting pure hydrogen. However, caution must be exercised when applying the Panhandle equation to these systems. Specifically, coefficients within the equation must be re-evaluated using analytical methods and validated experimentally for each scenario—whether it involves hydrogen blended with natural gas or pure hydrogen pipelines. Several critical factors come into play during this evaluation process, including the percentage of hydrogen blended, considerations of energy loss, and volumetric aspects. Each of these factors significantly influences pipeline capacity and must be carefully analyzed to ensure accurate and reliable capacity calculations.*

Figure 55: Panhandle Equation

$$Q = 1.1494 \times 10^{-3} \left(\frac{T_b}{P_b}\right)\left[\frac{(P_1^2 - e^s P_2^2)}{GT_f L_e Z f}\right]^{0.5} D^{2.5}$$

Table 39: Variables used in Panhandle Equation

S.no.	Particular	Symbol	Unit	Remarks
1	Pipe Length	L	km	
2	Elevation adjust. Parameter	S	Dimensionless	
3	Equivalent Length	L(e)	km	
4	Pipeline Diameter	D	mm	
5	Inlet Pressure	P1	kPa(Absolute and not gauge)	
6	Outlet Pressure	P2	kPa(Absolute and not gauge)	
7	Base Pressure	P(b)	kPa(Absolute and not gauge)	101.352
8	Base Temprature	T(b)	K	288.706
9	Average Flowing temprature	T(f)	K	
10	Specific Gravity	G	Dimensionless	0.0696

11	Compressibility Factor	Z	Dimensionless	0.98-1.3 for H2
12	Inlet Elevation	H1	m	
13	Outlet Elevation	H2	m	
14	Pipe Roughness	E	mm	

Access Code for Common Carrier or Contract Carrier Natural Gas Pipelines

Regulation No.	Existing Regulation (Reproduced Verbatim)	Suggested Amendment / Addition
5 - Gas Parameters	*(1) The authorized entity as referred to in sub-regulation (2) of regulation 3 shall formulate the calorific value (CV) band for the natural gas to be transported through natural gas pipeline keeping in view the following parameters, namely: -* *(a) CV of its own natural gas proposed to be transported.* *(b) CV of firmed up contracted capacity of natural gas.* *(c) requirements of downstream consumers of natural gas on the pipeline;* *(d) technical requirement of the pipeline system; and* *(e) CV band of the inter-state pipelines either supplying natural gas into the pipeline system or receiving natural gas from this pipeline system.*	Addition of Hydrogen blended natural gas alongside Natural gas
7 - Measurement of Gas	*(1) The transporter shall ensure the provision of the entry and exit point equipment to measure gas composition, calorific value, pressure and temperature on a continuous basis as specified in regulation 9……* *(2) ………..* …….	It is recommended that provision be extended to provide for entry and exit point equipment to measure gas composition, calorific value and temperature for hydrogen blended natural gas. Measurement equipment for natural gas is Process Gas Chromatograph (PGC) which measures the composition of gas in the pipeline. For hydrogen blended NG, the same equipment can be used after retrofitting the helium cylinder to an argon cylinder. Hence the measurement equipment remains the same, with minor adjustment.

Emergency Response & Disaster Management Plan (ERDMP) Regulations

Quantitative risk assessment of hydrogen systems is required to be conducted.

USA has QRA methodology. Testing and analysis need to be done to check if the same can be adopted in India or if modification is needed.[32]

C3.3- Regulations where change is not needed

Exclusivity for City or Local Natural Gas Distribution Network
Change not needed.

Code of Practice for Quality of Service for City or Local Natural Gas Distribution Networks
Change not needed.

Guiding Principles for Declaring City or Local Natural Gas Distribution Networks as Common Carrier or Contract Carrier
Change not needed.

Guiding Principles for Declaring or Authorizing Natural Gas Pipeline as Common Carrier or Contract Carrier[33]
Change not needed.

Technical Standards and Specifications including Safety Standards for Natural Gas Pipelines[34]
Change not needed.

Imbalance Management Services Regulations[35]
Change not needed.

C5- Recent Developments in Indian Hydrogen Framework

MNRE Hydrogen Hubs: Scheme guidelines for setting up hydrogen hubs in the country under the National Green Hydrogen Mission (NGHM)[36]

According to the ministry, the scheme, issued on March 15, 2024, will be implemented as per the detailed guidelines, the expenditure on the scheme will be met from the budget provisions made under the NGHM Head, and the MNRE and its nominated Scheme Implementing Agencies (SIAs) will be the implementing agency for these hydrogen hubs.
The objectives of the scheme are:

- to identify and develop regions capable of supporting large-scale production and/or utilization of hydrogen as green hydrogen hubs,

[32] 4th ISFEH.dot (h2tools.org)
[33] Available at: https://www.pngrb.gov.in/OurRegulation/pdf/Consolidated-Regulations/S-A-Admn01012015.pdf
[34] Available at: https://www.pngrb.gov.in/OurRegulation/pdf/Consolidated-Regulations/GSR808.pdf
[35] Available at: https://www.pngrb.gov.in/OurRegulation/pdf/Gazette-Regulation/English/IMS(E).pdf
[36] https://www.offshore-energy.biz/india-publishes-scheme-guidelines-for-setting-up-hydrogen-hubs/

- development of green hydrogen projects inside the hubs in an integrated manner to allow the pooling of resources and achievement of scale,
- to enhance the cost-competitiveness of green hydrogen and its derivatives vis-à-vis fossil-based alternatives,
- to maximize the production of green hydrogen and its derivatives in India within the stated financial support,
- to encourage large-scale utilization and exports of green hydrogen and its derivatives, and
- to enhance the viability of green hydrogen assets across the value chain.

To note, the National Green Hydrogen Mission was launched on January 4, 2023, to make India a global hub for the production, usage and export of green hydrogen and its derivatives.

In the newly published document, the ministry said the mission will contribute to India's goal to become self-reliant through clean energy and serve as an inspiration for the global clean energy transition, noting that it will also lead to significant decarbonization of the economy, reduced dependence on fossil fuel imports and enable India to assume technology and market leadership in green hydrogen.

Along with other initiatives, the mission envisages large-scale hydrogen hubs, which will act as a foundation for the development of the hydrogen ecosystem and as the backbone of the decarbonization efforts in the country, the ministry pointed out.

Under the mission, it is planned to set up at least two such green hydrogen hubs, the ministry stated, adding that the scheme will provide support for the development of the following core infrastructure at hydrogen hubs for common services/facilities only:

- storage and transportation facilities for green hydrogen/its derivatives,
- development or upgradation of pipeline infrastructure,
- green hydrogen-powered vehicle refuelling facility,
- hydrogen compression and/or liquefaction technologies, as required,
- hydrogen storage systems, including bulk liquid, gaseous, materials-based technologies or subsurface options (e.g., salt caverns, depleted oil and gas fields, unused coal mines etc.),
- water treatment facility and associated storage facility,
- development of bunkering facilities in the case of ports, including the provision of bunker barges for handling large vessels such as very large crude carriers (VLCC),
- infrastructure upgradation for shipping, including expansion of port/jetty infrastructure for exports,
- power transmission infrastructure to the nearest existing grid substation and establishment of new dedicated substations,
- land re-development,
- energy storage to manage RE intermittency,
- effluent treatment plants, and any other infrastructure required.

C6- Key Initiatives and Plans Across the Globe for Establishing Hydrogen Economy

Across the globe, a transformative shift is underway. Nations are recognizing the immense potential of hydrogen as a clean and versatile fuel, sparking a wave of initiatives and plans to foster a vibrant hydrogen economy. This section delves into the diverse landscape of these efforts, exploring how countries are laying the groundwork for a low-carbon future powered by hydrogen. From ambitious national strategies to innovative cross-border collaborations, we illuminate the key drivers, common themes, and unique approaches shaping the global hydrogen landscape. Through this comprehensive analysis, we gain valuable insights into the opportunities and challenges facing this nascent economic frontier, paving the way for informed decision-making and strategic adaptation for any nation seeking to harness the power of hydrogen.

C6.1 Existing and Planned Hydrogen Regulatory Frameworks and Certification Systems[37]

The global energy landscape is at a crossroads, marked by the urgent need for decarbonization and the immense potential of hydrogen as a clean and versatile fuel. Recognizing this transformative opportunity, nations are actively developing initiatives and plans to foster a vibrant hydrogen economy. This section provides an outline of these efforts. We analysed existing models from around the globe, identifying strategies and roadmaps adopted and key considerations for adaptation to the Indian context.

Governments worldwide are simultaneously taking steps to implement regulations and certification systems pertaining to the environmental attributes of hydrogen (Table 9). There are currently seven national and supranational governments with regulatory frameworks in place. A further six countries have announced forthcoming regulations, although the specific methodologies to demonstrate compliance with these frameworks are yet to be determined.

While these certification systems and regulatory frameworks share certain similarities in terms of scope, system boundaries and eligibility criteria, there are also significant divergences. This variability poses challenges for project developers – particularly those aiming to participate in a potential global market – who need to undertake ad-hoc certification processes for each country they wish to access, resulting in increased transaction costs.

Consequently, in the absence of greater interoperability in regulatory frameworks and certification, trade in hydrogen is likely to be limited to bilateral agreements, impeding the development of an international market. The establishment of a global hydrogen market could be greatly aided by collaboration and co-operation among governments to foster a certain level of interoperability among regulatory frameworks. A full harmonisation of these certification systems and regulatory frameworks seems infeasible in the short term, but enabling mutual recognition among the different certification schemes can be a first step to minimise market fragmentation. In July 2023, the IEA Hydrogen Technology Collaboration Programme started a new Task on Hydrogen Certification to work on technical matters of harmonisation of certification. The need for mutual recognition of certification schemes was also acknowledged in the G20 Energy Transitions Ministers' Meeting Outcome Document and Chair's Summary, and in the G7 Climate, Energy and Environment Ministers' Communiqué. Referencing the emissions intensity of hydrogen production, based on a joint understanding of the methodology employed for regulation and certification, can be a starting point to enable mutual recognition of certificates, facilitate smoother market access and support the growth of a thriving international hydrogen market.

Table 40: Hydrogen Regulatory Frameworks and Certification Systems

Government	Name	Purpose	Product	Status	Criteria

[37] Global Hydrogen Review 2023: https://iea.blob.core.windows.net/assets/ecdfc3bb-d212-4a4c-9ff7-6ce5b1e19cef/GlobalHydrogenReview2023.pdf

Australia	Guarantee of Origin certificate scheme	Voluntary	Hydrogen, hydrogen carriers	Under development	No eligibility criteria. The only requirement is to implement an emissions accounting methodology for the hydrogen produced
Canada	Clean Hydrogen Investment Tax Credit	Regulatory, access to tax credits	Hydrogen, ammonia	Under development	Production below certain emissions intensity levels (<0.75, 0.75-2, 2-4 g CO2-eq/g H2). For ammonia, only one emissions intensity level is defined (<4 g CO2-eq/g H2-eq)
Denmark	Guarantee of Origin certificate scheme	Voluntary	Hydrogen, hydrogen – based fuels	Operational	Production from renewable electricity
European Union	Renewable Energy Directive II	Regulatory, count against renewable energy targets	Hydrogen, hydrogen – based fuels	Operational (certification under development)	Production from renewable electricity (or grid electricity with <65 g CO2-eq/kWh) meeting criteria on temporal and geographical correlation and additionality of renewable generation.
France	France Ordinance No. 2021-167	Regulatory, access to public support programs	Hydrogen	Under development	"Low-carbon hydrogen": production with emissions intensity <3.38 g CO2-eq/g H2. "Renewable hydrogen": production with emissions intensity <3.38 g CO2-eq/g H2 and renewable sources
Japan	Basic Hydrogen Strategy	Regulatory, access to public support	Hydrogen, hydrogen – based fuels	Under development	Production with emissions intensity <3.4 g CO2-eq/g H2
Korea	Clean Hydrogen Certification Mechanism	Regulatory, access to public support	Hydrogen	Under development	Production with emissions intensity <4 g CO2-eq/g H2.
India	Green Hydrogen Standard for India	Regulatory, access to public support	Hydrogen	Under development	Production from renewable energy with emissions intensity <2 g CO2-eq/g H2.
Italy	Guarantee of Origin certificate scheme	Voluntary	Electricity and renewable gases (incl. hydrogen)	Operational	Production from renewable sources
Netherlands	Guarantee of Origin certificate scheme	Voluntary	Hydrogen	Operational	Production from renewable electricity
Spain	Guarantee of Origin certificate scheme	Voluntary	Renewable gases (incl. hydrogen)	Operational	Production from renewable electricity
United Kingdom	Low Carbon Hydrogen Standard	Regulatory, access to public support	Hydrogen	Operational (certification under development)	Production with emissions intensity <2.4 g CO2-eq/g H2.
United Kingdom	Renewable Transport Fuel Obligation	Regulatory, access to public support	Hydrogen (use in transport)	Under development	Production from renewable energy (excluding bioenergy) with emissions intensity <4.0 g CO2-eq/g H2.
United States	Clean Hydrogen Production Std; Tax Credit	Regulatory, access to public support	Hydrogen	Under development	Production below certain emissions intensity levels (<0.45, 0.45-1.5, 1.5-2.5, 2.5-4 g CO2-eq/g H2) eligible for different levels of investment tax credits support.

C6.2 Assessment of Global Planned Hydrogen Blending Projects[38]

Blends of natural gas and hydrogen are already being used in several town gas networks in Singapore, Hong Kong, and Hawaii, which plan to eventually replace fossil-based hydrogen with low-emission hydrogen.64 Since the GHR 2022, a few hydrogen blending demonstration projects have entered operation around the world (Table 10); nevertheless, hydrogen blending in distribution networks may sometimes meet strong local opposition. For instance, the United Kingdom's first hydrogen village trial proposal is no longer under consideration by the government due to a lack of support from residents.

Table 41: Global Planned Hydrogen Blending Projects

Project Name	Country	Location	Blending Volume	Announced Size
ATCO Community Blending Project	Australia	Cockburn	2-5%	2700 customers
ATCO Alberta blending project	Canada	Fort Saskatchewan	5%	2100 customers
Gasvalpo Energas Coquimbo	Chile	Coquimbo	5-20%	2000 customers
NTPC-CGL in Surat	India	Surat	5%	200 customers
Floene Seixal	Portugal	Seixal	20%	82 customers
20 HyGrid project- Delgas Grid	Romania	Darlos	20%	75 customers
Dominion Energy Utah	US	Delta	5%	1800 customers

Hydrogen blending in the transmission network is also being considered, as it could enable the co-utilisation of the existing network until dedicated infrastructure is in place, if deblending and purification technologies become available and cost-efficient. This would likely require a system of guarantees of origin, such as that in place in the Netherlands. In February 2023, Kogas (Korea) selected DNV to assess the feasibility of blending hydrogen into the country's 5000 km transmission network, as it aims to achieve 20% blending by 2026. In March 2023, the European Union altered the EU Gas Proposal, so that the maximum blending of hydrogen into the natural gas transmission system would be 2% instead of 5% to ensure a harmonised quality of gas. In April 2023, China National Petroleum Corporation announced that it had transported blended hydrogen (24%) using a 397 km gas pipeline in Ningxia for 100 days. In May 2023, Xcel Energy (United States) awarded Worley a study to assess the feasibility of injecting blended hydrogen in its 58 000 km distribution pipelines and 3 500 km transmission pipelines, including the assessment of blending rates. In June 2023, Portugal's REN announced that it had started adapting its high-pressure natural gas grid (1375 km) to allow it to carry up to 10% hydrogen. However, deblending technology is not yet available on a large scale. In January 2022, Linde commissioned the world's first full-scale demonstration plant in Dormagen (Germany), which can produce hydrogen with a very high purity from blends of 5- 60% using membrane separation followed by pressure swing adsorption.

[38] Global Hydrogen Review 2023: https://iea.blob.core.windows.net/assets/ecdfc3bb-d212-4a4c-9ff7-6ce5b1e19cef/GlobalHydrogenReview2023.pdf

C6.3 National hydrogen roadmaps and strategies since September 2022[39]

Table 42: National hydrogen roadmaps and strategies since September 2022

Government	Description
Algeria	Target to produce and export 30-40 TWh of hydrogen and hydrogen-based fuels by 2040. Focus on pilot projects until 2030 to start up the sector.
Brazil	The 2023-2025 Triennial Work Plan of the National Hydrogen Program defines the strategy of the country, with three timeframes: by 2025, deploy low-carbon hydrogen pilot plants across the country; by 2030, consolidate Brazil as a competitive low-carbon hydrogen producer; and by 2035 consolidate low-carbon hydrogen hubs
Costa Rica	Target to install 0.15-0.50 GW of electrolysis capacity, to replace 8-10% of liquefied petroleum gas (LPG) with "green" hydrogen and to deploy 100-250 fuel cell electric vehicles (FCEVs) and 200-600 fuel cell heavy-duty trucks by 2030.
Ecuador	Target to install 3 GW of electrolysers by 2040 and establish regulations for domestic hydrogen use and potentially for export to international markets.
India	Target to produce 5 Mt of "green" hydrogen by 2030 (with associated 125 GW of renewable capacity additions) with additional potential to reach 10 Mt/yr with exports. Interest in developing a domestic electrolyser manufacturing industry.
Israel	Plans explore options to integrate hydrogen into the national energy mix, along with consideration of underground storage.
Kenya	Target to install 150-250 MW of electrolysers and to produce 300-400 kt of nitrogen fertilisers by 2032. Aim to develop a local "green" fertiliser industry to decrease dependency on imported fertilisers.
Namibia	Target to produce 1-2 Mt of "green" hydrogen by 2030 and 10-15 Mt by 2050. Aims to develop three hydrogen valleys* to start production and use.
Panama	In transport, the country aims to increase hydrogen and derivatives for maritime fuels bunkering to 5% by 2030. Target to produce 0.5 Mt of hydrogen by 2030.
Singapore	Aim to transform Singapore into a hub for hydrogen and hydrogen fuels in the Pacific. Strong focus on electricity generation, with an estimate that hydrogen could meet up to 50% of electricity demand in 2050, as well as aviation and maritime.
Sri Lanka	Roadmap includes plans to export hydrogen derivatives by 2030.
Türkiye	Target to install 2 GW of electrolysers by 2030, 5 GW by 2035 and 70 GW by 2053. Support for demonstration projects for "blue" hydrogen production.
United Arab Emirates	Strategy includes a forecast for the production of 1.4 Mt of hydrogen by 2030, 7.5 Mt by 2040 and 15 Mt by 2050, through a mix of electrolysis powered with renewable and nuclear electricity, and natural gas with carbon capture, utilisation and storage (CCUS).
United States	Target to produce 10 Mt of "clean" hydrogen by 2030, 20 Mt by 2040 and 50 Mt by 2050. Update every 3 years (required by the Bipartisan Infrastructure Law).
Uruguay	Target to install 1-2 GW of electrolysers by 2030 and 10 GW by 2040, with initial focus on domestic demand in the short term and exports in the long term.
Belgium (update)	Vision structured around four pillars: become an import/transit hub for renewable hydrogen in Europe, expand technology leadership, establish a robust domestic market and international co-operation.

[39] Global Hydrogen Review 2023: https://iea.blob.core.windows.net/assets/ecdfc3bb-d212-4a4c-9ff7-6ce5b1e19cef/GlobalHydrogenReview2023.pdf

Germany (update)	Target to install 10 GW of electrolysers by 2030, and increased demand in industry and transport to replace larger shares of natural gas, with over 1 800 km of pipeline infrastructure.
Japan (update)	Interim target for 12 Mt of hydrogen demand by 2040 (complementing previous targets for 3 Mt by 2030 and 20 Mt by 2050) and to meet 1% of the gas supply in existing networks with synthetic methane by 2030, increasing to 90% by 2050. Target to install 15 GW of electrolysis globally. Shift focus from FCEVs to the use of hydrogen in applications, notably in steel and petrochemical industries.
Korea (update)	Updated target to reach 2.1% of total electricity production with hydrogen and ammonia by 2030, and 7.1% by 2036. Creation of a framework for a Clean Hydrogen Certification Mechanism to be released by the end of 2023.

These announcements of hydrogen strategies serve as the biggest driver of government funding. India's National Green Hydrogen Mission includes nearly INR 2 billion (Indian rupees) (~USD 25 million) subsidy to produce 5 Mt of hydrogen for domestic consumption and 10 Mt of hydrogen for exports by 2030. The United States adopted the US National Clean Hydrogen Strategy and Roadmap, revising their strategy to accord with recent carbon capture, utilisation and storage (CCUS), renewables, and sustainable aviation fuel (SAF) production tax credits and funding opportunities. In addition, Belgium, Germany, Japan and Korea have updated their existing hydrogen strategies, and a number of countries, particularly in Europe, are in the process of revising their strategies.

The new and updated strategies show an increase in global ambitions to deploy hydrogen technologies, as reflected in government targets for low emission hydrogen production, which now account for 27 to 35 Mt, compared with 15 to 22 Mt at the time the GHR 2022 was released (Table 11). The biggest contributors to this increase are the targets of the United States (10 Mt of "clean" hydrogen), India (5 Mt of "green" hydrogen) and Namibia (1-2 Mt of "green" hydrogen).

On the demand side, however, there has been no increase in ambition, and only two significant developments. In the European Union there has been a political agreement to set binding targets for the use of renewable fuels of non-biological origin (RFNBO) in industry, transport and aviation by 2030, though some targets were less ambitious than those proposed in the 'Fit for 55' package in 2021 (e.g. 42% of hydrogen demand to be met with renewable hydrogen, compared to an initial target of 50%). Binding targets of this kind can send a clear signal to industry about a future marketplace for low-emission hydrogen and hydrogen-based fuels. In Japan, the updated Basic Hydrogen Strategy includes a target to meet 1% of the gas supply in existing networks with synthetic methane by 2030.