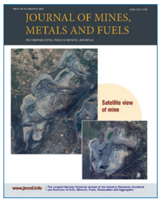
Journal of Mines, Metals and Fuels, *70(12) : 640-655; 2022. DOI: 10.18311/jmmf/2022/32321*

Print ISSN : 0022-2755

Journal of Mines, Metals and Fuels

Contents available at: *www.informaticsjournals.com/index.php/jmmf*



A Study on the Price Economics of natural gas vs. Green Hydrogen for Non-subsidized Industrial Customers

Prateek Vyas and Pramod Paliwal*

School of Petroleum Management, Pandit Deendayal Energy University, Gandhinagar - 382007, India; pramod.paliwal@spm.pdpu.ac.in

Abstract

Hydrogen as a molecule has seen traction from all the stakeholders of the energy ecosystem, with green hydrogen's ability to store renewable energy in volume and duration that overrides the capability of best of the battery storage system developed in the previous decades; hence, it also provides round the clock renewable power for both stationary and mobile applications. India Inc. has identified that its leadership in this initiative has a significant impact on its global economic presence, providing an opportunity to become energy independent in the next three decades and turn the fulcrum towards becoming a net energy exporter from one of the major importers of energy. India Inc has taken an aggressive approach termed as 1:1:1, targeting the cost of generating green hydrogen at $1/1kg/in 1 decade. This research paper identifies the positioning of key pricing variables like hydrogen generation technologies and storage and transport mechanisms for green hydrogen and simultaneously identifies the impact of 1:1:1 on natural gas pricing by 2030 overlaying the impact with the increasing demand for renewable fuel green hydrogen over clean fuel natural gas. This research paper will help identify readers with natural gas's estimated selling price point over the next decade under the influence of green hydrogen as the dominant fuel.

Keywords: *Carbon Tax, Energy Mix, Green Hydrogen, Green Hydrogen Pricing, natural gas, natural gas Pricing, Renewable Energy*

1.0 Introduction

1.1 Background

India's energy demand has seen a threefold rise in the last three decades; In the year 2000 the total energy demand was around 400 million ton of Oil Equivalent (Mtoe)[1], and to meet this rising energy demands the country has largely been dependent on fossil fuels namely coal, petroleum, and natural gas. For the last two decades, the domestic sourcing of coal has outpaced its imports, whereas it is not the same with oil and natural gas.

In the year 2000 with 28 Billion Cubic Meters (BCM) of total natural gas consumption, India's dependence on natural gas imports was negligible. But by 2010, natural gas imports increased to 20% of total consumption and in the last decade, 50% of total natural gas consumption is from imported sources i.e. 31BCM out of 62BCM consumption per annum[1]. This indicates a sharp transition in India's energy mix and with growing energy demand its reliance on natural gas for transportation and power generation has increased.

The use of natural gas as a fuel in the industry has increased about tenfold since 2010, against the backdrop

---

**Author for correspondence*

of an overall 50% increase in energy use in the sector. This has increased the share of natural gas in the industry from less than 2% to nearly 10%. India has a stated ambition to increase the share of natural gas in its primary energy mix to 15% by 2030, up from 6% in 2019[2].

Historically, the inclusion of natural gas-based power generation in the energy mix has been limited, but with increasing demand for reduction in emissions, industries are mulling their way towards renewable and cleaner fuel. However, renewable energy sources like wind and solar are not available consistently and they are not an onsite source of power generation. As a result, industries, even with PPA (Power Purchase Agreements) arrangements for renewable sources have to rely on sources like Diesel Generator (DG), Uninterrupted Power Supply (UPS), Batteries, and complex architecture for reliability, this eventually makes the facility grid dependent.

An alternative to avoid this complex architecture is by producing captive power which is either cleaner or renewable. This cleaner captive power generation with low or no carbon emission is possible by generating power using natural gas and implementing carbon capture or by generating power using blue or green hydrogen.

1.2 Contribution of this Study

This paper presents an analysis and identifies the market-generated selling price of natural gas by 2030. This is done by identifying the estimated levelized cost of electricity (LCOE) with green hydrogen (GH_2)as a fuel when produced at 1$/Kg, researching the possible price of GH_2 (green hydrogen) at the last mile of industrial consumption and considering the technological advancements in the equipment that could use GH_2 as feed and generate electricity. The study is reflective of natural gas pricing at these levels of LCOE to compete with GH_2 as a fuel.

- Whilst there are studies on estimated GDP growth rate, and estimated energy demand in India when the economy crosses $5 trillion and above, this research is unique to analyses of the impact on the pricing of natural gas with the advent of GH_2.
- This research will help the natural gas ecosystem from generation capacity, project timelines, project economics, and equipment life cycle cost for the next two decades. This will help predict the cost of Natural Galvis-a-vis estimated carbon tax/carbon capture estimates in the country.
- The research also enables government agencies and policy developers to realize the extent of carbon tax imposition to drive natural gas and GH_2 as fuel in the economy.

1.3 Structure of the Paper

In section 2, the natural gas and green hydrogen value chains in India are analyzed. In section 3 green hydrogen pricing points are analyzed with 1:1:1 as the base price of production and adding variables to reach last mile costs, also in section 3 these as delivered green hydrogen pricing points are used to identify LCOE for captive power generation. In section 4, LCOEs are identified using green hydrogen last mile estimated pricing and are set as baselines, and a corresponding range of natural gas prices are identified with scenarios including the impact of carbon tax and cost of carbon capture as a key variable. Finally, section 5 presents the results of these scenarios and discusses their implications.

2.0 natural gas Economy vs. Green Hydrogen Economy Debate

There is a strong debate in India around its investments and plan for natural gas, there is a strong government resolve to increase the utilization of natural gas in India's energy mix from 6% in 2019 to 15% by 2030. On the other side, the government of India has committed to reducing its carbon emissions by 33% compared to 2005 levels and achieving net zero by 2070. To support this, the government has set up steep targets of installing 400GW of renewable power by 2030 and has also drafted a hydrogen road map with the introduction of a hydrogen policy in early 2022.

This has initiated a debate about whether natural gas is a transition fuel or a bridge fuel for the next 3 to 4 decades before green hydrogen takes over as the primary fuel. This is also being discussed in context whether the government's investment in natural gas infrastructure in the previous decade was justified or have they spent too much on a transitioning fuel. This point of the debate can be discussed over 6 categories scale, sustainability, economics and efficiency, flexibility, infrastructure, and diversification. We will look at each of them in this segment.

2.1 Scale

India is the 4th largest Liquified Natural Gas (LNG) importer in the world, with 7% from Australia, 44% from Qatar, 15% from Russia, and 34% coming from the USA[3]. $60 bn of investment is planned in the natural gas infrastructure of the country by 2024, India has 17,000 km of pipelines laid and it envisages increasing this to 30,000 km by 2025. The natural gas demand is estimated to grow from 63 BCM in 2019 to 131 BCM in 2030 under the Stated Policy Scenario (STEPS) as per the India Energy Outlook 2021. With this scale of investment planned and already executed; clearly, natural gas is not considered as transition fuel alone, it has to be bridging fuel with these investments looking at a payback of 40 to 50 years.

2.2 Sustainability

An important question that arises is, whether natural gas being a fossil fuel can be classified as a sustainable fuel or not. As of 2017, the natural gas reserve in India were at 1427.13 BCM[4], whereas India consumes around 63 BCM per year. And with the current growth rate, this reserve will last for 15 years if the entire consumption is to be met by domestic production. However, it is observed that India meets its ~47% of natural gas demand from imports[5], and imports are increasing at a CAGR of 6% from 2011 to 2020, i.e. from 17.9 BCM in 2011 to 33.03 BCM in 2021[6]. If this trend continues in future; then natural gas infrastructure is going to be useful for the next 30 years. There are further methodologies to sustainably increase the utilization of natural gas infrastructure by blending natural gas with Bio Compressed natural gas (BioCNG), India has the potential of generating 82.15 BCM[7] of BioCNG per annum, and if 25% of this capacity is tapped by India then it increases the utility of infrastructure by a minimum of 5 years and beyond.

2.3 Economics and Efficiency

In 2019, approximately 28% of total natural gas consumption i.e. 17.3BCM[8] in India was for power generation. However, the majority of this total consumption is from domestic natural gas priced at 4.5 to 6.1$/MMBtu[9]. While considering natural gas for power generation, has steep competition from gradually falling prices of power generation from renewables. For India at natural gas, pricing of 7$/mmbtu using a Combined Cycle Gas Turbine (CCGT) would provide an LCOE of 77 to 108 $/MWh whereas solar PV would provide power at an LCOE of 54$/MWh to 163$/MWh from a solar PV farm and rooftop solar respectively[10]. These renewables are however generating an imbalance in the grid due to their intermittency. LCOE of reliable power at the site would include power generation cost, distribution cost, and implementation of local infrastructures like DG sets, UPS, batteries, and the cost of auxiliary power consumption associated with them. natural gas-based captive power generation has been a reliable source of onsite power generation and this would remain so with higher efficiency compared to the alternate mechanism of power generation.

2.4 Flexibility

In power generation, the OEMs have created an ecosystem with the flexibility to operate systems on hybrid fuels. Fuel cell manufacturer bloom energy has introduced fuel cells, which can work on a combination of biogas and natural gas. The systems can also operate on a combination of 50% natural gas and 50% hydrogen[11]. Moreover general electric's GE 7HA.02 gas turbine is designed to operate on 15-20 % hydrogen blended with natural gas and then transformed into a 100% Hydrogen based power generator[12]. Both conventional and path-breaking fuel cell-based technologies bring flexibility to enable the utilization of natural gas as a bridging fuel until green hydrogen in commercially available.

2.5 Infrastructure

With an ambition to increase the share of natural gas from 6% to 15% in the energy mix by 2030, India has planned an investment of $66 billion in infrastructure for the development and import of natural gas through LNG regasification terminals, distribution pipelines, and city gas distribution networks. 14,700km of the gas pipeline is being added to the existing 16,800 kms to form a national grid[13]. Infrastructure spending on the natural gas network becomes more viable with its ability to blend fuels like compressed biogas and hydrogen. A natural gas and hydrogen blending pilot project initiated by GAIL at Indore, India, is aimed at bridging the transition from a natural gas economy to a hydrogen economy[14]. A 2013 research in the United States indicate that 5% to 15% safe blending of hydrogen with natural gas and a mechanism for renewable power to be stored and transferred easily[15]. So Cal Gas in the United States has started operations to blend hydrogen with the natural gas pipeline, while they would initially start with 1% and will increase this gradually up to 20%[16].

2.6 Diversification

Energy system operators will look forward and identify avenues for diversifying sources to their electricity demands. While there is a policy push for natural gas, BioCNG, and hydrogen; there is an equivalent push for battery storage systems[17]. These technologies will help stabilize intermittent rush into the grid from renewables like solar and wind, and use of expensive source DG as a backup power source[18]. However, these storage technologies are marred by a need for special metals like nickel and cobalt and disruption in the global chain would make these mechanisms not very sustainable.

Government policies and investment indicate that the vision for natural gas is not just that of a transition fuel but for a bridging fuel to stay for at least the next four decades. But it is also true that future fuels and technologies like green hydrogen and battery storage are the sources of energy in the future. The price demand for natural gas will depend on these alternative fuels as well as on the ability of technologies to drive out carbon from natural gas and the efficiencies with various fuels that will be utilized in industrial captive power generation. To understand this we will analyze the value chain of natural gas and green hydrogen for non-subsidized industrial customers in India for power generation and we will use these sources as feed to best-in-class technologies to generate reliable power on-site. This analysis will help us identify the optimum pricing point of natural gas with the advent of green hydrogen in India.

3.0 An Overview of natural gas Value Chain for Non-Subsidized Industrial Consumers

This section analyses the value chain of natural gas for non-subsidized industrial customers in India, specifically for power generation. The pricing identification for the value chain is in US$ and a similar estimated value chain has been identified for green hydrogen in India. Though green hydrogen in the energy ecosystem is at a very nascent stage early information on possible pathways is analyzed and the pricing identification in terms of US$ has been arrived at for the analysis.

3.1 Non-Subsidized Industrial Consumers

Non-subsidized industrial consumers source natural gas for applications like the operation of the boiler, gas engines, or fuel cells for captive power generation, process utilization, or in laundry and kitchen areas. For industrial customers, the demand for natural gas is met through City Gas Distribution (CGD) or via LNG suppliers. The molecule that is received by a non-subsidized industrial customer is considered imported or has arrived in form of LNG. We will analyze the value chain of this imported natural gas for consumers in India.

3.2 natural gas Production

India is the 4th largest LNG importer in the world, with 7% from Australia, 44% from Qatar, 15% from Russia, and 34% from the USA[3]. Henry Hub is a natural gas pipeline network located in Erath, Louisiana, that serves as the official delivery location for futures contracts on the New York Mercantile Exchange (NYMEX)[19]. Since Henry Hub's pricing for natural gas is not indexed to crude oil, it creates true and transparent pricing of natural gas based on market demand. Though Henry Hub is primarily used for pricing natural gas for North America, due to the transparency levels of the hub, global LNG exporters like Qatar and Australia also utilize the Henry Hub pricing mechanism for spot prices and LNG prices. As a result to identify the natural gas pricing for industrial customers the base price is pegged at twelve monthly moving averages at Henry Hub (A) and the slope of the twelve-month moving average is multiplied by the base price to include the time factor from the price identification to the utilization of natural gas. Base price includes the cost of exploration and processing of natural gas

$$\text{Base Price} = A \times \text{Slope of 12-month moving average} \quad (1)$$

To export natural gas, it has to be converted to the liquid state and compressed to 600th of the volume of its gaseous state; this process is called liquefaction and natural gas is converted to LNG, the charges for this process are defined as B in Figure 1. The LNG gasification charges depending on volume vary from 0.7 to 4.2 \$/MMBtu[20].

$$\text{LNG Price} = A \times \text{Slope of } A + B \quad (2)$$

3.3 LNG Transportation

LNG is transported using LNG carriers for thousands of kms from various sources into India. The cost components include shipping charges (C), and insurance charges (D), and since both are services they attract GST components as indicated by (F) and (G) in Figure 1, imported natural gas also attracts custom duty as it enters Indian waters (G). Currently import duty on LNG is at 2.5% and an additional 10% SWS on the import duty takes the net component to 2.75%[21]. The imported liquefied natural gas also attracts central sales taxes CST (H) at 2% for interstate transmission of gas.

Foreign Component Charge (FCC) = LNG Price + Shipping Charges (C) + Insurance Charges (D) + GST Charges (E+F) + Custom Duty (G) + CST (H) *(3)*

3.4 LNG Regasification

LNG at the terminal is then re-gasified and transported to end -users through the national gas grid. The city gas distributors are responsible for delivering natural gas to industrial customers. The regasification and distribution charges are business variables for CGD entity and they provide a fixed component in INR termed as (I) in Figure 1, this net component is then subject to the state VAT component which varies from state to state and is denominated as component (J) in Figure 1.

Landed cost of natural gas = FCC*Exchange Rate + Re-gas and Transportation Component (I) + VAT (J) *(4)*

The value chain indicates that natural gas pricing depends on variables like the demand for natural gas, utilization factor of liquefaction facility, congestion in the transport of LNG, government policies in form of duties and taxes, and re-gasification and local transportation components. This is also indicative that when there is an alternative cleaner and greener fuel available in form of green hydrogen, it will impact the market demand for LNG.

4.0 green hydrogen Value Chain

The feed for green hydrogen is domestically generated renewable energy either in form of solar, wind, hydro, or other forms of renewable electricity. With India's demography, there are a plethora of sources to generate renewable energy consistently. Figure 2[22] indicates the energy map of India. The lowest solar electricity was bid in Rajasthan, India at 2.67US ¢/kWh[23] and 3.6 US ¢/kWh[24] for wind projects whereas the lowest bid for wind and solar hybrid is at 3.12 US ¢/kWh[25].

The renewable energy feed forms inputs to the electrolyzer in addition to the water or steam (Figure 3). The hydrogen molecule from this water is then derived through the electrolysis process. India, in its hydrogen policy released dated 17th February 2022 defined green hydrogen as one produced from the electrolysis of water using renewable energy[26].

Since green hydrogen is generated from the electrolysis of water it contains moisture, and hence

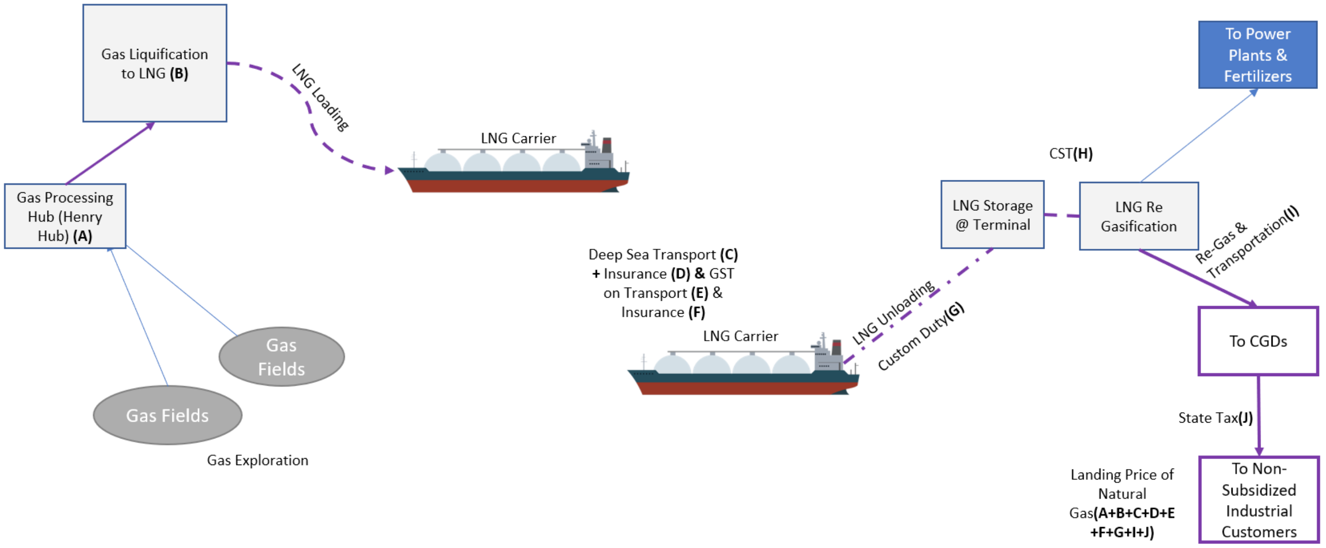


Figure 1. natural gas value chain.

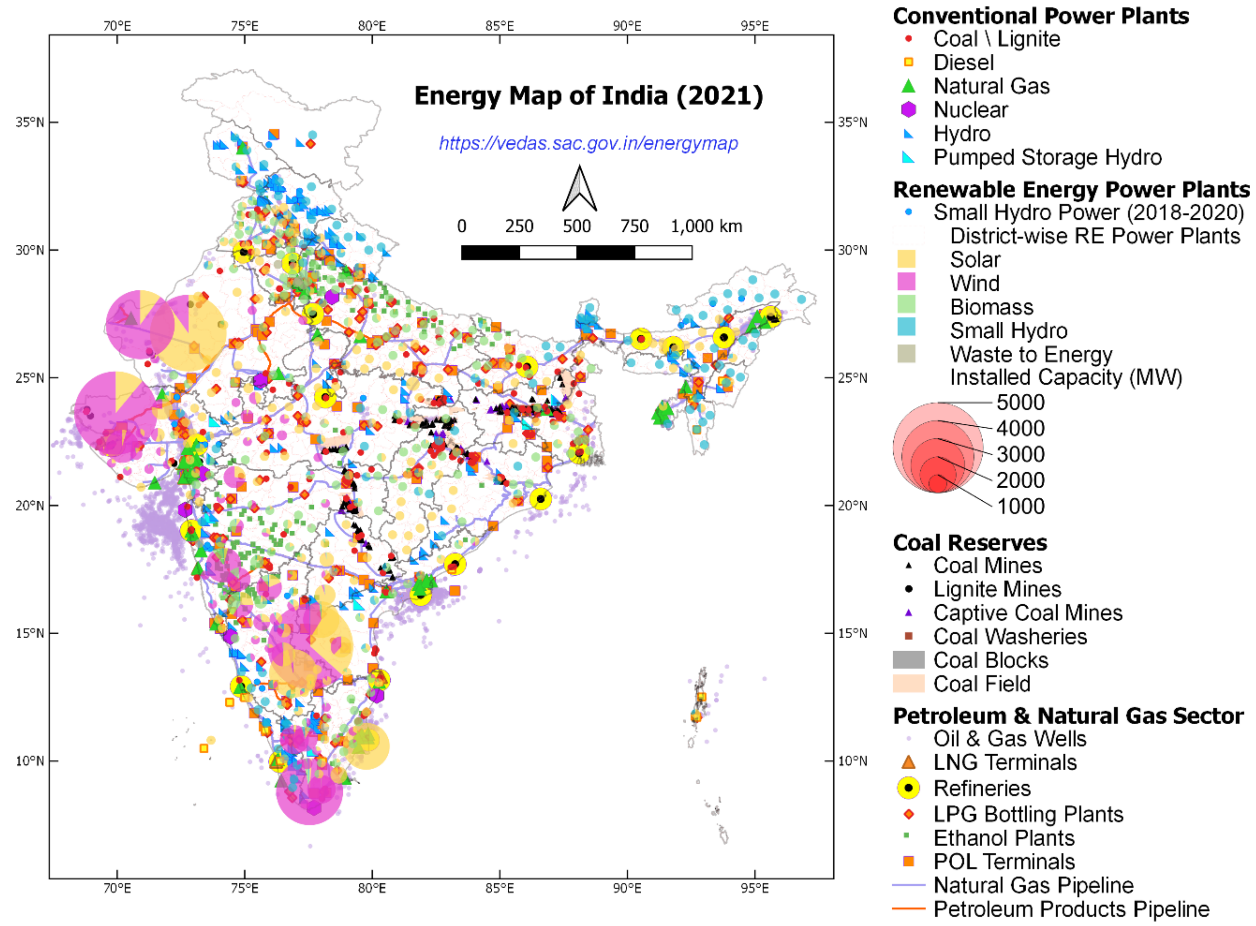


Figure 2. Energy Map of India[22].

drying of H_2 is required. The dried H_2 at a purity level of 99.9% is then compressed for various purposes like storage for short to medium-term, transmission in dedicated H_2 gas pipelines or blending with natural gas and transmission. A blending pilot project for up to 18% of natural gas pipelines is being implemented as a part of the Hydrogen mission of the government of India[27]. Other methodologies of transporting hydrogen as a liquid vector by converting it into ammonia or methanol. And at the point of utilization either it can be used directly in these vector modes or H_2 can be derived. H_2 in a liquid state as LH_2(Liquid Hydrogen) can also be transported by road or sea. However, the process is cryogenic and consumes a huge amount of electricity, and is not yet economical. Another innovative mechanism discovered is by converting H_2 into methane using a process called Methanation. This process has been available for decades[28] using minerals and chemicals but recently with the bio-methanation process developed by Electrochaea[29] for converting H_2 into biomethane, now this biomethane can also be transported using the existing natural gas network across the country.

For this research paper, the parameters that drive the pricing of green hydrogen are:

- Utility Feed
- Electrolysis Efficiency
- Processing Efficiency
- Compression Cost
- Storage and Transportation charges.

5.0 Green Hydrogen Pricing Points for Industrial Customers By 2032

The premise of this research paper is on identifying natural gas market pricing when GH_2 achieves the target set by India Inc in 2021 of 1:1:1[30]. Incidentally not just in India, DOE in the United States has also set a target of 1:1:1 and to propel this they have initiated Energy Earthshot in June 2021[31]. The target is to reach a production cost of 1 Kg of green hydrogen of US $1 in 1 decade. And this has been considered a starting point for identifying the landed cost of green hydrogen for industrial customers in India for power generation. As referred to in Figure 4, we will identify the cost range of Q, R, and S to identify the pricing range of green hydrogen.

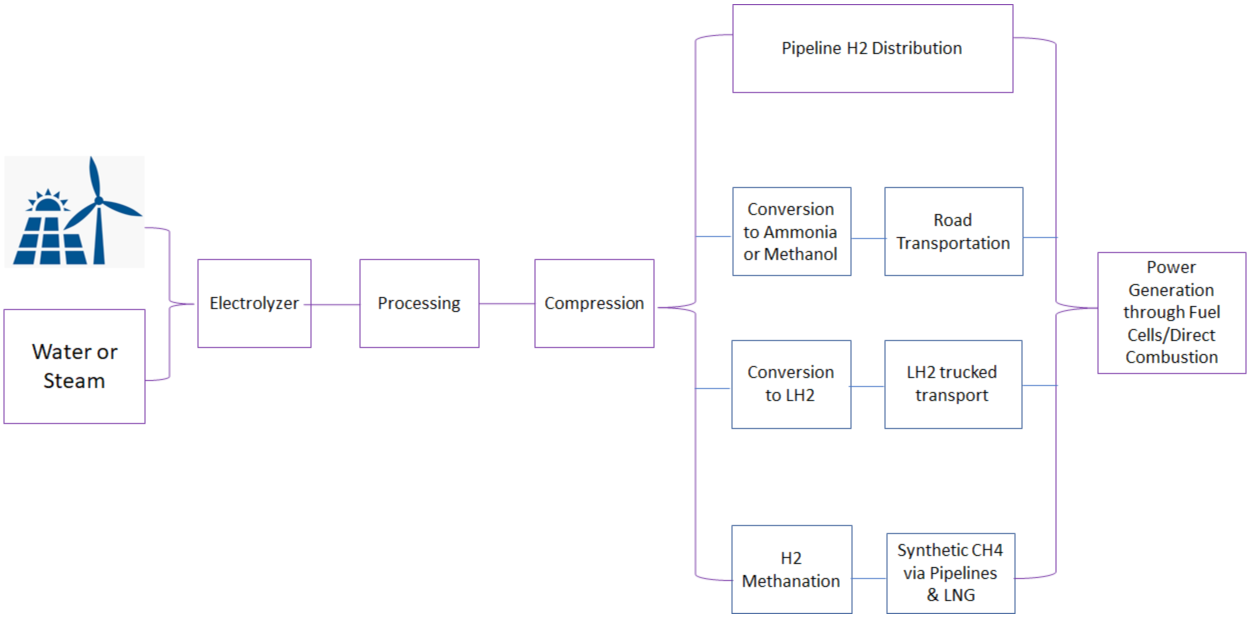


Figure 3. Green Hydrogen Value Chain for power generation.

Figure 4. Green hydrogen total cost of distribution.

5.1 Preparation Cost (Q)

The preparation of hydrogen involves processes like cooling, drying, and compression. However, the process of cooling is only attributable to green hydrogen production from solid oxide electrolyzers; since they operate at high temperatures, and hence the output of green hydrogen is also at a higher temperature which needs cooling before the state of drying and compression. These two stages are common to all technologies since green hydrogen is generated from the electrolysis of water and in its raw form; it contains moisture ranging up to 20%. This moisture removal is vital before the process of compression and hence drying is a key process of preparing green hydrogen for distribution.

5.2 Distribution Cost (R)

The last step of preparing green hydrogen for distribution includes compression. GH_2 is mostly distributed locally through three options i.e. (1) Compressed GH_2, where the GH_2 is compressed at pressure up to 350bar[32] and transported using high-pressure tube trailers. This is an economical option for distribution from the 200 to 300 Km range. (2) Liquefied GH_2 tankers, where GH_2 are liquefied using cryogenic techniques and transported to the destination. Although the liquefaction process is expensive, it enables hydrogen to be transported more efficiently (compared to high-pressure tube trailers) over longer distances by truck, railcar, ship, or barge. To distribute LH_2 through this process it must be compressed to 82 Bar pressure, the process also consumes up to 6.4kWh/kg of LH_2, but, it can carry larger volumes in a trip. (3) The last option for distribution is through gas pipelines, where GH_2 can be blended with existing natural gas pipelines for up to 18%. Alternatively, the transmission of GH_2 can also be done by laying dedicated gas pipelines, (with a significant CAPEX) which could be more cost competitive in the longer run[33].

5.3 Fueling Station (S)

The most expensive component is the fueling station or localized distribution component. However, this component has the capability of improvement with increased demand and growth in the number of buyers. But in the case of industrial consumers sourcing GH_2 with options indicated above in R, the cost components include bulk storage, compression/pumping, high-pressure buffer storage, and pre-cooling units[34]. The fueling station component cost has seen a decline in cost by 87% in 2020 compared to 2012 levels, this is due to increased demand and the trend is estimated to continue from 2020 to 2030.

Total Distribution Cost -TDC (T) = P + Q + R + S *(5)*

The below analysis is from data published by the Hydrogen Council[33], with the only difference being that the production cost of GH_2 has been considered at 1 $/kg in line with our earlier estimation of 1:1:1 being achieved.

From Figure 5, it is observed that the estimated cost of GH_2 for industrial customers in India will be in the range of 3.1 to 3.7 $/kg from 2030 onwards. GH_2 at this cost level will be fed if it is supposed to be utilized for 24x7 sustainable, reliable, and 100% renewable onsite power production.

6.0 Estimated LCOE for GH2-based Power Generation by 2032

To identify LCOE using GH_2 a decade from today, we would be considering only fuel cells as a source of power generation for three reasons:

1 As of today there is a clear path for fuel cells to run on 100% hydrogen, a few commercial models are ready and available for application[35].

2 While fuel cells generate power, they do not emit any other greenhouse gases. Whereas engines emit Nitrous Oxide (NO) even while they internally combust hydrogen for power generation[36].

3 For engines to be operated at high efficiency they need to be used in Combined Heat and Power (CHP) mode, which is subject to operating load and off-take guarantee of heat and related complications, whereas fuel cells have high electrical efficiency and we can have LCOE comparison purely based on electrical efficiency of power generating equipment. For this research paper, two advanced fuel cell technologies are

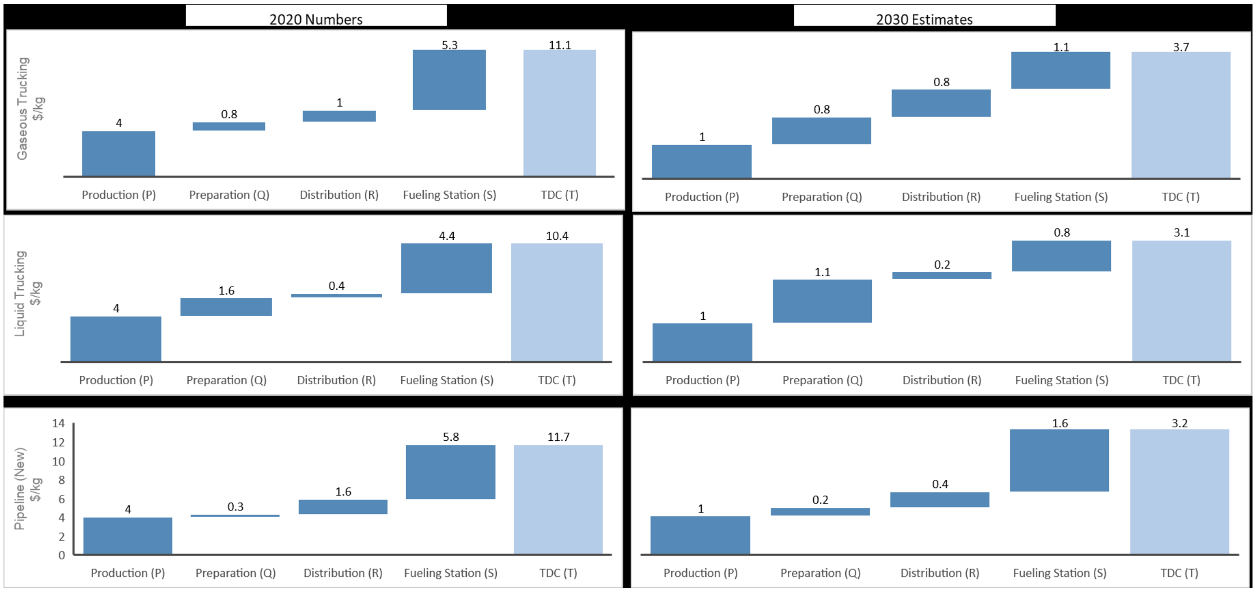


Figure 5. GH_2 total distribution cost 2020 levels vs. estimated 2030.

being considered i.e. Polymer Electrolyte Membrane (PEM) and Solid Oxide Fuel Cell (SOFC). These technologies are looked upon as the most efficient and futuristic.

Table 1 indicates the LCOE analysis using green hydrogen pricing identified in Figure 5 above, this indicates that onsite renewable and reliable power generation using GH_2 in India is estimated to cost 18 to 20 ¢/kWh. Further, a sensitivity analysis of varying GH_2 price and the equipment EPC price impact on the LCOE as well, as the impact of efficiency change on LCOE while keeping EPC cost fixed at 1500 $/kW for both the technologies is analyzed and as indicated in Table 2 for SOFC as fuel cell technology, and in Table 3 for PEM as fuel cell technology respectively.

From the above analysis, we observe that when the GH_2 price is in the range of 3.1 to 3.7 $/kg, the estimated LCOE for onsite power generation will be in the range

Key assumptions for LCOE analysis:

Table 1. LCOE analysis for GH_2 as fuel

	Scale	**SOFC Fuel Cells**	**PEM Fuel Cells**
Capacity*	kW	1000	1000
Historical EPC Capex[37]	$/kW	10000	2140
Learning Rate	%	14%	14%
Estimated 2030 Capex	$/kW	2354	535
Total EPC Capex by 2030	$	2,354,000	535,000
Plant lifetime*	Years	20	20
Plant utilization factor*	%	95%	95%
Plant efficiency (BOL) *	%	66%	58%
Operating Cost			
Annual kWh generated	kWh	8,322,000	8,322,000
Annual GH_2 consumed	kg	438,948	499,492
GH_2 Cost	$/kg	3.1	3.1
Warranty and Insurance (% of Capex)*	%	1%	1%
Warranty and Insurance escalation*	%	1%	1%
O and M (% of Capex)*	%	5%	5%
Annual Inflation[38]	%	6.7%	6.7%
Capital Structure[10]			
Debt	%	40%	40%
Cost of Debt	%	8%	8%
Equity	%	60%	60%
Cost of Equity	%	12%	12%
Tax Rate	%	25%	25%
WACC	%	9.60%	9.60%
LCOE	**$/kWh**	**0.20**	**0.18**

*Researchers assumption

Table 2. Sensitivity analysis for SOFC-based GH_2 fuel cells

SOFC EPC ($/kW) GH_2 ($/kg)	1500	1600	1700	1800	1900	2000	2100	2200	2300	2400
3.00	0.18	0.18	0.18	0.19	0.19	0.19	0.19	0.19	0.20	0.20
3.10	0.18	0.19	0.19	0.19	0.19	0.19	0.20	0.20	0.20	0.20
3.20	0.19	0.19	0.19	0.19	0.20	0.20	0.20	0.20	0.21	0.21
3.30	0.19	0.20	0.20	0.20	0.20	0.20	0.21	0.21	0.21	0.21
3.40	0.20	0.20	0.20	0.20	0.21	0.21	0.21	0.21	0.22	0.22
3.50	0.20	0.20	0.21	0.21	0.21	0.21	0.22	0.22	0.22	0.22
3.60	0.21	0.21	0.21	0.21	0.22	0.22	0.22	0.22	0.23	0.23
3.70	0.21	0.21	0.22	0.22	0.22	0.22	0.23	0.23	0.23	0.23
3.80	0.22	0.22	0.22	0.22	0.23	0.23	0.23	0.23	0.23	0.24
3.90	0.22	0.22	0.23	0.23	0.23	0.23	0.24	0.24	0.24	0.24
4.00	0.23	0.23	0.23	0.23	0.24	0.24	0.24	0.24	0.24	0.25

SOFC Eff($/kW) GH_2 ($/kg)	57%	58%	59%	60%	61%	62%	63%	64%	65%	66%
3.00	0.20	0.20	0.20	0.19	0.19	0.19	0.19	0.18	0.18	0.18
3.10	0.21	0.20	0.20	0.20	0.20	0.19	0.19	0.19	0.19	0.18
3.20	0.21	0.21	0.21	0.20	0.20	0.20	0.20	0.19	0.19	0.19
3.30	0.22	0.21	0.21	0.21	0.21	0.20	0.20	0.20	0.20	0.19
3.40	0.22	0.22	0.22	0.21	0.21	0.21	0.21	0.20	0.20	0.20
3.50	0.23	0.23	0.22	0.22	0.22	0.21	0.21	0.21	0.21	0.20
3.60	0.23	0.23	0.23	0.22	0.22	0.22	0.22	0.21	0.21	0.21
3.70	0.24	0.24	0.23	0.23	0.23	0.22	0.22	0.22	0.21	0.21
3.80	0.25	0.24	0.24	0.24	0.23	0.23	0.23	0.22	0.22	0.22
3.90	0.25	0.25	0.24	0.24	0.24	0.23	0.23	0.23	0.22	0.22
4.00	0.26	0.25	0.25	0.25	0.24	0.24	0.24	0.23	0.23	0.23

Table 3. Sensitivity analysis for PEM-based GH_2 fuel cells

PEM EPC ($/kW) GH_2 ($/kg)	500	700	900	1100	1300	1500	1700	1900	2100	2300
3.00	0.18	0.18	0.18	0.19	0.19	0.20	0.20	0.21	0.21	0.22
3.10	0.18	0.19	0.19	0.19	0.20	0.20	0.21	0.21	0.22	0.22
3.20	0.19	0.19	0.20	0.20	0.20	0.21	0.21	0.22	0.22	0.23
3.30	0.19	0.20	0.20	0.21	0.21	0.21	0.22	0.22	0.23	0.23
3.40	0.20	0.20	0.21	0.21	0.22	0.22	0.22	0.23	0.23	0.24
3.50	0.20	0.21	0.21	0.22	0.22	0.23	0.23	0.23	0.24	0.24
3.60	0.21	0.21	0.22	0.22	0.23	0.23	0.24	0.24	0.24	0.25
3.70	0.21	0.22	0.22	0.23	0.23	0.24	0.24	0.25	0.25	0.25
3.80	0.22	0.22	0.23	0.23	0.24	0.24	0.25	0.25	0.26	0.26
3.90	0.22	0.23	0.23	0.24	0.24	0.25	0.25	0.26	0.26	0.27
4.00	0.23	0.23	0.24	0.24	0.25	0.25	0.26	0.26	0.27	0.27

PEM Eff($/kW) **$GH_2$ ($/kg)**	**57%**	**58%**	**59%**	**60%**	**61%**	**62%**	**63%**	**64%**	**65%**	**66%**
3.00	0.20	0.20	0.20	0.19	0.19	0.19	0.19	0.18	0.18	0.18
3.10	0.21	0.20	0.20	0.20	0.20	0.19	0.19	0.19	0.19	0.18
3.20	0.21	0.21	0.21	0.20	0.20	0.20	0.20	0.19	0.19	0.19
3.30	0.22	0.21	0.21	0.21	0.21	0.20	0.20	0.20	0.20	0.19
3.40	0.22	0.22	0.22	0.21	0.21	0.21	0.21	0.20	0.20	0.20
3.50	0.23	0.23	0.22	0.22	0.22	0.21	0.21	0.21	0.21	0.20
3.60	0.23	0.23	0.23	0.22	0.22	0.22	0.22	0.21	0.21	0.21
3.70	0.24	0.24	0.23	0.23	0.23	0.22	0.22	0.22	0.21	0.21
3.80	0.25	0.24	0.24	0.24	0.23	0.23	0.23	0.22	0.22	0.22
3.90	0.25	0.25	0.24	0.24	0.24	0.23	0.23	0.23	0.22	0.22
4.00	0.26	0.25	0.25	0.25	0.24	0.24	0.24	0.23	0.23	0.23

of 18 to 24 ¢/kWh. Therefore, this becomes the range we work upon in the next section as target LCOE using natural gas with an additional cost component of a carbon tax.

7.0 Identification of natural gas Market Price in 2030

Natural gas as we have seen will be a bridging fuel for India, and it is estimated to be around for the next 40 years. Since natural gas is a fossil fuel containing carbon; its demand and pricing levels are bound to be impacted by how the market perceives carbon and carbon mitigation strategies by the government. India has committed to being net zero by 2070 during the COP26 summit in Glasgow on 02 November 2021[39] and will have a definite goal to either refuse, reduce or reuse the carbon emitted. This would mean an inevitable and definitive mechanism of the carbon tax will be available in India and would also create a market for carbon capture and utilization. As of today, 27 countries including the European Union (EU) have introduced carbon tax for emission reduction. In this section, we will analyze the extent to which carbon taxes will be implemented in India by 2030 and the estimated annual escalation rate, we will also identify the add-on cost of carbon capture to avoid carbon taxes as an offset mechanism.

7.1 Carbon Tax in India

Fossil fuels are charged with carbon taxes based on carbon content, the rationale being it is an effective tool for achieving domestic emissions targets. Since these taxes increase the prices of fossil fuels, electricity, and consumer goods products, and lower prices for fuel producers. They would in effect promote switching to fuels with lower carbon emissions or cleaner in composition, and would also promote energy conservation and demand-side management principles.

An estimate by IMF in 2019 says that a carbon tax of 35 $/ton of CO_2 in India and 70 $/ton of CO_2 in the USA is an adequate number to meet their 2015 Paris agreement targets of 2030 compared to the baseline[40]. One research in 2020 indicates at a carbon tax of 8$/ton CO_2 effective immediately is an adequate number for the mitigation of carbon emission[41]. Where research from Shakti Sustainable Research Foundation[42] says that there can be two motives for a carbon tax: (1) SCC – the social cost of carbon, which would mean the impact or loss to society due to carbon emissions; (2) Abatement approach – where the carbon taxes collected to be utilized for the mechanism to reduce emissions and motivate alternate cleaner options.

With either of the options, the research says that for India to reach its target commitment of a 33-35 % reduction in carbon emissions by 2030 against 2005 levels (as per India's commitment to the nationally determined contribution (NDC) under the Paris Agreement on climate change), it is advised to have India's carbon tax of 35 $/ton CO_2. Also observing parallels with for example the strategy adopted by Iceland by benchmarking its carbon tax to the EU Emission Trading System (ETS) by 2014 and then increasing at a rate of 3% per annum or inflation rate in the country whichever is higher. Along similar lines for our analysis in this research paper, we will assume that the carbon tax in India by 2030 will be around 35 \$/ton of CO_2 and escalate in coherence with the inflation rate.

7.2 Cost of Carbon Capture

While entities could choose cleaner and greener sources of power generation and avoid carbon tax, there is an alternate mechanism for avoiding emissions by implementing carbon capture at the captive site and avoiding carbon tax. However, this carbon capture technology is under continuous development and improvement stage and there are cost implications to it. Research in the U.S. says that for carbon capture implementation on natural gas-based power generation technology, an estimated cost of USD 2018 of carbon capture is \$76/Ton and for transportation purposes, an additional cost in the range of \$1.3 to \$15.3 is estimated based on the quantum of transportation per annum[43]. Another research with 2015\$ estimates ranges from \$67 to \$115 per ton of CO2[44]. Another research in 2021\$ finds that by 2030 the cost of carbon capture and compression is estimated to be around \$42/ton and for transportation and storage an additional cost of \$5 to \$20/ton[45]. From the above information, we would be computing the estimated price range of natural gas in 2030.

8.0 natural gas Pricing Computation

Natural gas pricing computation for 2030 is performed considering SOFC and PEM as the (prevalent) fuel cell technologies to draw parallels. As a result, we will be analyzing the natural gas pricing to achieve a target of 18 to 24 ¢/kWh and draw the sensitivity analysis and carbon tax cost from Table 4.

Table 4. Carbon Tax and Carbon Capture cost estimation for 2030 and beyond

Element	**\$/Ton of CO2**	**Annual Escalation/Reduction**
Carbon Tax	35	At an inflation rate of ~6.7%
Cost of Carbon Capture	47 to 62	Assumed 0%

Table 5. Natural gas price identification at target LCOE

	Scale	**SOFC Fuel Cells**	**PEM Fuel Cells**	**SOFC Fuel Cells**	**PEM Fuel Cells**
Capacity*	kW	1000	1000	1000	1000
Historical EPC Capex[37]	\$/kW	10000	2140	10000	2140
Learning Rate	%	14%	14%	14%	14%
Estimated 2030 Capex	\$/kW	2354	500	2354	500
Total EPC Capex by 2030	\$	2,354,000	500,000	2,354,000	500,000
Plant lifetime*	Years	20	20	20	20
Plant utilization factor*	%	95%	95%	95%	95%
Plant efficiency (BOL)*	%	66%	58%	66%	58%
Carbon Emission	T/MWh	0.304	0.346	0.304	0.346
Operating Cost					
Annual kWh generated	kWh	8,322,000	8,322,000	8,322,000	8,322,000
Annual NG consumed	MMBtu	47,326	53,854	47,326	53,854
NG Price (Identified for Target LCOE)	*\$/MMBtu*	*21.2*	*25.5*	*21.1*	*25.25*
Carbon Capture and Storage Cost	\$/Ton CO2	0	0	62.0	62.00
Carbon Tax	\$/Ton CO2	35	35	0	0
Warranty and Insurance (% of Capex)*	%	1%	1%	1%	1%

Warranty and Insurance escalation*	%	1%	1%	1%	1%
O and M (% of Capex)*	%	5%	5%	5%	5%
Annual Inflation[38]	%	6.7%	6.7%	6.7%	6.7%
Capital Structure[10]					
Debt	%	40%	40%	40%	40%
Cost of Debt	%	8%	8%	8%	8%
Equity	%	60%	60%	60%	60%
Cost of Equity	%	12%	12%	12%	12%
Tax Rate	%	25%	25%	25%	25%
WACC	%	9.60%	9.60%	9.60%	9.60%
Target LCOE	**$/kWh**	**0.18**	**0.18**	**0.18**	**0.18**

*Researchers assumption

Table 6. Natural gas price identification sensitivity analysis

@Target LCOE of 0.18 $/kWh

SOFC EPC ($/kW) Carbon Tax ($/Ton CO2)	1500	2000	2400
35	25.10	22.90	21.20
75	21.50	19.40	17.70
105	19.00	16.90	15.00
135	16.30	14.20	12.40

@2000 $/kW EPC Price

SOFC Target LCOE ($/kW) Carbon Tax ($/Ton CO2)	0.18	0.22	0.24
35	22.90	30.60	34.50
75	19.40	27.10	31.00
105	16.90	24.50	28.30
135	14.20	21.90	25.70

@Target LCOE of 0.18 $/kWh

PEM EPC ($/kW) Carbon Tax ($/Ton CO2)	500	1000	1500
35	25.51	23.59	21.67
75	21.50	19.40	18.18
105	19.39	17.47	15.55
135	16.77	14.94	12.93

@1500 $/kW EPC Price

PEM Target LCOE ($/kW) Carbon Tax ($/Ton CO2)	0.18	0.22	0.24
35	21.67	28.44	31.83
75	18.18	24.95	28.34
105	15.55	22.33	25.72
135	12.93	19.77	23.09

Key assumptions for natural gas price identification:

The above analysis suggests that the natural gas pricing at a target LCOE of 18 ¢/kWh would mean gas prices in the range of 21 to 25 $/MMBtu. However, it is important to run sensitivities around this price estimation. The reason is the extremely good learning rates* of solid oxide fuel cells and in Table 5 the carbon tax is assumed at 35$/ton of CO_2. $ 2022 e carbon taxes of 27 countries vary from 1$/ton of CO_2 in Poland to 137$/ton of CO_2 in Sweden[46].

The Table 6, sensitivity analysis indicates the estimated natural gas pricing varies with two important aspects:

(1) Federal government's policy on the carbon tax: Higher the carbon tax; the lower the estimated selling price of natural gas. It also indicates the effect on natural gas pricing with a higher cost of implementing CCS.

(2) With the technological advancements, lower the EPC price of fuel cell technologies higher would be the market-identified price of natural gas.

---*In machine learning and statistics, the learning rate is a tuning parameter in an optimization algorithm that determines the step size at each iteration while moving toward a minimum of a loss function.*

9.0 Discussion

While there is a multitude of geopolitical incidents that will shape the adaptability of GH_2, a couple of prominent such events are sudden demand post-Covid 19 recoveries in the market and conflict between Russia and Ukraine. It's a matter of discussion how such events would reset and settle the flow of natural gas demand-supply across the globe and affect its alternate GH_2 in the future. The price implication on natural gas has been northwards. During the period of an ongoing war between Russia and Ukraine, the Henry Hub index spot pricing varied from 4.4$/mmbtu in February 2022 to 9.85$/mmbtu in August 2022[47]. Such unpredictable incidents in the future would also govern in the next decade while shaping the estimated market price of GH_2.

10.0 Managerial Implications and Conclusion

The research indicates the probable journey of GH_2 pricing and hence impact of the same on natural gas pricing in the next decade, this allows the market to observe an opportunity to plan utility expansion, power purchase agreements, captive power generation sources, possible avenues of clean and green power generation while offering price predictability in their journey towards net-zero targets. The research also provides a dotted line for the industry to estimate how much it would cost. As identified in section 9 on natural gas pricing computation in this research paper, saturation in the learning curve of fuel cells and increasing carbon tax will cumulatively drive down the natural gas price in future. From the analysis and research conducted in the research paper, it can be realized that natural gas is the bridging fuel for India; it is bound to be around for 3 to 4 decades. And the natural gas for India will be a combination of imported and domestic natural gas. While India embarks on its journey of energy independence, green hydrogen will be the indigenous fuel to help India achieve its energy independence and emissions target. In this journey with India's target of producing GH_2 at 1$/kg by 2030, the landed cost of GH_2 including transportation and storage will bring the last mile price of green hydrogen in the range of 3.1 $/kg to 3.7$/kg; which will reduce in the coming years with development in transportation mechanism. While this GH_2 is used for captive power generation for reliable and resilient power; it will provide electricity at an LCOE range of 18 to 24 ¢/kWh. The alternative source to achieve this electricity is natural gas. However, natural gas being fossil in nature may be subject to either a carbon tax or will require implementation of carbon capture and storage. The carbon tax is estimated to be in the range of 35$/ton of CO_2, to begin with by 2030 and increase thereafter; whereas CCS will be at higher levels and inflation impacting its operational cost year on year. Depending on the technological advancements it is envisaged that the natural gas prices that the market would identify will be in the range of 14 to 23 $/MMBtu variance and more likely in the range of 16.9 to 19.40 $/MMBtu with aggressive government policies and infrastructure development in favour of green hydrogen. Thus, green hydrogen as a fuel is poised to play a significant role in India's Energy Mix in the near future onwards.

11.0 Appendix A: Abbreviations

BCM	-	Billion Cubic Meter
BioCN	-	Bio-Compressed natural gas
CCGT	-	Combine Cycle Gas Turbine
CHP	-	Combined Heat and Power
CGD	-	City Gas Distributors
DG	-	Diesel Generator
EU	-	European Union
ETS	-	Emission Trading System
FCC	-	Foreign Component Charge
LCOE	-	Levelized Cost of Electricity
Mtoe	-	Million tons of Oil Equivalent
PPA	-	Power Purchase Agreement
PEM	-	Polymer Electrolyte Membrane
SOEC	-	Solid Oxide Electrolyzer Cell
LNG	-	Liquified natural gas
STEPS	-	Stated Policy Scenarios
SCC	-	Social Cost of Carbon
GH_2	-	Green Hydrogen
LH2	-	Liquid Hydrogen
NOx	-	Nitrous Oxide
NYMEX	-	New York Mercantile Exchange
UPS	-	Uninterrupted Power Supply

12.0 References

1. International Energy Agency (IEA). "India Energy Outlook 2021", International Energy Agency. 2021.
2. M. o. P. Government of India. "Power sector at a Glance ALL India", 28 March 2022. [Online]. Available: https://powermin.gov.in/en/content/power-sector-glance-all-india
3. I. India, "National Investment Promotion and Facilitation Agency". 28 March 2022. [Online]. Available: https://www.investindia.gov.in/sector/oil-gas/natural-gas
4. Worldometer, "India natural gas". 30 March 2022. [Online]. Available: https://www.worldometers.info/gas/india-natural-gas/#:~:text=India%20holds%2043%20 trillion%20 cubic,22.1%20times%20its%20annual%20consumption
5. G. o. I. Ministry of Petroleum and natural gas, "natural gas Import". 30 March 2022. [Online]. Available: https://www.ppac.gov.in/content/153_1_ImportNAturalgas.aspx
6. G. o. I. Ministry of Petroleum and natural gas, "natural gas Consumption", 30 March 2022. [Online]. Available: https://www.ppac.gov.in/content/152_1_Consumption.aspx
7. I. O. C. Limited, "Compressed Bio Gas (CBG) The Fuel of the Future", 30 March 2022. [Online]. Available: https://www.iocl.com/download/White_Paper_EOI_1.pdf
8. I. E. Agency, "natural gas demand by sector in India in the Stated Policies Scenario, 2000-2040", 30 March 2022. [Online]. Available: https://www.iea.org/data-and-statistics/charts/natural-gas-demand-by-sector-in-india-in-the-stated-policies-scenario-2000-2040
9. G. o. I. Petroleum Planning and Analysis Cell, "Petroleum Planning and Analysis Cell", 30 March 2022. [Online]. Available: https://www.ppac.gov.in/WriteReadData/CMS/202203310524116787185DomesticNaturalGasPricefortheperiod1stApril2022-30thSeptember2022.pdf
10. Lazard, "Lazard's Levelized Cost of Energy Analysis — Version 15.0," Lazard, New York. 2021.
11. B. E. Corporation. "Bloom Energy Technology". 30 March 2022. [Online]. Available: https://www.bloomenergy.com/technology/
12. G. Electric. "Long rigde energy case study". 30 March 2022. [Online]. Available: https://www.ge.com/gas-power/resources/case-studies/long-ridge-energy
13. B. Today, "India to see $66 billion investment in building of gas infrastructure, says Dharmendra Pradhan," 03 December 2020. [Online]. Available: https://www.businesstoday.in/latest/economy-politics/story/india-to-see-66-billion-investment-in-building-of-gas-infrastructure-says-dharmendra-pradhan-280524-2020-12-03
14. G. o. I. Press Information Bureau, "GAIL starts India's maiden project of blending hydrogen into CGD network". 02 February 2022. [Online]. Available: https://pib.gov.in/PressReleasePage.aspx?PRID=1794428
15. O. A. a. M. P. M. W. Melaina, "Blending Hydrogen into natural gas Pipeline Networks: A Review of Key Issues". National Renewable Energy Laboratory, Department of Energy, Office of Energy Efficiency and Renewable Energy, U.S.A., Denver, 2013.
16. S. Gas, "SoCalGas Among First in the Nation to Test Hydrogen Blending in Real-World Infrastructure and Appliances in Closed Loop System". 30 September 2021. [Online]. Available: https://newsroom.socalgas.com/press-release/socalgas-among-first-in-the-nation-to-test-hydrogen-blending-in-real-world
17. E. Storage, "India's Ministry of Power clarifies 'essential role' of energy storage systems". 01 February 2022. [Online]. Available: https://www.energy-storage.news/indias-ministry-of-power-clarifies-essential-role-of-energy-storage-systems/
18. M. o. N. a. R. Energy, "Energy Storage". 30 March 2022. [Online]. Available: https://mnre.gov.in/new-technologies/energy-storage
19. Investopedia, "Henry Hub", 01 July 2019. [Online]. Available: https://www.investopedia.com/terms/h/henry_hub.asp#:~:text=What%20Is%20Henry%20Hub%3F,markets%20in%20the%20United%20States
20. H. M. R. B. A. F. Jinrui Zhang. "Comprehensive review of current natural gas liquefaction processes on technical and economic performance". *Applied Thermal Engineering*. 2020; 166. https://doi.org/10.1016/j.applthermaleng.2019.114736
21. I. Times, "Budget 2022: Bring natural gas under GST to realise vision of gas-based economy", 27 January 2022. [Online]. Available: https://energy.economictimes.indiatimes.com/news/oil-and-gas/budget-2022-bring-natural-gas-under-gst-to-realise-vision-of-gas-based-economy/89146169#:~:text=Presently%2C%20import%20of%20LNG%20attracts,only%20Rs%201%20per%20tonne
22. G. o. India, "Energy map of India," 30 March 2022. [Online]. Available: Energy map of India.
23. F. Express, "Solar auction tariff hits new low of Rs 1.99 per unit", 20 December 2020. [Online]. Available: https://www.financialexpress.com/industry/solar-auction-tariff-hits-new-low-of-rs-1-99-per-unit/2153422/
24. E. Times, "Tariff of Rs 2.69 to Rs 2.70 per unit discovered in SECI's latest wind power gen", 21 December 2021. [Online]. Available: https://energy.economictimes.indiatimes.com/news/renewable/tariff-of-rs-2-69-to-rs-2-70-per-unit-discovered-in-secis-latest-wind-power-generation-bid/88053811#:~:text=New%20Delhi%3A%20The%20tariff%20discovered,is%2039.99%20gigawatt%20(GW)
25. F. Express, "Tariff falls to Rs 2.34/unit in wind-solar hybrid auctions". 21 August 2021. [Online]. Available: https://www.financialexpress.com/industry/tariff-falls-to-rs-2-34-unit-in-wind-solar-hybrid-auctions/2316198/

26. G. o. India, “Green_Hydrogen_Policy”. 17 February 2022. [Online]. Available: https://powermin.gov.in/sites/default/files/Green_Hydrogen_Policy.pdf
27. G. o. India, “Hydrogen Mission,” 02 September 2021. [Online]. Available: https://mopng.gov.in/en/page/12
28. H. T. Martin Seemann, “9 - Methane synthesis”. *Substitute natural gas from Waste, Academic Press.* 2019; pp. 221-243. https://doi.org/10.1016/B978-0-12-815554-7.00009-X
29. Electrochaea, “Technology”. 30 March 2022. [Online]. Available: https://www.electrochaea.com/technology/
30. R. I. Limited, “ME12102021,” 12 October 2021. [Online]. Available: https://www.ril.com/DownloadFiles/Corporate Announcements/MR12102021.pdf
31. O. o. E. E. a. R. Energy, “Hydrogen Shot”. 31 September 2021. [Online]. Available: https://www.energy.gov/eere/fuelcells/hydrogen-shot
32. A. M. F. M. L. E. B. D. A. G. T. E. B.-J. Felipe Ignacio Gallardo, “A Techno-Economic Analysis of solar hydrogen production by electrolysis in the north of Chile and the case of exportation from Atacama Desert to Japan”. *International Journal of Hydrogen Energy.* 2021; *46(26):*13709-13728. https://doi.org/10.1016/j.ijhydene.2020.07.050
33. H. Council, “Path to hydrogen competitiveness: A cost perspective”. Hydrogen Council. 2020.
34. M. K. a. M. Melaina, “Hydrogen Fueling Stations Cost”. Department of Energy, United States , Washington D C, 2020.
35. B. Energy, “Hydrogen Data Sheet,” 30 March 2022. [Online]. Available: https://www.bloomenergy.com/resource/hydrogen-spec-sheet/
36. Cummins, “Economies of Scale in The Transportation Sector’s Journey to Lower Emissions”. 20 April 2022. [Online]. Available: https://www.cummins.com/news/2022/03/15/economies-scale-transportation-sectors-journey-lower-emissions
37. D. o. Energy. [Online]. Available: https://www.energy.gov/sites/prod/files/2016/12/f34/fcto_webinarslides_total_cost_ownership_stationary_fc_121316.pdf
38. T. Economics, “India Inflation Rate,” [Online]. Available: https://tradingeconomics.com/india/inflation-cpi#:~:text=Inflation%20Rate%20in%20India%20averaged,percent%20in%20June%20of%202017
39. E. A. W. Council on Energy, “COP-26: CEEW Unpacks India’s 2070 Net-Zero Target and other Climate Mitigation Measures,” 03 November 2021. [Online]. Available: https://www.ceew.in/news/cop-26-ceew-unpacks-indias-2070-net-zero-target-and-other-climate-mitigation-measures
40. I. M. Fund, “Putting a Price on Pollution,” 01 December 2019. [Online]. Available: https://www.imf.org/external/pubs/ft/fandd/2019/12/pdf/the-case-for-carbon-taxation-and-putting-a-price-on-pollution-parry.pdf
41. U. a. B. N. Kalita, “Determining a Carbon Tax Rate for India in the Context of Global Climate Change”. 2020; pp. 8185-8191. https://doi.org/10.35940/ijrte.C6655.098319
42. S. Foundation, “Discussion Paper on Carbon Tax Structure for India,” Shakti Sustainable Energy Foundation, New Delhi, 2018.
43. G. H. a. K. G. M. William J. Schmelz. “Total cost of carbon capture and storage implemented at a regional scale: northeastern and midwestern United States”. *Interface focus.* 2020; *10(5)*. https://doi.org/10.1098/rsfs.2019.0065
44. S. K. N. M. D. N. B. A. H. Sara Budinis, “An assessment of CCS costs, barriers and potential,” *Energy Strategy Reviews.* 2018; pp. 61-81. https://doi.org/10.1016/j.esr.2018.08.003
45. D. H. L. D. C. C. DR DAVID KEARNS, “TECHNOLOGY READINESS AND COSTS OF CCS”. Global CCS Institute, Docklands, Australia, 2021.
46. Normative, “Global carbon pricing and COP26: a primer”. 02 April 2022. [Online]. Available: https://normative.io/insight/global-carbon-pricing-cop26/
47. F. E. Data, “Henry Hub natural gas Spot Price”. 2022. [Online]. Available: https://fred.stlouisfed.org/series/DHHNGSP