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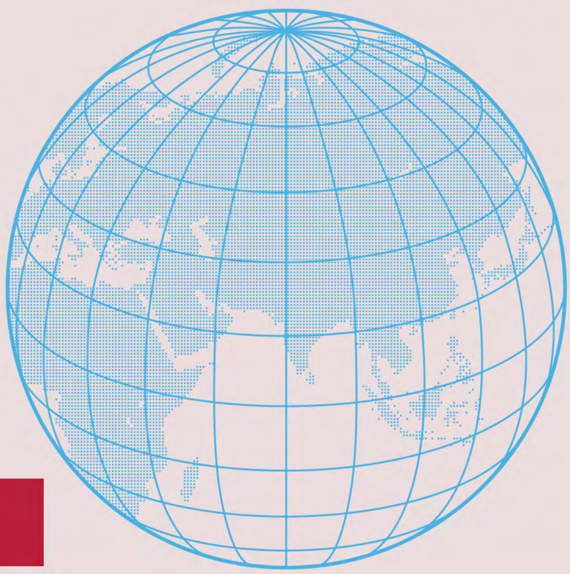
Benchmarking Green Hydrogen in India's Energy Transition

Expensive but Important for Some Uses

Rahul Tongia
Utkarsh Patel



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Benchmarking Green Hydrogen in India's Energy Transition

Expensive but Important for Some Uses

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List of Abbreviations

AC	Alternating Current
AEM	Anion Exchange Membrane
APM	Administered Pricing Mechanism
ARPA-E	Advanced Research Projects Agency-Energy
BNEF	Bloomberg New Energy Finance
BTU	British Thermal Unit
CBAM	Carbon Border Adjustment Mechanism
CCS	Carbon Capture and Sequestration
CIF	Carriage, Insurance, Freight
CIL	Coal India Ltd
CO2	Carbon dioxide
COVID	Coronavirus disease
CUF	Capacity Utilisation Factor
DAM	Day Ahead Market
DC	Direct Current
DRI	Direct Reduction of Iron ore
ETS	Emissions Trading System
EU	European Union
EV	Electric Vehicle
FOB	Free on Board
FY	Financial Year
GCV	Gross Calorific Value
GDAM	Green Day Ahead Market
GDP	Gross Domestic Product
GE	General Electric
GHG	Greenhouse Gas
GST	Goods and Service Tax
GW	Gigawatt
HB	Haber-Bosch
HHV	Higher Heating Value
H2	Hydrogen
ICE	Internal Combustion Engine
IEX	Indian Energy Exchange
INR	Indian National Rupee (₹)
IRA	Inflation Reduction Act (of the US)
IRENA	International Renewable Energy Agency

ISTS	Inter-State Transmission System
kWh	Kilowatt-hour
kWp	Kilowatt-peak
LCOE	Levelised Cost of Electricity
LHV	Lower Heating Value
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
LSMYSZ	Lanthanum Strontium Manganate–Yttria-Stabilised Zirconia
MACC	Marginal Abatement Cost Curves
MCP	Market Clearing Price
Mcal	Million Calories
MMBTU	Metric Million British Thermal Unit
Mt	Million Tonne
Mtpa	Million Tonnes Per Annum
MW	Megawatt
MWh	Megawatt-hour
NH3	Ammonia
NCM	Normal Cubic Meter
OECD	Organisation for Economic Co-operation and Development
O&M	Operation and Maintenance
PEM	Polymer Electrolyte Membrane
PLF	Plant Load Factor
PLI	Production Linked Incentive
PNG	Piped Natural Gas
PPAC	Petroleum Planning & Analysis Cell
PV	Photovoltaic
R&D	Research and Development
RE	Renewable Energy
RPO	Renewable Purchase Obligation
RTC	Round the Clock
SCM	Standard Cubic Meter
SECI	Solar Energy Corporation of India
SMR	Steam Methane Reforming
SOEC	Solid Oxide Electrolyser Cell
USD	United States Dollar ($)

Executive Summary

This paper examines the economics of producing and using green hydrogen in India, focusing on the 2030 timeframe. Green hydrogen is intended to decarbonise 'hard-to-abate' industries, such as fertiliser and steel, and certain end-use applications in transport, such as shipping and long-distance road freight.

Green hydrogen is produced by the electrolysis of water using renewable or "green" electricity. In our analysis, we link green hydrogen production costs with the cost and availability of renewable energy (RE) generation, which is measured by its capacity utilisation factors (CUFs). We also calculate the premium, if any, of using green hydrogen compared to energy-basis equivalent costs of fossil fuels for a range of applications.

Green hydrogen is an emerging technology globally, and India plans to increase its domestic production from a few kilo-tonnes at present to 5 million tonnes per annum (Mtpa) by 2030. Currently, India produces about 6 Mtpa of hydrogen from fossil fuels (mostly by steam reforming of natural gas, i.e., grey hydrogen), which is used primarily for fertiliser production and oil refining.

While the cost of green hydrogen is expected to decline in the coming years from its current range of 4–6 $/kg, it is unlikely to reach the oft-stated target of 1 $/kg by 2030 in India. Based on forward-looking assumptions about electrolyser efficiency, we estimate that the input cost of RE for green hydrogen production alone would be at least 1.4 $/kg in 2030 (even after factoring in rupee depreciation), which would be about two-thirds of the total production cost. Other costs include electrolyser capital expenditure (capex) and operation and maintenance (O&M) costs, including those of pure water supply. Incentives, such as a waiver of inter-state RE transmission charges and capital subsidies of up to 0.55 $/kg for green hydrogen production, under the National Green Hydrogen Mission of the Government of India, could potentially help bring the total costs under 2 $/kg.

Cheaper and more efficient electrolysers are important to lower the cost of green hydrogen production. Achieving high electrolyser utilisation (i.e., CUF) will be necessary for a faster payback of electrolyser capex (i.e., improved amortisation costs), which requires a steady supply of RE. There is an explicit trade-off between RE cost and CUF, and the most cost-effective RE supply is obtained from hybrid (wind + solar) power plants with oversizing, i.e., a total RE generation capacity much larger than the nameplate capacity of the electrolyser. Based on high CUF solar and wind capacity, using 2019 actual RE output data for India as a benchmark, we find that the lowest cost of producing green hydrogen is achieved when the capacity of RE generation (with wind to solar in the ratio 2:1) is about twice that of the electrolyser, resulting in over 60% electrolyser CUF. If electrolyser capex is higher, a higher CUF will be required to achieve the lowest production cost.

Considering only the cost of green hydrogen production, however, ignores the costs associated with handling, storing, transporting, and using hydrogen, which are significant compared to other fossil fuels due to the low volumetric energy density and high chemical reactivity of hydrogen.

To determine the cost-efficiency of replacing fossil fuels with green hydrogen, we suggest using the marginal cost of CO2 abatement ($/tonne-CO2), which considers end-use efficiency and the carbon-intensity of alternative fuels, as a more useful metric than $/kg-H2. We calculate abatement costs for the most commonly referred end-uses of green hydrogen: steelmaking, fertiliser, oil refining, transport, and heating/cooking. Even at an optimistic price of 2 $/kg-H2 in 2030, we find that abatement costs across applications range between 70–175 $/tonne-CO2, depending on whether green hydrogen displaces inexpensive but carbon-intensive domestic coal or price-controlled natural gas in India. This is very high compared to alternative abatement options, particularly electrification. It is also important to note here the significant effect of energy taxes on fuel costs.

Decarbonisation by displacing coal-based electricity with RE in the grid is more cost-effective (i.e., has a lower marginal cost of CO2 abatement) than displacing other fossil fuels elsewhere with green hydrogen, some of which are less carbon-intensive than coal (e.g., natural gas). Direct electrification of possible end-uses will also result in higher system efficiency due to reduced conversion losses (for instance, battery electric vehicles have a much higher roundtrip efficiency than hydrogen fuel-cell vehicles). This is a crucial consideration, as the production of the targeted 5 Mtpa of green hydrogen will require approximately 115 GW of dedicated RE capacity (under optimistic technology assumptions). Integration of RE into the grid and electrification of all viable end-uses in transport and industrial heating should, therefore, be prioritised as a more cost-efficient mitigation option.

In the medium-to-long term, green hydrogen will be needed to decarbonise sectors where alternative solutions are unlikely to be available, such as fertilisers, steelmaking, and refining—all of which use fossil fuels as chemical feedstocks. This will also reduce dependence on the import of natural gas and coking coal in the future. In the short term, we suggest promoting the use of green hydrogen in applications with relatively low marginal abatement costs, such as oil refining, as a steppingstone towards developing a green hydrogen ecosystem in India. In oil refining, switching to green hydrogen would not require significant changes in downstream processes and is, therefore, less capital-intensive compared to other processes, such as Haber-Bosch synthesis for fertilisers or iron ore reduction for steel.

Finally, we emphasise that defining the conditions for "green" electricity is essential to ensure that green hydrogen and its derivatives, thus produced, have low or zero carbon emissions. This is especially important if the products are to meet international emission standards. Current green hydrogen standards in India allow electricity "banking" with the electricity distribution company (DisCom) for up to 30 days, where an RE generator can overproduce RE at some times of the day and feed it into the grid and reclaim it from the DisCom when RE is not available. This means that some of the electricity consumed for electrolysis may not actually come from renewable sources, and the hydrogen so produced may have significant carbon emissions. The conditions to define "green", hence, should be based on the additionality, deliverability, and timing of the RE supply. This is key to determining the cost and availability of RE, which disproportionately affects the cost of green hydrogen production and, thus, the cost of decarbonisation.

1. Introduction: Green Hydrogen in the Context of India's Energy Transition

1.1 India's Emissions Have Many Sources

Decarbonisation will entail a range of solutions given the diverse sources of greenhouse gas (GHG) emissions across various sectors. For India, trends indicate the dominance of the power sector, followed by agriculture, forestry, and land use (AFOLU), and manufacturing and construction, contributing to almost three-quarters of the country's total emissions (Figure 1).

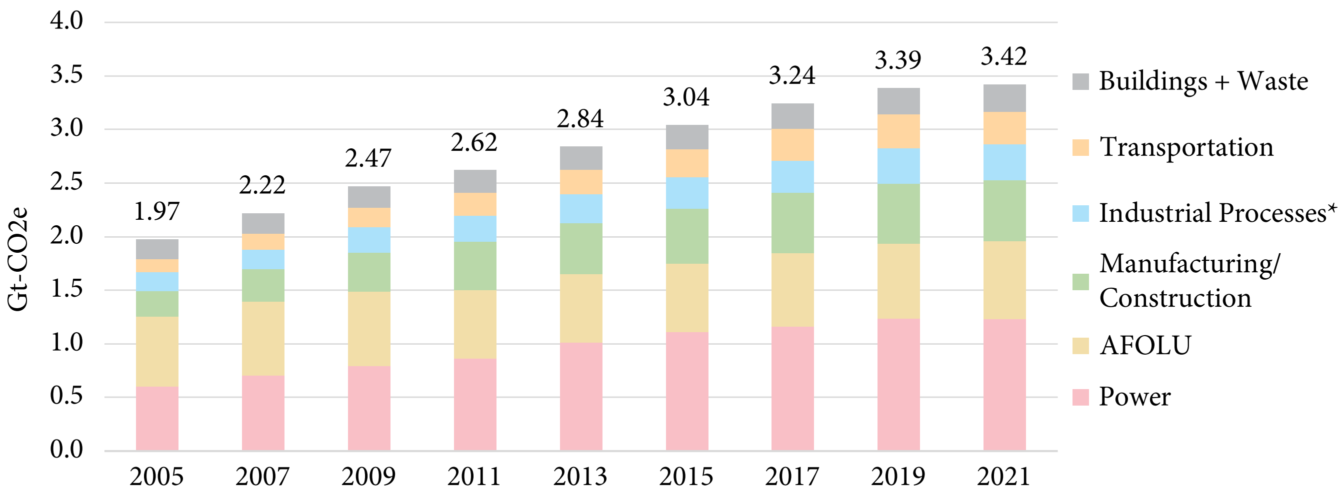
Within the power sector, coal-based generation dominates, with nearly a 75% share in India's electricity mix. About 15% of the emissions from the power sector are from captive power plants for industrial use (GHG Platform India, 2022). In manufacturing, the steel and cement industries account for two-thirds of the total sectoral emissions (Climate TRACE, n.d.). Industrial processes, which include fossil fuel extraction and processing and mineral extraction, are the next-largest contributor (9.9%), followed by transport (8.9%), buildings (4.9%), and waste (2.5%).

The decarbonisation strategy for the power sector is well known: add as much wind and solar as feasible with today's technologies and costs, and then (over time) add storage to handle the variability of wind and solar output. Both of these steps would overlay with a smarter grid, where demand could be flexible and controllable to match renewable energy (RE) supply. This needs to be complemented by the electrification of transport and industrial heating to the extent possible to minimise the direct use of fossil fuels as the final source of energy. As the share of renewables rises in the electricity mix, emissions from these sectors will subside.

However, there are applications within industry and transportation, such as long-distance road transport, shipping and aviation, and steel, cement, and fertiliser production, that are considered 'hard-to-abate' and require process changes, fuel substitution, and/or carbon capture and storage (CCS) to avoid emissions.[1]

Process changes require changing chemical processes to replace carbon dioxide-generating feedstocks with alternatives, such as hydrogen (e.g., to replace coking coal for iron ore reduction in steelmaking). Similarly, fuel substitution entails the use of biofuels or hydrogen or its derivatives, which may require specific energy conversion technologies (e.g., replacing internal combustion engines with hydrogen fuel cells). For the remaining cases where emissions cannot be avoided by either of the above two methods (e.g., clinker production from limestone for cement), CCS as a method of artificial carbon sequestration could be a viable solution.

Figure 1: India's GHG Emissions Over Time



Source: WRI Climate Watch (n.d.).
**Industrial processes include fugitive emissions and combustion of other fossil fuels.*

[1] Industrial processes utilise fossil fuels for a range of uses, from feedstock to heat generation. Each sub-process varies in abatement difficulty. In many cases, the chemical use of a fossil feedstock produces heat as a by-product, so simple chemical (stoichiometric) balancing would only show the hydrogen requirements for a subset of the total process (assuming a clean source of energy, perhaps hydrogen itself, is also required to provide heat).

1.2 India's Green Hydrogen Ambitions and Targets: 5 Mt/Year by 2030

In the long run, commensurate with its 2070 net-zero pledge, India would require significant amounts of green hydrogen. With the ultimate goal of eliminating emissions from industry, the short-term plans should focus on producing green hydrogen on a large but cost-effective scale. However, the cost-effectiveness of green hydrogen compared to alternatives is a complex issue dependent on both the cost of alternatives and the production cost of green hydrogen. We explore these issues in this paper.

India's current hydrogen demand—around 6 Mtpa—from oil refineries (50%), ammonia and fertiliser producers (42-45%), and secondary steel and the chemical industry, is almost entirely met by grey hydrogen produced by steam reforming of natural gas (and a small fraction by brown hydrogen from coal).[2]

The National Green Hydrogen Mission (MNRE, 2023b) envisages the creation of hydrogen hubs to enable large-scale production and utilisation of green hydrogen. This spans input materials, hydrogen production, and output supply. If the output is aimed for exports, many such sites are planned in coastal locations.

As we shall see, this ambition has several components. First are the electrolysers that use electricity to split water into hydrogen and oxygen. Second is the green electricity to power the electrolysers and its transmission from where it is generated to where the hydrogen would be produced. Third is the supply chain needed to handle the hydrogen, especially its transport via pipelines or in tanks.

Critics of many proposed uses point out that energy conversion penalties mean that alternatives (e.g., heat pumps for heat generation) can be most cost-effective and equally low emission. Appendix 1 shows a framework by Liebreich (2023) on hydrogen's alternatives.

1.3 Putting Hydrogen in Context

Table 1 below shows some of the key sectors where green hydrogen can potentially be used, their current production/consumption figures, and the amount of hydrogen required to produce the current amount of commodity/output. Note that this is hydrogen for process requirements only, like feedstock, and does not include heat requirements, which may also be generated from hydrogen.

We can see that the present sectoral potential uses are themselves more than the 5 Mtpa target for 2030, and possible demand by 2030 would be even higher. For instance, the ambition is to grow crude steel production in the country to 300 Mtpa by 2030 (Ministry of Steel, 2023a).

Table 1: India's Possible Uses of Hydrogen (Based on the Latest Available Data)

	Million Tonnes (Mt) of Product	Hydrogen Needed (Mt) Factoring in any process conversion to H2 as required
Crude oil refining (capacity, 01.04.2023)	253.9[a]	3.0
Ammonia (consumption, 2022-23)	21[b]	3.7
Crude steel (production, 2022-23)	124.7[c]	8.1
Diesel (consumption, freight trucks, 2021)	42.9[d]	13.0

Sources:

[a] *Petroleum Planning and Analysis Cell (PPAC) (n.d.).*
[b] *Lahiri (Paradeep Phosphates) (2023).*
[c] *Ministry of Steel (2023b).*
[d] *PPAC and CRISIL (2022).*

We lay out the scope of the paper and our methodology in the next section, followed by a simplified model to estimate the projected cost of hydrogen production in 2030 in Section 3. Our estimates suggest that the cost of green electricity alone for green hydrogen production would be well above the often-talked-about 1 \$/kg-H2 mark. Our calculations do not consider technological nuances, nor do they include the logistical costs of hydrogen. We also do not account for any production-related subsidies or

[2] Even blue hydrogen, where CO2 is captured when methane (natural gas) is steam reformed, releases significant CO2e GHG emissions per kg-H2. This is in part because of limitations of carbon capture (typically 95% or less today) as well as significant upstream fugitive emissions during the production of natural gas (Howarth and Jacobson, 2021).

tax implications. Even with the limited scope, we find (in Section 4) that there is a significant premium on an energy basis ($/MMBTU) to replace conventional fossil fuels with green hydrogen. In Section 5, we then consider the different potential use cases for hydrogen and present estimates of the marginal cost of carbon abatement using green hydrogen. Again, except in a few cases where it is technically easier to switch to green hydrogen, the cost, in terms of $/tonne-CO2 avoided, is very high with green hydrogen. We conclude with a discussion and policy recommendations in Section 6.

2. Scope of the Paper and Methodology

In this paper, we address several questions:

1) What are the economics of hydrogen production for India?
2) What is the netback value of hydrogen, and hence the cost of carbon abatement, across sectors?
3) Where are the uncertainties, and what factors matter?

There is extensive global and Indian literature on hydrogen that lays out many of the challenges and opportunities (EY, 2022; RMI/NITI Aayog, 2022; CEEW/Sripathy et al., 2023; McKinsey/Gupta et al., 2022). For example, RMI/NITI Aayog (2022) expects the cost of green hydrogen in India to be competitive with grey hydrogen by 2030, but significant investment in hydrogen transport and storage infrastructure will be needed to reduce the cost of delivered hydrogen. McKinsey/Gupta et al. (2022) estimate that a total investment of $242 billion will be needed to create RE generation and electrolysis capacity, as well as storage and pipeline infrastructure for green hydrogen. The availability of finance will be critical to realising these investments. However, these investments could yield benefits in the form of foreign exchange savings and export earnings.

One of the key factors for the economics of green hydrogen is the cost of input renewable energy. We build on the RE analysis by Tongia (2023) and extend it to add some grid-specific nuances for green hydrogen production in the country—e.g., how India's electricity grid mix impacts green electricity and, hence, green hydrogen.

We aim to bring together several disparate issues into a structured framework that focuses not on the cost of hydrogen ($/kg-H2) but rather on the cost per tonne-CO2 avoided. This inherently has two components, viz. (a) the cost of alternative fuels; and (b) process details and efficiencies in different sectors. We focus on the use of green hydrogen in the following sectors:

a) Refinery use → displacing grey or brown hydrogen
b) Steel production → displacing coking coal
c) Thermal process → displacing thermal coal
d) Ammonia production → displacing natural gas
e) Transportation → displacing diesel
f) Domestic cooking gas (PNG) blending

We project forward-looking cost structures for 2030. Such an analysis runs into the complex issue of price benchmarking. This is partly because green hydrogen is currently very expensive—4-7 $/kg, depending on the underlying assumptions for electrolysers (RMI/NITI Aayog, 2022). We expect costs to fall as electrolysers improve and green electricity becomes more affordable. On the other hand, we factor in multiple trends for cost structures with diverging implications:

1. Foreign exchange rate—relevant for imported components, export competitiveness, and cost of international capital;
2. Cost of green electricity—depends on more than nameplate levelised cost of electricity (LCOE)—e.g., a higher CUF will entail higher costs due to additional generation capacity required, usually in a combination of different sources (mainly wind and solar);
3. General inflation—affects O&M costs, transportation, etc., and also present values;
4. Costs of alternative fuels—used for netback calculations and abatement costs ($/tonne-CO2).

Even discount rates also vary across different models and stakeholders. Because all these factors will appreciate or depreciate at different rates, we choose to keep costs in nominal rupees for 2030.

Table 2 shows the ranges for costs outside the electrolyser hardware and forward costing as used in the paper.

Table 2: Assumptions and Ranges of Inputs Used in the Analysis

Parameter		2023	2030
₹ per US$		80	95 (base); 90–110 range
Cost of Green Electricity	LCOE, which ultimately increases with higher CUF via oversizing or storage; blend of wind and solar	2.4–3 ₹/kWh (LCOE)	Nominal basis span: depreciation–2% p.a. to appreciation of 3% p.a.
Inflation vs. 2023		n.a.	3%–5%
Thermal Coal Price	Domestic, mid-grade	As per CIL prices for industrial uses	Appreciation of 2%–4% p.a.; base of 3% per annum
Coking Coal Price	Imported. Delivered price including GST and cess and international transportation; domestic transportation costs vary by location	~300 $/tonne	100–350 $/tonne
Diesel Price	Retail (including taxes)	90 ₹/L	90–120 ₹/L
Natural Gas Price	$/MMBTU (imported vs domestic varies by sector)	Domestic: 5.6 $/MMBTU Imported: 12 $/MMBTU	$12.5 (base); 5–17.5 $/MMBTU range

Source: Present values based on data from Reserve Bank of India, Coal India Limited, and Petroleum Planning and Analysis Cell and author estimates for green electricity and coking coal.[3]

3. Hydrogen Economics

A holistic examination of the economics of hydrogen comprises three stages: production, storage and transportation, and utilisation. This section focuses on green hydrogen production, agnostic to its utilisation. This provides a basis for additional calculations where differences based on hydrogen's use can be incorporated.

Even when considering production costs of green hydrogen, independent of its use, it is inaccurate to ignore location. Utilisation is a far more complex issue with greater uncertainty than production cost estimates, as demonstrated by some applications discussed in this paper.

Three main cost structures guide the electrolysis process within production:

1) Clean electricity from renewable energy (RE) for electrolysis.
2) Electrolysis capacity (primarily, electrolysers, but also water purifiers and deionisers).
3) Operation and maintenance (O&M) costs.

3.1 Green Electricity for Green Hydrogen

How much electricity is needed to produce hydrogen? At 100% efficiency, 33.3 kWh of electricity would be required per kg of hydrogen.[4] However, today's practical efficiencies are closer to 60%. Even projecting an improved efficiency of 71% in 2030, results in a requirement of 47 kWh/kg-H2.

What will this cost? A simplified calculation uses the input price of electricity to determine the energy cost of hydrogen. At just 3 ₹/kWh, this equates to over 140 ₹/kg-H2, significantly higher than the 1 $/kg figure often quoted in media as an ambition (MoneyControl, 2023a).

Electrolysis necessitates electricity, for which we have a delivered price. While media reports tout "cheap solar" falling below 2 ₹/kWh, recent (Q3 2023) bids are in the range of 2.42 ₹/kWh or higher in certain locations. Many cheaper bids benefit from inter-state transmission system (ISTS) cost waivers offered by the Central Government. Not only are transmission costs socialised in these cases, but such bids are perceived as less risky due to counter-party risk—developers favour Central Government entities and special

[3] Monthly notified domestic natural gas price data available at: https://ppac.gov.in/natural-gas/gas-price
[4] Based on Lower Heating Value (LHV), as per green hydrogen norms.

purpose vehicles like SECI over state bids. However, such costs are not free and could exceed 0.8 ₹/kWh at the system level for long-distance, point-to-point transmission.

Theoretically, solar and an electrolyser could be co-located. However, optimal location considers not just these two factors, but also the proximity of downstream hydrogen consumers.

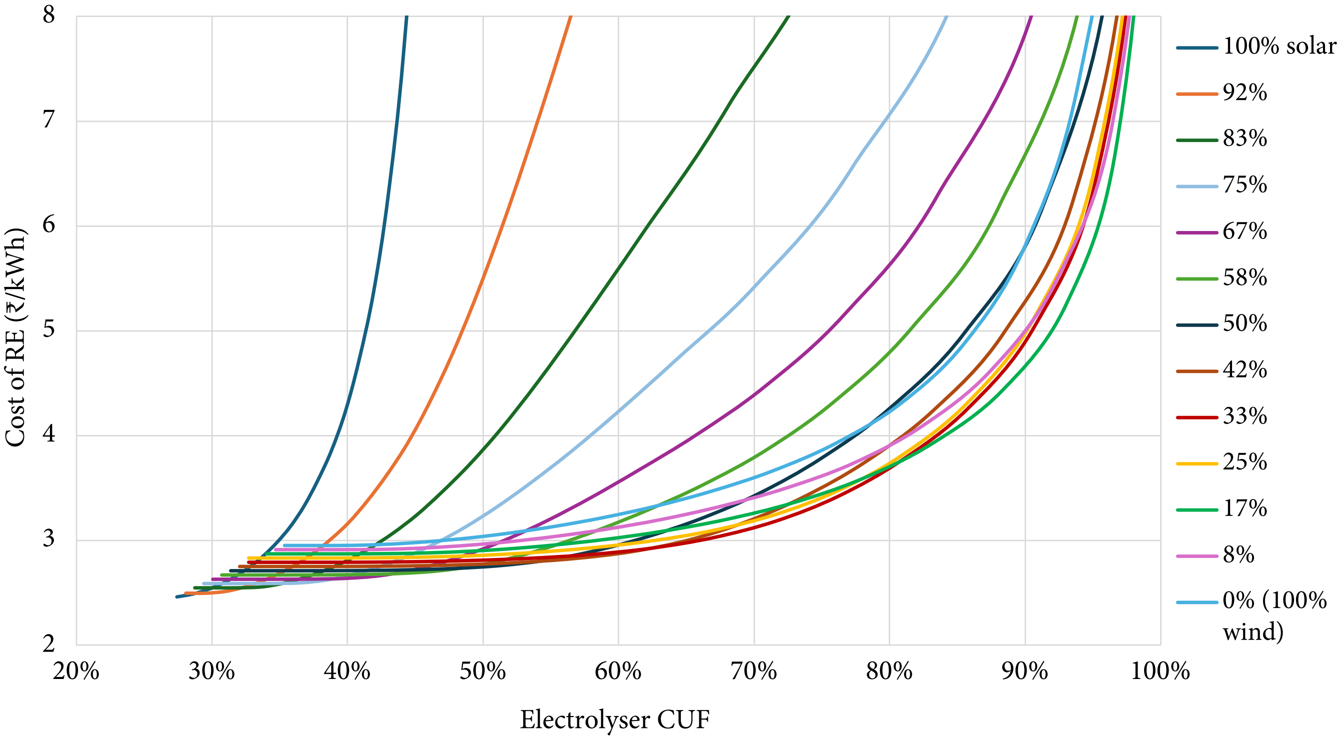
Location becomes even more complex when considering RE plant load factor (PLF), also known as CUF. New solar installations, even with higher efficiency, sun-tracking mechanisms, or oversized DC-to-AC conversion, typically achieve a maximum PLF of 25–27%. Similarly, wind energy, generally more expensive than solar in India, can achieve a PLF of 31–33% at suitable locations, or 36% or higher at rare, optimal locations.

Wind output is, on average, somewhat complementary to solar, which makes their combined use logical. However, achieving optimality for both at the same location, especially on a large scale, is rare. Therefore, interstate transmission becomes necessary.

A more complex calculation for RE acknowledges the link between PLF and cost. For instance, while solar at 2.5 ₹/kWh might seem attractive for the cheapest incremental green supply, it could only power the electrolyser 25% of the time. This would elevate total production costs due to increased amortisation costs for the electrolyser's capex.

As Tongia (2023) demonstrated, achieving a higher CUF for RE requires one of two options: (1) oversizing the RE while combining wind and solar for complementarity, or (2) adding storage. The latter is cost-prohibitive in the near term.[5]

Figure 2: Frontier of RE Supply Cost and Electrolyser CUF With Oversizing and Blending Wind + Solar



Source: Authors' calculations, based on Tongia (2023).

Note: This assumes solar at 2.46 ₹/kWh and wind at 2.95 ₹/kWh (aggressive prices) and uses 2019 all-India wind and solar profiles as captured via carbontracker.in. This graph does not show the oversizing required (with clipping for over-generation above nameplate, or re-rated capacity) to achieve the respective CUF. For example, 1 MW of re-rated total capacity could be oversized via 1 MW solar plus 1 MW wind with occasional output exceeding 1 MW. To be conservative, this excess is clipped or thrown away, as we assume it is available only when the rest of the grid is also surplus.

[5] There is an alternative accounting method for defining green, which relies on "banking" or offsetting, which may not always be truly green. See Appendix 3.

Utilising actual all-India RE data from 2019, Tongia (2023) created cost vs. CUF frontiers for oversized/ blended wind and solar. Such arrangements yield higher CUF by exceeding nameplate capacity (the definition of oversizing; sometimes by factor of two of more) but risk occasional over-generation, which is likely to be curtailed or discarded as RE share grows in India.[6] Figure 2 illustrates the cost frontier. Note that these are case samples based on 2019 data, and actual costs may differ depending on location and annual variations. Nonetheless, they demonstrate that a 50–60% CUF is achievable by oversizing generation capacity (the scale of which is not depicted in the graph) without significantly increasing costs, especially compared to addition of storage capacity.

3.2 Electrolyser Costs and Overall Costs of Production

A range of electrolyser technologies exists (alkaline, PEM, SOEC, and AEM), each with varying technical characteristics such as efficiency, capital cost, part-load capability, and stack life. Different technologies present advantages and limitations. For example, SOEC electrolysers offer higher efficiencies but are currently expensive, operate at higher temperatures, have shorter stack lives, and require longer start-up times. IRENA (2023a) provides further details on the potential price-performance trajectories of electrolysers.

Our focus is technology agnostic, aiming instead to examine system-level implications. While technology evolution presents some uncertainty, simple assumptions and benchmarks can be useful. Appendix 2 provides further details on different electrolysers.

Using the RE cost and oversizing frontier described above, we can propagate these into total hydrogen cost structures based on assumptions about electrolyser costs, efficiency, etc., and estimate the cost implications corresponding to a range of RE costs (Table 3).

Table 3: 2030 Electrolyser Scoping Scenario

Electrolyser cost	600 $/kW
₹ to US$ depreciation rate	95 (roughly 2.5% annual depreciation vs today)
O&M rate	1.5% p.a. (base) (of capex) + water at 0.1 ₹/L (base)
Efficiency	71% (base) = 47 kWh electricity per kg-H2

Source: Authors' assumptions.

Today, we face a trade-off: high-efficiency electrolysers with higher costs or cheaper options with lower efficiency. This paper explores a potential 2030 scenario (not a projection) assuming continued steep learning curves. As reported by Hydrogen Europe, current electrolysis systems have a capex of €1,250 ($1,370) per kW and an efficiency of 63.5% (European Hydrogen Observatory, n.d.).

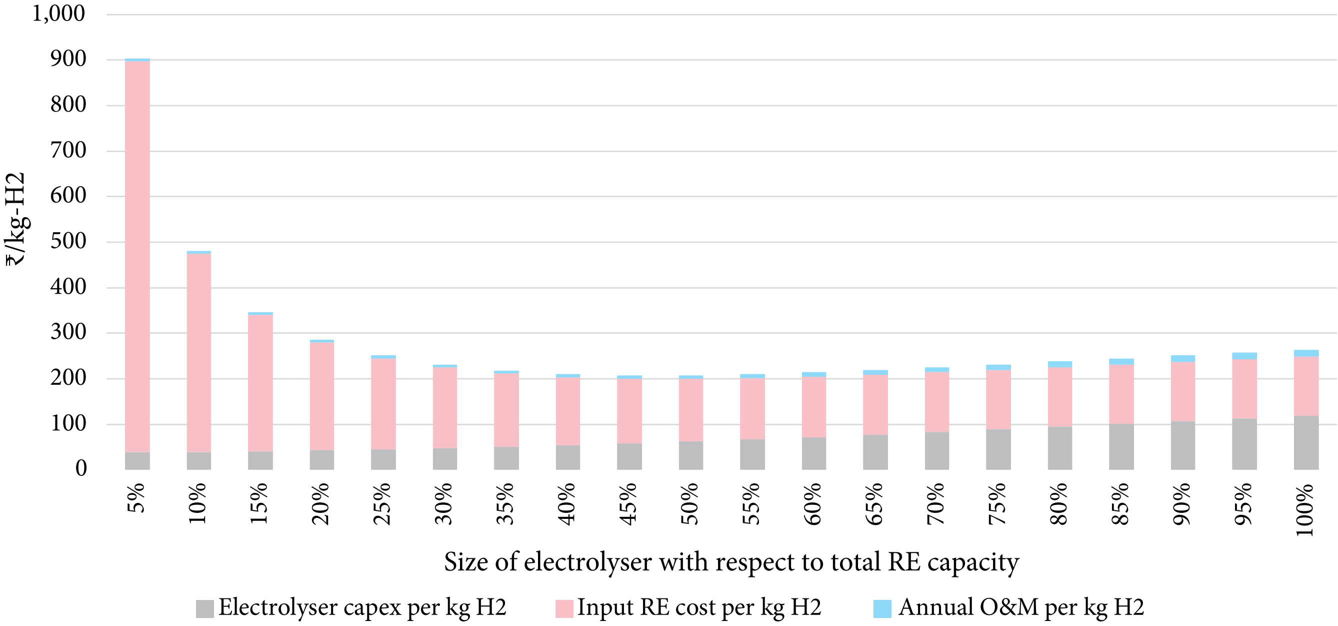
Assuming an electrolyser setup with the above price/ performance profile, the lowest hydrogen production cost, based on 2019 wind and solar profiles, would be achieved with a 2:1 wind:solar ratio and 100% total oversizing, i.e., 2 MW total RE (1.33 MW wind + 0.67 MW solar) for 1 MW electrolyser. This oversizing increases the CUF from the original (non-oversized) 32.7% for the wind + solar blend to over 62%, with less than 5% curtailment (based on periods when output exceeds 1 MW). Figure 3 illustrates the cost stack across various RE mixes, spanning electrolyser, RE, and O&M costs.[7]

Raw wind and solar costs for 2030 are assumed as 2.95 ₹/kWh and 2.46 ₹/kWh, respectively. As nominal 2030 figures, this assumes that price inflation is offset by technology improvements (base scenario). After blending and oversizing (with limited curtailment), the input cost to the electrolyser becomes 2.92 ₹/kWh (base). Higher solar and wind costs would slightly shift the optimal sizing and increase the cost of green hydrogen.

[6] In the short run, the surplus could find other users, but over time, the grid may be surplus overall, especially mid-day, evidenced by other countries finding negative prices for high RE periods. Thus, to be conservative, Tongia's (2023) calculations assume nil value for the surplus, which is typically in the single digit percentages for optimal scaling.

[7] Models have been developed to carry out similar analyses for other countries/regions, for example BNEF's Hydrogen Electrolyzer Optimization Model (H2EOM).

Figure 3: Hydrogen Production Costs for 2030



← More RE over-sizing = higher CUF.

Source: *Authors' calculation; $1 = ₹95.*

Notes: Based on the assumptions listed in Table 2 and Table 3 or otherwise mentioned in the text. These are scenarios, not forecasts.

The oversizing ratio for total RE capacity is the inverse of the downscaling or re-rating factor (RF). An RF of 0.5 means that the installed capacity is twice the nameplate capacity (1/0.5 = 2). Thus, a 100 MW nameplate RE plant could be 100 MW solar plus 100 MW wind, for an RF of 0.5. The graph ranges from 0.05 (maximum oversizing of 20:1) to 1 (no oversizing, 1:1).

This curve represents a 2:1 wind: solar ratio, yielding the lowest total production cost for national RE output as observed in 2019.

These figures are heavily assumption-laden and intended to illustrate insights and trends, not specific values. The analysis confidently demonstrates that: (1) energy costs dominate; (2) oversizing RE raises the effective CUF with non-linear impacts on energy costs; (3) blending wind and solar is crucial, and despite higher solo LCOE, wind partially complements solar and offers a higher CUF (assuming suitable installation sites).

The figures do not directly show the optimal CUF frontier, which also depends on electrolyser costs. Continuous, 100% electrolyser CUF operation throughout the year is unnecessary and would require prohibitively expensive RE. Exceeding a 50%- or 60%-CUF appears to be a sweet spot based on RE costs. Higher RE CUFs would be more desirable when electrolyser costs are higher.

Overall, even with aggressive electrolyser capex and efficiency assumptions, and maintaining wind and solar prices at roughly zero inflation in nominal terms through 2030, green hydrogen still costs over 200 ₹/kg-H2 (over 2 $/kg-H2). This analysis excludes ostensibly cheap banking/offset-based steady or high CUF 'RE' supply, as such inputs are green only on an *accounting* basis and not truly green (see Appendix 3 for details).

3.3 Hydrogen Transportation and Storage – Location Matters

Cost-effective green hydrogen production is only the first step. It must be utilised in various applications, highlighting a major challenge: optimal location for storage and transport (or potentially, transport and off-site storage).

Hydrogen's low density makes its storage and transport expensive. Pipeline transport of hydrogen is estimated to cost 2.5 to 3 times more than natural gas (Liebreich, 2022). While blending hydrogen into natural gas pipelines is being explored, currently deployed pipeline technologies—primarily designed for natural gas or other hydrocarbons—typically limit this to a 20% blend. This limitation arises because hydrogen, being a small molecule, can easily leak from conventional gas pipelines at high pressures. It is also a highly reactive gas, known to cause embrittlement of common metals and their alloys such as iron and steel.

The Gas Authority of India Limited (GAIL) has initiated a pilot project in Indore, blending hydrogen into a small part of its city gas pipeline network. However, the reported blend is only about 2% by volume. Since hydrogen has a much lower volumetric energy density than natural gas, the net energy displacement impact is less than 2%. In other words, a larger volume of the hydrogen + natural gas blend is needed to achieve the energy equivalent of 100% natural gas.

While pure hydrogen pipelines are technically feasible, they are expensive and their long-term real-world performance, including leakage, remains unknown.

These challenges have prompted some countries, particularly Japan, to investigate converting hydrogen into green ammonia or liquid organic carriers. Ammonia possesses a much higher volumetric energy density than hydrogen, simplifying long-distance transportation. It is also a feedstock for industries like fertiliser production. Japan even aims to generate power by burning ammonia in its thermal power plants. However, significant conversion losses at each process step result in poor end-to-end efficiency.

Examining various applications reveals that some require bulk inputs, like industries that use ammonia. These can be co-located or served by a single point-to-point network. Conversely, smaller, more diffuse uses, such as road transport fuel, would incur significantly higher logistics costs and conversion losses, or depend on modular electrolysis systems.

It is crucial to remember that even at a high pressure of 700 bar (which carries a nearly 20% energy-use penalty for compression), hydrogen's volumetric energy density is only 15% that of diesel and one-third that of natural gas (Bossel & Eliasson, 2003; Møller *et al.*, 2017). Furthermore, hydrogen storage tanks can be expensive due to their thick composite construction, necessary to withstand high pressure without leakage and resist embrittlement. These heavy tanks could, in some cases, offset the benefits of hydrogen's high gravimetric (weight-based) energy density.

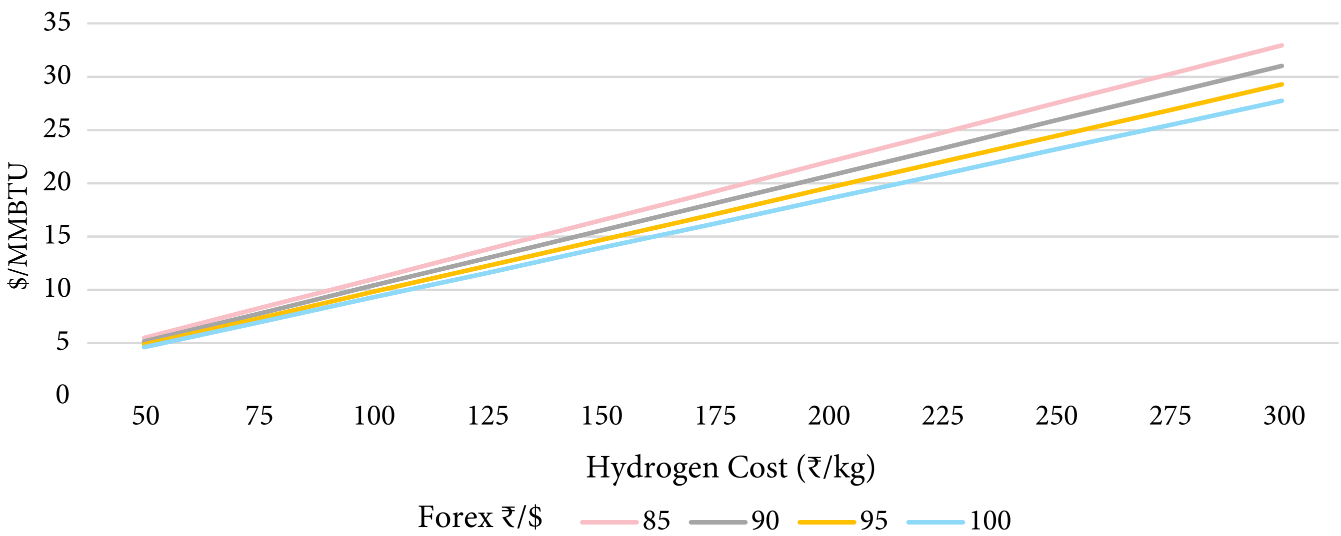
For studies discussing hydrogen hubs (CEEW/Biswas, Yadav, & Baskar, 2020), it is vital to factor in all inputs and outputs, including electricity transmission costs from wind and solar plants, which are unlikely to be co-located.

Due to insufficient data on hydrogen transport, this analysis focuses primarily on co-location activities, unless stated otherwise, leaving storage and transport costs as "extras."

3.4 Netback Value of Green Hydrogen – Depends on Alternatives

The simplest comparison for green hydrogen is against alternative fuels on an energy basis (i.e., per MMBTU) (Figure 4).[8]

Figure 4: Hydrogen Cost on an Energy Basis



Source: Authors' calculations.

[8] We use the lower heating value (LHV) of hydrogen for these comparisons.

Our base case assumes an annual rupee depreciation exceeding 2% per annum, resulting in an exchange rate of approximately $1 = ₹95 by 2030. Even with aggressive technological advancements, this translates to a forward-looking cost of roughly 19 $/MMBTU for green hydrogen as produced, and not as delivered. This also assumes zero taxes on green electricity and green hydrogen.

The cost of alternatives depends not only on market prices but also on factors like taxation, adding transport and insurance costs, i.e., free-on-board (FOB) or supplier costs vs. carriage, insurance and freight (CIF) or delivered costs, etc. We compare the energy-based costs ($/MMBTU) for plausible cost structures across different fuels as follows:

1. **Thermal coal:** Domestic, mid-grade coal at notified industrial use prices.
2. **Natural gas:** Imported LNG and domestic APM (Administered Pricing Mechanism) gas.
3. **Diesel:** With and without taxes.
4. **Green electricity:** At high PLF.

Table 4 summarises the fuel-basis comparison for energy costs ($/MMBTU) across fuels. Appendix 4 provides detailed information on each fuel and its respective cost range.

fuel switching (e.g., substituting natural gas for coal, which while costlier, emits less carbon).

Table 4: Summary of Representative Energy Costs Across Fuels for 2030

Fuel	Cost ($/MMBTU)	Details
Green Hydrogen	18.5	Based on 200 ₹/kg; lower than the aggressively modelled 209 ₹/kg
Thermal Coal	1.7	Delivered G12 grade coal, including levies, with 3% annual appreciation through 2030
Natural Gas	12.5	Imported LNG, re-gasified and delivered near the coast; APM domestic gas is ~50% lower in cost
Diesel	13	Without taxes, assumed to be 30% of retail 90 ₹/L
Green Electricity	12	4 ₹/kWh for high CUF, with oversized RE wind + solar; no battery

Source: Authors' calculations.
Notes: Assumes $1 = ₹95; all prices are nominal.

4. The Real Objective: Avoiding Carbon

Comparing prices in $/MMBTU terms is only one aspect of evaluating green hydrogen's potential. If it were genuinely cheaper than alternatives, a natural shift would occur. However, as demonstrated in the previous section, green hydrogen is likely to entail a measurable premium by 2030. This raises the question: is the premium worth it?

A useful economic metric to answer that question is $/tonne-CO2 avoided. This allows us to understand the value proposition of using green hydrogen in terms of carbon abatement and how it compares to other economy-wide decarbonisation measures such as efficiency improvements, process changes, and

Determining a "reasonable" cost of carbon abatement is complex and lacks a universal answer. One framework, based on Pigouvian taxes on externalities, advocates using the social cost of carbon, estimated to exceed 100 $/tonne-CO2 (Rennert et al. 2023).[9]

Some countries have implemented a carbon price, either directly through taxation or indirectly via an emissions trading system (ETS). While India plans to introduce an ETS, as of this writing, it relies on alternative carbon abatement mechanisms such as renewable purchase obligations (and similar planned green hydrogen consumption obligations), the coal cess, and an industry energy efficiency certificate trading scheme (Perform, Achieve, and Trade, or PAT).

Global CO2 prices vary, but European ETS prices have remained largely above 80 €/tonne-CO2 in recent

[9] Not only is there measurable uncertainty over climate change, but any estimate of impacts has at least two sets of distributions and variations—temporal (including intergenerational) and spatial (different countries are impacted differently and may have different economic structures). Poorer countries have lower GDPs and thus lower "economic impacts", but also have less capacity to recover from the impact (in other words, they pay a relatively higher price for the recovery). Poorer countries also have a lower ability to pay for the additional cost of decarbonisation in the short run (plus, they point out, on average, they didn't cause the problem). Thus, many suggest that a differential carbon price across countries, at least as a start, would be better (Parry, Black, & Roaf, 2021).

years, dipping to around 60 €/tonne-CO2 during February–March 2024.

Some experts consider India's coal cess a form of carbon tax. Converting the coal cess (400 ₹/tonne-coal) into $/tonne-CO2 (assuming specific coal quality and corresponding CO2 emissions) yields only about 3 $/tonne-CO2. This translates to roughly 0.25 ₹/kWh in terms of electricity (based on a specific coal consumption of 0.6 kg/kWh). Even a tenfold increase in carbon price would significantly raise electricity prices, potentially by around 2 ₹/kWh on average. For reference, the average power procurement cost for DisComs in FY2021-22 was 4.77 ₹/kWh (PFC, 2023).

While a high carbon price might enhance RE competitiveness, the resulting substantial increase in electricity costs could be untenable for average Indian consumers and face resistance from regulators due to political pressures. It is important to note that retail electricity prices already operate at a gross deficit exceeding 1 ₹/kWh on average, based on ex-post analysis, which considers actual operations rather than tariff order projections (Tyagi & Tongia, 2023).[10]

Given green hydrogen's wide-ranging application potential, examining its competitiveness across all sectors is crucial. McKinsey & Co popularised marginal abatement cost curves (MACCs), which illustrate the costs and carbon abatement potential of various interventions or solutions, stacked in ascending order of abatement cost. An early MACC for India for 2030 (developed in 2009) is presented in Appendix 5.

The MACC indicated negative prices for numerous interventions, implying both cost and carbon emission savings compared to alternatives (Gupta *et al.*, 2009).[11] Similarly, IPCC (2023) demonstrates how interventions like wind and solar power offer cost savings alongside substantial emission reductions.

Compared to abatement costs, even for hard to abate emissions, as estimated by Gupta *et al.* (2009), the projected cost of green hydrogen in 2030 is very high. This suggests prioritising other, more cost-effective interventions, especially given limited financial resources. However, as discussed later, this is not an "either/or" proposition, and there are compelling reasons to embark on the hydrogen journey now.

4.1 Converting Energy Costs to Abatement Costs–Fuel Basis

Table 4 presented the cost differentials for different fuel options (in $/MMBTU). Combining this with fuel-specific carbon emissions (tonnes-CO2/MMBTU) allows us to calculate the $/tonne-CO2 fuel-based premium for green hydrogen in 2030. We simplify the calculations by focusing solely on Scope 1 and 2 emissions (i.e., on-site, or off-site fuel usage), disregarding lifecycle emissions and end-use process/efficiency implications (discussed in the next section).

While Scope 1 and 2 calculations are helpful, lifecycle emissions—particularly leakage during production and transportation—can be significant. While these are relatively well-understood for fossil fuels (see Footnote 2), the same cannot be said for hydrogen. As highlighted by various studies, hydrogen is a secondary GHG[12] and has a global warming potential approximately 12 times that of CO2 over a 1-year period if released into the atmosphere (Hauglustaine et al., 2022; Dutta et al., 2023; Sand et al., 2023; Sun et al., 2024). Therefore, much will depend on the supply chains ultimately deployed for hydrogen, such as pipelines for distribution to refuelling stations. Table 5 presents CO2 abatement costs assuming green hydrogen costs either 200 or 100 ₹/kg.

At 100 ₹/kg, green hydrogen offers savings compared to many fuels, but the potential for displacement remains limited, particularly for fuels like thermal coal, which account for the bulk of India's non-power sector emissions. Even for diesel, only about 25% is consumed by trucks. Fortunately, green/low-carbon alternatives exist for segments where green hydrogen may not be suitable for displacing other fuels, such as electrification of the transport sector, either directly (e.g., railways) or through battery-powered EVs.

[10] Tyagi and Tongia (2023) showed that initial Tariff Orders had full cost coverage—i.e., regulators set prices to ostensibly cover costs—but the actual ex-post costs and revenues systematically deviate from plans, leading to a gap in the order of 1 ₹/KWh. Most of this gap is not due to failures by the utility, like excessive network losses, and hence requires a higher price.

[11] An updated version of the MACC for India shows that about two-thirds of the emissions can be abated at negative or low costs (< 10 $/tonne-CO2) (McKinsey/Gupta et al., 2022).

[12] Among several atmospheric reactions, hydrogen is mainly responsible for reduction of hydroxyl ions (OH^-) in the atmosphere which is the primary sink for CH4—a highly potent GHG (Ocko & Hamburg, 2022).

Realistically, assuming a minimum cost of 200 ₹/kg green hydrogen carries a measurable premium over alternatives. The most cost-effective fuel (energy) basis displacement is for coking coal, which is expensive and carbon intensive. The abatement cost shown for displacing diesel pertains to retail diesel excluding taxes, as green hydrogen is not currently taxed at the production level.

Figure 5 illustrates the impact of hydrogen price on CO2 abatement costs for different fuels (using the same baseline assumptions for other fuels as before).

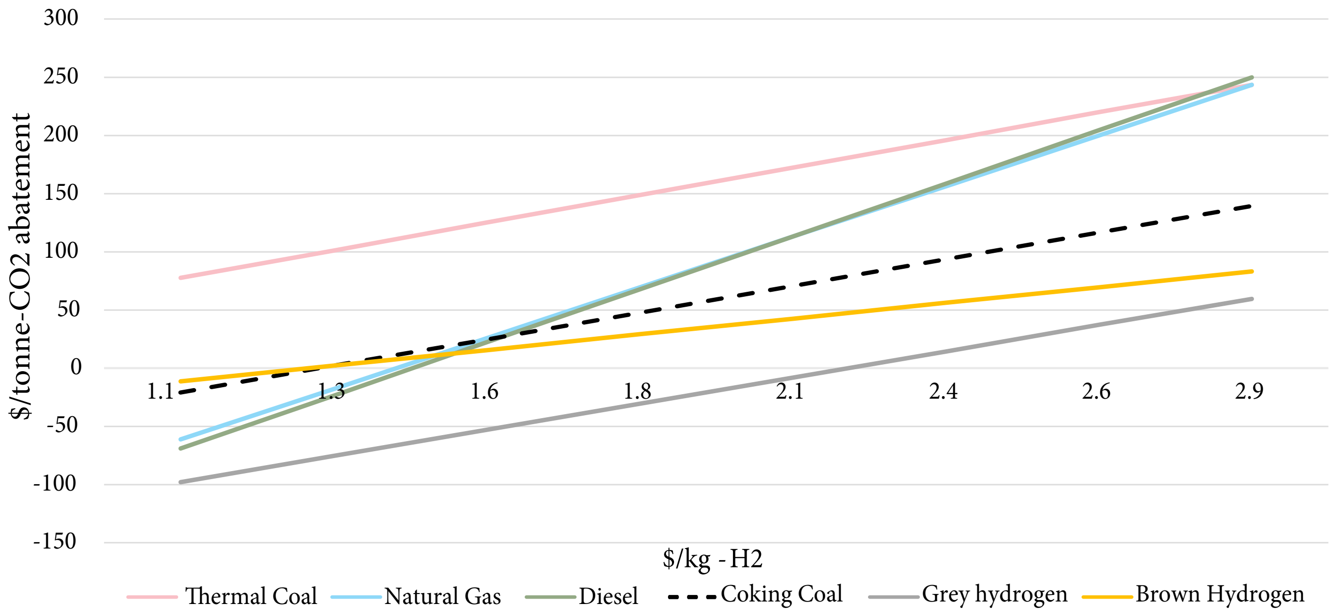
Table 5: 2030 Carbon Dioxide Abatement Costs using Green Hydrogen at 200 and 100 ₹/kg Nominal Price (Fuel Basis)

	Abatement Cost ($/tonne-CO2)		Details
	Green H2 at 200 ₹/kg	Green H2 at 100 ₹/kg	
Thermal Coal	172.3	77.6	G12 coal as delivered with 3% annual price escalation; includes levies/taxes/cess
Coking Coal	70.6	-21.0	300 $/tonne delivered coking coal; if prices fell slightly below $240, abatement costs with 100 ₹/kg-H2 would become positive (e.g., at 200 $/tonne-coking coal, they are 16.6 $/tonne-CO2 abatement).
Natural Gas	112.9	-61.2	Imported LNG, re-gasified, and delivered near the coast at 12.5 $/MMBTU.
Diesel	113.2	-69.1	Shown without taxes, assumed to be 30% of retail 90 ₹/L. With taxes, green hydrogen has an abatement cost of -176.8 $/tonne-CO2 at 100 ₹/kg-H2, or $5.5/tonne-CO2 at 200₹/kg-H2.

Source: Authors' calculations.

Notes: This assumes $1 = ₹95. Calculating the $/tonne-CO2 avoided from green electricity vs. green hydrogen is meaningless, as both ostensibly have zero emissions.

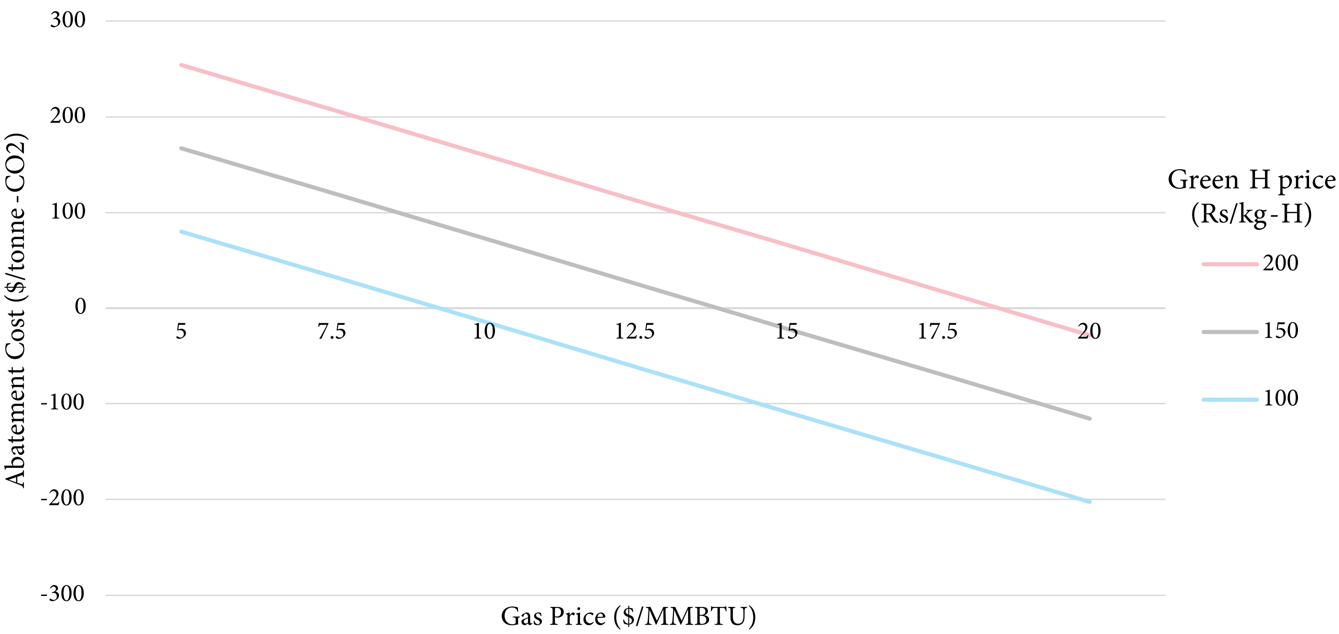
Figure 5: 2030 Carbon Dioxide Abatement Costs using Green Hydrogen (Fuel Basis Only)



Source: Authors' calculations.

Notes: This assumes $1 = ₹95. Other assumptions are consistent with previous tables, such as 600 $/kW capital costs for electrolysers and 71% efficiency (lower heating value basis). For grey hydrogen, we use data from Milbrandt and Mann (2009), estimating 4.5 NCM (normal cubic metres) of natural gas per kg grey hydrogen, and Ministry of Coal (2022), which provides Indian fixed cost estimates for grey and brown coal. Costs are back calculated using updated fuel numbers, estimating fixed costs of 31.5 ₹/kg for grey hydrogen and 85.3 ₹/kg for brown hydrogen.

Figure 6: Abatement Cost Against Natural Gas



Source: Authors' calculations.

Notes: This assumes $1 = ₹95.
Appendix 4 presents further comparisons for varying alternative fuel prices.

The figure also compares the abatement costs of replacing grey hydrogen (produced from natural gas without carbon capture), and brown hydrogen (produced from coal). These forms of hydrogen have a fixed cost per kg-H2 plus a variable cost based on the input fuel price, using the assumptions outlined above.

Figure 5 demonstrates that green hydrogen, on an energy basis, entails a substantial premium (resulting in a high abatement cost) at plausible 2030 cost ranges. The highest abatement cost is observed against thermal coal, which is carbon-intensive but cheap, while the lowest is against grey hydrogen, produced from expensive natural gas. The figure also highlights the sensitivity to green hydrogen prices.

Although green hydrogen at 100 ₹/kg appears attractive compared to many other fuels, this is partly attributable to the high price of these fuels in India. For instance, Indian LNG imports are costly, historically aligning with the "Asian premium." In contrast, the US enjoys bulk (Henry Hub) prices below 3 $/MMBTU as of September 2023, with delivered prices for bulk users only slightly higher. It is worth reiterating that the projected hydrogen prices are production-only, excluding taxes and transportation. Figure 6 depicts various CO2 abatement cost ranges for green hydrogen relative to natural gas prices.

4.2 Abatement Costs for Products or Uses

In this section, we go beyond fuel costs and emissions in our cost comparisons and look at specific products (ammonia and steel) or end uses (like transportation, heat generation, etc.) by delving into important production or conversion processes to show why simple fuel-based comparisons are insufficient.

Ammonia

Ammonia is predominantly used to produce urea, which is the most widely used fertiliser in India. At present, ammonia is made from natural gas. As the Royal Society (2020) points out, the Haber-Bosch (HB) synthesis of ammonia (NH3) synthesis, which combines hydrogen with nitrogen, requires high pressure and temperatures of 300-500 °C. The need for process heat applies to many production technologies, and therefore the true cost of displacing fossil fuels with alternatives, which requires process changes, is typically higher than a simple chemical mass balance would indicate.

Conventional ammonia production relies on steam methane reforming (SMR), which requires 0.35 tonnes of methane (from natural gas) per tonne of ammonia and releases 0.97 tonne-CO2 (excluding emissions from fuel combustion for heat) (Yüzbaşıoğlu et al., 2021). It is also possible to produce blue ammonia, where CO2 is captured.

Green ammonia is produced when green hydrogen is used in place of grey hydrogen as an input in the HB synthesis process. Theoretically, 177 kg of hydrogen is required as feedstock per tonne of ammonia, which would yield a relatively high carbon abatement cost. Switching to green hydrogen will, however, involve substantial changes to the second stage of the ammonia production process (i.e., HB synthesis).[13] The present method of steam reforming natural gas produces extensive heat and carbon monoxide (CO), both of which are required to obtain nitrogen (N2) from the air. Switching to green hydrogen would require an additional source of heat and an air separation unit to extract N2. Such needs are not part of the above chemical-process balancing calculations.

In addition, our focus is on urea production, which is typically integrated with ammonia production and uses CO2 obtained after the oxidation of CO. Thus, green urea would require a source of "green" CO2, which could either come from biomass or from direct air capture. Hence, green urea is likely to represent a substantial premium to traditional urea. Alternatively, ammonia-based non-carbonate fertilisers, such as diammonium phosphate or NPK complex fertilisers, can be produced with green hydrogen-derived ammonia, albeit with additional heat sources.

The ammonia sector accounts for nearly half of India's hydrogen demand, which is currently met with grey hydrogen and is expected to double over the course of this decade. The government had proposed including ammonia/fertiliser producers in the green hydrogen consumption obligation scheme (Business Line, 2023a). While this sector can be in the list of areas for initial green hydrogen deployment, we must remain cognisant of the need to keep cost differentials in check, more so factoring in any required process changes.[14]

Steel

The iron and steel industry are a major contributor to global GHG emissions. The actual emissions and their abatement through green hydrogen are highly dependent on the steelmaking process. India is the second-largest steel producer in the world, and its steel industry accounts for about 6% of the country's total emissions.

Steel is classified into two groups, depending on the use of base material: primary steel (from iron ore) or secondary steel (recycled from scrap steel). Primary steel can use coking coal as the primary iron ore reducing agent, or it can involve the direct reduction of iron ore (DRI) using natural gas or coal-derived syngas or hydrogen as the reducing agent. About half of the steel produced in India is via the basic oxygen/blast furnace route which uses coking coal; a third is via DRI, using either natural gas (7%) or syngas (26%) in electric furnaces; and 13-22% is from scrap steel, either mixed in blast furnaces or melted in electric furnaces (Ministry of Steel, 2023b). In terms of furnace type, about 46% of steel is produced in basic oxygen/blast furnaces (which use coking coal for iron ore reduction and also use thermal coal for heat), 31% in electric induction furnaces, and 23% in electric arc furnaces using largely coal-fired electricity (Ministry of Steel, 2023b).

There are multiple ways to reduce emissions in this sector, and they can be used in combination to achieve higher reductions (Berger, 2020). Improved process efficiency is an obvious choice. Switching to RE to power electric furnaces and increasing the proportion of scrap-based steel are the obvious solutions. However, these are constrained by the CUF of RE generation, as also noted in previous sections, and the limited availability of scrap steel.

Process emissions from iron ore reduction can be eliminated by using green hydrogen as a reducing agent. Taking the case of primary steel, CO2 emissions during steel production due to coke-related processes[15] are 1.77 tonne-CO2/tonne-crude steel, making it the most carbon-intensive form of steel (Fan and Friedmann, 2021). If coking coal is replaced by green hydrogen for the reduction process, 65 kg-H2/tonne-crude steel will be required, yielding a modest carbon abatement cost considering only process-related emissions (and excluding energy-related emissions).

While the CO2 abatement cost may be relatively less than in other sectors, because coking coal is both expensive and emission-intensive, switching

[13] First stage being upstream hydrogen production process (SMR to electrolysis).

[14] As Gulati and Banerjee (2021) point out, urea is highly subsidised in India, and thus any higher production cost will also lead to greater taxpayer subsidies.

[15] Approximately 1.5t of metallurgical coal is required to produce 1 tonne of coke. On average, about 0.63t of coke is required to produce 1t of steel (Corsa, n.d.).

to green hydrogen, or for that matter, any emission reduction technology for steel production, involves several process and equipment changes at the steel plant, requiring large capital investments. This is before considering the higher cost of green hydrogen. Devlin et al. (2023) estimate that green steel, using green hydrogen and RE, could be up to 40% more expensive than conventional steel in 2030 due to higher capex and operating expenditure (opex).

There are some hydrogen-DRI-based steel demonstration projects (e.g., HYBRIT by SSAB, Sweden) and some global steel producers have started the development of commercial-scale hydrogen-DRI steel plants (e.g., ArcelorMittal Dunkerque). Other technologies are emerging, such as molten oxide electrolysis, which substitutes the thermochemical iron reduction process with an electrochemical reaction, thus potentially further electrifying steelmaking and eliminating CO2 emissions (Boston Metal, n.d.).

Green Premium for Products

While we lack specific cost estimates for green steel and green ammonia, we can estimate abatement costs based on product differentials compared to conventional steel and ammonia, and emissions per tonne of conventional product, considering both process- and energy-related emissions.

The premium is estimated to be 25–40% for green steel (or about 125–180 $/tonne of steel) and even higher for green ammonia. Green ammonia prices in August 2023 were recorded by Platts (2023) between 753–802 $/tonne, or a premium of over 400 $/tonne. This represents a substantial abatement cost (Figure 7).

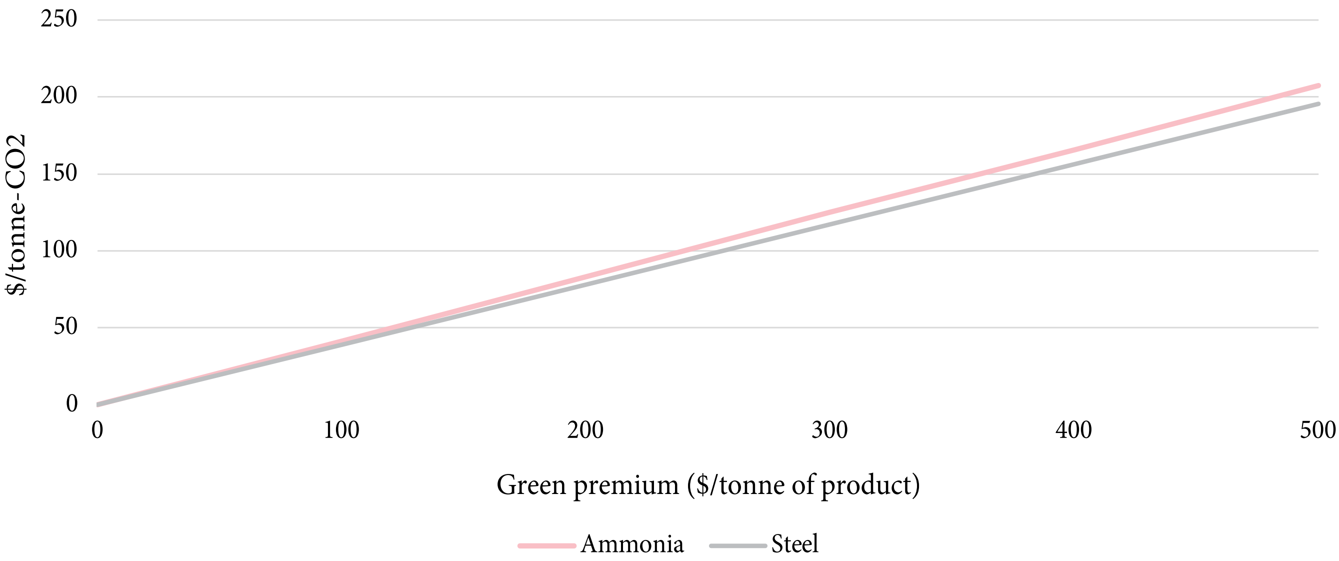
Within green ammonia, hydrogen accounts for 60–65% of the cost, so even if the cost of green hydrogen falls by 50%, that's only a one-third reduction in price, insufficient to overcome the premium in the visible future.

4.3 Abatement Costs for Other Processes/ Applications

While we alluded to process-level abatement differentials for steel and ammonia, similar analyses are difficult for other products and processes because the technologies are nascent and evolving, and it is, therefore, difficult to make price/performance projections for 2030 or beyond. In addition, cost differentials for storage and transportation would also need to be considered in such analyses. Nonetheless, we attempt to give some indicative figures or trends. The emphasis is not on a specific number, but on examining what the potential or scope may be based on first-principle fundamentals or expected trends, to the best of our knowledge.

In the following subsections, we examine some specific processes for use with green hydrogen. We do not delve into issues of compressing/storing or transporting hydrogen unless it is very germane. For a scoping analysis, we could bound the problem by assuming that hydrogen hubs are chosen to minimise the logistics cost of handling hydrogen.

Figure 7: Abatement Costs for Green Steel and Green Ammonia vs. Conventional



Source: Authors' calculations.

One industrial segment we do not cover is cement production because a significant proportion of its emissions are chemical process-related, involving the use of limestone and requiring carbon capture and sequestration to abate CO2 emissions. Green hydrogen can potentially be used to generate heat, but as noted earlier, it would be more efficient to use electricity directly than to burn hydrogen.

Power and Heat Generation

Hydrogen can be burned as a fuel, and GE Power has even demonstrated that it can be used in a gas turbine (Goldmeer, 2019). For high-temperature applications, there are two main factors of importance beyond fuel-basis costs (examined before). First, what is the efficiency of heat production and utilisation? Without further data, we can assume that the efficiencies of hydrogen are similar to those of other fuels for combustion. The second issue is hydrogen transport, which is directly related to location. Here, industrial users of thermal coal can be bifurcated. Some bulk users are amenable for hydrogen hubs, but users, such as glassworks or brickworks, are spread around the country. Refuelling stations for long-distance commercial vehicles would be another distributed system. Transporting hydrogen would be very expensive unless it was also produced in a decentralised manner. However, we do not expect individual brick kilns to set up their own electrolysers. For abating emissions from the brick industry, instead of fuel switching, we believe there can be a shift from red clay bricks to, say, grey fly ash bricks from coal power plant waste.

The economics of hydrogen supply to end-users via a gas pipeline network is relatively easy to compare on an energy-only basis, as natural gas is often sold in terms of $/MMBTU. If only small percentages of hydrogen are blended with natural gas—say, up to 20%—then existing infrastructure can be used. Putting the costs and emissions differentials together,[16] at 100 ₹/kg-H2, the CO2 avoidance cost would be 167 $/tonne-CO2 (at $1 = ₹95).

More problematic, however, are issues of scalability and utilisation. The current and planned pipeline networks are not designed for substantial hydrogen delivery, which would be very expensive to build out. It is unclear whether household cookstoves can be retrofitted[17] to burn hydrogen, and there are safety concerns for homes. Unlike many OECD countries, there is very little demand for space heating, and water heating in India is mostly electric.

Most calculations focus on CO2 avoidance with green hydrogen, but hydrogen combustion could raise NOx emissions, which is not just a local air pollutant but has high global warming potential (Lammel & Grassl, 1995).

The other alternative is to use electricity to generate heat. This is feasible up to a modest temperature (Gross, 2021), and there is global R&D on how to reach very high temperatures using electricity alone for industrial use. Even cooking has an alternative possible via induction cookstoves (which, of course, requires reliable electricity supply). Where heating is required, heat pumps are the most efficient option and can even produce temperatures approaching steam requirements, at which point a range of industrial uses are viable (Madeddu et al., 2020). The key issue for such use will be how to produce a steady and predictable RE output. This is likely to be a combination of oversizing and storage.

Transport

Private vehicles and intra-city commercial vehicles are more likely to decarbonise via batteries as electric vehicles (Poggio et al., 2023).[18] The cost-effectiveness for green hydrogen would mainly be for long-distance commercial vehicles (freight and passenger).

[16] The CO2 emissions from piped natural gas (PNG) supplied to domestic and commercial users are 1.86 kg-CO2 per standard cubic metre (SCM) (or 2.44 kg-CO2/kg). Gross calorific value of PNG is 10 Mcal/SCM (H-Energy, n.d.), and that of hydrogen is 3.05 Mcal/SCM. Blending 5% hydrogen by volume would yield a GCV of 9.65 Mcal/SCM. Delivering 10 Mcal equivalent energy will require 1.04 SCM of the PNG-hydrogen blend, having 0.0044 kg-H2. The blend would have an emissions factor of 1.83 kg-CO2 per SCM; 0.03 kg-CO2 less than unblended PNG.

[17] Even conversion from LPG to natural gas requires cookstove retrofitting, and the technical changes for hydrogen would likely be far higher based on density, pressure, and energy content.

[18] Poggio et al. (2023) collected daily running data for 16 fuel cell buses and 5 e-buses between January 2021 and April 2022 operating in South Tyrol province in Italy. They concluded that fuel cell buses cost 2.3 times more per km to operate than e-buses. This is because H2 fuel cells are much less efficient than batteries in delivering electricity. Ignoring the electricity required to compress hydrogen for storage in a bus tank, fuel cell buses needed 100 gram-H2 or 5.5 kWh electricity per km, compared to an average of 1.7 kWh/km for e-buses.

Aviation may use green hydrogen, but biofuels and e-fuels (green hydrogen-derived synthetic hydrocarbon fuels) are also alternatives.[19]

Focusing on diesel for long-distance commercial bulk transportation (such as road freight and intercity passenger buses), the good news is that process efficiency could be higher with hydrogen fuel cells (40%), compared to internal combustion engines (25%). When compared to battery EVs for road freight transport, hydrogen fuel cell-based trucks would have the advantage of longer range and much shorter refuelling time, plus higher hauling capacity (as batteries tend to be very bulky). The trade-off is that the capital cost of a hydrogen fuel cell vehicle will be higher than for ICE trucks. Thus, there will be higher capital costs and possibly lower operating (per kilometre) costs for a hydrogen fuel cell truck.

The fuel (green hydrogen) transportation cost would also be high, as green hydrogen will need to be distributed around the country. This is another aspect that needs further examination. As a first step, we suggest targeted deployments of hydrogen refuelling stations along the trunk highways. We also suggest a greater shift of freight from road to railways, whose share in total freight movement was only 27% in 2022 (Ministry of Railways, 2022) and has been falling for decades.

Refineries

The petroleum refining industry uses grey or brown hydrogen to desulphurise petroleum products. The industry accounts for half of India's hydrogen demand and is expected to grow in the coming years.

1 barrel (159 L) of crude oil requires 1.62 kg-H2 for desulphurisation (Bressan, Collodi, & Ruggeri, 2009). If grey hydrogen is used, 18.9 kg-CO2 is emitted per barrel of oil in the process, and if brown hydrogen is used, 31.6 kg-CO2 is emitted. Using green hydrogen will result in a CO2 abatement cost of 90 $/tonne-CO2 (if grey hydrogen is replaced) or 54 $/tonne-CO2 (if brown hydrogen is replaced).

The downstream oil desulphurisation process would not be affected if grey or brown hydrogen is replaced with green hydrogen. Given the high demand for hydrogen in this sector, the moderate abatement cost, and the low (downstream) integration costs, switching to green hydrogen would lead to substantial emission reductions in this industry—but the overall impact on emissions will be modest because of the limited proportion of emissions from such processes. In fact, the government is planning to include the sector in its proposed green hydrogen consumption obligation scheme. Several oil refineries in India, most notably those operated by the Indian Oil Corporation Ltd, have already chalked out plans to deploy electrolysers of several MWs within their refineries to produce green hydrogen, as part of their emission reduction efforts (*Business Line*, 2022).

5. Discussion and Policy Recommendations

The 2030 target for green hydrogen production is daunting (even more so when we add in the green electricity requirements), but at the same time it represents only a part of the total hydrogen that could be consumed if it were to be cost effective. The volumes required would then gradually increase as India moves towards net zero. Green hydrogen will be needed to decarbonise some segments of the economy that cannot be managed by fuel substitution like electrification (Ueckerdt *et al.* 2021).

This paper does not aim to predict what the price of green hydrogen will be over time but instead highlights the challenges and key issues in bringing the costs down dramatically. The higher green hydrogen costs, the greater the premium a country pays for decarbonisation, measured in $/tonne-CO2 terms.

5.1 International Benchmarking and Support

What will green hydrogen cost in 2030 (or 2050)? IRENA (2020) has some projections of learning curves but, as our analysis shows, the real issue is not electrolyser capex per se, but the cost of input RE. Electrolyser price declines and efficiency improvements will be higher because it is at the earlier stage of innovation and global interest in green hydrogen will spur investments in R&D and manufacturing. Solar PV, for example, still displays a learning rate of about 20% (Roser, 2023), but declines in panel costs aren't matched by declines in costs of inverters, installation, land, etc.

[19] Hydrogen-derived e-fuels can potentially replace fossil fuels without the need for downstream changes in final use, unlike electrification. However, as Ueckerdt *et al.* (2021) point out, it is unlikely that e-fuels will be available in large quantities and at sufficiently low prices in the foreseeable future, which risks locking in reliance on fossil fuels in the absence of demand-side transformation.

Projections of 1 \$/kg green hydrogen by 2030 are at best an extremely optimistic and, more generally, an unlikely scenario which builds on distortions and socialisation of costs in the form of government support (e.g., free electricity transmission). The recent US Inflation Reduction Act (IRA, a green energy industrial policy designed to lower energy costs) gives us some idea of what green hydrogen might cost. It offers a subsidy of 3 \$/kg green hydrogen if lifecycle emissions are below 0.45kg-CO2/kg-H2 (on a sliding scale).[20]

The level of government support in the US is enormous and would be difficult for India to match. Assuming that green hydrogen replaces natural gas, for illustration's sake, if natural gas costs 5 \$/MMBTU delivered in the US, then 3 \$/kg of green hydrogen would mean that over 350 \$/tonne-CO2 abatement costs would be subsidised on average! This is multiple times higher than the estimated average 61 \$/tonne-CO2 paid by taxpayers under the IRA (Bistline *et al*., 2023), varying heavily across industries.

5.2 Lowering Production Costs

There are two primary components of hydrogen production where cost reductions are critical. As we have shown, the variable cost due to the cost of RE is much higher than electrolyser capex. Even if the capital cost of the electrolyser does not fall to \$600/kW by 2030, a few hundred dollars more in capex per kW-electrolyser translates to only a few tens of rupees more per kg-hydrogen.

Lower RE cost is something that India is actively focusing on, primarily driven by aggressive reverse bidding norms and de-risking measures, combined with increasingly stringent Renewable Purchase Obligations (RPOs) that drive up volumes. The private sector dominates most RE deployment, even if it is through central or state government tenders (or special purpose vehicles/companies).

After record-low prices of 1.99 ₹/kWh for solar in 2020 and 2.43 ₹/kWh for wind in 2017, recent bids have been measurably higher–some bids in 2023 were north of 2.5 ₹/kWh for solar and 3.0 ₹/kWh for wind. For solar, part of the increase is due to the tariffs imposed by India on the import of PV panels, but there have been global increases in capital costs post-Covid-19. Interestingly, Indian solar production enjoys some of the lowest capital costs for hardware (₹/kWp) in the world (IRENA, 2023b). The only reason it does not have the lowest cost of solar electricity is due to higher interest rates and costs of capital.

Interest rates have been rising over the last few years, a phenomenon that impacts all capital-intensive deployments, especially clean energy projects, as they have no fuel costs. Access to cheaper global capital remains an imperative for India's energy transition. Part of this will need to come from domestic risk reduction, and the rest from lowering the rates at which global capital is available to developing countries, a focus of the Bridgetown Initiative (Barbados PMO, 2022). Multilateral Development Banks, through investment guarantees or project partnerships, can help leverage private capital at the scale and at the rates needed (Ahluwalia & Patel, 2023). However, dedicated efforts are needed to reduce counter-party risk for RE projects in India given the precarious financial position of DisComs, which lose over 1 ₹/kWh they sell.

Cheaper renewable energy is only one side of the coin; we also need steadier output with higher CUF. In the long run, batteries, and other forms of storage (like pumped hydro) should mitigate the variability issues with RE, but as Tongia (2023) has shown, grid-scale storage is likely to remain prohibitively expensive for green hydrogen production in India through 2030.

Higher CUFs are important for cost-effective hydrogen production, and one way is to combine wind and solar with oversizing. Historically, wind has received a short shift due to its higher LCOE than solar, but as Tongia (2022) showed, it has a higher value due to its generation over more time periods than solar. India's planning needs to stop looking at standalone LCOE values and apply both system-level cost analysis and time-of-day pricing. As Appendix 3 shows, even with just about 70 GW of solar (compared to a target of 280 GW by 2030), mid-day power exchange prices in 2022-23 are about half of the evening prices.

Discussions with experts suggest that European plans for green hydrogen are more focused on wind than solar. Europe's wind profile is measurably superior to India's, and it also has the world's leading deployment of offshore wind, which is years away from

[20] At the time of writing, the US Treasury Department had not clarified how electricity would be measured as green vs. not.

being established in India.[21] After several years of low growth in wind capacity, there is renewed interest after the launch of "Round the Clock" (RTC) or "Firm and Despatchable RE" (FDRE) generation bids. Developers have predominantly met these by relying on oversized wind and solar hybrid installations, instead of using storage. Such deployments are ideal for hydrogen production because most current tenders do not mandate 100% firm power, e.g., recent tenders by the Indian Railways for RTC power required only 85% annual availability, with 50% in any given 15-minute time block (Mercom, 2022). However, the higher CUF comes at a cost–many bids have been in the range of 4 ₹/kWh, a reflection of the inherent variability of wind and solar.

In addition to scale and consistency, India also must properly define "green electricity" for "green" uses. Current norms to allow banking (offsets) at best reduce the growth of emissions but do not lower emissions (Tongia, 2023). They may not conform to global standards and thus put green hydrogen exports at risk. Similarly, defining the standards for steel and other commodities to qualify as green or low carbon will be essential to achieve emissions reduction as intended and maintain export competitiveness.

Enforcing such standards takes precedence when countries impose carbon border adjustment taxes, such as the EU's CBAM, which may hurt India's exports if they fail to meet internationally accepted standards. Setting and enforcing such standards would also help consumers of green hydrogen to earn carbon credits, the sale of which would help offset some of the premium incurred on using green hydrogen. Voluntary carbon markets, which were recently allowed in India, typically have much lower prices than national compliance markets. It's unclear how Indian hydrogen, excluding exports, would achieve the higher carbon offset prices.

Supporting the production of nascent technologies that benefit from steep learning curve improvements due to scale economies, with public funds is another way to help lower costs. The Government of India has provided a budgetary outlay of Rs 4,440 crore ($555 million) under its Production Linked Incentives (PLI) scheme to support the setting up of electrolyser manufacturing units in India. The scheme grants fixed incentives to eligible manufacturers based on energy efficiency parameters and local value addition levels achieved.

Another possible use of taxpayers' money is for R&D to lower the cost of hydrogen production, e.g., by electrolyser efficiency improvements. Such efforts should extend not just to production but also to storage, transportation, conversion, and utilisation of hydrogen. While this remains a global challenge, Indian efforts can focus on both fundamental research as well as engineering and localisation. For such efforts, we should learn from global models of consortia and public-private partnerships (e.g., Germany's H2 Global Foundation) and risk-taking (e.g., US's SunShot for solar cells, ARPA-E for batteries).

It is worth noting that the flip side of making green hydrogen cheaper is getting the price of alternative fuels right. While the long-term need is for a price on fossil fuel's externalities, like a carbon price, the first step would be to remove explicit subsidies for fossil fuels. In India, these are primarily for cooking fuels and fertilisers. This would make green hydrogen more competitive but would also increase the price to the end-user (or, given these are subsidised, raise the burden on the taxpayer).

5.3 Putting Green Hydrogen in the Context of Broader Decarbonisation

Marginal abatement cost curves and $/tonne-CO2 are measures to help prioritise investments and government policies. But first principles can tell us directly which options are most effective for India. The first priority for India should be to scale up green electricity supply while electrifying its economy.

As grid electricity from RE is likely to displace coal power, it will lead to the highest emissions savings as coal has the highest CO2 emissions per unit of energy. Hydrogen, on the other hand, is very expensive on an energy basis and will only displace coal in some cases.

[21] In 2020, the US average wind PLF was 36% fleetwide, and for newer installations was over 40% (Wiser et al., 2021), while India's average wind PLF was only 19% in FY22-23, based on MNRE (2023c) data that had 43.8 GW installed producing 71,814 million kWh of electricity. While improved technologies and higher hub heights will raise this for new builds, only a handful of locations in India come even close to the average US output.

India does not yet have an explicit carbon price, but there are plans (and legislation already enacted) to set up an emissions trading scheme (also known as the Indian Carbon Credit Trading Scheme or CCTS), based on emission intensity-based targets for obligated entities. This will help equalise the cost of reducing emissions across the sectors covered[22] and allow the players to choose the most cost-effective carbon abatement measures. As the price of carbon rises, so will the demand for low-carbon/green alternatives such as green hydrogen.

While India has no formal carbon price today, several other policy actions India has taken towards decarbonisation, such as RPOs, the coal cess, etc. One useful step would be for formal accounting to convert all of these into a comparable metric in terms of costs, e.g., \$/tonne-CO2 abated. One challenge is that the costs should be based on incremental investments above and beyond business as usual. Thus, wind and solar today would have zero decarbonisation costs (rather, a negative cost).

Ultimately, when we place green hydrogen and broader decarbonisation efforts in the context of India's net-zero journey, we have to recognise that India's emissions are very low compared to the global average—and the net-zero target is several decades away (2070). Putting these two facts together, a dual strategy may be optimal—aggressively cutting low-cost emissions up front, while buying time to tackle the tail of emissions, which are hard-to-abate cost-effectively. Tongia (2021) expanded on such a strategy under a Flatten-the-Curve model.[23] Such a strategy also avoids locking into premature technologies, including selected modes of green hydrogen, which countries like India can ill afford.

5.4 Action Plans and Priorities

India must push the cost of green hydrogen production down through activities like R&D, niche subsidies, etc., as indicated above. We urge caution in support mechanisms, e.g., consumption mandates as for fertilisers. If there are price controls on the end-product, this simply means that the input price is subsidised, and the end-user does not face the true cost.[24]

Achieving the targeted green hydrogen production capacity will require building adequate RE generation capacity. India already has an ambitious RE capacity target of 450 GW by 2030, but the current pace of RE capacity expansion has been slow to meet the grid RE target on time. RE for hydrogen pushes an already stretched sector even further. There is an urgent need to identify and address the issues holding back the potential for RE capacity expansion, some of which have been mentioned above (i.e., high cost of capital, counterparty risk, regulatory uncertainty, etc.).

Planning also needs to understand the time-bound path-dependencies for a hydrogen ecosystem. Many infrastructures take years to build and last for decades. If a natural gas pipeline is built today, it should be compatible with a high share of hydrogen in the gas mix as a start—100% hydrogen pipelines are a niche and require distinct materials. This requires a focused analysis of the trade-off between learning from early deployments versus waiting for cost reductions. This must be overlaid with the expected lifespan of assets–some investments, such as vehicles, may only last about a decade. Thus, "getting it wrong" carries less risk of long-term lock-in.

While green hydrogen represents a premium to most alternative fossil fuels in India (as modelled through 2030), there are two areas where the data (Figure 5) suggest a short-term or disproportionate value. The first is displacing grey hydrogen with green hydrogen where hydrogen is already used, like in refineries. These do not require downstream process changes and also have a strong value proposition based on the high price of natural gas used to produce grey hydrogen.

A second important area is to meet global demand for green hydrogen products (like green steel or green ammonia), and many users in high-income countries should be willing to pay the premium for these products. In such cases, rather than comparing the abatement cost from green hydrogen in \$/tonne-CO2, it is sufficient to compare the cost of green hydrogen production relative to other countries.

Hydrogen hubs are a specific case that needs a holistic analysis. Is the hydrogen to be used for exports? Then coastal locations would be ideal if there is also

[22] Newspaper reports indicate only 15% emissions coverage, and that the power sector is unlikely to be included in covered sectors at least through 2030 (*MoneyControl*, 2023b).

[23] This framework focuses on cumulative emissions via the emissions trajectory, instead of the date of net-zero. Tongia (2021) suggested that low-emissions and poorer countries could lower total emissions by zeroing later but lower their upfront emissions.

[24] At a policy level, distorted fertiliser prices mean that India overuses nitrogenous fertilisers compared to other nutrients.

good RE potential and availability of upstream materials, like iron ore. There needs to be transparency in guiding the choice of location. Today, many states are clamouring to become hubs. Fiscal incentives and a top-down push can support, but these cannot overcome the physical and techno-economic fundamentals of logistics.

India is leading in the energy transition in many aspects, but it has to be judicious in its use of public resources. If green hydrogen leads to green exports, one has to be doubly cautious not to subsidise exports to consumers in high-income countries. In fact, green hydrogen can help reduce India's dependence on imports of natural gas and coking coal for domestic fertiliser and steel industries in the future.

Regarding exports, we also need to consider our comparative advantage. While our RE prices are low, they are not the lowest in the world, especially if we add a dimension of CUF. China (where the cost of electrolysers and other logistical equipment would be the lowest) is poised to export green hydrogen-based products to Korea and Japan, and the Middle East (where solar bids approached 1 ₹/kWh, thanks to cheap capital and land) is eyeing exports to Europe. Instead of focusing on the export of green hydrogen or its derivatives, the global interest in it can be an opportunity for India to move up the value chain in manufacturing, and look at products that use such green inputs, including to fulfil its domestic demand. For instance, an increase in the price of steel by 25% would only raise the cost of a large car by 1% (BNEF, 2023).

One policy discourse is that India should not miss the boat when it comes to new clean technologies. Until redoubled efforts towards self-reliance, almost all solar cells (not modules) were imported, for instance. An alternative framework for thinking about green hydrogen is not about "missing the boat," but about choosing the right vehicle. Green hydrogen has a role to play in the near term, but it would not be the dominant option in the decarbonisation portfolio in the coming decade. As this paper shows, $/tonne-CO2 abatement is an important metric to assess the options.

Leaving aside any speculation about volumes or capacity, the 2030 target is reasonable in terms of timing. It gives the industry adequate time to plan and allocate investments. However, it is also important that the target is supplemented with a detailed plan, spanning other aspects like electrolyser manufacturing, RE capacity, transport infrastructure, etc., that is internally consistent with other energy-related targets and policies of the Centre and the States, and duly accounts for the limited resources available with the government.

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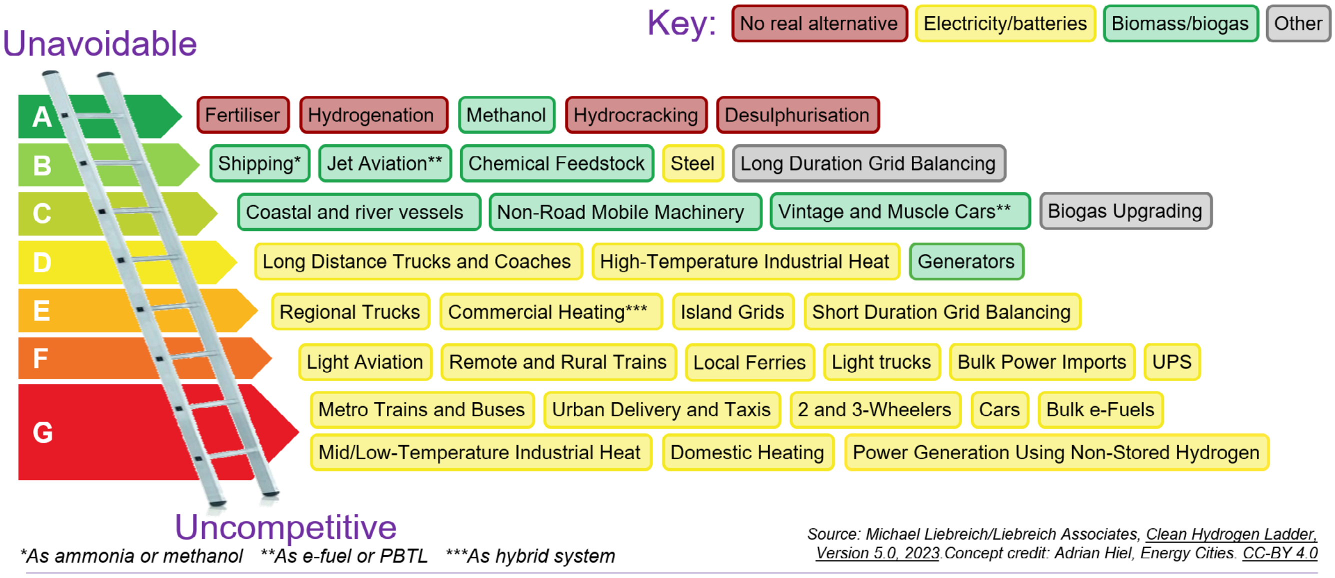
Appendices

Appendix 1. Liebreich's Hydrogen Ladder Version 5.0



Source: Liebreich, 2023.

Appendix 2. Comparison of Different Types of Electrolysers

Specification	PEM	Alkaline	AEM	SOE
Maturity	Commercial	Commercial	Commercial	Early Commercial
Charger carrier	H^+	OH^-	OH^-	O^{2-}
Electrolyte	Solid polymer	Aqueous solution 10-40% KOH/NaOH	Solid polymer	Solid ceramic
Working fluid	Distilled water	High concentration solution	Distilled water or low concentration solution	Steam
Anode material	Pt; Ir; Ru	Ni	Ni-based alloy	LSMYSZ#; $CaTi0_3$
Cathode material	Pt; Pt=C	Ni alloys	Ni, Ni-Fe, $NiFe_20_4$	Nicermets
Temperature, °C	70-90	65-100	50-70	650-1000
Operation pressure	15-30 bar	2-10 bar	up to 35 bar	<30 bar
Efficiency, HHV*	67-84%	62-82%	-	~ 90%
Cell voltage	1.80-2.40 V	1.80-2.40 V	~ 1.85 V	0.95-1.30 V
Current density	0.6-2 A/cm^2	0.2-0.4 A/cm^2	0.1-0.5 A/cm^2	0.3-1 A/cm^2
Startup duration	< 15 minutes	15 minutes	-	> 60 minutes
Stack lifetime	< 40,000 hr	< 90,000 hr	> 10,000 hr	< 40,000 hr
Energy consumption kWh/Nm3	4.5-7.5	4.5-7	~ 4.8	2.5-3.5
Estimated cost by 2050	~750 $/kW-H2 (HHV)	~600 $/kW-H2 (HHV)	-	~200 $/kW-H2 (HHV)
Advantages	• Compact and simple design • Fast response and startup • High H2 purity • Suitable for load fluctuation	• Low capital cost • Stable and well-established • No use of noble materials	• A mixture of the advantages of PEM and Alkaline • Cheap components • Suitable for load fluctuation	• Can be used in reverse mode as an H2 fuel cell • High efficiency • Low capital cost due to the absence of noble materials
Disadvantages	• Use noble materials • High membrane cost • Low durability • Acidic environment	• Corrosive electrolyte • Low H2 purity • Low current density • Slow startup	• Low ionic conductivity • Low membrane stability • Low lifetime	• Unstable electrodes • Safety and sealing problems • Bulky design • Uses brittle material

Source: Nasser *et al.* (2022).

#Lanthanum Strontium Manganate–Yttria-Stabilised Zirconia.

**Higher Heating Value (HHV) of H2 = 39.39 kWh/Kg. Using HHV for calculating efficiency of electrolysers returns a higher value. 47kWh/kg-H2 energy consumption implies 71% efficiency in LHV terms, and 84% efficiency in HHV terms.*

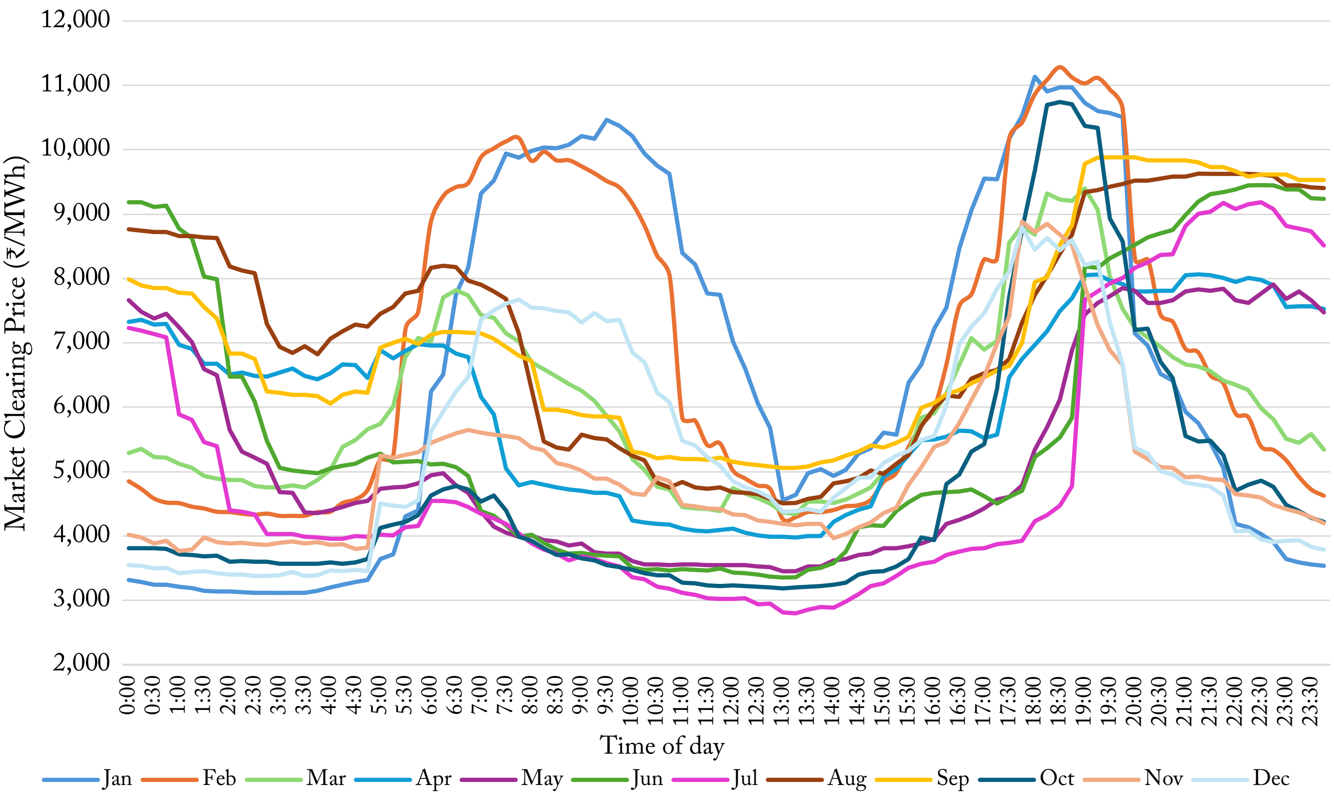
Appendix 3. What is Green Power? Banking Power Shouldn't Qualify

Present norms in India allow banking of electricity for 30 days with the distribution company (DisCom) to produce green hydrogen. This, for instance, could create 4 MW of intermittent solar capacity (at 25% PLF), to ensure 1 MW of "steady" supply of green power. The underlying assumption being that the excess solar avoids coal during midday, and hence the total is zero. The problem is that this is based on accounting offsets, under a consequential emissions framework (Tongia, 2023). Even if said solar displaces coal 100%, there is still some incremental coal used in the evenings to power the electrolysers. Thus, on an attributional (averaging) basis, the hydrogen is not 'green'. Stated another way, the excess green power during the midday has to go through the DisCom to another user. Both that user and the hydrogen producer cannot be simultaneously green!

Banking has other issues. During the day, the utility will soon be inundated with power (when there is high solar generation), while in the evening it may struggle to meet the demand. Even if it does find sufficient power, it won't cost the same. Figure 8 shows the IEX (Indian Energy Exchange–India's largest power exchange) Green Day Ahead Market (GDAM) prices for 12 months for average hourly curves. We can see there is an enormous spread in prices by time of day.

As Tongia (2023) elaborates in his paper "Properly Defining 'Green Electricity' is Key to India's Broader Energy Transition," experts call for green power that is (1) additional, (2) deliverable, and (3) matches consumption at a granular (e.g., hourly) level.

Figure 8: GDAM Market Clearing Prices Daily Curve Monthly Averages October 2022–Sept 2023 on IEX



Source: IEX.

Notes: 1 MWh = 1,000 kWh; MCP = Market Clearing Price. The above data do not show how liquid (or not) the market is. There was earlier a price cap of 12 ₹/kWh (12,000 ₹/MWh), which was subsequently lowered by the government to 10 ₹/kWh.

Appendix 4. Comparison of Energy Cost Across Fuels

The costs of different fuels vary significantly due to a combination of regulation, structural reasons, and market forces. In the following, we give more details on the cost of different fuels in India and what this means in terms of \$/MMBTU (energy value).

Coal

Thermal coal is typically, or at least can be, domestic, for which we have 3 main cost components–miner costs, levies/taxes, and transport. In contrast, coking coal used for steel production is often imported.

Using CIL notified industrial-user prices for 2023 for different grades (qualities) of thermal coal, and adding in all taxes/levies/etc., plus a modest cost of nearby transport (under 100 km which is feasible without using the railways), we can estimate the cost of coal as delivered to industry using it for thermal processes (Table 6).

A key variable is the annual rate of appreciation in coal price—over the last few years, after the coal cess (earlier Clean Energy Cess and now termed as a GST Compensation Cess) was doubled to 400 ₹/tonne-coal in 2016, the CIL costs have risen at a lower rate than inflation (the government wants to keep coal affordable as it fuels three-quarters of power plants in the country). Going forward, there is a push for private sector mining, which could further keep price rises in check.

Thermal coal is very cheap on an energy basis (including the coal cess and other levies, but without any carbon tax). Even if we assume substantial transportation costs, if delivered far away, or even double the rate of appreciation, it will still be much cheaper than green hydrogen on $/MMBTU basis.

If we consider coking coal, its delivered price can vary significantly since a large fraction of India's coking coal is imported. Based on recent global price volatility, a plausible range is 100-350 $/tonne, depending on the supplier market and the location of the steel plant. When converted to $/MMBTU, even high coking coal prices are cheaper than most ranges of green hydrogen costs on a pure energy basis, and these prices include transportation, taxes and levies like the coal cess.[25]

Natural Gas

Natural gas is another fossil fuel that green hydrogen could displace—more likely than thermal coal, based on cost differentials. Energy-basis comparisons are straightforward as natural gas is often quoted directly on a $/MMBTU basis. We assume that limited domestic natural gas, which is cheaper, will be prioritised for fertiliser production and city gas networks, leaving other industries and the power sector dependent on imports. India lacks international pipelined gas import infrastructure and relies on LNG (liquefied natural gas) imports.

As LNG is more expensive to transport than oil (due to lower volumetric energy density and requirement of specialised vessels and loading/unloading terminals), its price varies significantly by location. And unlike spot prices at trading hubs, LNG prices are often based on contracts that may be indexed to other markers (like crude oil prices or hub prices).

Table 6: Thermal Coal's Cost Modelled for 2030 (nominal ₹/tonne)

	Annual Appreciation of Coal from 2023							
	0%		1%		2%		3%	
Coal grade	₹/tonne	**$/MMBTU**	₹/tonne	**$/MMBTU**	₹/tonne	**$/MMBTU**	₹/tonne	**$/MMBTU**
G8	3,017	**1.59**	3,235	**1.70**	3,466	**1.82**	3,711	**1.95**
G10	2,315	**1.38**	2,483	**1.48**	2,660	**1.59**	2,848	**1.70**
G12	1,978	**1.36**	2,121	**1.46**	2,273	**1.57**	2,433	**1.68**
G14	1,772	**1.45**	1,900	**1.55**	2,035	**1.66**	2,179	**1.78**

Source: Authors' calculations based on data from Coal India Limited.

Notes: This is the CIL-notified price for industrial coal, including all levies/taxes, plus a small transportation charge of 150 ₹/tonne, available for nearby locations.

[25] Even at a delivered price of 350 $/tonne for coking coal, the energy value is just over 13 $/MMBTU.

Many hydrogen comparisons with natural gas show viability based on high gas prices, but that may not be applicable equally across the globe. Europe, in particular, is reeling under high gas prices after Russia's invasion of Ukraine (and stoppage of Russian gas supplies). In contrast, the US also had a modest spike, but recent Henry Hub prices in the US (through October 2023) are now back below 3 $/MMBTU. As of 2023, several Indian LNG prices are in the order of 10 $/MMBTU, after spikes in the previous years following COVID-19 and the start of Russia-Ukraine war. Delivered prices vary by location (with a small add-on internalised for regasification), but still remain less than the modelled production-only cost of green hydrogen in 2030. Therefore, in our calculations (Figure 6) we show a wide range of gas prices from 5–20 $/MMBTU.

Diesel

The cost of diesel is well known, but we incorporate several assumptions, as shown in Table 7 (we choose diesel over petrol/gasoline because industry typically uses diesel, or sometimes other distillates, and all commercial land transport, and some private transport as well, uses diesel). Diesel is refined from crude oil, the price of which is set globally and can vary significantly. Retail prices in India include a refinery cost, transportation, and retailer margin, in addition to the elephant in the room: taxes. Taxes have been as high as half the retail price in the past.

For our analysis, we compare green hydrogen to diesel with and without taxes (since green hydrogen is exempt from all taxes for now). Diesel taxes vary partly with changes in oil prices, but also with other fiscal considerations. As Bhandari and Dwivedi (2022) have quantified, taxes on oil and petroleum products are a major contributor to the exchequer and are at risk as part of the energy transition.

Assuming two sets of unknowns (retail price in 2030 and share of taxes, which we vary as 80-120 ₹/L and 30%-50%, respectively), we calculate the price of diesel in $/MMBTU with and without taxes. The government's Petroleum Planning & Analysis Cell (PPAC) and Indian Oil Marketing Companies show the monthly tax structure, and it has varied significantly over time (crossing well over 50% at times for some products). Our estimates for 2030 are given in Table 7.

For diesel to be used in long-distance heavy commercial transportation (e.g. road freight, where EVs may not be easily viable due to the weight/volume requirements of batteries, and charging times and network), as Table 4 showed, green hydrogen is only competitive by 2030 on an energy basis after taxes are included in the retail prices. Hindustan Petroleum's data for price breakdown of diesel as of November 1, 2023, showed that 33% of the retail price is taxes (HPCL, n.d.).

Electricity

If hydrogen is to be burnt simply for high temperature process heat, it might compete with electricity, which can also be used to provide heat. However, as Gross (2021) observes, electricity cannot easily reach very high temperatures, except in cases where there is high conductivity, like with metals. This is one reason why coal (or natural gas where relatively cheap) is often used by industry for process heat, e.g., in brick kilns. As discussed in Section 1.2, heat is a (small) subset of possible/certain industrial uses of green hydrogen.

Table 7: Modelled 2030 Diesel Cost ($/MMBTU), With and Without Taxes

			₹/L Retail				
			80	**90**	**100**	**110**	**120**
Excluding Taxes	(Fraction taxes)	(30%)	11.34	12.75*	14.17	15.59	17.00
		(40%)	9.72	10.93	12.14	13.36	14.57
		(50%)	8.10	9.11	10.12	11.13	12.14
Including Taxes	Retail Cost		16.19	18.22	20.24	22.27	24.29

Source: Authors' calculations.

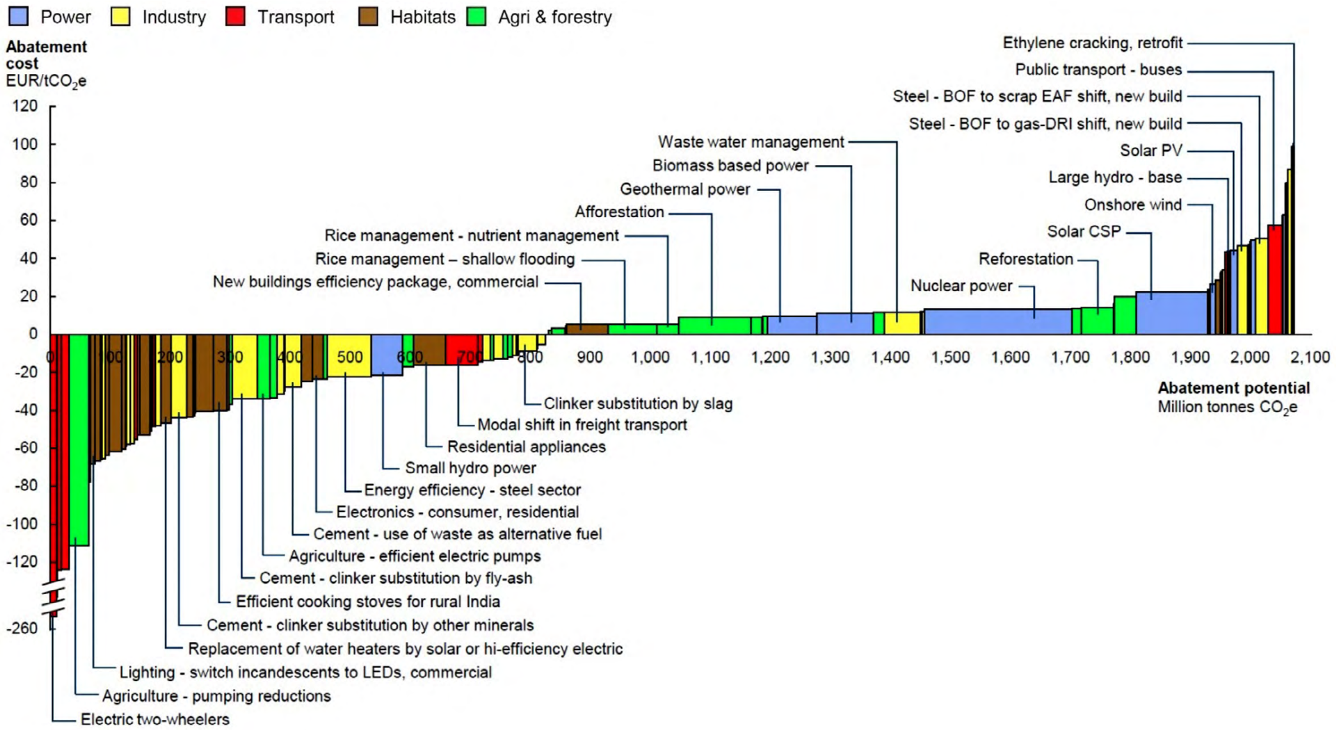
**Note: Pricing and taxation structure in Delhi as of late 2023.*

The cost of green electricity in \$/MMBTU terms can be calculated by converting kWh of electricity to MMBTU (both are energy terms). Of course, this is the raw conversion at 100% efficiency, as a theoretical (bounding) analysis. Given that 1 kWh is 3,412 BTU of energy, we can calculate the conversion based on the price of green electricity. At 4 ₹/kWh, green electricity would cost only a little over 12 \$/MMBTU. We can produce solar power at close to ₹2.5/kWh today but with only 25% CUF, which is not practical for many users, especially large industrial process users. Oversizing and blending wind + solar can increase the CUF measurably. If we blend storage with projected 2030 prices to create true 100% firm power, and add transmission, the cost would be well above 6.5 ₹/kWh. As a reference, 2023 saw storage costs above 10 ₹/kWh in small bids (Ministry of Power, 2023) (which we believe includes free transmission for input electricity).

Direct use of green electricity (without storage) will almost always be cheaper than producing green hydrogen to only convert it back to electricity or even heat due to process conversion losses.

Appendix 5. India's Marginal Abatement Cost Curve (MACC) for 2030

(Cost below 100 €/tonne-CO2)



Source: Gupta et al. (2009).

About the authors

Rahul Tongia is a Senior Fellow at CSEP, co-leading the Energy, Natural Resources, and Sustainability group. His work addresses sustainable development through technology and policy, focusing on energy supply options, renewable energy finance, smart grids, access issues, and energy reforms. His book, *Future of Coal in India: Smooth Transition or Bumpy Road Ahead?* (2020), was named a Top Energy Policy Book by BookAuthority in 2021. Dr. Tongia pioneered the Smart Grid space in India, serving as Technical Advisor to the Government of India's Smart Grid Task Force and Founding Advisor of the India Smart Grid Forum. He is also a non-resident Senior Fellow at Brookings, Adjunct Professor at Carnegie Mellon, and a Fellow of the Indian National Academy of Engineering.

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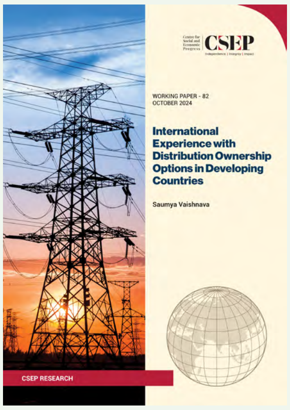
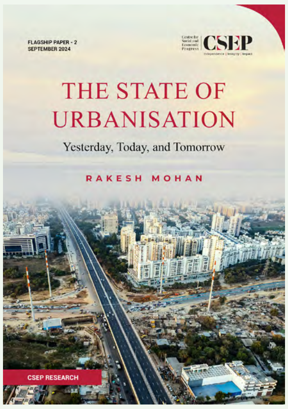
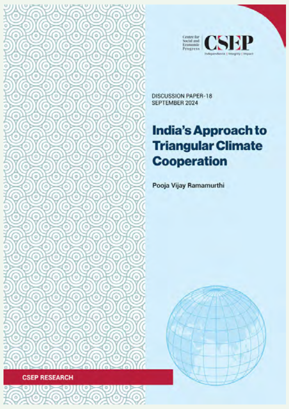
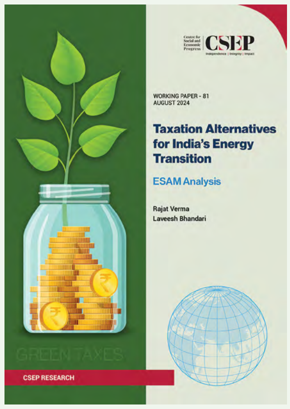
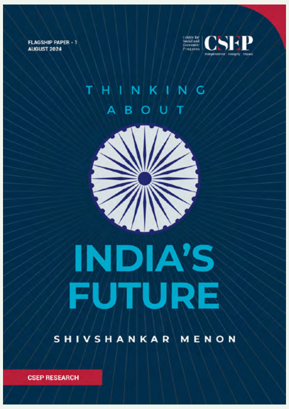
Other publications

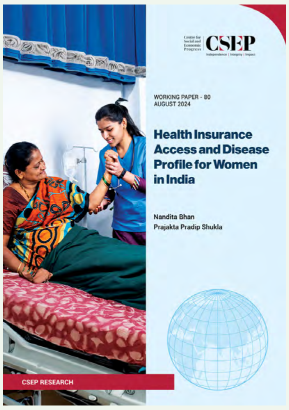


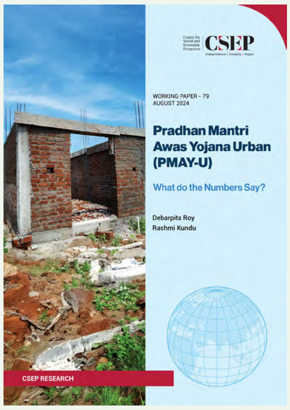


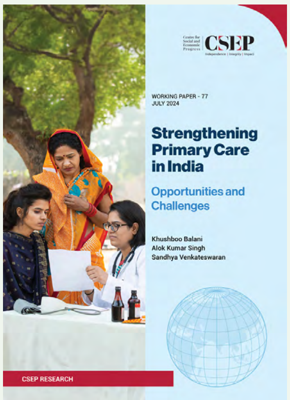


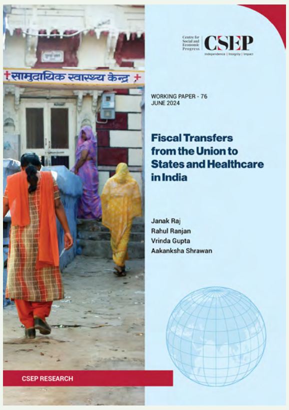


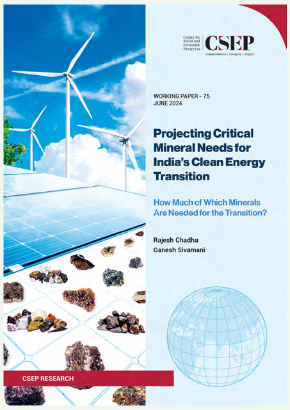


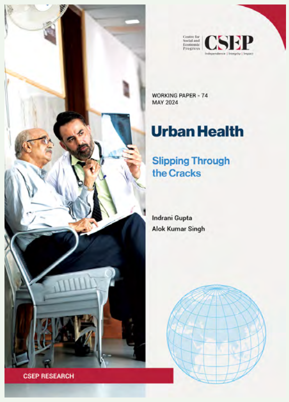


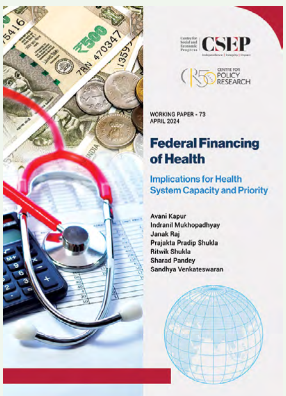


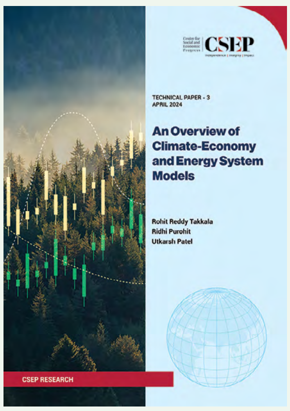


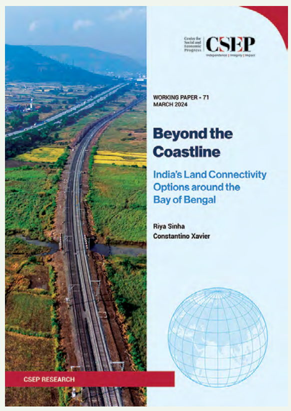












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