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Hydrogen fuel for transport in India

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Introduction

Many of India's largest cities promote the use of compressed natural gas (CNG) in place of diesel and gasoline for motor vehicles because of its relative pollution benefits, cheaper cost, and greater efficiency than oil on a calorific-value basis.[1] However, the risk of methane leakage along the natural gas supply chain and methane's short-term global warming potential can greatly diminish or reverse the climate and pollution benefits of CNG.[2] Indeed, decarbonization of the transport sector in line with India's ambitious climate, air pollution, and energy security goals is not likely to be achieved by CNG and will instead require other, low-carbon sources of energy that can serve as sustainable, long-term solutions.

Hydrogen fuel is increasingly being discussed as an alternative fuel in a myriad of sectors, and particularly in transportation. The development of hydrogen fuel cell electric vehicle markets in California, Japan, and Germany, to name a few, has provided evidence of hydrogen's feasibility in the road sector.[3] When combusted, hydrogen only emits water and oxygen and thus it generates no tailpipe pollution. Additionally, hydrogen can be produced using a variety of energy sources and technologies, and these different pathways can enhance energy security and promote the development of a domestic industry.

In 2003, India joined the International Partnership for the Hydrogen Economy. The country has since developed a National Hydrogen Energy Roadmap and provided funding for research and development and pilot projects for hydrogen production

1 Ministry of Petroleum & Natural Gas, "Government Taking Steps for Promotion of CNG Services in the Country," (2021), https://pib.gov.in/PressReleseDetailm.aspx?PRID=1744756.

2 Oscar Delgado and Rachel Muncrief, *Assessment of heavy-duty natural gas vehicle emissions: Implications and policy recommendations*, (ICCT: Washington, D.C., 2015), https://theicct.org/sites/default/files/publications/ICCT_NG-HDV-emissions-assessmnt_20150730.pdf;
Georg Bieker, *A global comparison of the life-cycle greenhouse gas emissions of combustion engine and electric passenger cars*, (ICCT: Berlin, Germany, 2021), https://theicct.org/publications/global-LCA-passenger-cars-jul2021

3 Ivan Penn and Clifford Krauss, "California is Trying to Jump-Start the Hydrogen Economy," *The New York Times*, November 11, 2020, https://www.nytimes.com/2020/11/11/business/hydrogen-fuel-california.html.

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and storage, and for fuel cells.[4] Currently, hydrogen use in transport is limited to bus pilots that run on hythane, a blend of 18% hydrogen and CNG, and these began in New Delhi in 2020; India also announced plans to expand this pilot to other major cities in 2021.[5] While commercialization and market development have not progressed rapidly, recent advancements in hydrogen technology and political support for developing more robust and independent energy systems in India have enhanced the feasibility of greater hydrogen use in transportation.[6] In August 2021, India's prime minister announced the launch of the National Hydrogen Mission, which seeks to scale up renewable electrolysis hydrogen ("green" hydrogen) production and use it in multiple sectors including transportation.[7]

The advantages of hydrogen fuel align well with India's broader objectives in terms of energy independence and pollution and climate mitigation. One factor that will influence its likely uptake is whether it will be economical to use hydrogen fuel in the transportation sector. To investigate, this study estimates the at-the-pump cost of two types of hydrogen that could have great deployment potential in India: green hydrogen and hydrogen produced from natural gas with carbon capture and storage ("blue" hydrogen). We estimate the costs in 2030 and 2050 for three of India's largest cities: Mumbai, Ahmedabad, and New Delhi.

Understanding the hydrogen fuel system

Green hydrogen production

Green hydrogen is produced through electrolysis powered by renewable electricity from sources such as solar and wind. Electrolysis is an electrochemical process that splits water into hydrogen and oxygen. India has a goal of 175 gigawatts (GW) of installed capacity from renewable electricity by 2022 and 450 GW by 2030.[8] These ambitious goals reflect the vast renewable electricity potential in India that could be deployed for green hydrogen production.[9] Because it is sourced from renewable electricity, one key advantage of green hydrogen is that it results in very low life-cycle greenhouse gas (GHG) emissions.

The solar electricity market

India has achieved record-low solar electricity auction prices in recent years. This is a consequence of multiple programs that support ambitious deployment of solar generation.[10] Examples include a Viability Gap Funding program that improves the financial returns of solar projects; a Central Financial Assistance program that covers 20%–40% of project costs, depending on project size; and an accelerated depreciation

4 National Hydrogen Energy Board and Ministry of New and Renewable Energy, "National Hydrogen Energy Roadmap," (2007), http://164.100.94.214/sites/default/files/uploads/abridged-nherm.pdf

5 "India Is Looking Towards Kick-Starting the Hydrogen Ecosystem Development," Petroleum and Natural Gas Regulatory Board, April 15, 2021, https://pngrb.gov.in/eng-web/public_notice.html; FuelCellsWorks, "India: Shri Pradhan Inaugurates H-CNG Plant And Launches Trials In Delhi Of 50 Hydrogen-Powered Buses," October 21, 2020, https://fuelcellsworks.com/news/india-shri-pradhan-inaugurates-h-cng-plant-and-launches-trials-in-delhi-of-50-hydrogen-powered-buses/; S Dinakar, "India Sees Hydrogen as Transportation, Industrial Fuel," *Argus Media*, April 15, 2021, https://www.argusmedia.com/en/news/2205576-india-sees-hydrogen-as-transportation-industrial-fuel.

6 International Energy Agency, "India Energy Outlook 2021," (2021), https://www.iea.org/reports/india-energy-outlook-2021.

7 Uma Gupta, "Indian Prime Minister Announces National Hydrogen Mission," *PV Magazine*, August 17, 2021, https://www.pv-magazine.com/2021/08/17/indian-prime-minister-announces-national-hydrogen-mission/

8 Sanjay Dutta, "India on Track to Meet 175 GW Green Energy Target by 2022: PM Modi," *Times of India*, October 26, 2020, https://timesofindia.indiatimes.com/business/india-business/india-on-track-to-meet-175-gw-green-energy-target-by-2022-pm-modi/articleshow/78878269.cms.

9 David Palchak et al., "Greening the Grid: Pathways to Integrate 157 Gigawatts of Renewable Energy into India's Electric Grid" (Volume I. National Study, National Renewable Energy Laboratory, June 2017), https://ies.lbl.gov/publications/greening-grid-pathways-integrate-0.

10 "Grid Connected Solar Schemes," Government of India, Ministry of New & Renewable Energy, accessed January 2021, https://mnre.gov.in/solar/schemes/.

tax benefit for project developers.[11] In addition, India offers project developers and equipment manufacturers priority lending through the Reserve Bank of India, including bank credit up to 40%; exemptions on import and excise duties for solar machinery; and allows 100% foreign direct investment without need for prior approval.[12] More targeted financial and risk reduction support for developers and manufacturers is made available through the Modified-Special Incentive Package Scheme, which provides capital subsidies for solar photovoltaic manufacturers, and through a Production Linked Incentive scheme, which provides funding over a 5-year period for high-efficiency solar module manufacturing.[13]

Electric grid regulations in India also favor solar generation. These include granting renewable projects must-run status (i.e., the power plant is always able to supply electricity to the grid and will not be curtailed), setting renewable purchase obligations for electric distribution companies, and transmission charge exemptions.[14] Together these policies have enabled India to drive down the per-kilowatt hour (kWh) solar auction price to record lows domestically and globally.[15]

Blue hydrogen production

Blue hydrogen is produced from natural gas, combined with carbon capture and storage (CCS). The most common technology applied today is steam-methane reforming (SMR). In this process, methane from natural gas and high-temperature steam are used to produce hydrogen. CO_2 that is co-produced is then captured and sequestered underground long term.

While blue hydrogen results in higher GHG emissions than green hydrogen, it could be of interest in India in the near future because SMR is already a mature technology, and the natural gas market is developing quickly. Natural gas made up 6.2% of total energy consumption in India in 2017 and that is projected to increase to 20% by 2025, due to rapid expansion of transmission and distribution pipeline networks.[16] This expanded access to natural gas across India could provide the opportunity for widespread, localized production of blue hydrogen.

Transporting hydrogen

In gaseous form, hydrogen can be transported via truck, rail, or pipeline, and once liquefied, it can be transported via truck or rail. In this study, we focus on pipeline transport of gaseous hydrogen because of its emissions benefits and advantageous economies of scale relative to other forms of transport.

We assume dedicated hydrogen pipelines would be used to transport hydrogen. India's Petroleum and Natural Gas & Steel Minister Shri Dharmendra Pradhan announced

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11 International Energy Agency, "India 2020 Energy Policy in Review," (January 2020), https://iea.blob.core.windows.net/assets/2571ae38-c895-430e-8b62-bc19019c6807/India_2020_Energy_Policy_Review.pdf.

12 Reserve Bank of India, "RBI Releases Revised Priority Sector Lending Guidelines," September 4, 2020, https://rbidocs.rbi.org.in/rdocs/PressRelease/PDFs/PR2840BDEE73502104CA5AA9B973D308777CF.PDF; "India Customs Tariff 2020-2021," Central Board of Indirect Taxes and Customs, accessed January 2021, https://www.cbic.gov.in/htdocs-cbec/customs/cst2021-311220/csgen-expemtns-idx-311220; "Renewable Energy," Make In India, accessed January 2021, https://www.makeinindia.com/sector/renewable-energy

13 "Modified Special Incentive Package Scheme," Ministry of Electronics & Information Technology, accessed January 2021, https://www.meity.gov.in/esdm/incentive-schemes#:~:text=In%20order%20to%20promote%20large,and%20Manufacturing%20(ESDM)%20Industries; "Renewable Energy," Make In India

14 International Energy Agency, "India 2020 Energy Policy in Review."

15 Jules Scully, "Solar Tariffs in India Hit Record Low After Gujarat's 500MW Auction," *PV Tech,* December 21, 2020, https://www.pv-tech.org/news/solar-tariffs-in-india-hit-record-low-after-gujarats-500mw-auction#:~:text=Solar%20tariffs%20in%20India%20hit%20record%20low%20after%20Gujarat's%20500MW%20auction,-By%20Jules%20Scully&text=Image%3A%20NTPC.,solar%20tariff%20seen%20in%20India.

16 Usua Amanam, *Natural gas in India: market and influencers*, (Stanford Natural Gas Initiative, Palo Alto: 2017), https://ngi.stanford.edu/sites/g/files/sbiybj14406/f/NGI_India_LitReview%284-17%29%20rev1_Final.pdf; "Vision 2030: Natural Gas Infrastructure in India," Industry group report for the Petroleum and Natural Gas Regulatory Board, (April 2013), https://www.pngrb.gov.in/Hindi-Website/pdf/vision-NGPV-2030-06092013.pdf ; Government of India, Ministry of Petroleum & Natural Gas, "Annual Report 2019-20: Energizing India's Progress," (2020), http://petroleum.nic.in/sites/default/files/AR_2019-20E.pdf.

an intent to blend hydrogen with CNG in the existing natural gas network for use in transportation. However, there are several reasons why this might not be practical. While small quantities, 5%–15% of hydrogen by volume, can be blended with natural gas and transported through existing natural gas pipeline networks, increasing blending levels introduces risk to the integrity of dedicated natural gas pipelines, and the risk stems from the differences in the physical characteristics of hydrogen and natural gas.[17] Additionally, if blended hydrogen were to be used in fuel cell vehicles that require high purity, close to 100% hydrogen, then separation and purification technology at the end point of the pipeline would be necessary. This separation technology is very expensive at low blends. Furthermore, future hydrogen demand might exceed the volume that can safely be transported via CNG pipelines.[18] Therefore, this study assumes India will build a dedicated hydrogen pipeline network, and we consider the related costs in our cost analysis.

Methods and cost assumptions

We selected New Delhi, Mumbai, and Ahmedabad for detailed hydrogen cost analysis. These three cities have large populations and consequently large potential hydrogen demand. Additionally, their existing access to natural gas and renewable resources make hydrogen production and transport potentially economical. We project the at-the-pump price of green hydrogen and blue hydrogen for each of the three cities in both 2030 and 2050.

There are four cost components that make up the at-the-pump hydrogen price that consumers pay:

1. **Hydrogen production cost.** To estimate this, we utilized a prior report on green hydrogen (hereafter, "the Christensen study"[19]) and an ICCT study on blue hydrogen (hereafter, the Baldino study"[20]), and contextualized the models using India-specific cost data including the renewable electricity price and natural gas price.
2. **Hydrogen transport cost.** We estimate the cost of a dedicated hydrogen pipeline network that transports hydrogen from the production facility to hydrogen fueling stations.
3. **Hydrogen fueling station cost.** We project potential fueling station numbers, capacity, and cost of building and operating fueling stations in each city in 2030 and 2050.
4. **Tariffs.** We estimate all possible tariffs along the hydrogen supply chain that fuel consumers might end up paying.

The following sections contain more detailed descriptions of the data and methodology for the four components. We present the final hydrogen price in the unit of per kg hydrogen purchased.

Cost of green hydrogen production

We utilized a cashflow model developed in the Christensen study to calculate the cost of producing green hydrogen in India.[21] The inputs in this model are based on a literature

17 Chelsea Baldino et al., *Hydrogen for heating? Decarbonization options for households in the United Kingdom in 2050*, (ICCT: Washington, D.C., 2020), https://theicct.org/sites/default/files/publications/Hydrogen-heating-UK-dec2020.pdf.

18 Ibid.

19 Adam Christensen, *Assessment of hydrogen production costs from electrolysis: United States and Europe*, (Three Seas Consulting: 2020), https://theicct.org/publications/assessment-hydrogen-production-costs-electrolysis-united-states-and-europe

20 Baldino et al., *Hydrogen for heating? Decarbonization options for households in the United Kingdom*.

21 Christensen, *Assessment of hydrogen production costs from electrolysis*.

review of all system cost components for green hydrogen production—electrolyzer, compressors, short-term storage, water, and piping—plus the levelized cost of electricity. The model scenarios include three system configurations: grid connection, direct connection, and curtailment; each of these connects renewable generators (solar, onshore wind, or offshore wind) to an electrolyzer to produce green hydrogen. Within each model scenario, there are three electrolyzer technology options: alkaline electrolyzers (AE), proton exchange membranes (PEM), and solid oxide electrolyzers (SOE). The Christensen study also included three techno-economic outlooks—pessimistic, optimistic, and mid-level. In this study, we utilize the mid-level outlook for core analysis and use the optimistic scenario as a comparison.

While the Christensen study calculated renewable electricity costs endogenously in the model, in this study, we put exogenous solar electricity prices for each city into the model, and those are shown in Table 1. For Mumbai and Ahmedabad, we used the average solar auction price in each of the states over the past 3 years as the baseline renewable electricity price for each respective city. For New Delhi, due to a lack of auction data within Delhi, we instead used the nationwide 3-year historical average solar auction price.[22] To project solar prices in 2030 and 2050, we applied an annual cost reduction term consistent with the optimistic scenario in the Christensen study, and this is due to the strong ambitions for the solar market in India; this is also shown in Table 1. In this study, we assumed a direct-connection configuration for green hydrogen production where an electrolyzer is connected directly to an off-grid solar generator. This means that the capacity factor of the electrolyzer would be the same as the solar capacity factor. We collected the state-specific solar capacity factors for India from the National Renewable Energy Laboratory's (NREL) National Solar Radiation Database, and those also serve as the electrolyzer capacity factors in Table 1.[23]

Table 1. Renewable electricity inputs used in our green hydrogen production cost cashflow modeling.

Location	Ahmedabad		Mumbai		New Delhi	
Baseline price of solar electricity	$0.035/kWh		$0.042/kWh		$0.040/kWh	
Projected price of solar electricity	2030	2050	2030	2050	2030	2050
	$0.022/kWh	$0.015/kWh	$0.027/kWh	$0.018/kWh	$0.026/kWh	$0.017/kWh
Solar and electrolyzer capacity factor	20%		20%		20%	

Cost of blue hydrogen production

In the Baldino study, the cost of blue hydrogen was estimated by harmonizing an extensive literature review of SMR+CCS cost analyses. While SMR is not the only technology capable of producing blue hydrogen, it is the most commercially mature.[24] Thus, we assumed in this study that SMR will be the dominant technology used and, because it is already fully commercially mature, that its costs will be constant over time. We also assume no cost change in CCS nor any change in capture efficiency rate. Therefore, in the projection of future blue hydrogen cost, the only cost component that varies with time is the feedstock (natural gas) price. For both green and blue hydrogen, we adopt the short-term hydrogen storage fee that is in both the Christensen and Baldino studies, as storage might be a necessary system component to balance supply and demand.

22 "Tender Compendium," Bridge to India, India RE Navigator, accessed February 2021, https://india-re-navigator.com/utility/tender-tracker.

23 "National Solar Radiation Database Data Viewer," National Renewable Energy Laboratory, accessed December 2020, https://maps.nrel.gov/nsrdb-viewer.

24 Baldino et al., *Hydrogen for heating? Decarbonization options for households in the United Kingdom*.

Natural gas price

We estimated India's retail natural gas price for industrial consumers in 2030 and 2050 in order to estimate blue hydrogen production costs in those years. This is a non-public retail price that includes wholesale gas prices, pipeline tariffs, and taxes. India links its pricing to international markets and bi-annually sets the price of domestically produced natural gas in order to subsidize the fertilizer industry and power sector, which are India's largest natural gas consumers.[25] We collected the historic domestic wholesale onshore and offshore gas prices from the Government of India's Petroleum Planning & Analysis Cell[26] and historical and forecasted natural gas prices from Henry Hub, the American natural gas benchmark from the U.S. Energy Information Administration. Because Henry Hub prices are an input for India's market-linked prices, we performed a regression analysis between historical Henry Hub prices and India's domestic onshore and offshore prices.[27] Next, we forecasted domestic prices for onshore and offshore gas in India using their regression coefficients and Henry Hub price forecasts as inputs.[28] The average domestic wholesale natural gas price was weighted using onshore versus offshore supply projections from the Petroleum and Natural Gas Regulatory Board's "Vision 2030" for natural gas in India and kept constant for 2050.[29] Finally, the industrial consumer natural gas valued added tax (VAT) of 6% in Ahmedabad, 3% in Mumbai, and 5% in New Delhi was applied.

We also considered the cost of transporting natural gas through transmission pipelines. India is transitioning to a unified transmission tariff that will be determined by the weighted average of approved, pipeline-specific tariffs and the volume of gas they transport. As proposed, the unified tariff is broken into two zones, distances under 300 km and those over 300 km, with the tariff for the first zone set as a percentage of the tariff for the second zone. The proposed regulation from the Petroleum and Natural Gas Regulatory Board demonstrated this new calculation using data from fiscal year (FY) 2019–20 and showed a unified tariff set at INR 56.84 per MMBtu for both zones.[30] As this proposed regulation has not been finalized and there are multiple transmission pipelines being planned and built, predictions of the tariff amount are difficult. Therefore, we used the FY 2019–20 value as the transmission tariff in both 2030 and 2050. Finally, transportation of natural gas via pipelines incurs a 5% integrated Goods & Services Tax applied to the pipeline tariff, and we add that to the price of natural gas.[31] We present the projected 2030 and 2050 natural gas prices for the three Indian cities in Table 2.

25 Amanam, *Natural gas in India: market and influencers*.

26 "Domestic Gas Prices," Petroleum Planning & Analysis Cell, accessed September 2020, https://www.ppac.gov.in/content/155_1_GasPrices.aspx

27 "Henry Hub Natural Gas Spot Price," Energy Information Administration, accessed November 2020, https://www.eia.gov/dnav/ng/hist/rngwhhdA.htm.

28 "Natural Gas Supply, Disposition, and Prices," Energy Information Administration, accessed November 2020, https://www.eia.gov/outlooks/aeo/data/browser/#/?id=13-AEO2020&cases=ref2020&sourcekey=0.

29 "Vision 2030: Natural Gas Infrastructure in India," Industry group report.

30 Petroleum & Natural Gas Regulatory Board, "Public Consultation Document: Amendment of the Petroleum and Natural Gas Regulatory Board [Annexure 2]," September 29, 2020, https://pngrb.gov.in/eng-web/public_notice.html.

31 "Goods and Services Tax Rates," Central Board of Indirect Taxes and Customs, June 30, 2020, https://cbic-gst.gov.in/gst-goods-services-rates.html.

Table 2. Projected 2030 and 2050 natural gas prices for industrial users in Ahmedabad, Mumbai, and New Delhi.

	Ahmedabad	Mumbai	New Delhi
Wholesale natural gas price	2030: US$6.5/MMBtu (INR 460/MMBtu) 2050: US$6.9/MMBtu (INR 490/MMBtu)		
Natural gas value added tax	6%	3%	5%
Transmission pipeline tariff plus tax	US$0.85/MMBtu (INR 59.68/MMBtu)		
Retail natural gas price	2030: US$7.8/MMBtu (INR 547/MMBtu)	2030: US$7.6/MMBtu (INR 533/MMBtu)	2030: US$7.7/MMBtu (INR 542/MMBtu)
	2050: US$8.2/MMBtu (INR 577/MMBtu)	2050: US$8/MMBtu (INR 562/MMBtu)	2050: US$8.1/MMBtu (INR 572/MMBtu)

Hydrogen transport cost

We estimated the cost of building dedicated hydrogen pipelines to transport hydrogen from production plants to retail fueling stations. Our estimates of both pipeline lengths and hydrogen demand serve to demonstrate the contribution of transportation costs to the total cost per kg of hydrogen. They represent an approximation of the length of pipelines necessary to provide adequate connectivity and accessibility to meet fueling demand. We assumed the same pipeline length and demand, and by extension the same hydrogen transport cost, for both blue and green hydrogen.

The hydrogen pipeline network consists of transmission pipelines and high-pressure distribution pipelines. Transmission pipelines are better suited for the transport of hydrogen at larger volumes over longer distances, and these transport hydrogen from the production facility to each city center. Distribution pipelines then deliver hydrogen around each city to various fueling stations. We utilized the same per-meter hydrogen pipeline cost estimates as in the Baldino study for transmission, US$1,855 per meter, and for high-pressure distribution pipelines, we used US$1,033 per meter.

We estimate the length of transmission and distribution pipelines based on assumed production locations using Google Maps. Specifically, we collected the locations of facilities in the fertilizer, petrochemical, and power sectors in proximity to each of the three cities, to identify areas with access to natural gas. These locations informed the approximations for the length of the transmission pipeline. Because we do not expect the daily demand to exceed the maximum daily throughput capacity of our transmission pipeline, which is 1 million kg hydrogen per day, we did not assume that additional transmission pipelines are built between 2030 and 2050. To approximate the length of distribution pipeline, we used the dimensions of each city as well as existing city gas distribution pipelines to provide approximations of both linear distance and terrain suitability. Unlike transmission pipelines, we assumed that distribution pipeline lengths triple by 2050, for accessibility and connectivity with a growing number of fueling stations in each city. We show the estimated pipeline lengths in Table 3.

Table 3. Estimated hydrogen transmission and distribution pipeline lengths in Ahmedabad, Mumbai, and New Delhi in 2030 and 2050.

	Transmission pipeline		Distribution pipeline	
	2030	2050	2030	2050
Ahmedabad	32 km	32 km	21 km	65 km
Mumbai	40 km	40 km	22 km	79 km
New Delhi	16 km	16 km	27 km	82 km

With the per-meter cost and estimated pipeline length, the total cost of both transmission and distribution pipeline for each city was then amortized over the pipeline's lifetime of 30 years. To get the per-kg hydrogen transport cost, the amortized annual pipeline cost needs to be divided by the amount of hydrogen transported in 1 year, in other words, annual hydrogen demand. To inform the assumption for hydrogen delivered, we looked to the development of the hydrogen market and fueling station networks in California, the first and most mature hydrogen market in the United States and a world leader in fuel cell electric vehicle sales and infrastructure. California's Air Resources Board projects there will be 10 new hydrogen fueling stations installed in the state annually by 2024.[32] Informed by this projection and considering both the smaller population of Indian cities compared to the entire state of California and that locations outside of California might not share the same ambitions, we assumed New Delhi, Ahmedabad, and Mumbai will each have 10 hydrogen fueling stations by 2030 and that number increases to 50 by 2050. Based on California's experience, stations with a fueling capacity below 400 kg per day would struggle to be profitable. We therefore assumed all stations built in 2030 have a capacity of 400 kg per day. As a result, the daily hydrogen demand in 2030 would be 4,000 kg.

Looking out to 2050, we expect additional fueling stations with higher fueling capacity would be needed to meet a growing demand and maturing market. We assumed an additional 40 hydrogen fueling stations are built in each city; 10 of these new stations have a capacity of 400 kg/day and the remaining 30 have a higher capacity of 1,000 kg/day, taking the advantage of economies of scale. This is a total of 38,000 kg hydrogen delivered daily per city.

The maximum daily throughput capacity of our transmission pipeline is 1 million kg of hydrogen per day, and for high-pressure distribution pipeline, it is 150,000 kg of hydrogen per day; each is capable of servicing the maximum hydrogen demand that we assumed.

Hydrogen fueling station costs

Our hydrogen fueling station cost estimate is based on a literature review. Specifically, we used a recent NREL study on the cost of hydrogen fueling stations serviced by high-pressure pipelines to inform our calculations of total capital costs and operational and maintenance (O&M) costs over a 10-year equipment lifespan.[33] We limited our scope to stations configured to receive gaseous hydrogen via high-pressure pipelines as opposed to other methods such as low-pressure pipelines or truck delivery. This configuration enables centralized storage and compression equipment to be co-located at the production facility, and that achieves greater economies of scale and reduced O&M costs relative to locating this equipment at each individual station.[34] Additionally, stations serviced by pipelines require less land, which reduces station capital costs and makes siting, particularly in the densely populated cities assessed in this study, easier.[35] As mentioned in the previous section, we expect stations with larger capacities to be built in favor of smaller stations over time, due to increased hydrogen demand and technical economies of scale. Following the methodology from the NREL study, we assumed an annual cost reduction of 1% for the first 10 years of deployment for each 400 kg/day station, such that a station built in 2040 costs 9% less than one in 2030, excluding inflation.[36] Therefore, for 2050, we used the 400 kg/day station cost after 10 years of annual reductions. For the 30 1,000 kg/day stations, because they are newly built in 2050, we used the average annual cost for a station of this capacity without cost reduction. Similar to hydrogen transport cost, to normalize the final result in per-kg

32 California Air Resources Board, "2019 Annual Evaluation of Fuel Cell Electric Vehicle Deployment & Hydrogen Fuel Station Network Development," (July 2019), https://ww2.arb.ca.gov/sites/default/files/2019-07/AB8_report_2019_Final.pdf.

33 Michael Penev, Jarret Zuboy, and Chad Hunter, "Economic Analysis of a High-Pressure Urban Pipeline Concept (HyLine) for Delivering Hydrogen to Retail Fueling Stations," *Transport Research Part D* 77, (December 2019): 92–105. https://doi.org/10.1016/j.trd.2019.10.005.

34 Ibid.

35 Ibid.

36 California Air Resources Board, "2019 Annual Evaluation of Fuel Cell Electric Vehicle Deployment."

hydrogen, we amortized the total capital and O&M costs by 10 years and divided by the annual amount of hydrogen supplied, assuming 100% capacity utilization.

In addition to the fueling station construction and O&M costs, we also considered the cost of hydrogen purification. Fuel cell electric vehicles require hydrogen with very high purity, and purity can be compromised during the pipeline transportation process. We followed the Baldino study and assumed pressure swing adsorption (PSA) technology is used at each fueling station due to its relative commercial maturity and cost effectiveness at purifying large volumes of already nearly pure hydrogen. We added this hydrogen purification cost to derive a final fueling cost per kg of hydrogen.

Hydrogen tariffs

The last step in our calculation was to apply the relevant tariffs to each cost component to get the final at-the-pump hydrogen price that consumers are likely to pay. Hydrogen produced in India is subject to a 12.5% per kg Central Excise tariff, which is an indirect tax on goods manufactured in India.[37] We applied this rate to our estimated hydrogen production cost and assumed no difference in the rate between blue and green hydrogen. Next, we assumed hydrogen transported via pipelines will also fall under the pipeline transport tax that currently applies to the transport of natural gas. Therefore, we applied this 5% tax to our estimated per kg hydrogen transport costs.

Results and discussion

Figure 1 displays our estimated at-the-pump hydrogen price averaged across the three Indian cities, expressed in 2019 U.S. dollars and INR per kg of hydrogen.[38] Each cost component and the cumulative tariff amount for both the blue and green hydrogen pathways is also illustrated, to show the total and proportional contributions of each component to the final cost of hydrogen across each pathway and over time. We show separate results for each of the three cities in the Appendix.

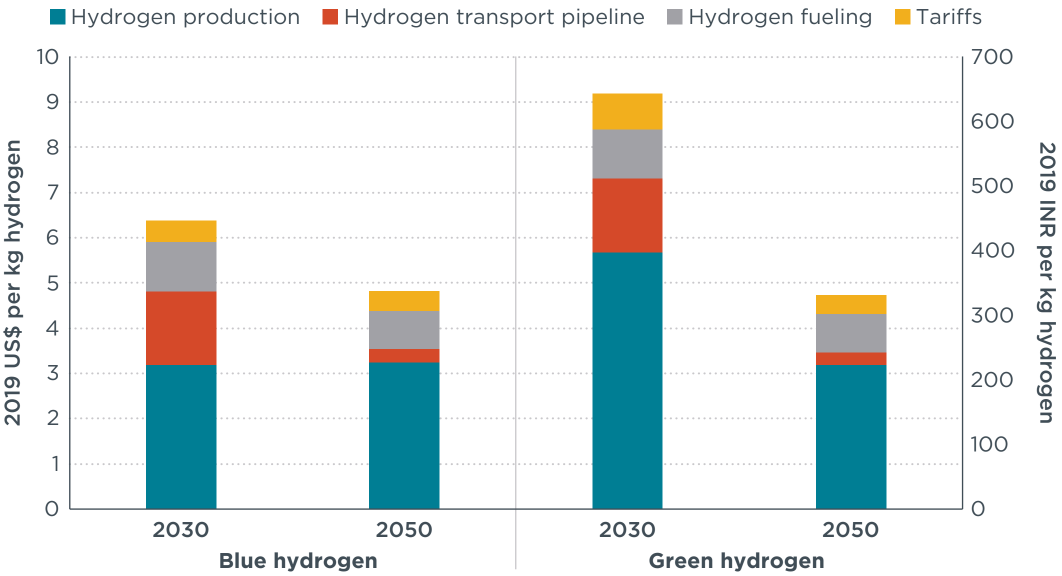

Figure 1. At-the-pump hydrogen costs averaged across Mumbai, Ahmedabad, and New Delhi. The blue hydrogen is produced from natural gas using SMR combined with CCS and the green hydrogen is produced from solar electricity through water electrolysis.

37 "Central Excise Tariff 2017–18," Central Board of Indirect Taxes and Customs, Chapter 28, June 30, 2017, https://www.cbic.gov.in/htdocs-cbec/excise/cxt2017-2018/cxt-1718-idx.

38 We used the exchange rate of 70 INR to 1 U.S. dollar.

We find that while the at-the-pump price decreases over time for both green and blue hydrogen, it does so to a greater extent for green hydrogen. In 2030, the at-the-pump price of green hydrogen is significantly higher than that of blue hydrogen–US$9 per kg hydrogen (INR 650 per kg) compared to US$6.5 per kg hydrogen (INR 450 per kg). However, the price gap between green and blue hydrogen narrows by 2050, when they have a similar at-the-pump price of US$5 per kg hydrogen (INR 340 per kg).

Looking at the cost breakdown for blue hydrogen, we find that the production cost increases slightly over time, by 2% from 2030 to 2050. This is a consequence of rising natural gas prices. In contrast, we project that green hydrogen's production cost will decrease significantly, by 45% from 2030 to 2050. This is attributable to our assumption of a lower solar electricity price and decreasing electrolyzer capital cost. Nonetheless, for both pathways in both 2030 and 2050, hydrogen production cost is the most expensive component and about 50% to 70% of the at-the-pump price is attributable to hydrogen production.

Our model assumes the same hydrogen transport and fueling configuration for blue and green hydrogen and this does not vary by hydrogen pathway. We find the hydrogen transport cost through pipeline infrastructure decreases by 80% between 2030 and 2050 as a result of a nearly ten-fold increase in assumed annual hydrogen demand. The average total hydrogen pipeline network length expands from 53 km in 2030 to 105 km by 2050 as a result of additional distribution pipelines servicing a growing fueling station network. Nonetheless, this increased total capital cost from building additional pipeline is spread across a greater volume of delivered hydrogen that grows from 4,000 kg per day in 2030 to 38,000 kg per day in 2050 for each city, as per our assumptions. This reveals the advantage of scalable pipeline infrastructure and how a lower per-kg hydrogen price results from improved capacity utilization and economies of scale.

More specifically, the capacity utilization for both types of pipelines increases between 2030 and 2050 without exceeding maximum pipeline capacity. Therefore, even more optimistic demand projections for hydrogen fuel use would not be limited by pipeline capacity in our scenario, but they would require more or larger fueling stations to deliver the greater volumes of hydrogen. At the same time, the additional cost of increasing accessibility through new distribution pipelines has a correspondingly greater benefit from more and larger fueling stations delivering greater volumes of hydrogen. This demonstrates economies of scale. Because the total cost of pipelines infrastructure is spread over a greater volume of hydrogen, the per-kg cost is reduced.

Hydrogen fueling station cost decreases by 20% from 2030 to 2050. This is attributable to improved experience and technology improvements that we assume will lead to annual cost reductions and economies of scale achieved by larger fueling stations. Because hydrogen is transported via high-pressure distribution pipelines from the distribution center, there is no compression equipment necessary at the pump. If a low-pressure pipeline transport were used, the added cost of compression is likely to increase the per-kg fueling cost by three-fold.[39]

The tariffs collected along the hydrogen supply chain—the Central Excise tariff on production and pipeline tariff on transport—are applicable to each kg of hydrogen. This cumulative tariff makes up roughly 9% of the hydrogen price that consumers pay regardless of the type of hydrogen and year in question, as it is proportional to the production cost and transport cost.

While all of the above results are based on a mid-level hydrogen price outlook, in Figure 2, we compare this mid-level scenario with an optimistic scenario for green hydrogen production cost in the three Indian cities. On average, the green hydrogen production

39 Penev et al., "Economic Analysis of a High-Pressure Urban Pipeline Concept (HyLine)."

cost in the optimistic outlook is approximately 40% cheaper than the mid-level outlook. In other words, if there is significant improvement in the efficiency of electrolyzer technology and capital cost is reduced, green hydrogen production cost is projected to reach almost US$2 (INR 140) per kg hydrogen by 2050.

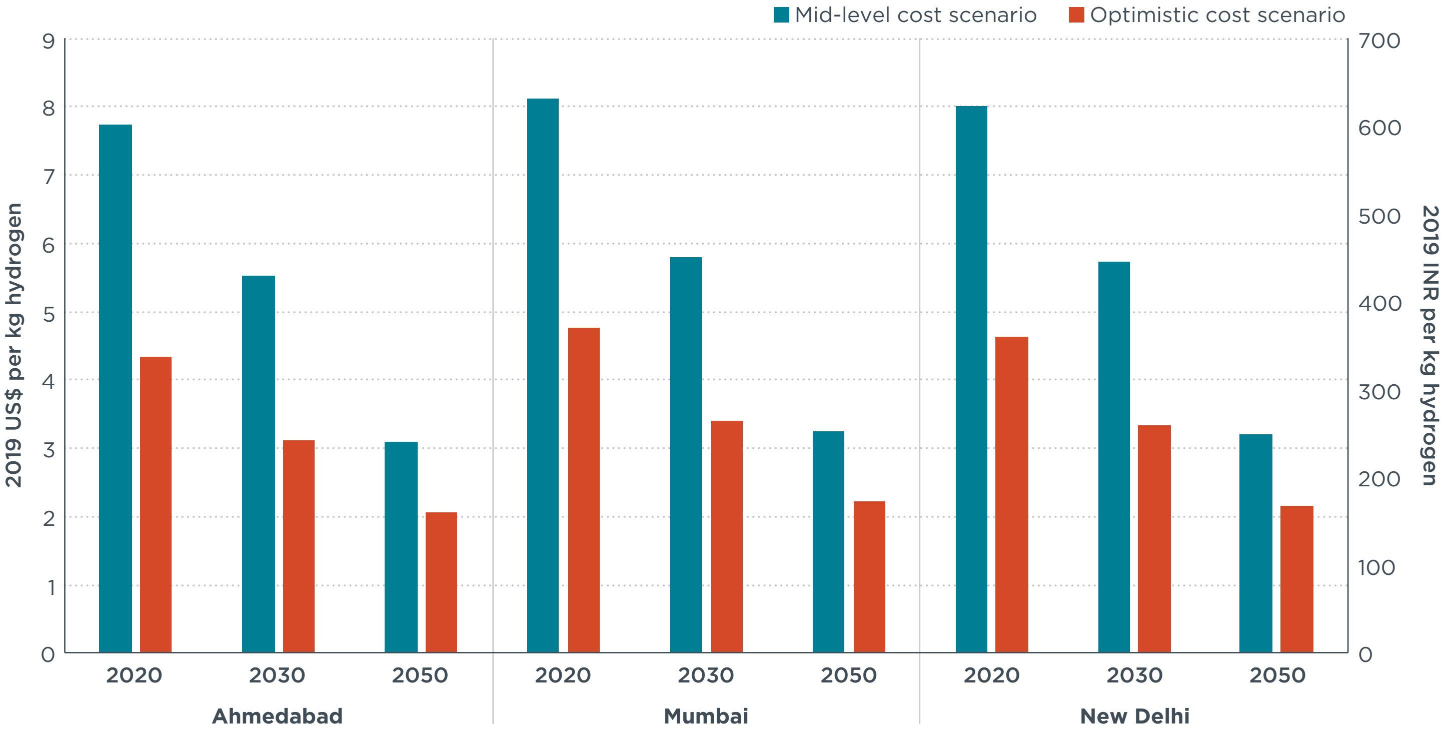

Figure 2. A comparison of the mid-level and optimistic costs of green hydrogen production.

Comparison with other studies

Here we compare our findings primarily with two other India-specific assessments of hydrogen fuel costs: a 2007 study by the Indira Gandhi Institute of Developmental Research (IGIDR) and a 2020 study by The Energy and Resources Institute (TERI). We summarize how the results of our study differ from the other two studies in order to identify current gaps in knowledge, understand alternative methods and sources of information, and show how our research adds to the existing body of work. In addition, a 2021 report by the International Energy Agency (IEA) provided a cost estimation for green hydrogen in India. Although we compare our results with this IEA report, as well, there is less detail because that report did not provide underlying model information.

The 2007 IGIDR study was a well-to-wheel analysis of hydrogen cost and GHG emissions for multiple hydrogen pathways, including hydrogen produced from natural gas using SMR without CCS and hydrogen produced from grid electricity.[40] The 2020 TERI study projected the 2030 and 2050 cost of hydrogen production and transport without specifying what kind of hydrogen.[41] We summarize the cost results from our analysis and the other two studies in Table 4.

40 P. Balachandra and B. Sudhakara Reddy, "Hydrogen Energy For Indian Transport Sector: A Well-To-Wheel Techno-Economic and Environmental Feasibility Analysis," (Indira Gandhi Institute of Development Research, 2007), http://www.igidr.ac.in/pdf/publication/WP-2007-004.pdf.

41 Will Hall et al., "The Potential Role of Hydrogen in India," (TERI: New Delhi, India, 2020), https://www.teriin.org/sites/default/files/2020-12/Report%20on%20The%20Potential%20Role%20of%20Hydrogen%20in%20India%20%E2%80%93%20%27Harnessing%20the%20Hype%27.pdf.

Table 4. Comparison of hydrogen costs from IGIDR (2007) and TERI (2020) with the present study.

<table>
<tr><th></th><th>IGIDR</th><th colspan="2">TERI</th><th colspan="2">This study</th></tr>
<tr><th>Year of cost estimate</th><th>2007</th><th>2030</th><th>2050</th><th>2030</th><th>2050</th></tr>
<tr><td>Natural gas price per MMBtu</td><td>3.1 (220)</td><td>11.6 (815)</td><td>12.6 (890)</td><td>7.7 (540)</td><td>8.1 (570)</td></tr>
<tr><td>Natural gas-based hydrogen production cost</td><td>1.6 (115)</td><td>2.3 (160)</td><td>2.1 (150)</td><td>3.2 (225)</td><td>3.3 (230)</td></tr>
<tr><td>Electricity price per kWh</td><td>0.11 (8)</td><td>0.023 (1.6)</td><td>0.018 (1.3)</td><td>0.025 (1.8)</td><td>0.017 (1.2)</td></tr>
<tr><td rowspan="2">Electrolysis hydrogen production cost</td><td rowspan="2">9.1 (640)</td><td rowspan="2">2.1 (150)</td><td rowspan="2">1.1 (80)</td><td>5.7 (400)
mid-level</td><td>3.2 (224)
mid-level</td></tr>
<tr><td>4.6 (325)
optimistic</td><td>2.2 (150)
optimistic</td></tr>
<tr><td>Pipeline transport cost</td><td>0.9 (70)</td><td>0.12 (8)</td><td>0.1 (7)</td><td>1.6 (115)</td><td>0.3 (20)</td></tr>
<tr><td>Fueling Infrastructure cost</td><td>1.2 (85)</td><td>—</td><td>—</td><td>1.1 (76)</td><td>0.8 (60)</td></tr>
<tr><td>Natural gas-based hydrogen at the pump price</td><td>3.8 (265)</td><td rowspan="2">4 (280)</td><td rowspan="2">2.2 (154)</td><td>6.4 (450)</td><td>4.8 (340)</td></tr>
<tr><td>Electrolysis hydrogen at-the-pump price</td><td>11.3 (795)</td><td>9.2 (650)</td><td>4.7 (335)</td></tr>
</table>

Note: All costs are expressed in 2019 U.S. dollars per kg hydrogen and the INR per kg hydrogen costs are in the parentheses. Results from IGIDR (2007) are inflation adjusted. IGIDR's hydrogen pathways differ from TERI's and ICCT's in that natural gas-based hydrogen is not combined with CCS and electrolysis hydrogen is made from grid electricity.

The scope of system components and cost model methodologies differ among the three studies in notable ways, and this contributes to cost differences. For one, TERI's hydrogen production cost model included the capital expense and O&M expense for the production facility only. In contrast, IGIDR's study and this study included compression and hydrogen storage costs in the estimate of hydrogen production cost, in addition to the capital and O&M costs. The exclusion of these additional costs explains why TERI's hydrogen production costs for both blue and green hydrogen are lower than ours even though TERI had a higher natural gas price and a similar solar electricity price as our study. Additionally, while IGIDR considered compression and storage costs, that study did not include CCS for the natural gas-based pathway as TERI and ICCT did. This exclusion of the CCS cost combined with a lower natural gas price in earlier years led IGIDR to the lowest natural gas-based hydrogen production cost among the three studies.

IGIDR also modeled electrolysis hydrogen powered by grid electricity instead of the solar electricity that was used by TERI and in our study. The high grid electricity price led to the highest electrolysis hydrogen production cost among the three studies. In IGIDR's study, the cost of electricity from the grid was US$0.11 per kWh after inflation adjustment, and that is almost 5 times the 2030 solar electricity cost inputs from our study and TERI's study. We can understand this difference to be partially attributable to the 50% decline in solar costs globally that occurred between 2013 and 2018 and the aforementioned domestic policies that the Indian government has crafted to induce greater solar deployment, both of which occurred after IGIDR's study.[42] The second contributing factor is the grid charges and fees incurred by India's industrial consumers; these led to higher rates per kWh than standalone renewable generation, as assumed in our study.[43] The economic benefit of using grid electricity instead of standalone solar generators is that the hydrogen facility can operate at more times and is not limited by whether there is the sun and how bright it is. However, when comparing our study with IGIDR's, it seems that this benefit does not fully offset the much higher cost of grid electricity compared to standalone solar. In summary, these fundamental differences–

42 Alex Mey, "Average U.S. Construction Costs for Solar and Wind Generation Continue to Fall," Energy Information Administration, *Today in Energy*, September 16,2020, https://www.eia.gov/todayinenergy/detail.php?id=45136#:~:text=Natural%20gas%20generator%20costs%20also,the%20United%20States%20in%202018

43 Nantoo Banerjee, "Why Are Indians Paying Three to Four Times the Cost of Generating Electricity?" *National Herald*, July 25, 2020, https://www.nationalheraldindia.com/india/why-are-indians-paying-three-to-four-times-the-cost-of-generating-electricity.

feedstock prices and the inclusion or exclusion of certain cost components, such as CCS, compression, and storage—have important cost implications in hydrogen production.

Techno-economic improvement rate assumptions are highly influential in hydrogen production cost projections. While both TERI's study and our study estimate an increasing natural gas price from 2030 to 2050, TERI projected a decreasing blue hydrogen production cost and we estimated an increasing cost. This is because our analysis assumes SMR cost will remain constant over time, as it is already a commercially mature technology; TERI, however, assumed that SMR capital cost will decrease by 22% from 2030 to 2050. Likewise, TERI's electrolysis production cost model assumed a greater rate of techno-economic improvements over time. While both TERI's study and our study had a similar starting capital cost of US$950–$980 per kW in 2020, TERI had significantly lower cost in the future. Specifically, TERI followed a 2019 IEA report and adopted a capital cost of US$400 per kW in 2030 and US$200 per kW in 2050 for alkaline electrolyzers. In this study, we use the mid-level alkaline electrolyzer capital cost outlooks from an extensive literature review on electrolyzer cost projections presented in the Christensen study; our costs are US$800 per kW in 2030 and US$540 per kW in 2050—about 1.5 times higher than TERI's assumptions. The high electrolyzer improvement rate by TERI enabled cost parity of green hydrogen with blue hydrogen as early as 2030, which would not happen until 2050 in our analysis. Note that the Christensen study found that the methodology, data sources, and assumptions behind IEA's cost projections—the ones that TERI adopted—were not clearly stated nor explained in its report. In addition, IEA's estimates of India's green hydrogen production cost in its 2021 report, which is $6 per kg hydrogen in 2020 and about US$1.8 per kg hydrogen in 2050 using solar electricity, is lower than even our optimistic scenario.[44]

Where pipeline transport cost is concerned, it is hard to make direct comparisons among the studies because each study uses very different assumptions for things like pipeline construction cost, pipeline length, pipeline lifetime, and the amount of hydrogen delivered, and these factors have a mixed impact on normalized per-kg hydrogen pipeline transport cost. For example, comparing IGIDR's study with our own, we see that IGIDR assumed a pipeline length of almost four times our pipeline length, but one-fourth the per-meter pipeline cost of our cost. This leads to very similar total pipeline cost. In normalizing the total pipeline cost into per-kg hydrogen cost, hydrogen demand plays a big role. IGIDR assumed almost 35 times more hydrogen demand in 2030 than our study, and that would theoretically lead to a much smaller per-kg hydrogen transport cost. However, the transport cost from IGIDR is only half of our 2030 cost. This is because IGIDR included additional compression costs and costs associated with O&M for pipeline, and we did not, because we included compression costs at the hydrogen production site. These additional costs narrowed the difference between our per-kg hydrogen transport cost and that of IGIDR. On the other hand, among the three studies, TERI estimated the smallest cost per kg for hydrogen pipeline transport; this we can attribute to the significantly higher hydrogen throughput assumed in that study. This and the cost difference between our 2030 and 2050 projections and TERI's projections suggests that pipeline transport infrastructure is scalable and has the potential to deliver growing volumes of fuel at diminishing marginal costs.

Although the hydrogen fueling cost from IGIDR was similar to the 2030 cost from our study, the underlying methodologies differed. In IGIDR's study, the fueling station, which had enough capacity to dispense 470 kg of hydrogen daily, was assumed to be equipped with on-site compression and storage to receive gaseous hydrogen from a pipeline. We assumed no compressors or storage at fueling stations and instead included the cost of pressure swing absorption equipment to purify the hydrogen before

44 International Energy Agency, "Global hydrogen review 2021," (2021), https://iea.blob.core.windows.net/assets/3a2ed84c-9ea0-458c-9421-d166a9510bc0/GlobalHydrogenReview2021.pdf.

dispensing; IGIDR did not include this equipment cost in their fueling station calculation. TERI did not investigate the per-kg cost of fueling stations in its 2020 report. However, TERI did estimate a hydrogen price delivered to fuel cell vehicles of US$4 per kg hydrogen in 2030 and US$2.2 per kg hydrogen in 2050, without specifying the type of hydrogen. TERI's 2050 hydrogen price is only half of our projection.

Well-to-pump GHG impact

We use carbon intensity estimates, measured in grams of CO_2-equivalent per megajoule of hydrogen (gCO_2e/MJ), to compare the climate impact of each production pathway detailed in each study. In the IGIDR study, the estimated carbon intensity for hydrogen produced via SMR was the highest out of all three studies, 94.78 gCO_2e/MJ; we can attribute that to the absence of CCS technology deployed. IGIDR's study does not state whether it includes upstream methane leakage in the SMR carbon intensity estimate, but in the SMR+CCS carbon intensity calculations completed in both TERI's report and another recent ICCT study,[45] the uncertainty of these rates and the efficiency of CCS technology are included. In TERI (2020), the emissions intensity estimate for each hydrogen production pathway is not stated in the text, but rather is depicted graphically in Figure 14, which indicates that SMR+CCS has a maximum emission intensity of roughly 80g/kWh in TERI's analysis. We converted kWh to the energy content per kg of hydrogen at a low heating value.[46] TERI (2020) assumed a carbon capture rate of 70% in both 2030 and 2050 and provided a range of methane leakages rates that could add between 13 and 44 gCO_2e/MJ to the carbon intensity of natural gas-based production. This resulted in a carbon intensity range of 22–66 gCO_2e/MJ for hydrogen produced via SMR+CCS. In the other recent ICCT study, the authors found that the typical carbon capture rate at an SMR plant is about 50%, and that led to a carbon intensity of 47 gCO_2e/MJ for blue hydrogen.[47] However, the same study showed that if a high upstream methane leakage happened—as high as a 20% leakage rate—blue hydrogen's carbon intensity could increase to almost 94 gCO_2e/MJ.

These findings reinforce the significant impact of CCS technology and upstream methane leakage rates on the overall climate benefit of hydrogen produced from natural gas-based pathways. Because of the risk of adverse climate impact, both TERI's report and the other recent ICCT study emphasized the importance of identifying and reducing upstream methane leakage in natural gas-based production processes.

In IGIDR, the carbon intensity for hydrogen produced via grid-powered electrolysis reflects emissions from grid electricity, which the paper stated would be powered by 70% coal. As a result, this production pathway has an enormous carbon intensity, 422.81 gCO_2e/MJ. In contrast, the hydrogen produced via electrolysis powered directly from solar generators modeled in the other recent ICCT study, as well as in TERI's study, has a carbon intensity of close to 0 gCO_2e/MJ. These findings demonstrate the consequence of not using renewable electricity to produce hydrogen via electrolysis. The greatest opportunity to achieve emissions savings and reap the greatest overall climate benefit is to power electrolysis from 100% renewable electricity such as solar.

Policy implications

With the recent success of India's renewables industry, there is an opportunity to apply similar policies and programs to hydrogen technology and projects to accelerate the

45 Yuanrong Zhou et al., *Life-cycle greenhouse gas emissions of biomethane and hydrogen pathways in the European Union*, (ICCT: Washington, D.C., 2021), https://theicct.org/publications/lca-biomethane-hydrogen-eu-oct21

46 National Research Council and National Academy of Engineering, *The Hydrogen economy: Opportunities, costs, barriers and R&D needs*, (National Academies Press: Washington, DC, 2004), https://doi.org/10.17226/10922

47 Zhou et al., *Life-cycle greenhouse gas emissions of biomethane and hydrogen pathways*.

growth of production. Grant funding programs such as Viability Gap Funding and Central Finance Assistance, and favorable tax policies like accelerated depreciation tax benefits, could improve the financial viability of hydrogen projects. There is also an option to reduce or eliminate the taxes and tariffs incurred along the hydrogen supply chain, especially for low-carbon hydrogen such as green hydrogen.

India currently has little fuel cell electric vehicle manufacturing capacity, so the deployment of programs that support the development of domestic manufacturing capabilities like priority sector lending, reduced or eliminated import and excise duties on equipment and material, and grant funding for research and development, will likely be necessary. Public-private partnerships and cost-sharing for infrastructure have been a hallmark of fuel cell electric vehicle markets in California, Japan, and Germany.[48] Inclusion of industry stakeholders on both the supply and demand side of the hydrogen and fuel cell electric vehicle market are characteristic of the most prolific markets. Likewise, public-private cost-sharing programs, albeit with different structures, were common in early markets to support profitably for businesses when there were low levels of vehicle adoption and demand. As fuel cell electric vehicle adoption increases and profitability improves, there will be less need for public funding. India can look to strategies demonstrated in other countries in order to facilitate early market development.

International technology and safety standards that are already utilized by major markets would help to streamline and accelerate the deployment of fuel cell electric vehicle and hydrogen fuel infrastructure in India.[49] Fueling station network planning will be particularly important during early market development due to the challenges inherent in introducing a new fuel and technology in an established market. Existing successful fuel cell electric vehicle markets have emerged by focusing on coverage and convenience in station placement. For instance, California's successful early market development can be attributed to the use of analytical decision-making tools developed through collaborations with academic institutions.[50]

Conclusions

We estimated the 2030 and 2050 at-the-pump hydrogen price for the transportation sector using the Indian cities of Ahmedabad, Mumbai, and New Delhi as case studies. The four key cost components of the at-the-pump price for hydrogen fuel are production cost, transport cost, fueling cost, and potential tariffs along the supply chain. We covered two production pathways: green hydrogen produced via water electrolysis powered by solar electricity and blue hydrogen produced via SMR combined with CCS. We also assumed the hydrogen is delivered through pipeline.

Our estimates show that the cost of green hydrogen is expected to be almost 1.5 times higher than blue hydrogen in 2030. However, by 2050, results show green hydrogen is cost competitive with blue hydrogen because of cost reduction in solar electricity and electrolysis and an increasing natural gas price. The solar cost declines are assumed because of the recent record-low solar auction prices in India, which are themselves reflective of multiple cross-sector programs and policies put in place by the Indian government to support its ambitious renewable generation targets.

We also found that the expansion of pipeline and fueling station infrastructure drives down the at-the-pump hydrogen price between 2030 and 2050. The per-kg cost of pipeline transport is almost six times less in 2050 than in 2030, as a result of

48 Aaron Isenstadt and Nic Lutsey, *Developing hydrogen fueling infrastructure for fuel cell vehicles: A status update*, (ICCT: Washington, D.C., 2017), https://theicct.org/sites/default/files/publications/Hydrogen-infrastructure-status-update_ICCT-briefing_04102017_vF.pdf

49 Ibid.

50 Ibid.

increased capacity utilization and economies of scale. Critical to realizing these per-kg cost reductions is developing sufficient demand through policies and programs that coordinate and support early market development of pipeline infrastructure and fuel cell electric vehicle manufacturing.

Green hydrogen produced from 100% renewable electricity such as solar, with almost zero GHG emissions, offers significant decarbonization potential for India's transportation sector. Given that it is an emerging industry and capital costs are high early in the industry's development, policy supports would be needed to achieve cost reductions that make it competitive with other fuels. Grant funding and favorable tax policies for green hydrogen production projects would help improve the financial viability of this new industry. In the long term, green hydrogen powered by domestic, renewable electricity would expand and diversify India's energy supply, and it aligns with India's energy independence goals in ways that natural gas-based hydrogen does not.

Appendix

Table A1 displays the breakdown of at-the-pump hydrogen costs, in 2019 U.S. dollars per kg and INR per kg hydrogen, across all three cities. The differences in blue hydrogen production cost among the cities stem from the different value added tax (VAT) rates on natural gas purchased by industrial consumers. The differing green hydrogen prices across cities are attributable to the difference in solar price. Pipeline transport cost also varies among the cities as a result of their different transmission and distribution pipeline lengths, which are due to geographic variations. Hydrogen fueling cost is the same across the cities because we assume the same number of fueling stations and fueling capacities for each city.

Table A1. Hydrogen cost breakdowns in the unit of 2019 U.S. dollars per kg hydrogen and INR per kg hydrogen in the parentheses.

2019 U.S. dollars per kg hydrogen (2019 INR per kg hydrogen)	Ahmedabad		Mumbai		New Delhi	
Target year	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**
Blue hydrogen production cost	3.21 (226)	3.27 (230)	3.18 (224)	3.24 (228)	3.2 (225)	3.26 (230)
Green hydrogen production cost_mid-level outlook	5.52 (390)	3.1 (220)	5.8 (410)	3.25 (230)	5.73 (400)	3.2 (225)
Green hydrogen production cost_ optimistic outlook	3.11 (220)	2.06 (145)	3.41 (240)	2.22 (156)	3.34 (235)	2.16 (152)
Pipeline transport cost	1.7 (120)	0.28 (20)	2.02 (142)	0.34 (25)	1.19 (85)	0.25 (18)
Hydrogen fueling cost	1.08 (76)	0.85 (60)	1.08 (76)	0.85 (60)	1.08 (76)	0.85 (60)
Blue hydrogen at-the-pump price	6.47 (455)	4.82 (340)	6.77 (480)	4.85 (340)	5.92 (420)	4.77 (335)
Green hydrogen at-the-pump price_ mid-level outlook	9.07 (640)	4.63 (325)	9.72 (685)	4.86 (340)	8.77 (620)	4.71 (330)
Green hydrogen at-the-pump price_ optimistic outlook	6.36 (450)	3.46 (245)	7.03 (495)	3.7 (260)	6.08 (430)	3.54 (250)