UNITED NATIONS
INDUSTRIAL DEVELOPMENT ORGANIZATION

INTERNATIONAL HYDROGEN FUEL CELL ASSOCIATION

aramco



CHINA'S MEDIUM- AND LONG-TERM HYDROGEN SUPPLY–DEMAND DYNAMICS AND TRADE OUTLOOK

Global Hydrogen Transportation Pathways Analysis

gef global environment facility
INVESTING IN OUR PLANET

China's Medium- and Long-term Hydrogen Supply–Demand Dynamics and Trade Outlook

United Nations Industrial Development Organization
International Hydrogen Fuel Cell Association
Aramco

With Support from Global Environment Facility

Disclaimer

This document has been produced without formal United Nations editing. Thedesignations employed and the presentation of the material in this document donot imply the expression of any opinion whatsoever on the part of the Secretariatof the United Nations Industrial Development Organization (UNIDO) concerning thelegal status of any country, territory, city or area or of its authorities, or concerningthe delimitation of its frontiers or boundaries, or its economic system or degree ofdevelopment. Designations such as "developed", "industrialized" and "developing" areintended for statistical convenience and do not necessarily express a judgment aboutthe stage reached by a particular country or area in the development process. Mentionof firm names or commercial products does not constitute an endorsement by UNIDO.

This document may be freely quoted or reprinted but acknowledgement is requested.

Copyright@2026 United Nations Industrial Development Organization, International Hydrogen Fuel Cell Association and Aramco

Images@2026 Image provider

FOREWORD

Hydrogen is becoming a central element of global energy strategy, industrial transformation and international cooperation. As the world's largest hydrogen producer and consumer, China occupies a pivotal position in this transition. Its hydrogen system remains deeply rooted in established industrial sectors, yet under carbon-peaking and carbon-neutrality goals the structure of hydrogen supply, demand, infrastructure and trade will change profoundly.

This report offers a systematic assessment of China's hydrogen development pathway, with particular attention to the spatial relationship between low-carbon hydrogen resources and future demand centers. It finds that although China's renewable resources are abundant, economically competitive hydrogen supply concentrates in specific regions, notably northern and western China. Demand growth, by contrast, is expected in industrial clusters, coastal provinces, ports, and transport and power applications. The resulting supply–demand mismatch will require coordinated development of production bases, transport corridors, storage, conversion routes, port infrastructure and market mechanisms.

The report also underlines the value of a diversified approach. Dedicated hydrogen pipelines can serve large-scale, stable demand; ammonia and methanol can support flexible transport and direct-use applications; and international trade in hydrogen-derived products can complement domestic supply where cost, reliability and carbon credentials are competitive. Across all pathways, credible carbon accounting, certification and long-term commercial arrangements will be essential.

The International Hydrogen Fuel Cell Association (IHFCA) believes this report offers useful insights for government, industry, financial institutions and research organizations. We thank our research partners and the external experts who reviewed the analysis, and we look forward to continued international cooperation in building hydrogen value chains that are economically viable, environmentally credible and globally connected.

ACKNOWLEDGMENTS

China's Medium- and Long-term Hydrogen Supply–Demand Dynamics and Trade Outlook was prepared by International Hydrogen Fuel Cell Association(IHFCA). The study was designed and directed by Ju Wang, Secretary General, Member of the UN Council of Engineers for the Energy Transition.

The principal authors and contributors were: Kangning Zhao, International Hydrogen Fuel Cell Association; Frank Tsu-Fang HONG, Aramco; Yibu Cheng, Sinopec Economics and Development Research Institute; Wenying Chen, Tsinghua University; Dimai Hu, United Nations Industrial Development Organization. They served as lead authors and coordinated the research, analysis, drafting and review process.

The report benefited from the insights and technical contributions of colleagues from this steering committee including: Ju Wang, Wei Zou, International Hydrogen Fuel Cell Association; Petra Schwager, Heng Liu, United Nations Industrial Development Organization; Xingyu Xue, Daniel De Castro, Mohammad Ajishi, Moonho Kim, Omar Hurtado Perez, Aramco.

The development of this report benefited from contributions provided by the following IHFCA colleagues: Rongjing Bao, Xuehao Tian, Yunxuan Jia, Muchen Li.

Special thanks go to the following organizations and initiatives for their valuable contributions: United Nations Industrial Development Organization, Aramco, Tsinghua University, Sinopec Corp., Sinopec Economics and Development Research Institute, PipeChina; Energy Research Institute of the National Development and Reform Commission.

The authors thank the following reviewers and external experts for their comments and suggestions: Fuyuan Yang, Tsinghua University; Wei Wei, Southeast University; Xianling Zheng, China International Marine Containers (Group) Co., Ltd.; Kai Li, Department of Energy Conservation and Resources Utilization, Ministry of Industry and Information Technology; Jian Liu, Energy Research Institute of the National Development and Reform Commission; Hao Wang, Sinopec Corp., Yong Cao, Sinopec Economics and Development Research Institute; Yingying Wang, Shenzhen 863 New Material Technology Co, Ltd; Xu Hao, Song Hu, University of Science and Technology Beijing; Jianguo Liu, North China Electric Power University; Hongjian Wang, Beijing Gas and Heating Engineering Design Institute Co., Ltd.; Huaien Li, Enric (Langfang) Energy Equipment Integration Co.,Ltd; Shiyao Peng, PipeChina; Xijia Zhao, Beijing University of Technology; Zepu Tian, Hydrogen Energy Industry Development Consulting Center, China International Engineering Consulting Corporation; Miao Lv, Beijing Gas Group Company Limited; Shi Zhong, Yohei Okamoto, Intelligent ElectroMobility R&D Center by TOYOTA (China) Co., Ltd.; Zhong Liu, SinoHy Energy Co., Ltd.; Ronghua Yao, Guochuang Hydrogen Energy Co., Ltd.; Miao Miao, Hyundai Motor (China) Investment Co., Ltd.; Yaopeng Cui, China Automotive Engineering Research Institute Co., Ltd. Their feedback strengthened the report's treatment of hydrogen resource assessment, supply–demand scenarios, transport economics, low-carbon certification and trade in hydrogen-derived products.

The findings, interpretations and conclusions expressed in this report are those of the authors and do not necessarily reflect the views of all contributing organizations, reviewers or their affiliated institutions.

EXECUTIVE SUMMARY

Delivery, not production, is the binding constraint on China's hydrogen transition. China already operates the world's largest hydrogen market, with production and consumption exceeding 38 Mt in 2025. Yet around 76% of supply comes from coal and natural gas, renewable hydrogen accounts for less than 0.5%, and demand remains concentrated in ammonia, methanol, refining and coal chemicals. The challenge is increasingly to deliver reliable, cost-competitive and certifiable low-carbon hydrogen—in the required form and with verifiable emissions attributes—to the regions and industries that need it.

China's hydrogen system could more than double in size by 2060—and its geography will be reshaped. In this report's scenario, demand rises from 42.6 Mt in 2035 to 85.8 Mt in 2060, with transport and power driving much of the growth beyond traditional industrial uses. Renewable hydrogen increases from around 24% of supply in 2035 to 85.9% in 2060, while unabated fossil-based production declines to a residual role and fossil-based hydrogen with carbon management provides a bridge. Low-cost production concentrates in the "Three Norths", while demand remains strongest in the Bohai Rim, Yangtze River Delta, southern coast and central industrial provinces.

Establishing a well-developed hydrogen transport infrastructure and an integrated transport system is essential China's low-carbon hydrogen transition. Scale and utilization determine the economics. Pipelines are competitive where large, stable demand and long-term offtake support high utilization. Ammonia and methanol are better suited to smaller or less certain markets—and to applications that can use them directly—as reconversion to hydrogen increases delivered costs by 25–34%. The priority is not to select a single carrier, but to match each carrier to the scale, location and form of demand.

Coastal China could anchor a market for hydrogen-derived products of global significance. The Bohai Rim, Yangtze River Delta and South China combine concentrated industrial and maritime demand with deep-water ports, storage facilities and established trading capabilities, enabling domestic pipeline supply and imports to develop in parallel. The near-term import channel is ammonia and methanol, which already move in large volumes: China imported about 13.5 Mt of methanol in 2024, mainly from the Middle East, and Japan, Korea and Europe have co-firing, bunkering and chemical demand that imports could serve. The longer-term market implied by published national targets is far larger, but it remains an ambition rather than a contracted market: firm low-emissions hydrogen offtake worldwide was about 1.6 Mt/yr by 2025, against import targets in Japan, Korea and the European Union equivalent to roughly 15 Mt/yr of hydrogen by 2030.

Competition will be decided primarily by cost, carbon intensity and credibility, Distance still matters, but its effect may be limited. The Middle East is well positioned, combining high-quality renewable resources with established ammonia, methanol, port and trading infrastructure; shipping accounts for less than 9% of landed cost in the cases assessed. The decisive factors will be production cost, life-cycle emissions, certification and long-term supply reliability.

This report assesses China's resource and cost distribution, provincial supply–demand balances through 2060, the economics of transport and international trade, and the policy conditions needed to support these developments. China has sufficient resources to produce low-carbon hydrogen at scale. Realizing this potential, however, will require investment in transport infrastructure, demand-side markets and credible standards for delivery and emissions accounting.

KEY FINDINGS

FINDING 1

—China's binding constraint is cost-effective delivery, not resource potential.

China's technical wind and solar potential of around 56.55 TW could support 1.37–1.45 billion tonnes of hydrogen per year, far above future demand. The constraint is converting that potential into reliable, low-cost supply. Low-cost resources concentrate in the "Three Norths"—including Inner Mongolia, Gansu, Qinghai, Xinjiang and Jilin—whereas major demand centers lie in central-eastern and coastal regions. This mismatch will move the market from local balancing toward interregional allocation.

FINDING 2

—Interregional transport becomes critical after 2035.

By 2035, the scenario projects hydrogen demand of 42.6 Mt, with renewable hydrogen supplying about 24% and cross-provincial allocation needs limited to 2.6 Mt, or 6% of demand. By 2060, demand reaches about 85.8 Mt, the renewable share rises to about 85.9%, and demand provinces face an aggregate provincial deficit of 34.5 Mt—roughly 40% of national demand. Interregional transport therefore becomes a core element of the low-carbon hydrogen system.

FINDING 3

—Pipeline economics depend on scale and utilization.

At an electricity price of RMB 0.15/kWh, a dedicated pipeline moving 500,000 t/yr delivers hydrogen at about RMB 15.64/kg over 1,000 km and RMB 19.69/kg over 2,500 km; a 100,000 t/yr line costs about RMB 26.44/kg and RMB 46.69/kg at the same distances. Pipelines become competitive only where demand is concentrated, utilization is high and long-term offtake is secured.

FINDING 4

—Ammonia and methanol work best when used directly.

Direct use of liquid ammonia in fertilizer, chemicals and shipping fuels avoids reconversion losses, with hydrogen-equivalent delivered costs of RMB 21.3–24.9/kg H_2 over 1,000–2,500 km. Where high-purity hydrogen is required, cracking or reforming plus purification and compression can account for 25–34% of total cost, weakening the carrier advantage. Pipelines suit large, continuous pure-hydrogen demand; ammonia and methanol suit direct-use applications and markets where demand is not yet locked in.

FINDING 5

—In international trade, FOB price and carbon credentials matter more than distance.

FOB ("free on board") is the price of the product loaded on the vessel at the export port; it excludes freight, insurance, import duty and tax. Middle East liquid ammonia and methanol could land at Chinese ports at about USD 498/t and USD 377/t respectively, with the FOB price accounting for nearly 80% of landed cost and shipping and logistics for less than 9%. That is roughly USD 2.8–3.0/kg H_2 equivalent before reconversion, against a domestic plant gate of about RMB 12.94/kg—so imports are not yet competitive with domestic production on a cost basis, and their near-term role is to serve coastal demand that domestic supply cannot reach economically, particularly high-purity hydrogen and directly used ammonia and methanol. Extending voyages from 3,000 to 8,000 nautical miles raises landed costs by less than 6%. Competitiveness will depend mainly on energy costs, financing, utilization, long-term pricing and credible carbon certification. In the medium term the traded channel is ammonia and methanol rather than pipeline hydrogen, and the volumes that can realistically be served are far smaller than published national targets imply; see Section 5.5.

On the basis of these findings, the report recommends a phased pathway: prioritize regional coupling, anchor corridors in demand, let scale support trunk infrastructure, and build an integrated low-carbon hydrogen network gradually. Near-term deployment should focus on stable demand in refining, chemicals, steel, ports and heavy-duty transport; medium-term development should coordinate production bases, pipelines, carrier conversion and port infrastructure; and the long-term strategy should integrate domestic renewable hydrogen, hydrogen-derived products and international imports, supported by carbon accounting, certification, infrastructure interconnection and long-term offtake mechanisms.

CONTENTS

FOREWORD 1

ACKNOWLEDGMENTS 2

EXECUTIVE SUMMARY 3

KEY FINDINGS 4

INTRODUCTION—WHY DELIVERY BECOMES THE DECISIVE QUESTION 8

PART I THE WIDENING GAP—CHINA'S HYDROGEN GEOGRAPHY, 2025–2060 9

Chapter 1 The world's largest hydrogen system—and why so little of it travels 10

1.1 Anchored in fossil feedstocks, coupled to local industry 10

1.2 Producing provinces are the consuming provinces 11

Chapter 2 Resource is not the constraint—renewable hydrogen potential and its cost map 14

2.1 Nine times the 2060 requirement: the scale of the resource 14

2.2 Wind in the north, sun in the west, demand on the coast 15

2.3 A cost map that redraws China's hydrogen geography 15

Chapter 3 The mismatch opens after 2035—concentrating supply, dispersing demand 17

3.1 Supply doubles—and turns renewable 17

3.2 Five provinces, nearly two-thirds of national supply 18

3.3 From one dominant sector to four drivers 20

3.4 Demand spreads from heartlands to the coast 21

3.5 The interprovincial gap: 2.6 Mt in 2035, 34.5 Mt in 2060 23

PART II THE COST OF DISTANCE—DELIVERING HYDROGEN AT SCALE 24

Chapter 4 Scale decides—the economics of long-distance delivery 25

4.1 Three ways to move hydrogen, one cost yardstick 25

4.2 Throughput, not distance, sets the pipeline cost 26

Box 4.1 Sinopec's "Ulanqab–Yanshan Petrochemical" dedicated hydrogen pipeline demonstration project: a pilot for long-distance hydrogen delivery in China 27

4.3 Ammonia buys distance—and pays for it at the terminal 29

4.4 When to pipe, when to ship 30

PART III BEYOND THE BORDER—CHINA IN HYDROGEN-DERIVED TRADE 31

Chapter 5 What really decides hydrogen trade—cost, carbon and reliability 32

5.1 Carriers and the corridor: how transoceanic trade is configured 32

5.2 The cost structure of trade: FOB, logistics and the four cost layers 33
5.3 Terminal options: use the carrier, or crack it back to hydrogen 37
5.4 Carbon and certification: the new competitive frontier 38
5.5 The addressable market: sizing the import opportunity 40
5.6 China's offtake: which sectors buy imported hydrogen-derived products 41
Chapter 6 From projects to networks—a three-phase delivery roadmap 42
6.1 China's policy support: 32 national documents in five years 42
6.2 Delivery, not production, is the binding constraint 43
6.3 Three capabilities, one system 43
6.4 2025–2030: anchor demand before building 44
6.5 2030–2035: connect resource regions, demand centers and ports 45
6.6 2035–2060: a national network with two-way trade 46
REFERENCES 48
ANNEX HOW WE DID IT—SCOPE, METHOD AND ASSUMPTIONS 50
A.1 Research scope and methodology 50
A.2 Scenario design 50
A.3 Supply–demand structure: data and models 50
A.4 End-use hydrogen demand: structure and potential 52
A.5 Techno-economic assessment of long-distance transport 52
A.6 Delivered-cost model and key assumptions: electrolysis hydrogen production 53
A.7 Transport combined model 54
A.8 Renewable electricity and hydrogen production potential 54
A.9 Vessel parameters for transoceanic trade 54
A.10 Generic CO_2 emission factors 55
A.11 Current CBAM certificate prices 55
A.12 China reference carbon prices 56
A.13 Boundary parameters for carbon border adjustment on ammonia and methanol landed costs 56

INTRODUCTION

—WHY DELIVERY BECOMES THE DECISIVE QUESTION

Hydrogen is moving from a discrete energy technology to a strategic component of China's low-carbon energy and industrial system. It can help integrate variable renewable power, decarbonize emissions-intensive industries, produce low-carbon chemicals and fuels, and support heavy-duty transport, shipping and power-system flexibility. China already operates the world's largest industrial hydrogen market, but the system remains predominantly fossil-based, captive and locally balanced. Hydrogen is produced and consumed mainly within refining and chemical clusters, while transport is generally limited to industrial parks and short-distance distribution. The next challenge is therefore not simply to expand production, but to deliver hydrogen and hydrogen-derived products to end users at competitive cost, with reliable supply and verifiable low-carbon attributes.

This delivery challenge will become more pronounced as the market evolves through 2035 and 2060. Established applications—including refining, ammonia, methanol and coal chemicals—will continue to provide baseload demand, while steel, heavy transport, power generation, maritime fuels and low-carbon chemicals could create new sources of growth. Supply, however, is likely to shift toward regions with the strongest renewable resources. Northern, northwestern and northeastern China could emerge as the principal sources of low-cost renewable hydrogen, while much of the strongest industrial, transport and port demand remains concentrated along the eastern coast and in parts of central China. As a result, the geography of China's hydrogen system will increasingly be shaped by resource quality and delivered cost rather than by the location of incumbent hydrogen-consuming industries. Connecting low-cost production with distant demand centers will become a central requirement for market development.

No single transport pathway can bridge this emerging geographic divide. Dedicated pipelines could provide the lowest-cost option for large, continuous and high-purity demand, but only where long-term throughput supports substantial upfront investment. Ammonia and methanol could be more suitable for long-distance transport, maritime trade and applications able to use these products directly, although reconversion to hydrogen would add cost and efficiency losses. Regional distribution networks will remain important for smaller and more dispersed users, while imports could supplement domestic supply in coastal markets where local production is costly or infrastructure development lags demand. This report assesses how these pathways may combine across different distances, scales and end uses through 2035–2060. Rather than prescribing a single technology or forecasting a fixed market outcome, it identifies the conditions under which alternative supply, transport and trade routes could become competitive—and the infrastructure, policy and certification frameworks required to build a deliverable low-carbon hydrogen system.

Note on terminology

This report adopts a technology-neutral, carbon-intensity-informed terminology. "Renewable hydrogen" refers to hydrogen produced using renewable energy; "low-carbon hydrogen" refers to hydrogen meeting defined carbon-intensity criteria, including but not limited to fossil-based hydrogen with effective carbon management. "Fossil-based hydrogen without carbon management" and "industrial by-product hydrogen" are used where relevant to reflect China's current system. Color labels ("grey", "blue", "green") are avoided as primary terminology because their meanings differ across markets and policy frameworks; where they appear, they serve only as secondary references. Carbon intensity is the organizing principle, the production pathway the descriptor.

PART I

THE WIDENING GAP

—CHINA'S HYDROGEN GEOGRAPHY, 2025–2060

CHAPTER 1

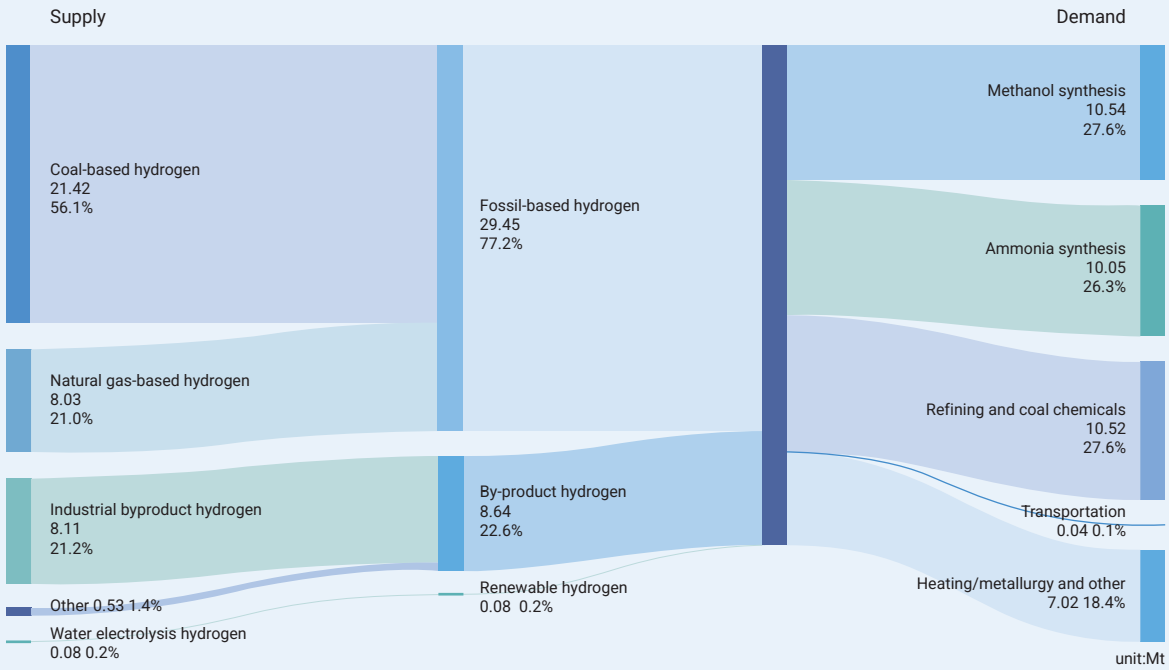
THE WORLD'S LARGEST HYDROGEN SYSTEM —AND WHY SO LITTLE OF IT TRAVELS

1.1 Anchored in fossil feedstocks, coupled to local industry

China has built the world's largest hydrogen production and consumption system, still mainly an industrial feedstock. In 2025, production and consumption exceeded 38 Mt, up about 4.6% year on year. Fossil-based hydrogen dominates: coal-based about 21 Mt, natural-gas-based about 8 Mt, some 76% of total production, plus industrial by-product hydrogen. Renewable hydrogen is less than 0.5% of supply, at the market-introduction stage. Based on National Energy Administration data [1].

Demand concentrates in industrial applications: in 2025, hydrogen consumption for methanol and for ammonia synthesis each approached 10 Mt, and consumption in refining and coal chemicals exceeded 10 Mt; the three end-uses dominate.

Figure 1 China's 2025 hydrogen supply by production route and demand by end use



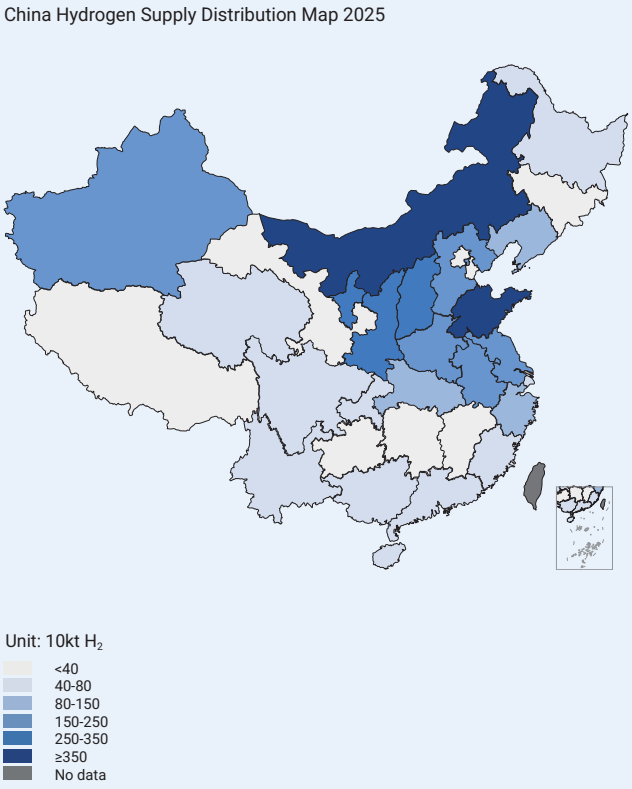
Note: IHFCA conducts tracking, statistics and assessment of the supply side and demand side across the entire hydrogen energy industry chain through a multi-channel approach of "research and data collection". Data on the supply side are mainly derived from equivalent conversion of consumption-side data and compilation of publicly available official government documents. The samples collected for the consumption side include plant-scale datasets for ammonia synthesis, methanol production and refining; Unit: Mt H_2. Based on 2025 data. Coal- and natural-gas-based production accounts for about 77% of supply (coal-based 21.42 Mt, natural-gas-based 8.03 Mt), industrial by-product hydrogen for a further 21.2%, and renewable hydrogen for less than 0.5%. Methanol synthesis, ammonia synthesis and refining with coal chemicals each take about a quarter of demand; transport accounts for 0.1%.

External transport is short-distance regional distribution; large-scale, interregional, long-distance transport demand has not yet emerged.

1.2 Producing provinces are the consuming provinces

Hydrogen production is spatially concentrated, reflecting energy resources and heavy-industrial foundations. Shandong, Inner Mongolia, Shaanxi, Shanxi and Ningxia lead with combined output of about 17.2 Mt, close to 45% of the national total; the top ten producers exceed 70%.

Figure 2 Provincial hydrogen production, 2025



Province	Fossil fuel-based hydrogen	Industrial byproduct hydrogen	Other hydrogen production methods	Total
Shandong	370.1	83.7	0.4	454
Inner Mongolia	321.4	71.3	14	407
Shaanxi	243.7	59.9	1.7	305
Ningxia	265.5	14.3	3	283
Shanxi	141.1	139.1	1.8	282
Henan	193.6	29.2	0	223
Hebei	97	101.1	2	200
Jiangsu	134.9	42.3	0.3	178
Xinjiang	140.6	31	5	177
Anhui	139.8	15.1	0.1	155
Hubei	142.9	11.7	0.1	155
Liaoning	92.5	28.8	5.5	127
Zhejiang	82.2	22.6	0.1	105
Guangdong	53.6	20.2	0.3	74
Sichuan	60.2	12.8	0.2	73
Fujian	50.5	15	0	66
Heilongjiang	46.8	11.6	5.4	64
Yunnan	40.8	16.6	0	57
Qinghai	41.8	5.7	1.6	49
Guangxi	36.4	11.7	0	48
Chongqing	43.1	4.4	0	48
Tianjin	31.1	11.8	0.2	43
Shanghai	30.5	12.5	0	43
Guizhou	34.4	4.7	0	39
Gansu	26.8	8.1	2	37
Jiangxi	23.2	12.8	0	36
Jilin	8.7	5	17	31
Hunan	19.3	8	0	27
Hainan	22.1	0	0	22
Beijing	10.4	0	0.3	11
Tibet	0	0	0	0
National total	2945	811	61	3817

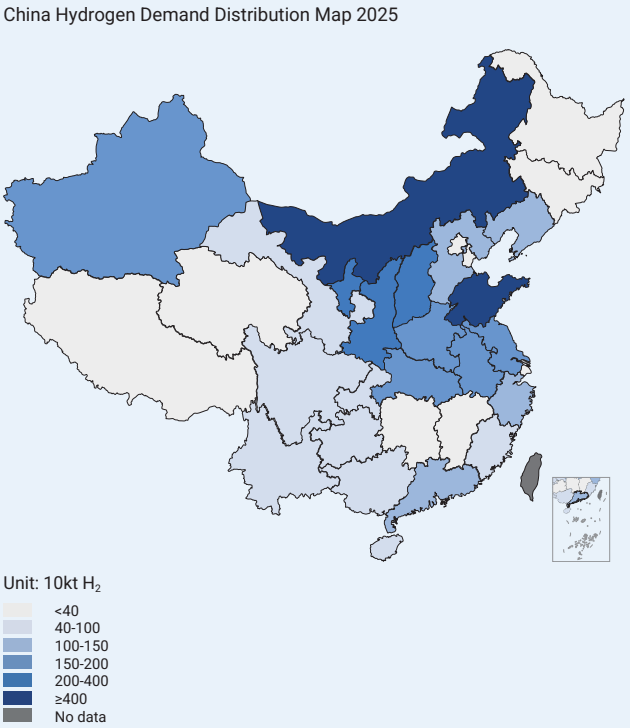
Note: The top five provinces produce close to 45% of national hydrogen and the top ten more than 70%. Historical data, 2025; unit: 10 kt.

Disclaimer: This map is provided for illustration purposes only. Boundaries and names shown on this map do not imply the expression of any opinion on the part of IHFCA concerning the status of any region, country, territory, city, or area or of its authorities, or concerning the delimitation of frontiers or boundaries.

These regions built large fossil-based hydrogen capacity on coal, coal-chemical, ammonia, methanol and refining bases (Shandong, Inner Mongolia, Ningxia, Shaanxi, Shanxi, Henan and Xinjiang), with production and consumption coupled inside industrial parks and locally absorbed.

Industrial by-product hydrogen is prominent in heavy-industry provinces: Hebei, Shanxi, Shandong, Inner Mongolia and Shaanxi have large volumes; Shanxi's exceeds fossil-based production; Hebei's is a major regional supply source.

Figure 3 Provincial hydrogen consumption, 2025



Province	Ammonia synthesis	Methanol synthesis	Refining	Other	Total
Shandong	118.9	372.6	4.4	0.0	496
Inner Mongolia	166.3	73.9	199.6	14.4	454
Shaanxi	42.2	233.7	22.0	7.4	305
Ningxia	119.7	57.7	0.0	35.6	213
Shanxi	24.4	148.0	8.9	18.9	200
Henan	68.9	71.2	30.1	6.4	177
Hebei	56.7	29.7	48.6	32.8	168
Jiangsu	99.7	38.6	11.5	10.7	161
Xinjiang	18.8	11.1	93.3	34.6	158
Anhui	88.1	60.6	7.6	0.0	156
Hubei	115.1	19.7	17.8	2.1	155
Liaoning	45.3	15.5	42.2	39.2	142
Zhejiang	20.7	8.9	83.1	28.5	141
Guangdong	2.1	0.0	83.9	37.1	123
Sichuan	49.8	10.3	11.5	14.2	86
Fujian	41.1	16.0	11.5	11.5	80
Heilongjiang	27.9	0.0	30.2	15.8	74
Yunnan	12.5	19.2	13.8	9.0	55
Qinghai	1.6	23.8	14.6	13.7	54
Guangxi	22.2	22.8	1.3	6.7	53
Chongqing	2.2	3.0	25.8	21.4	52
Tianjin	16.0	9.2	14.8	7.1	47
Shanghai	30.1	7.5	0.0	5.1	43
Guizhou	4.2	4.0	18.7	14.9	42
Gansu	14.8	9.1	8.9	6.1	39
Jiangxi	13.2	1.3	17.6	5.9	38
Jilin	0.0	0.0	9.8	26.0	36
Hunan	10.1	5.6	1.3	8.3	25
Hainan	11.3	0.0	10.0	3.6	25
Beijing	7.1	0.0	10.2	3.0	20
Tibet	0.0	0.0	0.0	0.0	0
National total	1251	1273	853	440	3817

Note: The top five provinces consume more than half of national demand; consumption closely tracks the production map. Historical data, 2025.

Disclaimer: This map is provided for illustration purposes only. Boundaries and names shown on this map do not imply the expression of any opinion on the part of IHFCA concerning the status of any region, country, territory, city, or area or of its authorities, or concerning the delimitation of frontiers or boundaries.

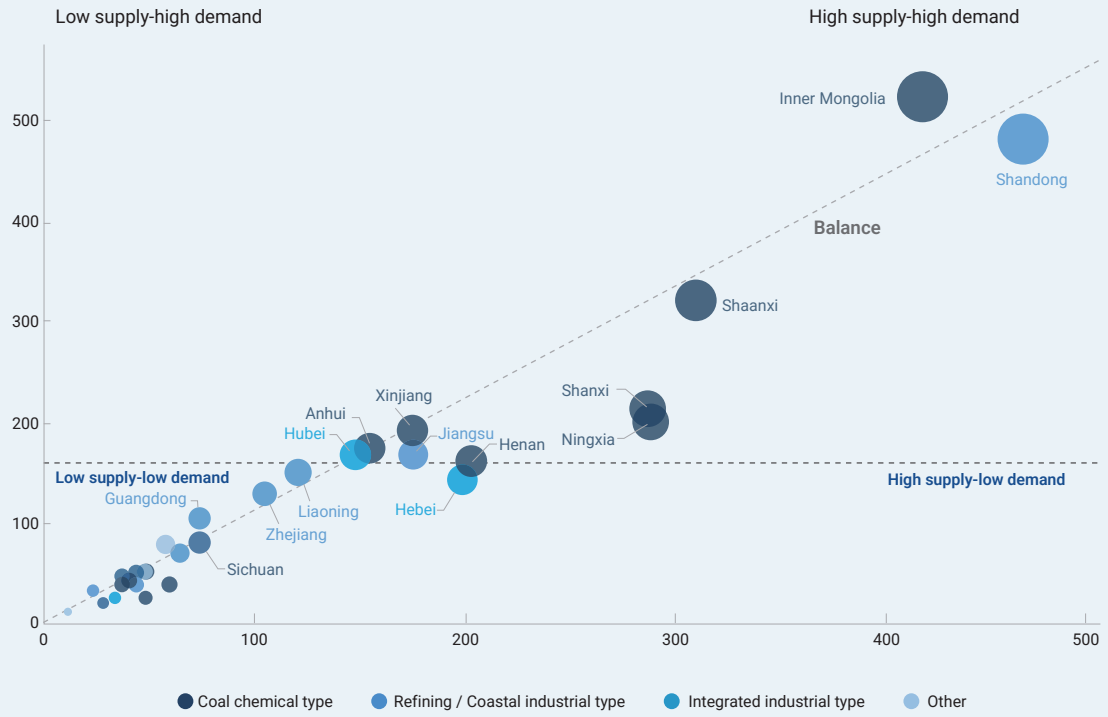
Demand is similarly concentrated: Inner Mongolia, Shandong, Shaanxi, Jiangsu, Shanxi, Ningxia, Xinjiang, Hebei, Henan and Hubei lead, with the top five above half of national demand and the top ten above 70%.

Demand follows local industrial bases: Inner Mongolia, Shaanxi and Ningxia consume hydrogen mainly for methanol, ammonia and modern coal chemicals; coastal Shandong and Jiangsu have large refining demand; steel- and coking-intensive Shanxi and Hebei consume it across coking, metallurgy and other processes.

By end-use, ammonia synthesis has the largest potential for scalable renewable-hydrogen substitution, with sizeable demand in Shandong, Jiangsu, Inner Mongolia, Shanxi, Hebei, Hubei, Henan and Xinjiang. Mature processes, stable load and easy storage and transport make ammonia a stable outlet for local renewable hydrogen and a channel for interregional and cross-border green ammonia trade.

Refining demand concentrates in coastal petrochemical provinces (Shandong, Zhejiang, Guangdong, Liaoning, Jiangsu and Fujian) where continuous operation, stable volumes and exacting purity and reliability make it an anchor for dedicated hydrogen pipelines, port receiving facilities and low-carbon hydrogen import projects.

Figure 4 Provincial hydrogen supply against demand, 2025



Note: Most provinces sit close to the supply–demand diagonal, and the modest imbalances are bridged locally rather than through a mature interprovincial market. Historical data, 2025; units: 10 kt/yr.

Shandong, Inner Mongolia, Shaanxi, Shanxi, Ningxia, Hebei, Jiangsu and Xinjiang form the core of China's hydrogen production and consumption, most in the "high supply–high demand" quadrant. Shandong, Shaanxi and Xinjiang are self-balanced: hydrogen is still produced and consumed locally. Mismatches emerge: Ningxia, Shanxi, Henan and Hebei run surpluses, while Inner Mongolia, Guangdong, Zhejiang, Hainan and Liaoning run deficits, bridged by park-level supply, neighboring-region allocation or hydrogen co-products, not a mature interprovincial pure-hydrogen transport market.

CHAPTER 2

RESOURCE IS NOT THE CONSTRAINT
—RENEWABLE HYDROGEN POTENTIAL AND ITS COST MAP

2.1 Nine times the 2060 requirement: the scale of the resource

China's renewable hydrogen technical potential is very large: a techno-economic assessment at 1 km × 1 km grid resolution estimates wind and solar capacity potential at about 56.55 TW, roughly nine times the 2060 carbon-neutrality requirement, with annual generation potential of about 71.28 PWh . This far exceeds demand from energy-intensive industry and other end-use sectors; development should focus on economic developability and cost, not gross potential[2].

Figure 5 Renewable hydrogen production potential by technology, 2060

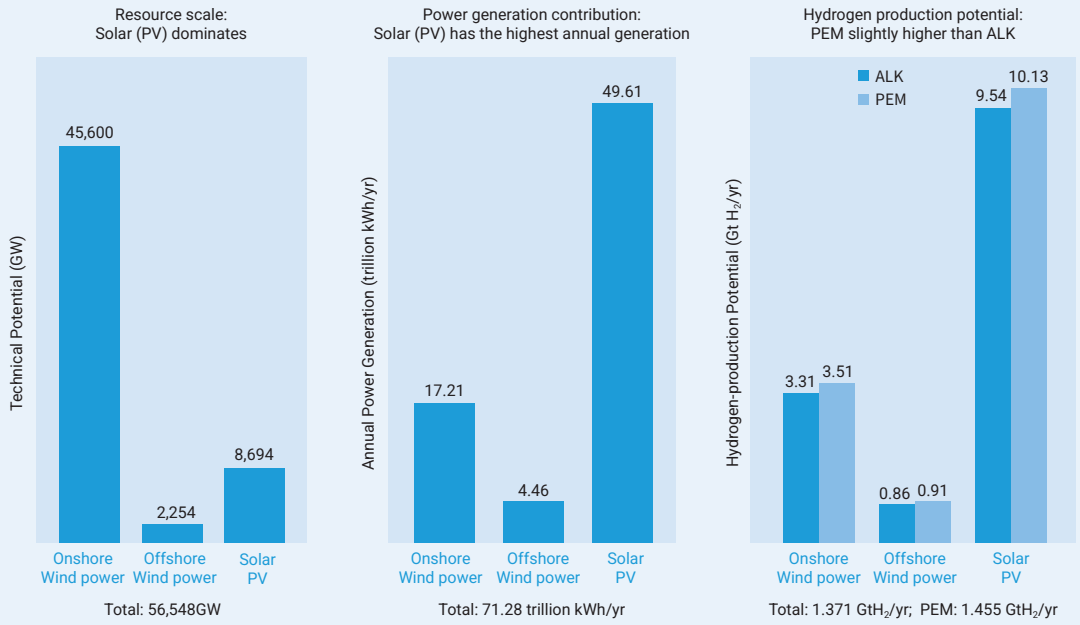


Note: Technical potential is about nine times the 2060 requirement, led by solar at 0.90–1.01 billion tonnes per year and onshore wind at 0.331–0.351 billion tonnes per year. Scenario; technical potential, not economic potential.

Disclaimer: This map is provided for illustration purposes only. Boundaries and names shown on this map do not imply the expression of any opinion on the part of IHFCA concerning the status of any region, country, territory, city, or area or of its authorities, or concerning the delimitation of frontiers or boundaries.

By 2060, China's technical potential for hydrogen production from renewable electricity is projected at 1.37–1.45 billion tonnes per year. Solar-based hydrogen leads at roughly 0.90–1.01 billion tonnes per year, followed by onshore wind at about 0.331–0.351 billion tonnes per year.

Figure 6 Spatial distribution of wind and solar hydrogen potential



Note: The figures shown represent theoretical technical potential estimates and do not account for real-world constraints such as grid integration and absorption capacity, land availability, transmission capacity, equipment utilization rates, water resources, or project economics. Wind potential concentrates in the north and solar potential in the west, while demand is concentrated on the eastern coast. Scenario; theoretical technical potential excluding real-world constraints such as grid absorption, land availability, transmission capacity, equipment utilization, water resources and project economics.

2.2 Wind in the north, sun in the west, demand on the coast

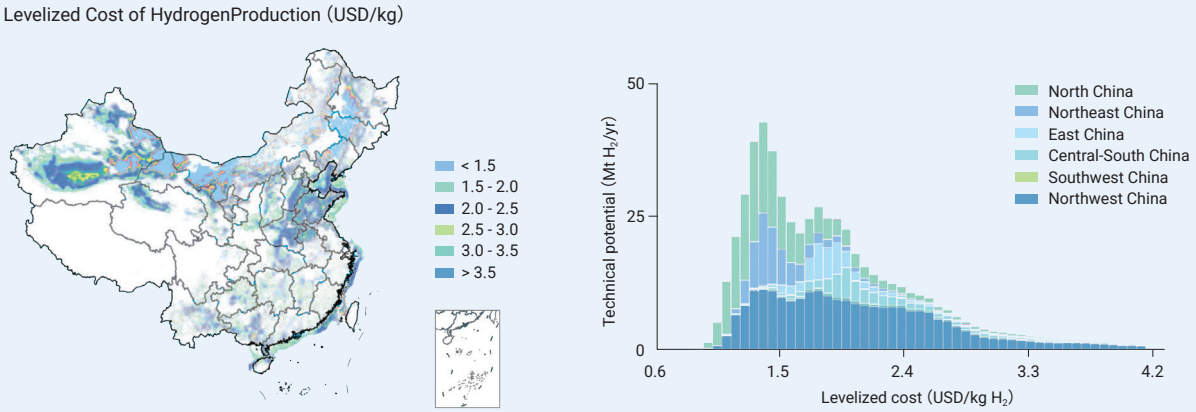
Wind and solar hydrogen potential is uneven. Wind is "abundant in the north, scarce in the south" (the northeast, north China, Inner Mongolia, Gansu and Xinjiang). Solar is "abundant in the west, scarce in the east" (the Qinghai–Tibet Plateau, western Inner Mongolia, Xinjiang and the Hexi Corridor in Gansu). The eastern coast and central China concentrate refining, chemical and port demand but have limited low-cost local potential and cannot rely on local production alone.

2.3 A cost map that redraws China's hydrogen geography

2060 production costs vary clearly by region: low-cost supply concentrates in the resource-advantaged north, northwest and northeast, while central-south and southeast-coastal provinces face higher local production costs.

For onshore wind-based hydrogen, northeast and north China show the strongest cost advantages: 2060 weighted-average costs of about USD 1.54/kg and USD 1.55/kg. East China and northwest China follow at roughly USD 1.96/kg and USD 2.06/kg; southwest and central-south China reach about USD 2.22/kg and USD 2.43/kg, less competitive.

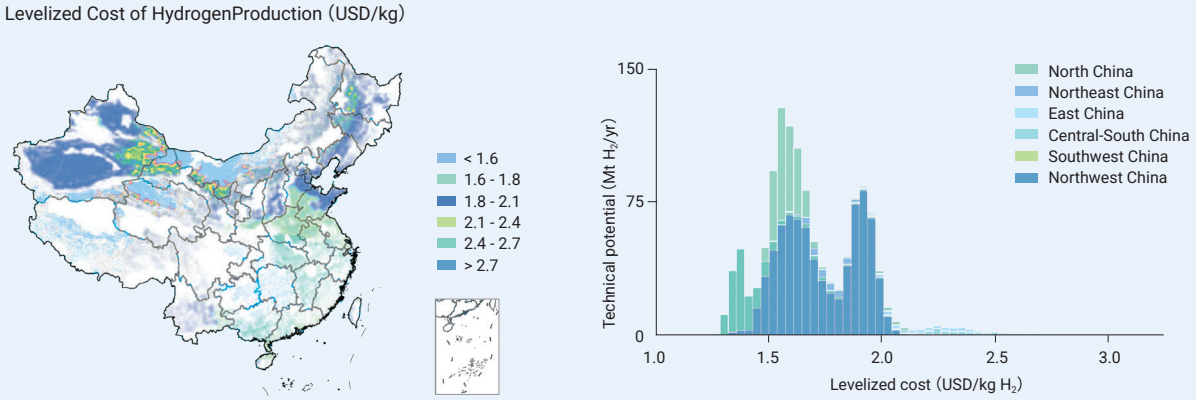
Figure 7 Delivered cost of wind-based hydrogen by region, 2060



Note: National wind-power hydrogen production cost at 1 km×1 km grid scale in 2060 (taking ALK as an example); Distribution of onshore wind-power hydrogen production cost across different regions in 2060 (taking ALK as an example). Weighted-average costs are lowest in the northeast and north at about USD 1.54–1.55/kg and rise toward the south, reaching about USD 1.96/kg in east China and about USD 2.43/kg in central-south China. Scenario, 2060.

Low-cost solar-based hydrogen lies mainly in the Qinghai–Tibet Plateau, western Inner Mongolia and the Hexi Corridor of Gansu, where solar resources are rich and land constraints limited; parts can produce below USD 1.8/kg. Some northeast and North China Plain areas offer potential below USD 2/kg.

Figure 8 Delivered cost of solar-based hydrogen, 2060



Note: National photovoltaic hydrogen production cost at 1 km × 1 km grid scale in 2060 (taking ALK as an example); Distribution of photovoltaic hydrogen production cost across different regions in 2060 (taking ALK as an example). Solar-based hydrogen can be produced below USD 1.8/kg across the Qinghai–Tibet Plateau, western Inner Mongolia and the Hexi Corridor of Gansu. Scenario, 2060.

Inner Mongolia, Gansu, Qinghai, Ningxia, Xinjiang, Jilin and Liaoning can host low-cost renewable hydrogen production and export bases; the eastern coastal provinces (Shandong, Jiangsu, Zhejiang, Guangdong and Fujian) concentrate refining, chemical, port and green-fuel demand but have limited low-cost local resources. The cost gap between resource regions and load centers will strengthen the economic case for interregional hydrogen and derivatives transport.

Low-cost renewable hydrogen will first emerge in north, northwest and northeast China; the eastern coast is more likely to become a demand and import node.

Supply centers will shift from today's coal-chemical, refining and ammonia synthesis geography toward resource-rich regions with strong wind and solar resources and competitive costs. Inner Mongolia, Gansu, Qinghai, Ningxia and Xinjiang combine strong wind–solar resources, ample land and an energy-industry base, making them core regions for scaled renewable hydrogen development and export. Jilin and Liaoning may also anchor wind-based hydrogen, industrial absorption and northeast-Asian energy cooperation.

CHAPTER 3

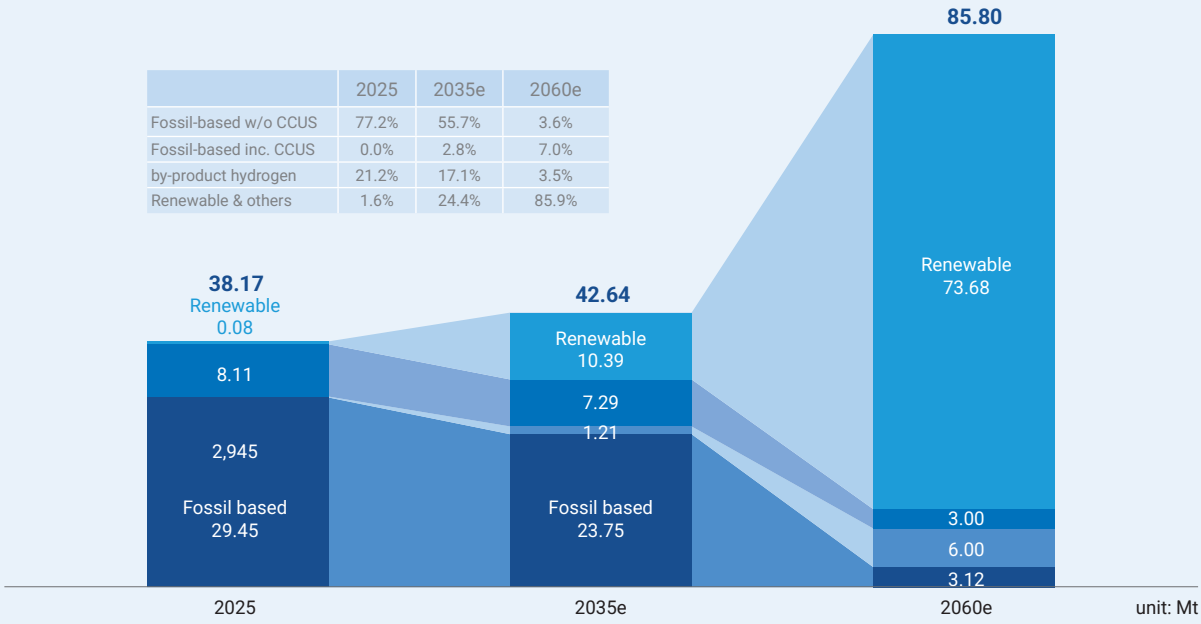
THE MISMATCH OPENS AFTER 2035
—CONCENTRATING SUPPLY, DISPERSING DEMAND

3.1 Supply doubles—and turns renewable

China's hydrogen supply roughly doubles from 42.6 Mt in 2035 to about 85.8 Mt in 2060 —about 2.8% average annual growth—turning renewable-led and low-carbon.

Figure 9 Hydrogen supply by source, 2035 and 2060

	2025	2035e	2060e
Fossil-based w/o CCUS	77.2%	55.7%	3.6%
Fossil-based inc. CCUS	0.0%	2.8%	7.0%
by-product hydrogen	21.2%	17.1%	3.5%
Renewable & others	1.6%	24.4%	85.9%



Note: Renewable hydrogen rises from about 24% of supply in 2035 to about 86% by 2060, while unabated fossil-based output falls to a residual share. Scenario, 2035 and 2060.

In 2035, fossil-based hydrogen remains the largest source at about 23.75 Mt (55.7% of supply); industrial by-product hydrogen contributes about 7.29 Mt (17.1%); renewable hydrogen reaches about 10.39 Mt (24.4%), the main source of supply growth; fossil-based hydrogen with carbon capture, utilization and storage (CCUS) stands at about 1.2 Mt (2.8%).

By 2060, renewable hydrogen rises to 73.68 Mt (85.9% of supply), the backbone; unabated fossil-based hydrogen falls to 3.12 Mt, down 86.9% from 2035, or 3.6%; industrial by-product hydrogen falls to 3.0 Mt (3.5%); fossil-based hydrogen with CCUS rises to 6.0 Mt (7.0%), a low-carbon complement.

Tighter carbon-neutrality constraints and falling wind- and solar-based production costs drive renewable hydrogen's growing competitiveness.

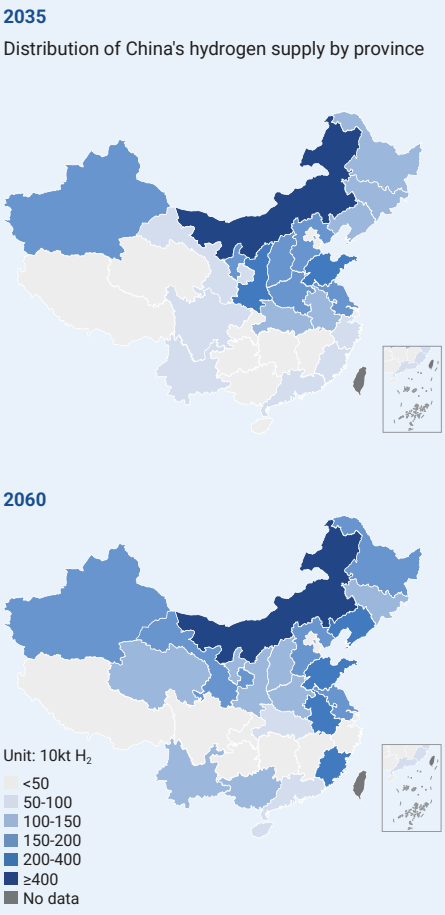
3.2 Five provinces, nearly two-thirds of national supply

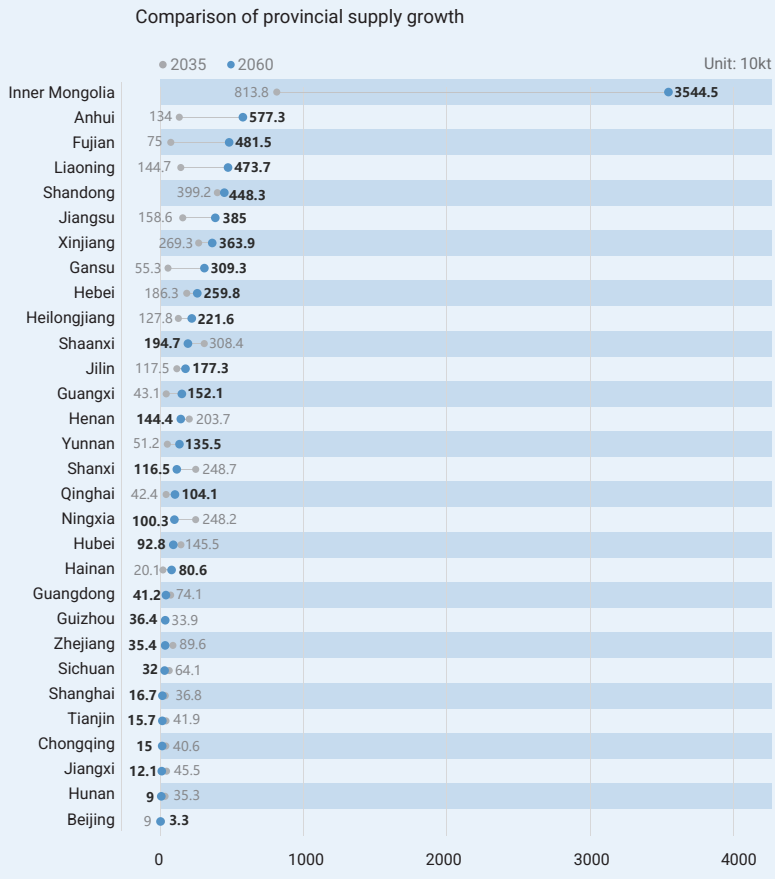
The top five supplying provinces hold about 47.8% of national supply in 2035 and about 64.4% in 2060—nearly two-thirds—and the top ten about 69.9% and about 82.3%.

In 2035, Inner Mongolia, Shandong, Shaanxi and Shanxi—traditional energy and heavy-industry provinces—remain the main supply centers, while renewable hydrogen expands first in Inner Mongolia, Xinjiang and Jilin.

By 2060, with renewable hydrogen dominant, supply concentrates further in low-cost wind–solar regions, widening the spatial mismatch with central-eastern demand centers and adding to the need for interregional transport of hydrogen and hydrogen-derived products.

Figure 10 Provincial shares of national hydrogen supply, 2035 and 2060





Note: Inner Mongolia reaches about 46% of national renewable hydrogen supply by 2060, while resource-poor coastal provinces come to depend on inflows from other provinces. Scenario, 2035 and 2060.

Disclaimer: This map is provided for illustration purposes only. Boundaries and names shown on this map do not imply the expression of any opinion on the part of IHFCA concerning the status of any region, country, territory, city, or area or of its authorities, or concerning the delimitation of frontiers or boundaries.

Provincial supply structures: resource endowment leads; industry and location shape the outcome.

Fossil-energy and industrial provinces remain the main producers of fossil-based and by-product hydrogen in 2035 and pivot to a "renewable-led, blue-supported" structure by 2060, while provinces with stronger wind–solar and port conditions become important renewable suppliers and resource-poor regions depend on inflows from other provinces. Inner Mongolia remains the largest renewable supply center, reaching 34,187 kt in 2060—about 46.4% of national renewable hydrogen supply. Shandong shifts from a grey- and by-product-led structure (renewable hydrogen at just 2.7% of provincial supply in 2035) to a renewable-led one (67.6% by 2060, with blue hydrogen supporting). Provinces with weaker resources but better land and market position, such as Anhui—500–800 km from the Yangtze River Delta—can supply that demand center by pipeline or by carriers such as ammonia.

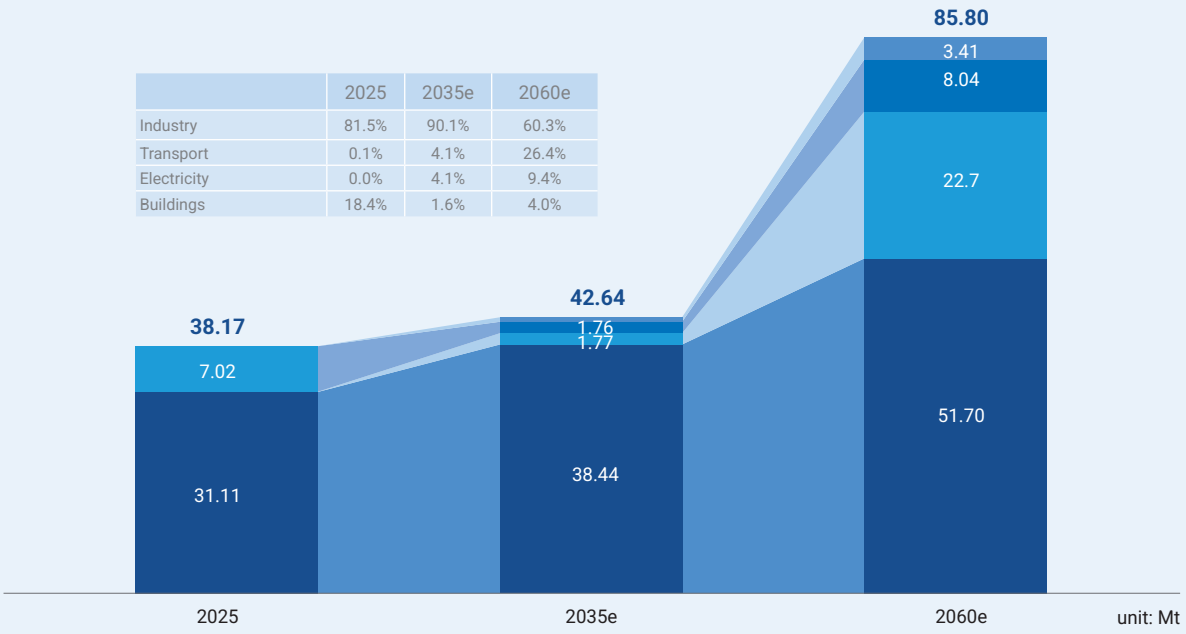
Table 1 Provincial hydrogen supply by source, 2035 and 2060 (kt)

Province	Year	Industrial by-product hydrogen	Grey hydrogen	Blue hydrogen	Renewable hydrogen	Total supply
Inner Mongolia	2035	645	2,716	0	4,777	8,138
	2060	266	340	653	34,187	35,445
Anhui	2035	136	1,181	0	23	1,340
	2060	56	148	284	5,286	5,773
Fujian	2035	131	429	0	190	750
	2060	54	54	103	4,604	4,815
Liaoning	2035	255	786	0	406	1,447
	2060	105	98	189	4,345	4,737
Shandong	2035	740	2,649	494	109	3,992
	2060	304	393	756	3,031	4,483
Jiangsu	2035	371	1,146	0	70	1,586
	2060	153	143	275	3,279	3,850
Xinjiang	2035	278	1,001	187	1,227	2,693
	2060	115	149	286	3,090	3,639
Gansu	2035	72	227	0	254	553
	2060	30	28	55	2,980	3,093
Hebei	2035	894	701	131	137	1,863
	2060	368	104	200	1,926	2,598
Heilongjiang	2035	105	338	63	771	1,278
	2060	43	50	97	2,026	2,216

Note: Units: kt (thousand tonnes); 1 Mt = 1,000 kt. Scenario, 2035 and 2060.

3.3 From one dominant sector to four drivers

Figure 11 Hydrogen demand by sector, 2035 and 2060



Note: Industry provides about 90% of consumption in 2035; by 2060 transport and power grow into co-drivers of a multi-sector market. Scenario, 2035 and 2060.

In 2035, industry remains the dominant hydrogen consumer and the base load for scaled renewable hydrogen: ammonia, methanol, refining, coal chemicals and steel total about 38.44 Mt, or 90.1% of national demand, while transport, power and buildings account for about 4.2 Mt (roughly 10%). By 2060, demand is co-driven by industry, transport and power: industrial use rises to about 51.7 Mt but falls to roughly 60% of demand, and transport, power and buildings reach 34.1 Mt, or about 40%.

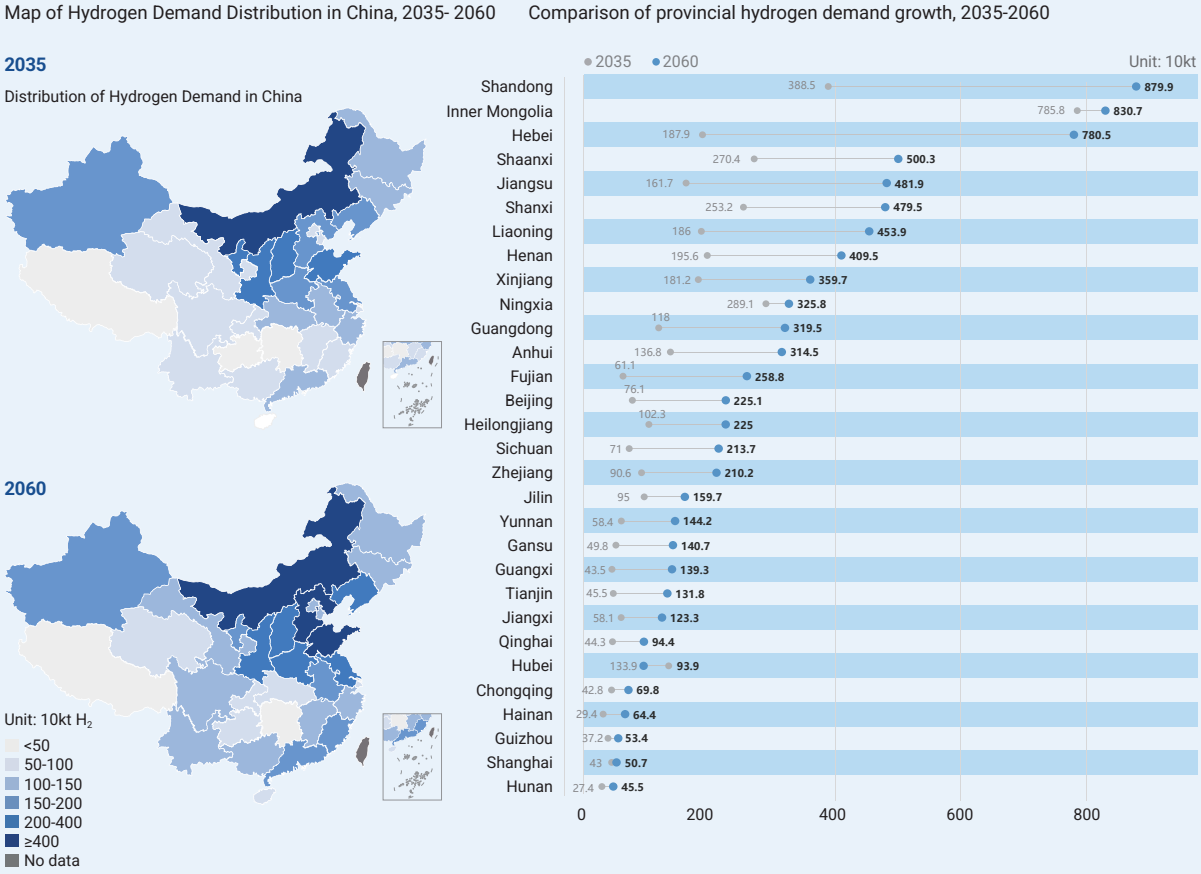
The 2060 projection of about 85.8 Mt sits toward the lower end of published estimates: close to Sinopec's 2023 outlook (nearly 86 Mt), below the IEA's 90 Mt and well below the China Hydrogen Alliance's roughly 130 Mt (2020 white paper). The gap reflects the white paper's assumption of hydrogen meeting about 20% of terminal energy consumption; this estimate aligns with Sinopec and the IEA[3–5].

Transport is the fastest-growing sector: renewable hydrogen rises from about 1.75 Mt in 2035 to about 22.65 Mt in 2060, concentrated in long-haul heavy-duty transport and port logistics, while hydrogen-derived ammonia and methanol decarbonize shipping and aviation.

Power and buildings demand is modest but grows quickly: by 2060, hydrogen for power reaches 8.04 Mt, or 9% of total demand, mainly for power-system flexibility and long-duration storage, and hydrogen for buildings rises to 3.41 Mt, or about 4.0%, mainly for heat supply.

3.4 Demand spreads from heartlands to the coast

Figure 12 Provincial shares of national hydrogen demand, 2035 and 2060



Note: The top five provinces fall from 46.6% of national demand in 2035 to 40.5% by 2060 as demand disperses toward coastal and central provinces. Scenario, 2035 and 2060.

In 2035, demand remains concentrated in traditional heavy-industry provinces—the top five hold about 46.6% of national demand and the top ten about 68.0%—closely overlapping the main supplying provinces, with production and consumption co-located.

By 2060, demand disperses: the top five fall to about 40.5% of national demand and the top ten to about 64.1%—both below the concentration of supply—as consumption extends toward coastal and central provinces with strong industrial bases and large end-use markets.

Table 2 Provincial hydrogen demand by end use, 2035 and 2060 (kt)

Province	Year	Renewable hydrogen—industry	Renewable hydrogen—transport	Renewable hydrogen—buildings	Renewable hydrogen—power	Non-renewable hydrogen	Total demand
Shandong	2035	0	0	2	1	3,883	3,885
	2060	3,878	3,414	52	3	1,453	8,799
Inner Mongolia	2035	3,965	385	7	140	3,362	7,858
	2060	5,489	856	63	641	1,258	8,307
Hebei	2035	0	101	31	22	1,725	1,879
	2060	4,171	2,509	355	100	672	7,805
Shaanxi	2035	0	0	44	58	2,603	2,704
	2060	2,926	750	87	265	976	5,003
Jiangsu	2035	45	46	8	2	1,517	1,617
	2060	1,847	2,349	42	10	571	4,819
Shanxi	2035	0	0	57	22	2,453	2,532
	2060	2,487	1,055	196	102	954	4,795
Liaoning	2035	490	311	14	4	1,041	1,860
	2060	2,687	1,402	37	21	392	4,539
Henan	2035	0	0	31	23	1,901	1,956
	2060	1,777	1,224	281	107	707	4,095
Xinjiang	2035	121	103	34	89	1,466	1,812
	2060	1,880	645	116	407	549	3,597
Ningxia	2035	317	120	75	6	2,373	2,891
	2060	1,929	351	79	27	873	3,258

Note: Units: kt (thousand tonnes); 1 Mt = 1,000 kt. Renewable hydrogen is split across industry, transport, buildings and power; non-renewable hydrogen is shown as a single total; row sums may differ by rounding. Scenario, 2035 and 2060.

Renewable hydrogen demand.

Industrial renewable hydrogen demand concentrates in northern heavy-industry provinces, whose top five hold 48.7% of the national total in 2060; Hebei reaches 4,171 kt as hydrogen-based steelmaking spreads across China's largest steel-producing province.

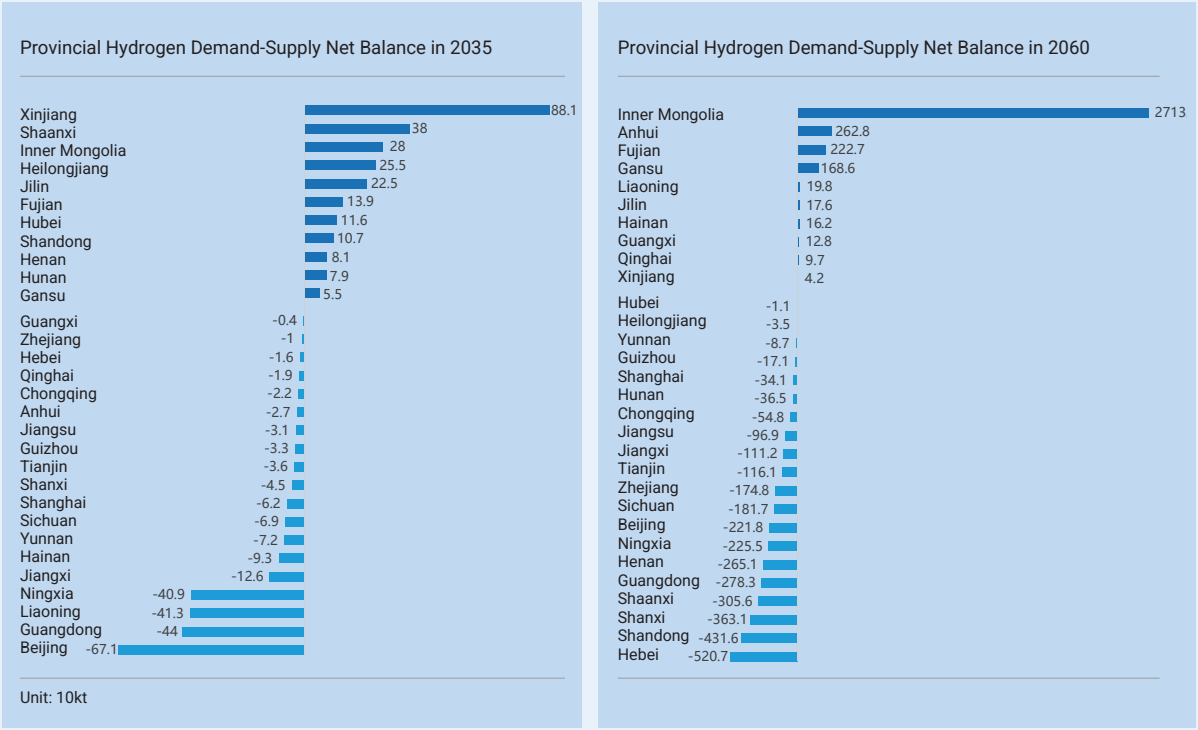
Transport renewable hydrogen demand concentrates in developed, freight-intensive coastal provinces and central hubs: from only 1.75 Mt in 2035 (4.1% of the national total) to 22.65 Mt (about 26.4%) by 2060, the second-largest demand source after industry; the top five provinces hold 47.3% of it.

Non-renewable hydrogen demand.

Non-renewable hydrogen totals 32.25 Mt in 2035 (75.6% of national demand), falling to 12.12 Mt (14.1%) by 2060, with little change in provincial distribution.

3.5 The interprovincial gap: 2.6 Mt in 2035, 34.5 Mt in 2060

Figure 13 Provincial hydrogen supply–demand balances, 2035 and 2060



Note: Provincial balances remain broadly regional in 2035. By 2060, the aggregate provincial deficit reaches approximately 34.5 Mt, equivalent to around 40% of national demand. Scenario, 2035 and 2060.

Around 2035, hydrogen requiring interprovincial allocation totals about 2.6 Mt, roughly 6% of national demand: most provinces balance supply and demand internally or with neighbors, so spatial mismatch remains limited and regional balance dominates.

Around 2060, demand grows to about 85.8 Mt while supply concentrates in wind–solar-rich provinces, widening the interprovincial mismatch: the aggregate provincial deficit reaches about 34.5 Mt (around 40.2% of national demand), met through interprovincial allocation, transport of hydrogen-derived products or imports, with supply broadly "surplus in the west and north, deficit in the east and south." Long-distance hydrogen pipelines, ammonia and methanol carrier networks and import-receiving facilities become foundational for interregional flows. This deficit is a national delivery requirement—the sum of provincial shortfalls, to be met first by interprovincial allocation and by the transport of hydrogen-derived products—not a coastal net-import requirement; see Section 5.5.

PART II

THE COST OF DISTANCE

—DELIVERING HYDROGEN AT SCALE

CHAPTER 4

SCALE DECIDES
—THE ECONOMICS OF LONG-DISTANCE DELIVERY

Renewable hydrogen supply concentrates in resource-advantaged regions while demand spreads across central-eastern and coastal China; the spatial mismatch will widen and long-distance transport becomes critical to scaling renewable hydrogen. Competitiveness depends on production cost, an acceptable end-use price, reliable transport capability and a matching product form. The two representative pathways covered: dedicated hydrogen pipelines and ammonia-based transport, the latter in two terminal forms—liquid ammonia with reconversion to hydrogen, and direct use of liquid ammonia.

4.1 Three ways to move hydrogen, one cost yardstick

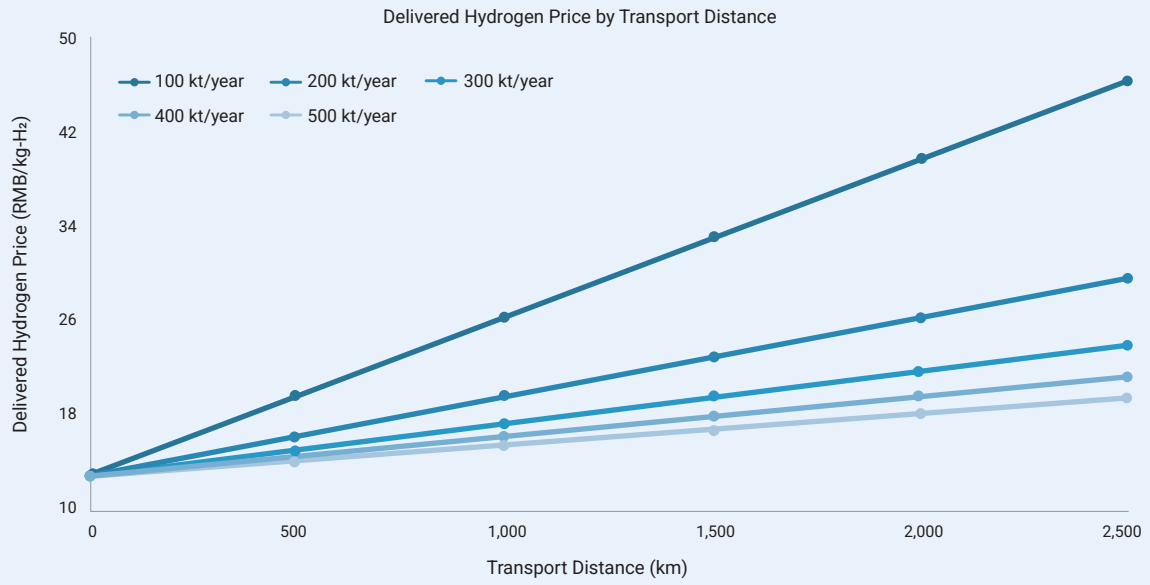
Dedicated hydrogen pipelines. Hydrogen is produced at the source and delivered through a dedicated pipeline; costs cover production, storage and pipeline transport. The route suits large-scale, continuous, high-purity demand in refining, steel, fuel-cell transport and fine chemicals; economics depend on throughput, distance, utilization and capital cost.

Ammonia carrier transport. Hydrogen is converted to liquid ammonia at the source and shipped to the terminus for direct use as chemical feedstock, shipping fuel, or power or industrial fuel—no cracking back to hydrogen. Avoiding terminal cracking, purification and compression lowers delivered costs and raises whole-chain efficiency.

Liquid ammonia with reconversion to hydrogen. Hydrogen is converted to liquid ammonia at the source and, after storage and transport, reconverted to high-purity hydrogen at the terminus through cracking, purification and compression. The route offers high volumetric hydrogen density and a mature ammonia storage-and-transport system, but adds synthesis at the source and reconversion at the terminus, with added cost and energy losses.

4.2 Throughput, not distance, sets the pipeline cost

Figure 14 Delivered cost of pipeline hydrogen by annual throughput and distance



Note: Raising annual throughput from 100,000 t to 500,000 t at 2,500 km cuts delivered cost by about 58%. Illustrative; base electricity price RMB 0.15/kWh, corresponding to a renewable hydrogen reference price of approximately RMB 13/kg H_2.

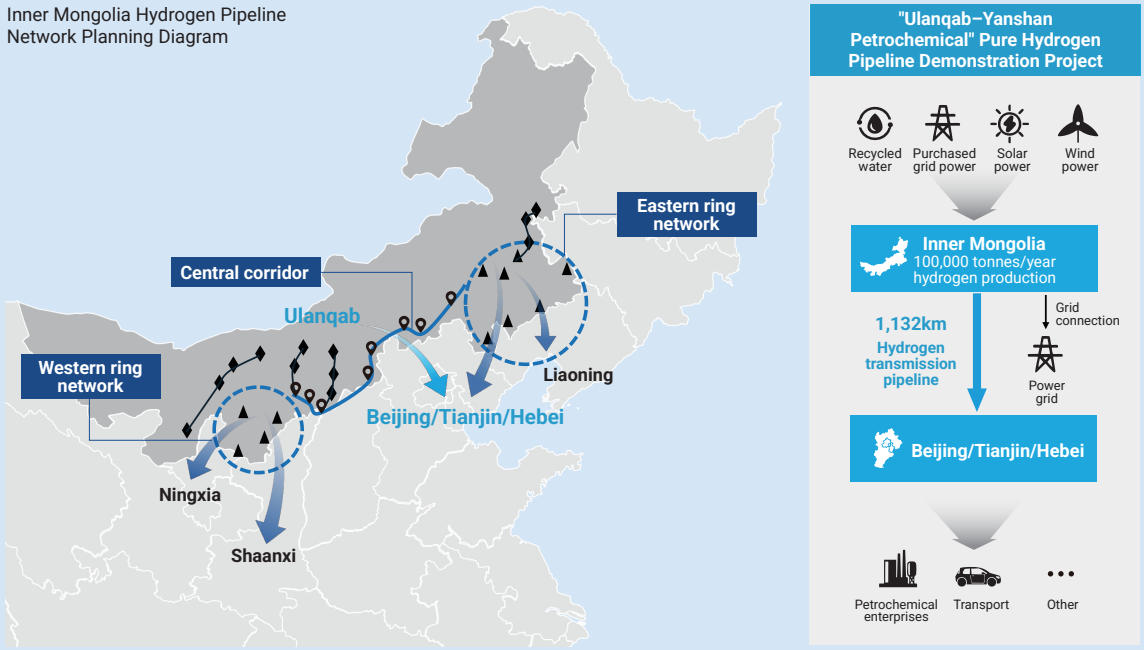
At the base-case electricity price of RMB 0.15/kWh, plant-gate renewable hydrogen costs about RMB 13/kg H_2. Distance raises delivered costs, but throughput dominates: at an annual throughput of 100 kt, hydrogen costs about RMB 26.44/kg H_2 at 1,000 km and RMB 46.69/kg H_2 at 2,500 km; at 500 kt, only about RMB 15.64/kg H_2 and RMB 19.69/kg H_2 at the same distances.

At 500 kt/yr, pipeline transport costs about RMB 2.70/kg H_2 over 1,000 km, RMB 5.40/kg H_2 over 2,000 km and RMB 6.75/kg H_2 over 2,500 km; at 100,000 t/yr, about RMB 13.50/kg H_2, RMB 27.00/kg H_2 and RMB 33.75/kg H_2. At 2,500 km, raising throughput from 100 kt to 500 kt cuts the transport component by about 80% and delivered cost by about 58%.

Annual throughput is therefore the primary driver of pipeline economics: at low throughput, fixed investment is hard to amortize and distance inflates unit transport cost. From 1,000 km to 2,500 km at 100,000 t/yr, delivered cost rises by about 77% and the transport component 2.5-fold, making transport the dominant element of end-use cost.

At 500 kt/yr, fixed-asset investment amortizes far more effectively, keeping long-distance increases manageable. Large-scale, stable, continuous demand is the basic precondition for long-distance dedicated pipelines: secure base loads in refining, steel and chemicals and raise utilization through long-term hydrogen purchase agreements. Without demand anchors, pipelines built ahead of demand risk high unit delivered costs, extended paybacks and stranded infrastructure.

Box 4.1
Sinopec's "Ulanqab–Yanshan Petrochemical" dedicated hydrogen pipeline demonstration project: a pilot for long-distance hydrogen delivery in China



Sinopec's "Ulanqab–Yanshan Petrochemical" dedicated hydrogen pipeline demonstration is a landmark for China's interregional renewable hydrogen delivery system. Using Ulanqab, Inner Mongolia's wind and solar resources, it produces renewable hydrogen at the resource site for long-distance dedicated delivery to refining, chemical and other potential hydrogen markets in the Beijing–Tianjin–Hebei region. According to the National Energy Administration, the "West-to-East Hydrogen Delivery" pipeline demonstration is in the Implementation Plan for Building a "National Single Network" of Oil and Gas Pipelines: from Ulanqab in Inner Mongolia to Sinopec Yanshan Petrochemical in Beijing, more than 400 km, phase-one capacity of 100,000 t/yr and headroom for 500,000 t/yr; China's first cross-province, large-scale, long-distance dedicated hydrogen pipeline, moving the country from park-level, short-distance applications to national demonstration[6].

The Ulanqab initiative is an integrated demonstration spanning "green power–hydrogen production–long-distance delivery–industrial substitution–multi-scenario absorption." Public information indicates the Ulanqab 100 kt/yr wind–solar hydrogen integration project's hydrogen production plant has been approved: in Shangdu County, Ulanqab, total investment about RMB 5.94 billion; 25

hydrogen-production buildings, each housing eight electrolyser sets (200 alkaline electrolyser units of 1,000 Nm³/h in total); a 6,000 m³ low-pressure buffer tank; and about 47.6 km of reclaimed-water pipeline—typical resource-site features, with large-scale renewable power, reclaimed-water use and buffering for engineering sustainability and operational stability.

Two planning scopes appear in the public record. The earlier "Ulanqab–Yanshan Petrochemical" scheme runs more than 400 km; the later "Ulanqab-to-Beijing–Tianjin–Hebei hydrogen pipeline demonstration project" totals about 1,132 km, designed for 6.3 MPa, phase-one capacity of 100 kt/yr and a planned increase to 500 kt/yr, supplying Xiong'an New Area, Shijiazhuang refining, Tianjin Petrochemical and Yanshan Petrochemical, among other priority regions and enterprises. The two lengths reflect different planning stages and should not be conflated as one confirmed, fully commissioned pipeline.

Its demonstration value: addressing the spatial mismatch between China's renewable hydrogen resources and demand centers, and testing whether long-distance dedicated pipelines can achieve economic viability at large scale and stable load in an integrated "production–storage–delivery–use" configuration—validating the long-distance commercial loop. Such pipelines also raise new issues—hydrogen-compatible pipe materials, weld inspection, station safety, leak monitoring, compression and metering, valve-station layout, dispatch and operations, cross-province permitting, pipeline tariffs, third-party access and capacity allocation—pushing the sector from engineering toward institutional development: standards, regulation and pricing for hydrogen networks, and a foundation for interregional pure-hydrogen expansion.

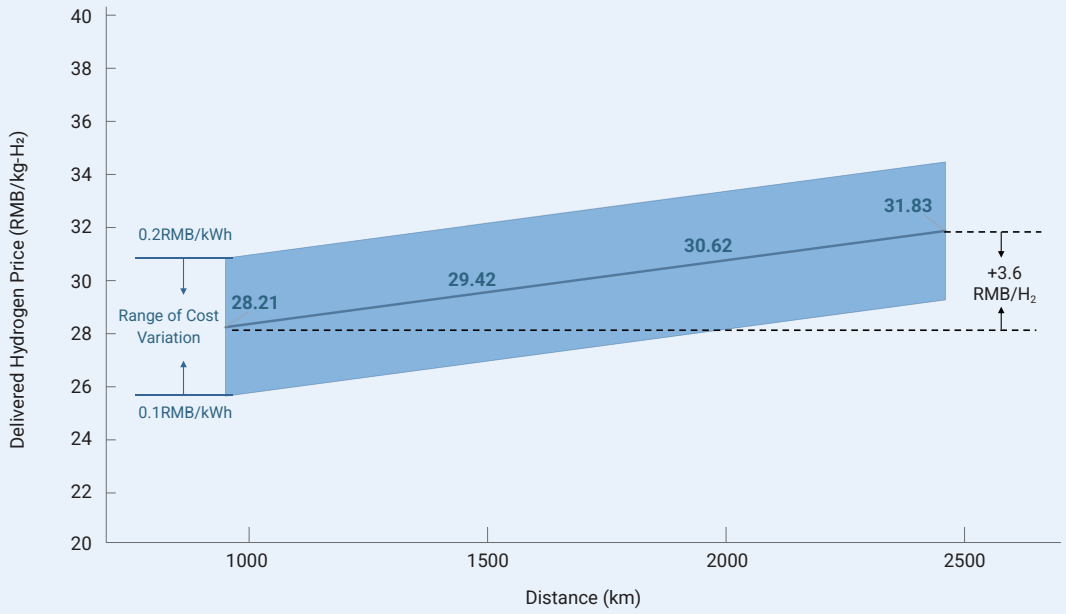
The demonstration has moved from planning into engineering: in 2023, the National Energy Administration announced the "West-to-East Hydrogen Delivery" pipeline's national-plan incorporation; in 2024, the Ulanqab 100 kt/yr wind–solar integration project's hydrogen production plant was approved; in 2025, official Inner Mongolia information showed the Ulanqab-to-Beijing–Tianjin–Hebei pipeline demonstration project's Inner Mongolia section had been formally approved—the country's first cross-province, long-distance, large-scale renewable hydrogen pipeline project and a priority export initiative in Inner Mongolia's hydrogen delivery network.

In May 2026, Binhai Investment's wholly owned subsidiary Binhai (Tianjin) signed a five-year renewable hydrogen supply framework agreement with Sinopec Star New Energy Co., Ltd., covering hydrogen purchase and sale from the Ulanqab project and the pipeline demonstration, and blending into Binhai (Tianjin)'s core natural-gas trunk network and future planned pipelines. It aims to connect the Tianjin section of the Ulanqab–Beijing–Tianjin–Hebei pure-hydrogen pipeline with Binhai (Tianjin)'s natural gas network by the end of 2028. From 2029, Sinopec Star New Energy will supply hydrogen to Binhai (Tianjin) on a stable basis, with an agreed initial annual volume (roughly 20,000–30,000 t, scalable as blending volumes grow) at the most favorable price (current reference range RMB 19–22/kg). With large-scale city-gas blending as the entry point, the project scales renewable hydrogen in the city gas sector and extends applications to power generation, metallurgy, transport, hydrogen liquefaction and refueling stations, supporting the Beijing–Tianjin–Hebei hydrogen industry and a replicable "renewable hydrogen + natural gas" commercial model advancing the country's energy transition.

4.3 Ammonia buys distance—and pays for it at the terminal

Compared with dedicated pipelines, the ammonia-reconversion route is far less sensitive to transport distance, suiting long-distance, interregional markets that pipelines do not yet cover. Its advantages are transport flexibility and low dependence on early-stage infrastructure; its economics remain constrained by ammonia synthesis at the source and cracking at the terminus.

Figure 15 Delivered cost of ammonia reconversion by distance

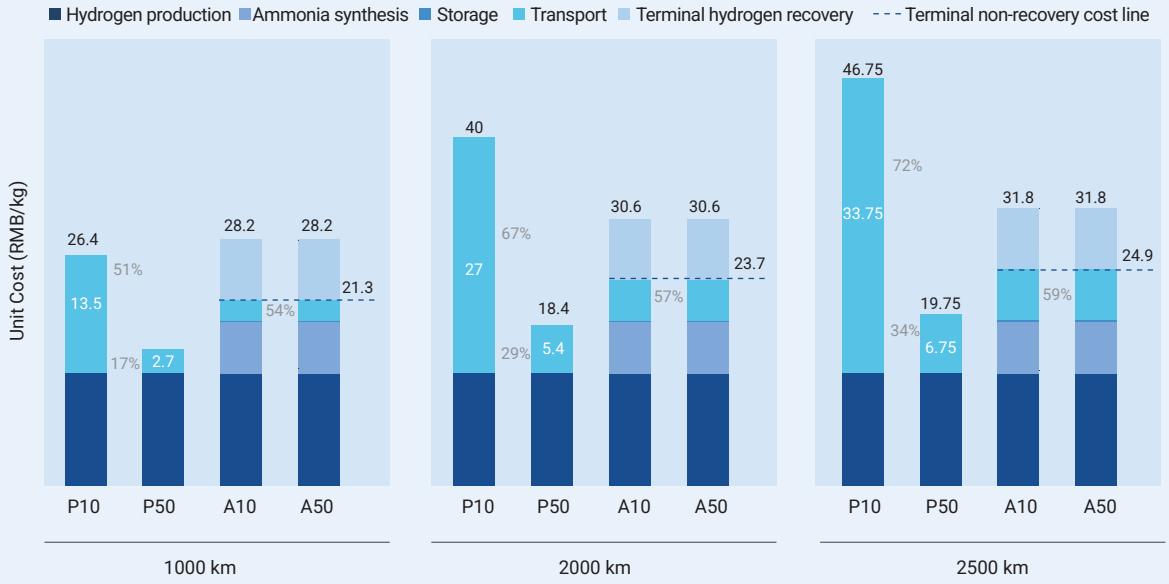


Note: Delivered cost rises by only about RMB 3.6/kg H2 as the route extends from 1,000 km to 2,500 km, far less than the increase for a 100 kt/yr pipeline. Illustrative.

Ammonia-reconversion delivered costs are about RMB 28.2/kg H_2 at 1,000 km, RMB 30.6/kg H_2 at 2,000 km and RMB 31.8/kg H_2 at 2,500 km; extending the route from 1,000 km to 2,500 km adds only about RMB 3.6/kg H_2. Against a 100 kt/yr pipeline, the route is broadly comparable at 1,000 km and increasingly advantageous at longer distances.

4.4 When to pipe, when to ship

Figure 16 Delivered cost against annual throughput for pipelines and ammonia routes



Note: Pipeline costs compress as throughput rises, while ammonia costs cannot be diluted by volume. Illustrative; hydrogen production cost taken as approximately RMB 13/kg H_2. P10 and P50: Pure-Hydrogen Pipeline, 100 kt/yr and 500 kt/yr; A10 and A50: Road-transported, 100 kt/yr and 500 kt/yr hydrogen-equivalent Ammonia.

Dedicated pipelines show strong economies of scale. Raising throughput spreads construction and operating costs and compresses transport's share of delivered cost; ammonia-based transport offers no such dividend—costs cannot be diluted by volume, with or without reconversion.

Where ammonia can be used directly, it is more competitive than reconversion—but not against a large-scale pipeline. Direct-use liquid ammonia delivered costs, on a hydrogen-equivalent basis, are about RMB 21.3/kg H_2 at 1,000 km, RMB 23.7/kg H_2 at 2,000 km and RMB 24.9/kg H_2 at 2,500 km. The RMB/kg H_2 unit converts ammonia's commodity cost into a hydrogen equivalent, not its purchase price by mass. Direct-use ammonia is cheaper than ammonia with reconversion and than a 100 kt/yr pipeline at every distance, but remains above a 500 kt/yr pipeline—about 36% higher at 1,000 km and about 26% higher at 2,500 km. For resource-based regions, exporting green ammonia through existing chemical logistics adds supply flexibility; where end-use can take ammonia directly, evaluate it first.

The main constraint on the ammonia-reconversion route lies in the conversion steps. Ammonia synthesis and terminal reconversion cost about RMB 5.9/kg H_2 and RMB 6.9/kg H_2—together more than 40% of delivered cost. For high-purity hydrogen, ammonia with reconversion is comparable to a 100,000 t/yr pipeline at 1,000 km (RMB 28.2/kg H_2 against RMB 26.44/kg H_2) and markedly cheaper beyond it (RMB 31.8/kg H_2 against RMB 46.69/kg H_2 at 2,500 km), but remains well above a 500 kt/yr pipeline (RMB 19.69/kg H_2 at 2,500 km).

Sensitivity drivers. For dedicated pipelines the critical variables are throughput and utilization; for ammonia, whether the terminus needs reconversion. Electricity price affects all routes but is a system-level variable rather than a decisive factor in carrier choice. For China, low-cost power regions matter, but planning low-cost production, stable demand, long-distance corridors and end-use product form as one system matters more.

PART III

BEYOND THE BORDER

—CHINA IN HYDROGEN-DERIVED TRADE

CHAPTER 5

WHAT REALLY DECIDES HYDROGEN TRADE —COST, CARBON AND RELIABILITY

China's low-carbon hydrogen development faces a growing spatial mismatch: low-cost renewable hydrogen concentrates in the northwest, north and northeast, while demand sits in the eastern coastal and central heavy-industry regions. Domestic pipelines cannot cover all coastal demand in the medium term, so hydrogen-derived-product imports can complement domestic supply.

Trade's competitive basis is changing: natural gas resources and chemical capacity are giving way to low-cost energy, mature storage-and-transport infrastructure and verifiable low-carbon attributes. The IEA's Global Hydrogen Review 2026 records a landmark shift: in 2025, trade-related agreements outnumbered domestic self-use among newly signed low-emission hydrogen offtake agreements for the first time[7].

This chapter costs ammonia and methanol from the Middle East to China's core energy ports under different transport distances, FOB prices and carbon-price assumptions, and assesses the carriers' economics and regulatory constraints. Results are techno-economic judgments, not forecasts of future prices or trade flows.

5.1 Carriers and the corridor: how transoceanic trade is configured

Beyond 5,000 km, gaseous hydrogen's low volumetric energy density and high compression-and-storage costs, and liquid hydrogen's energy-intensive liquefaction and cryogenic conditions, limit transoceanic trade. Liquid ammonia and methanol suit the role better: ammonia's high hydrogen content and mature storage-and-transport system fit fertilizer, coal-power co-firing, shipping fuel and direct uses, while methanol, an ambient-temperature liquid, reuses existing oil-product, chemical and marine-fuel infrastructure and suits green shipping fuels, chemical feedstock and low-carbon liquid fuels. IRENA's (2025) 2050 scenarios put hydrogen-derived products at roughly 73–80% of international trade on a hydrogen-equivalent basis, with pure hydrogen at 20–27% [8].

Global Hydrogen Review 2026 reports global hydrogen demand exceeded 100 Mt in 2025, with ammonia and methanol production consuming about 34 Mt and 16 Mt—around half of demand—and the Middle East accounts for more than a quarter of global ammonia trade and close to 45% of methanol trade[7].

The Middle East can supply China with low-carbon hydrogen-derived products on strong solar resources, large-project capacity and oil-and-gas, refining, chemical, port and shipping infrastructure. Global Hydrogen Review 2026 reports it produces about one-sixth of global hydrogen, mostly for chemicals, fertilizer and refining, and accounts for more than 25% of global ammonia trade, close to 40% of urea trade and nearly 45% of methanol trade[7]. Priority destinations: China's coastal energy ports and industrial clusters—Bohai Rim (Shandong, Hebei, Liaoning), Yangtze River Delta (Jiangsu, Zhejiang, Shanghai) and South China (Guangdong, Fujian). They can receive domestic hydrogen by pipeline while serving as import terminals for green ammonia, green methanol and green shipping fuels. Long-standing China–Middle East energy ties support long-term contracts, port receiving, investment and mutual carbon-certification recognition.

Figure 17 Middle East–China trade corridor and its landed-cost composition



Note: The corridor connects the Middle East to three Chinese port clusters—the Bohai Rim, the Yangtze River Delta and South China; shipping and logistics account for less than 9% of landed cost. Illustrative.

Disclaimer: This map is provided for illustration purposes only. Boundaries and names shown on this map do not imply the expression of any opinion on the part of IHFCA concerning the status of any region, country, territory, city, or area or of its authorities, or concerning the delimitation of frontiers or boundaries.

5.2 The cost structure of trade: FOB, logistics and the four cost layers

For scenarios that use ammonia or methanol directly: total landed cost = FOB price + ocean freight, port, insurance and other logistics costs + import duty + import VAT + potential carbon cost (0 in the base case).

For scenarios that reconvert the carrier to high-purity hydrogen: unit hydrogen-equivalent terminal cost = carrier landed cost converted on the basis of hydrogen content and conversion efficiency + cracking or reforming cost + purification cost + compression cost—computed separately from direct commodity use.

Table 3 Cost components of the landed-cost mode

Cost component	Sub-item	Definition
FOB price	FOB price	Spot or long-term contract price at the port of loading
Total transport cost	Ocean freight	Includes vessel fuel consumption and shipping carbon cost
	Carbon cost	—
	Port charges	Discharge, terminal handling charges (THC) and short-term storage at the Chinese destination port
	Insurance	Standard marine cargo and hull insurance
	Other logistics costs	Documentation, agency and miscellaneous fees
Import duty	Import duty	Based on the model's assumed 2026 provisional tariff scenario
After-clearance cost (excl. VAT)	After-clearance cost (excl. VAT)	FOB price + total transport cost + import duty; where applicable, state whether carbon cost is included in total transport cost
Import VAT	VAT (assumed 13% in the model)	(FOB price + total transport cost + import duty) × 13%; not the statutory rate applicable to all tariff lines
Potential import carbon tax/carbon border adjustment scenario	0 in the base case	Sensitivity scenarios calculated as product emission intensity × reference carbon price; treated in this report as an after-tax add-on, without secondary VAT effects
Total landed cost	Total landed cost	After-clearance cost + import VAT; where carbon cost is not included in total transport cost, it should be added separately and the tax base stated

Note: Landed cost = FOB price + ocean freight, port, insurance and other logistics costs + import duty + import VAT + potential carbon cost. Hydrogen-equivalent terminal cost adds cracking or reforming, purification and compression.

Table 4 Base-case assumptions of the landed-cost model

Parameter	Liquid ammonia	Methanol
Typical vessel type	80,000 m³ VLGC	51,600 DWT MR
Cargo per vessel	50,000 t	40,000 t
One-way sailing distance	6,000 nm	6,000 nm
Laden service speed	16.0 knots	14.5 knots
Port stay incl. loading and discharge	5.0 days	4.0 days
At-sea fuel consumption	45 t/day	25 t/day
In-port fuel consumption	8 t/day	3 t/day
VLSFO price	USD 650/t	USD 650/t
Daily vessel cost	USD 50,000/day	USD 30,000/day

Parameter	Liquid ammonia	Methanol
Port charges	USD 8/t	USD 8/t
Other logistics costs	USD 1.5/t	USD 1.5/t
Insurance rate	0.20%	0.20%
FOB price	USD 400/t	USD 300/t
Import duty	0	0
Import VAT	13% (model assumption)	13% (model assumption)
Base-case shipping carbon price	excluded	excluded

Note: Base case, 6,000 nautical miles; carbon cost excluded; the 13% import VAT rate is a model assumption.

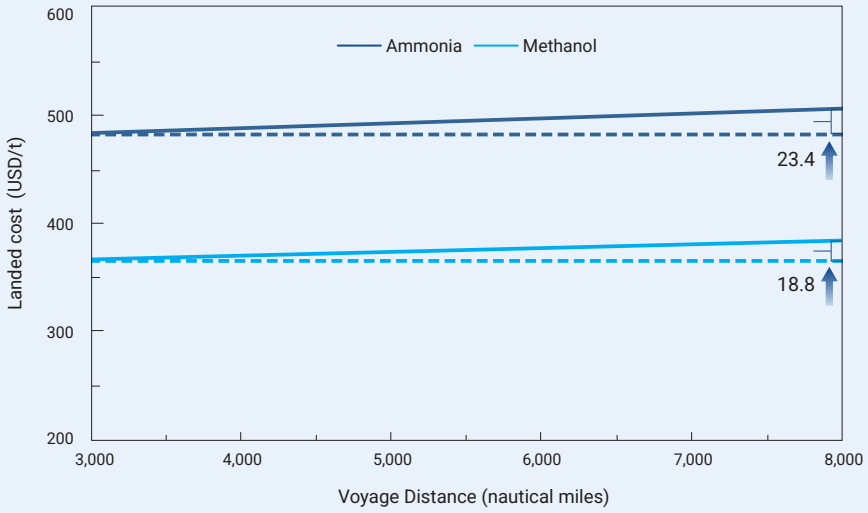
Under the model's assumed 13% import VAT, liquid ammonia and methanol land at Chinese ports at about USD 498/t and USD 377/t. Structures are similar: FOB price accounts for 80.3% and 79.7% of cost, transport for 8.2% and 8.8%, and import VAT for about 11.5% in both cases. Cost is therefore set mainly by upstream production, synthesis, financing and FOB pricing, not shipping.

Table 5 Landed-cost structure in the base case (6,000 nautical miles, approximately 11,100 km)

Cost item	Liquid ammonia (USD/t)	Share	Methanol (USD/t)	Share
FOB price	400.00	80.3%	300.00	79.7%
Total transport cost	40.66	8.2%	33.29	8.8%
Import duty	0	0	0	0
Import VAT	57.29	11.5%	43.33	11.5%
Potential import carbon tax / carbon border adjustment	0	0	0	0
Total landed cost	**497.95**	**100%**	**376.62**	**100%**

Note: FOB price accounts for 80.3% of ammonia cost and 79.7% of methanol cost; transport for 8.2% and 8.8%; import VAT for about 11.5% in both cases. Base case; carbon cost excluded.

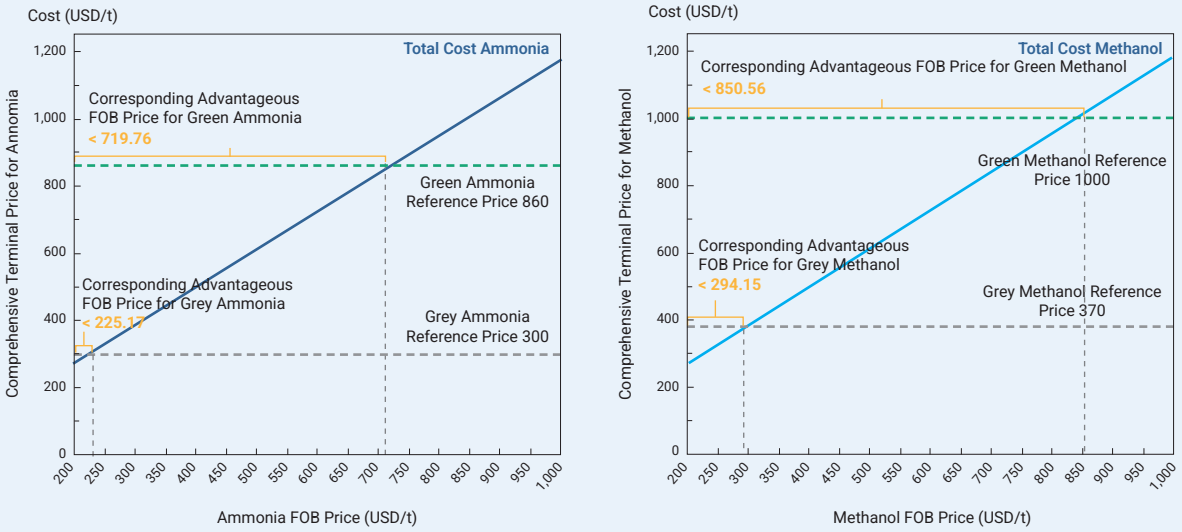
Figure 18 Landed cost against voyage distance for liquid ammonia and methanol



Note: Extending a voyage by about 167% (3,000 to 8,000 nautical miles) raises landed costs by less than 6%. Illustrative; 1 nautical mile = 1.852 km. Distance has limited effect on landed cost: from 3,000 to 8,000 nautical miles, Ammonia's landed cost rises from USD 483.9/t to USD 507.3/t—USD 23.4/t, or about 4.8%—Methanol's from USD 365.3/t to USD 384.1/t, USD 18.8/t, or about 5.1%. A voyage extended by about 167% lifts costs by less than 6%.

Distance has limited effect on landed cost: from 3,000 to 8,000 nautical miles, ammonia's landed cost rises from USD 483.9/t to USD 507.3/t—USD 23.4/t, or about 4.8%—methanol's from USD 365.3/t to USD 384.1/t, USD 18.8/t, or about 5.1%. A voyage extended by about 167% lifts costs by less than 6%.

Figure 19 Landed cost against FOB price for liquid ammonia and methanol



Note: Each USD 100/t of FOB price adds about USD 113/t to landed cost, which defines the FOB levels at which ammonia and methanol retain a price advantage. Illustrative; fixed assumptions: cargo volumes (ammonia 50,000 t; methanol 40,000 t), a 6,000 nautical mile voyage, and the stated vessel, port and import-tax parameters; dashed lines are Chinese market reference prices.

When the ammonia FOB price rises from USD 200/t to USD 1,000/t, landed cost increases from about USD 271.5/t to USD 1,177.2/t; methanol's from about USD 263.4/t to USD 1,169.2/t. Each USD 100/t increase in FOB price raises landed cost by about USD 113/t—USD 100 of it the commodity price, the rest ad valorem import VAT and insurance. Overseas production costs, FOB quotations and contract prices thus dominate shipping and port charges.

Price advantage holds below these FOB ceilings:

- Imported liquid ammonia: about USD 225.17/t against coastal Chinese grey ammonia at USD 300/t, and USD 719.76/t against green ammonia at USD 860/t.
- Imported methanol: about USD 294.15/t against coastal Chinese grey methanol at USD 370/t, and USD 850.56/t against green methanol at USD 1,000/t.

Thresholds can guide contracts and investment; decisions must weigh exchange rates, carbon intensity, certification and substitution costs.

5.3 Terminal options: use the carrier, or crack it back to hydrogen

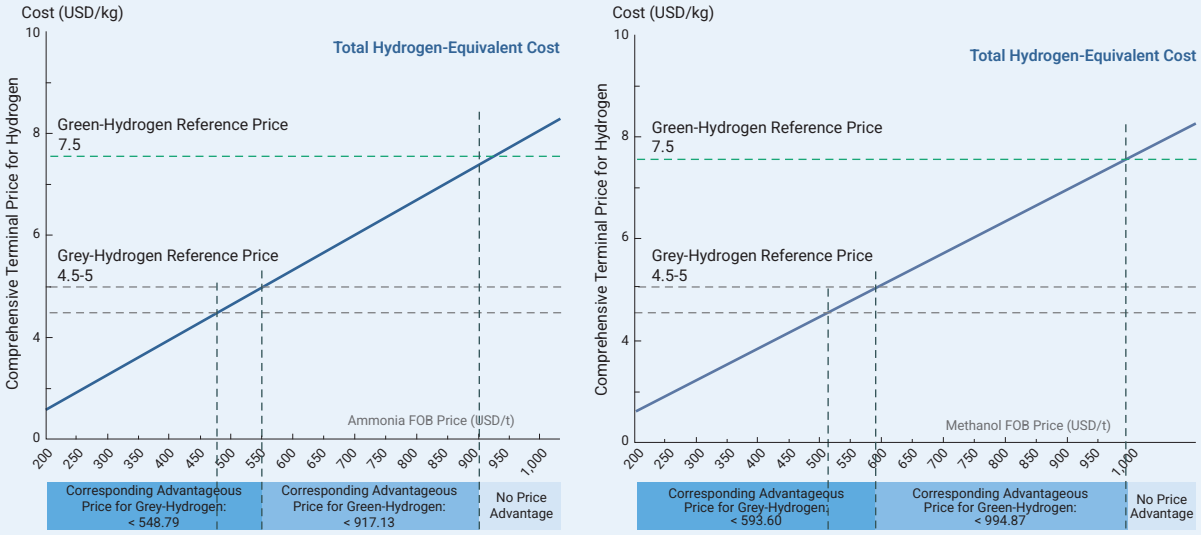
Table 6 Derivation of ammonia, methanol and hydrogen-equivalent landed costs (per kg H_2)

Cost item	Price (USD/kg)	Share
Carrier hydrogen-equivalent cost—ammonia cracking route	2.99	74.92%
Cracking, purification and compression cost	1.00	25.08%
Integrated landed cost—ammonia cracking to hydrogen	3.99	
Carrier hydrogen-equivalent cost—methanol reforming route	2.07	65.32%
Reforming, purification and compression cost	1.10	34.68%
Integrated landed cost—methanol reforming to hydrogen	3.17	

Note: Reconversion—cracking or reforming, purification and compression—adds about 25–34% to the hydrogen-equivalent cost of the landed carrier. Illustrative.

Reconverting the carrier to high-purity hydrogen adds costs for ammonia cracking or methanol reforming, purification and compression—about 25–34% of the unit hydrogen-equivalent combined cost under this report's parameters, materially eroding the carriers' cost advantage. The "import carrier–reconvert at the terminus" model is therefore a supplementary pathway. Coastal merchant hydrogen demand may grow; reconversion is assessable only where FOB prices are low, pipelines cannot yet supply stably, and ports have mature receiving, cracking, purification and safety-management capability.

Figure 20 Post-reconversion hydrogen-equivalent cost against FOB price



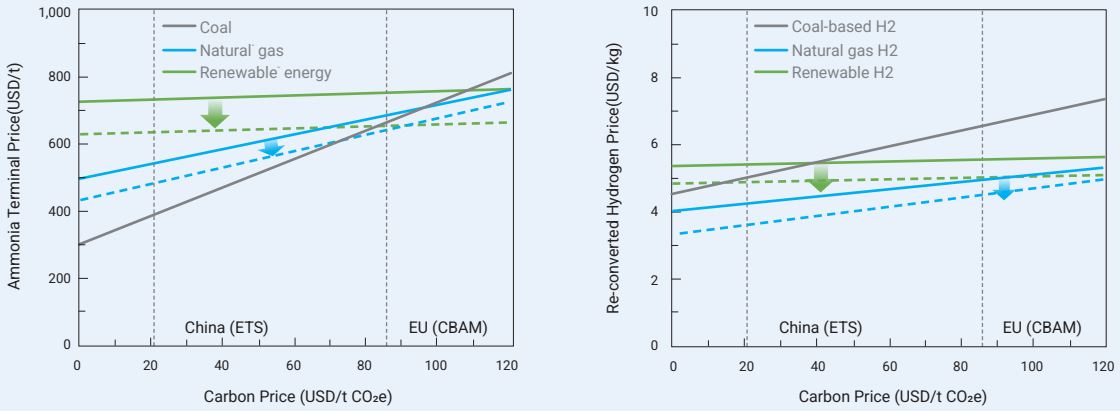
Note: Ammonia and methanol retain a price advantage up to FOB prices of about USD 548.79/t and USD 593.60/t against the grey-hydrogen reference (USD 5/kg H_2) and about USD 917.13/t and USD 994.87/t against the renewable-hydrogen reference (USD 7.5/kg H_2). Illustrative; the figure plots carrier FOB price against unit hydrogen-equivalent combined cost after landing, conversion, purification and compression.

Methanol tolerates a slightly higher FOB ceiling than ammonia at the same reference hydrogen price—a small cost advantage. Both routes also depend on low FOB quotations and plant utilization.

Imported ammonia and methanol are best used directly: ammonia for fertilizer, coal-power co-firing, shipping fuel and selected chemicals, methanol for shipping fuel, chemical feedstock and liquid low-carbon fuels. Imported ammonia already competes with green ammonia shipped long distances within China; methanol's base is more mature: by mid-2025, more than 60 methanol-fueled vessels were operating globally with nearly 300 more on order (IEA, Global Hydrogen Review 2025), reusing existing marine-fuel bunkering systems—the lowest threshold among hydrogen-derived products[9].

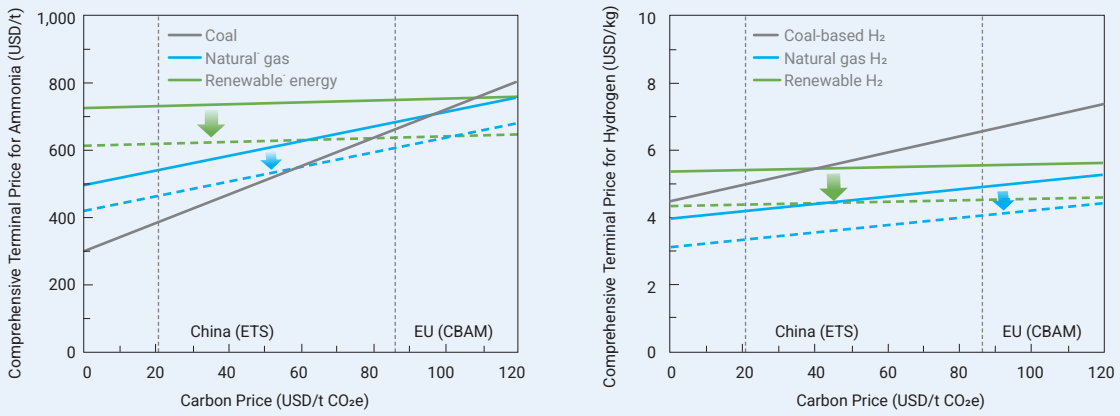
5.4 Carbon and certification: the new competitive frontier

Figure 21 Landed cost of ammonia against the unit carbon price



Note: Landed costs rise linearly with the unit carbon price, increasing the cost of high-carbon routes relative to verifiable low-carbon supply. Illustrative; left panel: directly used liquid ammonia, right panel: ammonia cracking to hydrogen; carbon cost treated as an after-tax add-on; emission factors and base prices in the Annex.

Figure 22 Landed cost of methanol against the unit carbon price



Note: Landed costs rise with the unit carbon price, making verifiable low-carbon attributes part of the competitive equation. Illustrative; left panel: directly used methanol, right panel: methanol reforming to hydrogen; carbon cost treated as an after-tax add-on; emission factors and base prices in the Annex.

The base case excludes an import carbon tax or carbon border adjustment; embodied carbon may become an explicit trade cost as consuming markets tighten life-cycle carbon management. With FOB price, voyage, cargo scale, vessel and tax parameters unchanged, landed costs rise linearly with the unit carbon cost. High-carbon-intensity products bear higher costs; verifiable low-carbon attributes may gain relative advantage.

Trade will not compare FOB prices and shipping costs alone: as major consuming markets build low-carbon, renewable-fuel and carbon-footprint rules, whether ammonia and methanol can prove low-carbon attributes will affect market access, policy support and green premium.

These rules now span the full life cycle—renewable power, hydrogen production, synthesis, storage, shipping, port handling and end use. Some markets require additionality, temporal and geographic correlation for renewable electricity; for green methanol, CO_2 sourcing and accounting also shape recognition[10–13].

Regions differ in emission thresholds, accounting boundaries, definitions and certification, raising data-collection, verification and compliance costs for multi-market projects. Whether green ammonia and methanol count as low-carbon or renewable directly affects their value: a product unable to demonstrate its renewable-electricity source, carbon intensity, temporal and geographic correlation and life-cycle footprint may struggle in high-standard markets or for policy support even at a low landed cost.

The rules affect China's imports, exports and domestic substitution. Imports: the competitiveness of Middle East and Australian resources must be weighed across carbon border adjustments, transport distance, terminal conversion efficiency and domestic substitution costs. Exports: green methanol, green ammonia or other hydrogen-derived products for Europe, Japan and Korea must meet those markets' carbon-footprint, renewable-attribute certification and third-party verification rules. Domestically, clean-hydrogen certification, subsidy and demonstration policies will shape the boundary between imported ammonia and methanol and domestic renewable hydrogen.

5.5 The addressable market: sizing the import opportunity

Global hydrogen trade is likely to develop in two stages. Through 2030–2035, ammonia and methanol will anchor the market because they can use established production, shipping, storage, port and end-use infrastructure. Over the longer term, falling costs, credible certification and new terminals could support trade in a wider range of hydrogen-derived products. Policy ambitions indicate substantial potential, but targets, contracted procurement and commercially addressable demand are not interchangeable; the indicators below are therefore separated by horizon and should not be added together.

Table 7 Import demand and market potential by horizon

Horizon	Market or channel	Volume indicator	Status	Interpretation
2030–2035	Japan—ammonia procurement	0.5–1.0 Mt NH_3/yr contracted or under tender	Contracted or under tender	Emerging direct-use market, well below Japan's national supply ambition
2030–2035	South Korea—clean-hydrogen imports	2.0 Mt H_2e/yr by 2030	Government plan	Potential demand; carrier mix and project realization remain uncertain
2030–2035	European Union, including Germany	Up to 10 Mt H_2/yr by 2030	Policy ambition	Potential market, not contracted procurement; Germany is included and not additive
2030–2035	China—existing methanol trade	13.5 Mt methanol imported in 2024, equivalent to 1.7 Mt H_2	Current commodity trade	Established supply chain, but predominantly not certified as low-carbon
2040–2050	Japan and South Korea	35–45 Mt H_2e/yr if published targets are realized	Illustrative policy ceiling	Potential long-term scale, not a forecast
2060	China—coastal renewable-hydrogen demand	22.9 Mt H_2e/yr	Model output	Total coastal demand, not an import requirement
2060	China—aggregate provincial deficit	34.5 Mt H_2e/yr	Model output	National delivery requirement, only part of which might be met by imports

Note: Rows are not additive across markets or horizons. Japan's figures are hydrogen-and-ammonia supply targets rather than import targets; South Korea's are planned imports; the EU figure is an import ambition that includes Germany. Volumes published in energy units are converted at 33.3 TWh per Mt H_2 on a lower heating value basis. China's 34.5 Mt aggregate provincial deficit is a national delivery requirement, not a coastal net-import requirement. Sources: METI (2023) [14]; MOTIE (2021) and S&P Global Commodity Insights (2021) [15][18]; European Commission, REPowerEU (2022) [16]; BMWK (2024) and Energy Partnership Chile–Alemania (2025) [17][19].

China's import opportunity may be front-loaded toward the medium term. Imported low-carbon ammonia and methanol could bridge coastal supply gaps while domestic renewable production, pipelines and carrier networks are still developing. By 2060, China's larger domestic renewable-hydrogen supply could reduce import dependence even as total demand grows. The 22.9 Mt coastal-demand estimate and 34.5 Mt aggregate provincial deficit cannot be treated as import volumes: the first is total demand, while the second may be served by domestic pipelines, domestic carrier transport, local production and imports. A defensible import estimate must isolate the residual coastal deficit and compare domestic and imported options on a delivered-cost basis.

The Middle East is well positioned to support this transition through its ammonia and methanol production, ports, storage and shipping capabilities. In the medium term, collaboration can focus on certified low-carbon products for direct use in chemicals, fertilizer and marine fuels; over time, it can expand into joint investment, receiving terminals, shipping corridors, certification and technology cooperation. Long-term partnership can therefore grow even if China's net import dependence declines. Competitiveness will be determined by delivered cost, carbon credentials, infrastructure compatibility and reliability—with distance relevant through freight, losses and route risk, even where it is not the largest cost component.

5.6 China's offtake: which sectors buy imported hydrogen-derived products

The strongest import opportunities lie in the Bohai Rim, Yangtze River Delta and southern coastal clusters, where industrial and maritime demand is supported by deep-water ports, storage and trading infrastructure. Ammonia and methanol offer the most immediate routes because they are already traded at scale and can often be used directly, avoiding reconversion costs. Refining and other high-purity users offer higher-value demand but will require dedicated infrastructure, consistent quality, credible certification and long-term supply commitments.

The table below sets out the offtake segments that imported low-carbon hydrogen-derived products would serve, with volumes drawn from the model's coastal demand and allocated by sector.

Table 8 Coastal offtake segments for imported hydrogen-derived products, 2035 and 2060 (Mt H2)

Offtake segment	Imported product form	2035 (Mt H_2)	2060 (Mt H_2)	Notes
Ammonia and fertilizer	Ammonia—direct use	0.1	3.3	Stable load and mature coastal infrastructure
Methanol and chemicals	Methanol—direct use	0.1	3.3	Existing import, storage and processing systems
Refining and petrochemicals	Hydrogen; ammonia with reconversion	0.2	3.5	Continuous, high-purity demand that could anchor infrastructure
Steel and other heavy industry	Hydrogen; hydrogen-derived reductants	0.1	2.5	Concentrated coastal capacity; uptake depends on technology and cost
Port logistics and shipping fuels	Ammonia; methanol	0.5	9.7	Largest potential segment by 2060, led by bunkering and maritime demand
Power and heat, including ammonia co-firing	Ammonia—direct use	0.1	0.6	Policy-dependent opportunity subject to efficiency and emissions performance
Total coastal demand		1.1	22.9	Modeled demand—not an import forecast

Note: The figures are indicative allocations of total coastal low-carbon hydrogen demand, not projected imports. Industrial demand is allocated using the current sector mix and should be refined with plant-level data; the import-addressable share depends on whether imported products can compete with domestic supply on delivered cost and carbon intensity.

China's largest coastal demand may not coincide with its greatest import need. Imports could play a comparatively important bridging role in 2030–2035, while domestic production and delivery networks are still scaling; by 2060, they may serve a more selective role in cost competition, supply diversification and resilience. The strategic direction is clear: ammonia and methanol anchor the medium-term import channel, while long-term trade evolves toward a broader, more competitive and increasingly two-way value-chain partnership.

CHAPTER 6

FROM PROJECTS TO NETWORKS —A THREE-PHASE DELIVERY ROADMAP

6.1 China's policy support: 32 national documents in five years

Since September 2021, China's central and local governments have issued hundreds of hydrogen-related policies. This report reviews 32 key national documents from the State Council, the National Development and Reform Commission, the National Energy Administration and other central authorities. They cover strategy, standards, pricing, financing and industrial applications; 28 are assessed as strongly supportive.

The documents address six main objectives. Support is strongest for hydrogen production and the use of renewable electricity in non-power applications. Policies on transport costs, infrastructure and carbon value remain less developed.

Table 9 China's national hydrogen policy objectives and representative documents, 2021–2025

Policy objective	Documents addressing it	Representative document
Lower green electricity prices	12	Notice on deepening market-oriented reform of new energy feed-in tariffs (2025)
Enable renewable electricity use in non-power applications	18	Notice on new energy consumption excluded from total energy consumption control (2022)
Lower hydrogen production costs	19	Medium and Long-Term Plan for the Development of the Hydrogen Energy Industry (2021–2035) (2022)
Lower storage and transport costs	13	Guidelines for the construction of the hydrogen energy industry standard system (2023)
Address storage and transport bottlenecks	19	Guiding opinions on promoting high-quality development of energy equipment (2025)
Reward low-carbon attributes	5	Work plan for accelerating the construction of the carbon emission dual control system (2024)

Note: Based on 32 key national documents issued since September 2021, of which 28 are assessed as strongly supportive; counts show the number of documents addressing each objective.

Policy has focused largely on expanding supply. The next priority is delivery: transport infrastructure, market coordination, carbon valuation and certification.

6.2 Delivery, not production, is the binding constraint

China's hydrogen strategy now needs to shift from expanding production capacity to building a low-cost, reliable and certifiable delivery system. As hydrogen use grows in industrial decarbonization, transport, power-system flexibility and low-carbon chemicals through 2035 and 2060, the distance between low-cost hydrogen resources and major demand centers is set to increase.

An effective delivery system will require three capabilities to develop in parallel:

- Scalable, low-cost supply of renewable and other low-carbon hydrogen.
- Transport and conversion infrastructure matched to demand, including pipelines, ammonia and methanol logistics, and port receiving facilities.
- Robust carbon accounting and certification, covering life-cycle emissions, traceability and low-carbon attributes.

Together, these capabilities will determine whether China can convert its renewable resource potential into commercially competitive products for domestic and international markets.

6.3 Three capabilities, one system

China's hydrogen industry is moving from demonstration projects towards systematic deployment. However, a substantial gap remains between developing individual projects and delivering hydrogen at scale. Supply, demand, infrastructure and certification frameworks will need to mature together if hydrogen is to support industrial decarbonization, transport and low-carbon chemical production.

Stable demand must anchor investment. Hydrogen demand is currently concentrated in refining, ammonia, methanol and coal chemicals. Under China's carbon-peaking and carbon-neutrality goals, its use could expand into steel, heavy-duty transport, maritime fuels, power-system flexibility and low-carbon chemicals. These applications have different requirements for cost, purity, supply continuity and carbon intensity. No single price threshold, product form or technology pathway can serve them all.

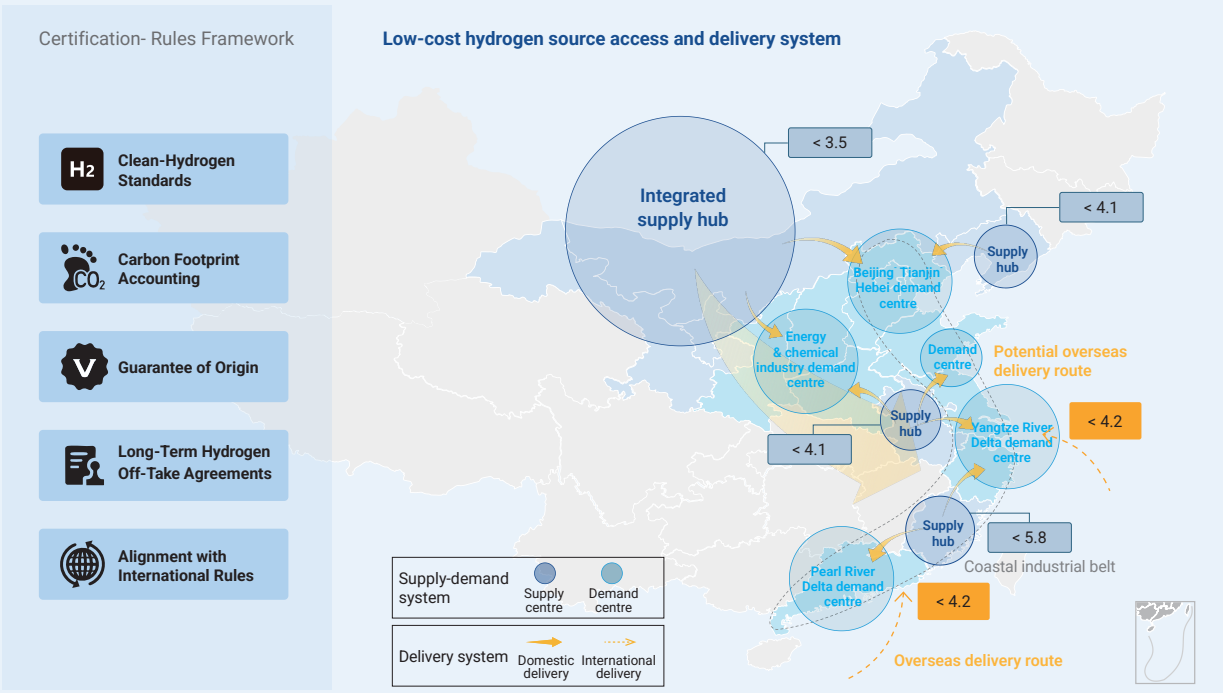
The supply–demand mismatch will become increasingly geographic. Low-cost renewable hydrogen potential is concentrated in the northwest, north and northeast—the "Three Norths"—while major demand centers are located along the eastern coast, in central heavy-industry provinces, around ports and along transport corridors. This divergence will progressively displace the current model of local production and consumption.

Infrastructure economics depend on scale and utilization. Dedicated pipelines offer substantial economies of scale, but their unit costs are highly sensitive to throughput and load factors. Without anchor customers, long-term offtake agreements and coordinated planning, projects face underutilization and extended payback periods.

Carrier economics depend on the final product required. Ammonia and methanol are well suited to long-distance transport and international trade, particularly where they can be used directly. If high-purity hydrogen is required at the destination, cracking or reforming, purification and compression can materially weaken their competitiveness.

Carbon attributes are becoming a source of market value. International trade will increasingly be shaped by life-cycle emissions, renewable-energy sourcing, certification and supply reliability—not price alone. Exports to Europe, Japan and Korea will need to comply with market-specific accounting and verification requirements. Import decisions will also need to consider carbon-related trade measures, transport emissions, terminal conversion losses and the cost of domestic alternatives.

Figure 23 The delivery system as layered supply centers, corridors and ports



Note: Low-cost supply centers feed demand centers and ports through domestic corridors and international routes, underpinned by carbon accounting and certification rules. Illustrative.

Scaling China's hydrogen system is therefore not a choice between pipelines, ammonia and methanol. Each option should be assessed against its delivery scale, utilization, end-use requirements and total delivered cost. The objective is to develop a portfolio in which each carrier serves the applications to which it is best suited.

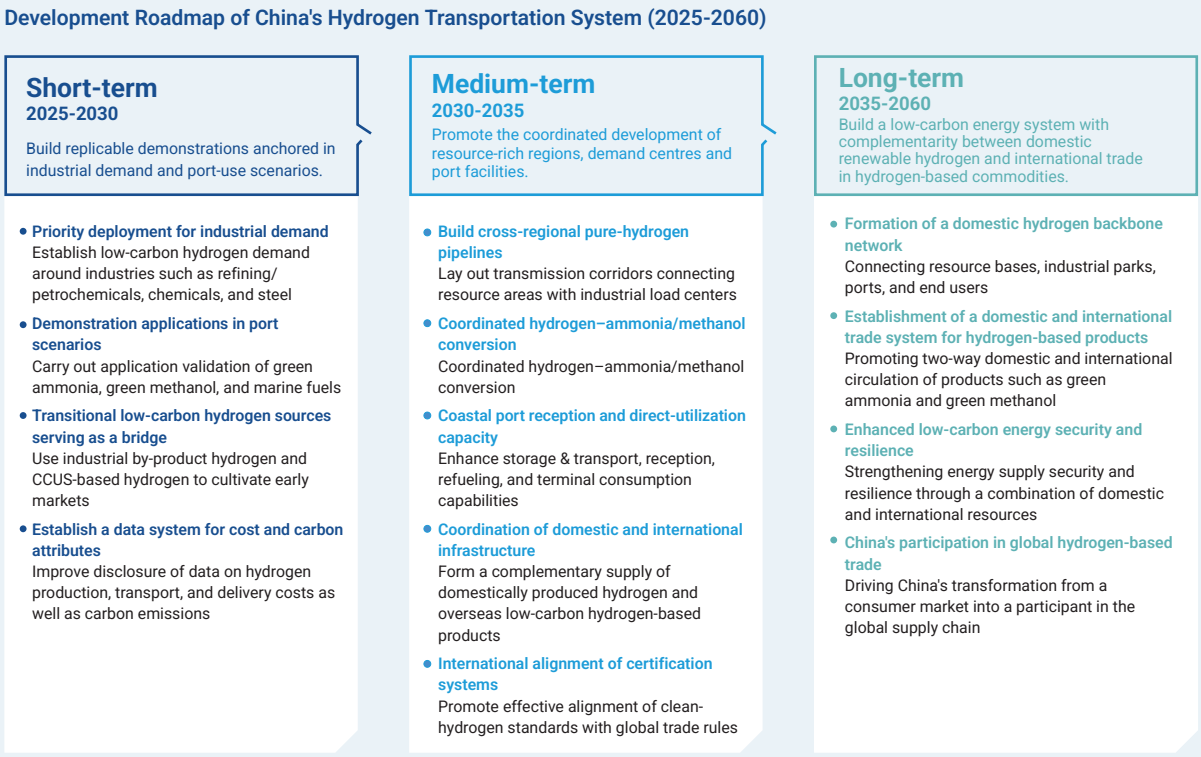
6.4 2025–2030: anchor demand before building

Between 2025 and 2030, China's hydrogen delivery system is expected to move from demonstration towards early commercial scale. Priority should be given to applications with stable demand, clear use cases, policy support and infrastructure that can be replicated or expanded.

Industrial demand can provide the initial baseload. Refining, ammonia, methanol, coal chemicals and steel combine large volumes with relatively continuous demand. These sectors are better suited to long-term offtake agreements than many transport demonstrations and can support investment in low-carbon hydrogen production, regional pipelines and ammonia or methanol conversion facilities. Resource-rich provinces can integrate renewable hydrogen with local chemical production, while demand centers can define substitution pathways, quality requirements and acceptable cost ranges.

Ports can test imported products and low-carbon fuels. The Bohai Rim, Yangtze River Delta and South China port clusters already possess energy-import, chemical-storage and marine-fuel infrastructure. They provide natural locations for demonstrating renewable and low-carbon ammonia and methanol in refining and chemical parks, shipping, port logistics, power generation and chemical feedstock substitution.

Figure 24 Three-phase delivery roadmap, 2025–2060



Note: Anchor demand with replicable demonstrations (2025–2030); connect resource regions, demand centers and ports (2030–2035); integrate a national network with two-way trade (2035–2060). Illustrative.

Transitional supply can support early market formation. Industrial by-product hydrogen, fossil-based hydrogen with effective carbon management, and imported low-carbon ammonia and methanol can support selected regions and applications while renewable hydrogen costs decline and pipeline networks develop. Their role should be clearly defined to avoid locking in emissions-intensive production.

Transparent data will be essential for scaling investment. Demonstration projects should report production, transport and delivered costs alongside carbon intensity, infrastructure utilization and contracted purchase prices. Reporting only investment, production volumes or vehicle deployment provides insufficient evidence for decisions on pipelines, port facilities and international procurement.

The near-term objective is not maximum deployment. It is to establish verifiable, replicable and scalable demand anchors that can support interregional pipelines, product-conversion projects and port import systems after 2030.

6.5 2030–2035: connect resource regions, demand centers and ports

Between 2030 and 2035, renewable hydrogen could enter a phase of larger-scale deployment, making the geographic mismatch between supply and demand increasingly visible. System development will need to move beyond individual projects towards coordinated infrastructure linking resource regions, demand centers, ports and terminals.

Demand-anchored pipelines can connect the largest markets. Interregional routes should focus on refining, chemicals, steel, heavy-duty transport and city-cluster demand. Potential priority corridors include:

- the "Three Norths" to the Bohai Rim and Beijing–Tianjin–Hebei;
- the northwest to industrial and port demand in the Yangtze River Delta; and
- resource-rich provinces to heavy-industry centers in central China.

Each trunk-line project should identify anchor users, expected throughput and utilization, third-party access arrangements and long-term offtake commitments before construction.

Conversion in resource regions can diversify delivery options. Not all renewable hydrogen produced in Inner Mongolia, Gansu, Qinghai, Ningxia and Xinjiang needs to be transported as pure hydrogen. Converting part of the supply into ammonia, methanol and other low-carbon products would enable delivery through existing rail, road, waterway and chemical-logistics networks. It could also reduce pressure on hydrogen pipelines and retain more value in producing regions.

Coastal ports can become integrated receiving and consumption hubs. Shandong, Jiangsu, Zhejiang, Guangdong, Fujian and Liaoning combine port infrastructure, industrial demand and international trading capabilities. Development should extend beyond import terminals to cover safe storage and handling, hazardous-chemical regulation, low-carbon fuel bunkering, local consumption, carbon-footprint tracking and links to third-party certification systems.

Imports and domestic supply should be planned as complements. Imported ammonia and methanol can serve coastal markets where domestic pipelines are unavailable, local production is expensive or demand develops ahead of infrastructure. At the same time, resource-rich regions with structural cost advantages may supply domestic or overseas markets with renewable ammonia, methanol and other low-carbon products. The emerging system could therefore combine domestic hydrogen pipelines, product shipments from inland resource regions and supplementary coastal imports.

Certification must support both domestic policy and international trade. Within China, certification can provide a basis for subsidies, public procurement and participation in carbon markets. For imports, it determines whether products meet domestic low-carbon thresholds; for exports, it is a prerequisite for access to markets such as Europe, Japan and Korea.

The medium-term objective is regional integration: connecting producers, infrastructure operators, ports and end users into an operational low-carbon hydrogen supply chain.

6.6 2035–2060: a national network with two-way trade

After 2035, China's hydrogen system enters multi-sector scaled application. Industry remains the largest base; transport, power-system flexibility, port fuels, low-carbon chemicals and long-duration storage expand further. China no longer needs demonstration projects or single trunk lines but a low-carbon energy system spanning domestic resource regions, coastal ports, international supply regions and diversified end-use demand.

First, form a national interregional hydrogen backbone network. As demand and pipeline load rates rise, dedicated pipelines expand from point-to-point projects into regional networks organized around resource regions, industrial parks, refining and steel bases, transport corridors and port nodes—evolving toward multi-source feed-in, multi-user absorption, multi-route allocation.

Second, build a domestic and international trading system for ammonia, methanol and other hydrogen-derived products. China's future participation in global hydrogen-derived trade should be two-way, calibrated to regional cost, demand, port capability and certification requirements—not one-way import or export.

Third, strengthen low-carbon energy security and resilience. Trade in hydrogen-derived products carries risks from shipping routes, prices, geopolitics and certification rules. China should avoid over-reliance on any single supplier country, product form or transport route, and build a supply pattern of domestic renewable hydrogen, imported green ammonia, green methanol, low-carbon ammonia and methanol, synthetic fuels and regional storage-and-transport systems that complement one another.

Fourth, move China from a demand market toward two-way participation. In the short-to-medium term, China is likely to remain an important import and end-use market for low-carbon hydrogen-derived products; over the longer term, selected resource regions of the northwest, north and northeast may also develop export potential for green ammonia, green methanol or synthetic fuels, if renewable power costs, ammonia and methanol conversion capacity, port export capability and international certification mature.

The long-term goal is a low-carbon energy network that is domestically and internationally complementary, multi-carrier, traceable and certifiable, and energy-security-resilient.

REFERENCES

[1] Department of Energy Conservation and Science & Technology Equipment, National Energy Administration; Department of Innovation and High-Tech Development, National Development and Reform Commission; Guoneng Hydrogen Innovation Technology Co., Ltd. China Hydrogen Development Report (2026) [R/OL]. Beijing: National Energy Administration, 2026. https://www.nea.gov.cn/20260811/de5edbfaa0de4df2897c2acdb0b62a4c/c.html

[2] Wang Y, Chao Q, Zhao L, et al. Assessment of wind and photovoltaic power potential in China [J]. Carbon Neutrality, 2022, 1: 15. https://doi.org/10.1007/s43979-022-00020-w.

[3] China Hydrogen Alliance. China Hydrogen Energy and Fuel Cell Industry White Paper 2020 [R]. 2020. https://www.chinahydrogen.org

[4] Sinopec. China Hydrogen Energy Industry Outlook Report [R]. 2023. http://edri.sinopec.com

[5] International Energy Agency. An Energy Sector Roadmap to Carbon Neutrality in China [R/OL]. Paris: IEA, 2021. https://www.iea.org/reports/an-energy-sector-roadmap-to-carbon-neutrality-in-china

[6] China Petrochemical Corporation (Sinopec). China's first "West-to-East Hydrogen Delivery" pipeline incorporated into the national plan [EB/OL]. 2023-04-11. https://www.sinopecgroup.com/group/000/000/044/44638.shtml.

[7] International Energy Agency. Global Hydrogen Review 2026 [R/OL]. Paris: IEA, 2026. https://www.iea.org/reports/global-hydrogen-review-2026.

[8] International Renewable Energy Agency. Analysis of the Potential for Green Hydrogen and Related Commodities Trade [R/OL]. Abu Dhabi: IRENA, 2025. https://www.irena.org/Publications/2025/Jun/Analysis-of-the-potential-for-green-hydrogen-and-related-commodities-trade.

[9] International Energy Agency. Global Hydrogen Review 2025 [R/OL]. Paris: IEA, 2025. https://www.iea.org/reports/global-hydrogen-review-2025.

[10] International Organization for Standardization. ISO/TS 19870:2023 Hydrogen Technologies—Methodology for Determining the Greenhouse Gas Emissions Associated with the Production, Conditioning and Transport of Hydrogen to Consumption Gate [S]. Geneva: ISO, 2023.

[11] European Commission. Commission Delegated Regulation (EU) 2023/1184 on Rules for the Production of Renewable Liquid and Gaseous Transport Fuels of Non-Biological Origin [Z/OL]. 2023. https://eur-lex.europa.eu/eli/reg_del/2023/1184/oj/eng.

[12] European Commission. Commission Delegated Regulation (EU) 2023/1185 on Greenhouse Gas Emissions Savings of Renewable Fuels of Non-Biological Origin and Recycled Carbon Fuels [Z/OL]. 2023. https://eur-lex.europa.eu/eli/reg_del/2023/1185/oj/eng.

[13] European Parliament and Council. Regulation (EU) 2023/956 Establishing a Carbon Border Adjustment Mechanism [Z/OL]. 2023. https://eur-lex.europa.eu/eli/reg/2023/956/oj/eng.

[14] Ministry of Economy, Trade and Industry (METI). Basic Hydrogen Strategy [R/OL]. Tokyo: METI, 2023. meti.go.jp/shingikai/enecho/shoene_shinene/suiso_seisaku/pdf/20230606_5.pdf

[15] Ministry of Trade, Industry and Energy (MOTIE). 1st Basic Plan for Implementing the Hydrogen Economy [R/OL]. Sejong: MOTIE, 2021. h2hub.or.kr/main/info/policy-industry-techinfo.do

[16] European Commission. REPowerEU Plan: Joint European Action for More Affordable, Secure and Sustainable Energy [R/OL]. Brussels: European Commission, 2022. eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM%3A2022%3A108%3AFIN

[17] Federal Ministry for Economic Affairs and Climate Action (BMWK). National Hydrogen Strategy 2023 and Import Strategy for Hydrogen and Hydrogen Derivatives [R/OL]. Berlin: BMWK, 2024. bmwk.de/Redaktion/DE/Wasserstoff/Dossiers/wasserstoffstrategie.html

[18] S&P Global Commodity Insights. S Korea to provide 27.9 mil mt/year of 'clean hydrogen' by 2050 [EB/OL]. 2021-11-26. spglobal.com/commodityinsights/pt/market-insights/latest-news/energy-transition/112621-s-korea-to-provide-279-mil-mtyear-of-clean-hydrogen-by-2050

[19] Energy Partnership Chile-Alemania. German Hydrogen Strategy [EB/OL]. 2025-06-10. energypartnership.cl/news/german-hydrogen-strategy-1

[20] National Development and Reform Commission; National Energy Administration. Medium- and Long-Term Plan for the Development of the Hydrogen Energy Industry (2021–2035) [R/OL]. 2022. https://www.ndrc.gov.cn/xxgk/zcfb/ghwb/202203/t20220323_1320038.html.

[21] International Energy Agency. The Future of Hydrogen [R/OL]. Paris: IEA, 2019. https://www.iea.org/reports/the-future-of-hydrogen.

[22] International Renewable Energy Agency. Global Hydrogen Trade to Meet the 1.5°C Climate Goal: Part II—Technology Review of Hydrogen Carriers [R/OL]. Abu Dhabi: IRENA, 2022. https://www.irena.org/publications/2022/Apr/Global-hydrogen-trade-Part-II.

[23] International Energy Agency. Ammonia Technology Roadmap: Towards More Sustainable Nitrogen Fertiliser Production [R/OL]. Paris: IEA, 2021. https://www.iea.org/reports/ammonia-technology-roadmap.

[24] International Maritime Organization. 2023 IMO Strategy on Reduction of GHG Emissions from Ships [R/OL]. London: IMO, 2023. https://www.imo.org/en/ourwork/environment/pages/2023-imo-strategy-on-reduction-of-ghg-emissions-from-ships.aspx.

[25] Global Maritime Forum. At a Crossroads: Annual Progress Report on Green Shipping Corridors 2025 [R/OL]. Copenhagen: Global Maritime Forum, 2025. https://globalmaritimeforum.org/report/annual-progress-report-on-green-shipping-corridors-2025/.

[26] Customs Tariff Commission of the State Council. Announcement on the 2026 Tariff Adjustment Plan (Announcement No. 11 of 2025) [EB/OL]. 2025-12-26. https://gss.mof.gov.cn/gzdt/zhengcefabu/202512/t20251229_3980625.htm.

[27] General Administration of Customs. Announcement on the List of Commodities Not Fully Subject to the 9% Import VAT Rate [EB/OL]. 2026. https://www.customs.gov.cn/customs/2026-02/04/article_2026020408531755120.html.

[28] General Office of the Ministry of Ecology and Environment; General Department of the National Energy Administration. Methodology for Greenhouse Gas Voluntary Emission Reduction Projects: Hydrogen Production from Water Electrolysis Using Renewable Energy (CCER-01-004-V01) [S/OL]. 2025. https://www.mee.gov.cn/xxgk2018/xxgk/xxgk06/202512/t20251226_1139056.html.

[29] National Energy Administration. China Green Fuels Development Report (2026) [R/OL]. 2026. https://www.nea.gov.cn/20260805/f8df6964aed44f12a70e27fefa762b9d/c.html

ANNEX

HOW WE DID IT
—SCOPE, METHOD AND ASSUMPTIONS

A.1 Research scope and methodology

The study covers China's medium- and long-term hydrogen transport pathways and global hydrogen trade—renewable production, inland transport, end-use demand matching, hydrogen-derived imports—across macro energy-system judgment, spatial supply–demand matching, techno-economic route assessment and scenario comparison.

A.2 Scenario design

Scenario axes: demand scale, supply structure, transport distance, infrastructure utilization and terminal product form.

- Demand scenarios. 2035: low-carbon substitution of existing industrial demand, regional pipelines, port demonstrations; 2060: large-scale renewable hydrogen across industry, transport, power flexibility, green fuels.
- Supply scenarios. Fossil-based, blue-transition, renewable-dominant and imported-derivative combinations, compared on relative economics under different supply-cost assumptions.
- Transport scenarios. Domestic interregional routes of 1,000–2,500 km and beyond; representative Middle East–China ocean distances; unit costs for pipeline, ammonia and methanol.
- Terminal-form scenarios. High-purity hydrogen costed to end use after recovery, purification and compression; ammonia and methanol entering chemical, fuel or port applications.
- Techno-economic comparisons under stated assumptions, not forecasts; geopolitical risk, regulation, financing, commercial strategy, land approvals, public acceptance and safety enforcement are excluded.
- Cost parameters change rapidly; results should be updated as new data emerge.

A.3 Supply–demand structure: data and models

Coverage: demand in industry, transport, power and buildings; supply potential and cost by technology at 1 km.

Renewable hydrogen supply potential module. Land-cover and elevation data at 1 km identify candidate grids under land-use and terrain constraints; wind and solar suitability reflects land-use regulations, ecological protection, socio-economic conditions and cost-decline trends; offshore wind uses water depth and vessel-density data within China's exclusive economic zone; nature reserves, ecological-function zones and poor-resource areas are excluded.

Wind technical potential. Capacity factors from hourly ERA5 wind speeds (0.25°, 1-hour), hub-height extrapolation (power-law), air-density correction; turbines Gold Wind 155-4.5 MW (onshore), Gold Wind 175-8.0 MW (offshore). Equations (1)–(4): installed potential and annual generation per grid cell—P installed capacity, E annual generation, P_rated rated power, D rotor diameter, A_i area, s suitability coefficient, CF capacity factor (2018–2020); spacing per model parameters.

Equation (1): onshore wind installed potential $C_n^{\text{onshore}} = \frac{P_r^{\text{onshore}}}{3D_{\text{onshore}} \times 10D_{\text{onshore}}} A_n S_n$

Equation (2): onshore wind annual generation $E_n^{\text{onshore}} = C_n^{\text{onshore}} \times 8760 \times \overline{cf}_n^{\text{onshore}}$

Equation (3): offshore wind installed potential $C_n^{\text{offshore}} = \frac{P_r^{\text{offshore}}}{5D_{\text{offshore}} \times 10D_{\text{offshore}}} A_n S_n$

Equation (4): offshore wind annual generation $E_n^{\text{offshore}} = C_n^{\text{offshore}} \times 8760 \times \overline{cf}_n^{\text{offshore}}$

Solar technical potential. PV capacity factors from hourly ERA5 solar radiation; equation (5): installed potential and annual generation per grid—λ layout coefficient (panel area over suitable land), q module peak power (161.9 MW/km²), CF capacity factor (2018–2020).

Equation (5): solar PV installed potential $C_n^{\text{PV}} = PF_n P_0^{\text{PV}} A_n S_n$

Equation (5b): solar PV annual generation $E_n^{\text{PV}} = C_n^{\text{PV}} \times 8760 \times \overline{cf}_n^{\text{PV}}$

Renewable hydrogen technical potential and levelized cost. ALK and PEM electrolysis for wind and solar. Equations (7) and (8): hydrogen technical potential (grid i, renewable r, electrolyser e) and LCOH; LCOE and CRF separate. LHV lower heating value, η electricity-to-hydrogen efficiency, CAPEX/OPEX investment and O&M costs, r discount rate, N project lifetime. Renewable and electrolyser parameters are exogenous for 2035 and 2060, reflecting learning and scale.

Equation (7): renewable hydrogen technical potential $M_n^{i,t} = \frac{E_n^i \eta^t}{q}, \forall i \in I, \forall t \in T$

Equation (8): levelized cost of hydrogen (LCOH) $LCOH_n^{i,t} = \frac{CAPEX^{H_2,t} CRF^i C_n^i + OPEX^{H_2,t} C_n^i + LCOE_n^i E_n^i}{M_n^{i,t}}, \forall i \in I, \forall t \in T$

Levelized cost of electricity (LCOE) $LCOE_n^{i,t} = \frac{CAPEX^i CRF^i C_n^i + OPEX^{H_2,t} C_n^i}{E_n^i}, \forall i \in I$

Capital recovery factor (CRF) $CRF = \frac{(1+r)^m r}{(1+r)^m - 1}$

Table 10 Techno-economic parameters used in the supply module

Parameter	Year	Onshore wind	Solar PV	ALK	PEM
Unit investment (USD/kW)	2025	713	515	275	1,000
	2035	618	338	230	500
	2060	527	221	187	214
O&M cost (% of unit investment)	All years	1.5	1	2.5	2.5
Technology / project lifetime	2025	20 yr	25 yr	60,000 h	45,000 h
	2035	20 yr	25 yr	71,428 h	60,714 h
	2060	20 yr	25 yr	100,000 h	100,000 h
Electrolysis efficiency (%)	2025	–	–	60	65
	2035	–	–	64	69
	2060	–	–	75	80
Discount rate (%)	All years	8	8	8	8

A.4 End-use hydrogen demand: structure and potential

Industrial demand. Plant-level database of ammonia synthesis, refining, methanol, coal-to-liquids, coal-to-gas, coal-to-olefins and coal-to-ethylene-glycol: about 2,400 point sources with location, capacity and techno-economic attributes. Facility-level demand (facility i, sector s, node n): D hydrogen demand, C design capacity, U utilization rate, k specific consumption per unit of product.

Industrial hydrogen demand $DMD_{k,g,l} = CAP_{k,g,l}\, AF_{k,g,l}\, \omega_{k,g,l}$

Road-transport demand. Freight and passenger demand follows the China Hydrogen Alliance's 2060 national road-transport hydrogen consumption (base scenario), allocated to provinces by vehicle stock and to hubs from 1 km GDP-grid data.

China SHINE framework. Provincial supply and demand distinguish fossil-based, industrial by-product, blue and renewable hydrogen, and refining, ammonia, methanol, steel, transport, power flexibility and green-fuel demand; off-grid or grid-connected wind and solar set provincial renewable potential and cost ranges. China SHINE (Tsinghua University, Prof. Wenying CHEN) combines renewable supply potential, end-use demand potential and shared transport network modules.

Domestic corridor identification. Three route families: medium-to-long-distance routes from the “Three Norths” to the Bohai Rim and Beijing–Tianjin–Hebei; ultra-long-distance from the northwest to the Yangtze River Delta; interregional allocation from Xinjiang, Qinghai and Inner Mongolia to Sichuan–Chongqing, Shandong, Shanxi and Guangdong.

A.5 Techno-economic assessment of long-distance transport

Dedicated hydrogen pipelines: cost covers construction, compressor stations, terminals, O&M, compression electricity, utilization, discount rate and lifetime; unit cost driven by annualized capital, O&M and throughput, highly sensitive to load rate.

Ammonia and methanol routes: domestic cost covers renewable hydrogen production, synthesis, storage, loading, rail/road/waterway transport, terminal receiving and, where needed, cracking/reforming and purification; direct terminal use keeps the boundary short, high-purity hydrogen adds reforming, purification and compression.

International trade routes: landed cost of liquid ammonia and methanol = FOB price, ocean freight, port charges, insurance, import duty, VAT and possible carbon cost; hydrogen-equivalent conversion applies hydrogen content, conversion efficiency and terminal processing cost.

A.6 Delivered-cost model and key assumptions: electrolysis hydrogen production

Table 11 Base-case parameters of the electrolysis hydrogen production cost model

Category	Parameter	Value	Unit
I. Base operating parameters	Electrolyser type	ALK	—
	Rated gas output per electrolyser	1,000	Nm³/h
	Installed scale	5	MW
	Annual operating hours	3,100	h/yr
	Annual load factor	90.0	%
	Specific electricity consumption	4.5	kWh/Nm³
	Transformer and rectifier efficiency	96.5	%
II. Investment parameters	Equipment price	500	RMB 10,000/unit (RMB 5.0 million per set)
	Civil works and ancillary unit investment	1,200	RMB/kW
	Other comprehensive charge rate	15.0	%
III. Process parameters	Hydrogen outlet pressure	1.6	MPa
	Auxiliary electricity consumption	0.15	kWh/Nm³
	Pure-water consumption	0.9	t per 1,000 Nm³
	Cooling-water consumption	15	t per 1,000 Nm³
IV. Operating-cost parameters	Industrial electricity price	0.15	RMB/kWh
	Pure-water unit price	7.5	RMB/t
	Cooling-water unit price	1.0	RMB/t
	Annual operation and maintenance	45	RMB 10,000/yr (RMB 450,000/yr)
	Major-repair reserve rate	2.5	%/yr
	Management cost rate	5.0	%
V. Depreciation and project cycle	Project operating life	20	yr
	Equipment depreciation life	10	yr
	Civil-works depreciation life	20	yr
	Residual-value rate	5.0	%
VI. Carbon accounting and carbon assets	Grid emission factor	0.03	kgCO2e/kWh
	Custom emission factor	0	kgCO2e/kWh
	Equipment embodied carbon	0.8	kgCO2e/kg H2
	CO_2 price	75	RMB/t
VII. Full production cost (incl. depreciation)	Electricity unit cost	7.84	RMB/kg
	Water unit cost	0.076	RMB/kg
	Cooling unit cost	0.169	RMB/kg
	O&M unit cost	1.81	RMB/kg
	Depreciation unit cost	3.06	RMB/kg
	Full hydrogen production cost	12.96	RMB/kg

A.7 Transport combined model

Terminal combined cost applies the whole-chain delivered-cost basis: production + conversion + storage + transport + terminal processing.

- Dedicated hydrogen pipeline: delivered cost = production + storage + pipeline transport, covering construction depreciation, O&M, compression energy and throughput amortization.
- Ammonia reconversion route: delivered cost = production + synthesis + storage + liquid-ammonia transport + terminal reconversion; advantage: liquid ammonia's energy density and logistics; constraint: source synthesis (about RMB 5.9/kg H_2), terminal reconversion (about RMB 6.9/kg H_2).
- Direct-use ammonia route: delivered cost = production + synthesis + storage + liquid-ammonia transport, without terminal reconversion.
- Electricity-price sensitivity. At RMB 0.15/kWh, production cost is about RMB 13/kg H_2; each RMB 0.05/kWh rise adds about RMB 2.6/kg H_2, raising all routes without altering the route ordering.

A.8 Renewable electricity and hydrogen production potential

Table 12 Renewable electricity resources and their hydrogen production potential

Type	Technical developable capacity	Equivalent full-load hours	Annual generation	ALK hydrogen output	PEM hydrogen output
Onshore wind	8,694 GW	1,979 h/yr	17.21 trillion kWh/yr	~0.331 billion t H_2/yr	~0.351 billion t H_2/yr
Offshore wind	2,254 GW	1,979 h/yr	4.46 trillion kWh/yr	~0.086 billion t H_2/yr	~0.091 billion t H_2/yr
Solar PV	45,600 GW	1,088 h/yr	49.61 trillion kWh/yr	~0.954 billion t H_2/yr	~1.013 billion t H_2/yr
Total	56,548 GW	—	71.28 trillion kWh/yr	~1.371 billion t H_2/yr	~1.455 billion t H_2/yr

Note: Onshore and offshore wind equivalent full-load hours are shown as printed in the source data.

A.9 Vessel parameters for transoceanic trade

Representative vessels: Kawasaki 82,416 m³ VLGC; Hyundai Heavy Industries Eletson-series.

Table 13 Vessel and shipping parameters

Parameter	Liquid ammonia	Methanol	Unit
Typical vessel type	80,000–84,000 m³ VLGC	51,600–51,900 DWT MR	—
Cargo per vessel	50,000 t NH_3	40,000 t MeOH	t
One-way sailing distance	6,000	6,000	nautical miles
Laden service speed	16.0	14.5	knots
Port stay incl. loading and discharge (round trip)	5.0	4.0	days
At-sea fuel consumption	45	25–31	t/day
In-port fuel consumption	8	3	t/day

Parameter	Liquid ammonia	Methanol	Unit
VLSFO price	650	650	USD/t
Fuel CO_2 emission factor	3.114	3.114	tCO_2/t fuel
Carbon price	0	0	scenario carbon price
Daily vessel cost (excl. fuel)	50,000	30,000	USD/day
Port charges	8	8	USD/t
Other logistics costs	1.5	1.5	USD/t
Base cargo insurance rate	0.20%	0.20%	—

A.10 Generic CO_2 emission factors

Table 14 Generic emission factors for hydrogen and hydrogen-derived products

Product	Main production route	Typical range	Recommended value for cost model
Grey hydrogen	Natural-gas steam reforming, no CCUS	10–12	11.0
Grey hydrogen	Coal gasification, no CCUS	22–26	24.0
Renewable hydrogen	Electrolysis with renewable electricity	0.4–2.7	1.5
Grey ammonia	Natural-gas-based hydrogen + ammonia synthesis	1.8–2.6	2.2
Grey ammonia	Coal-based hydrogen + ammonia synthesis	3.8–4.8	4.2
Green ammonia	Green hydrogen + renewable-powered synthesis	0.2–0.5	0.3
Grey methanol	Natural-gas methanol	0.5–1.1	0.8
Grey methanol	Coal methanol	2.6–3.8	3.2
Green methanol	Green hydrogen + biogenic or DAC CO_2	0.2–0.8	0.4

Note: Units: hydrogen factors in $kgCO_2e/kg\ H_2$; product factors in tCO_2e/t product. These are model references, not statutory defaults under Chinese or EU CBAM rules: hydrogen (IEA, Global Hydrogen Review 2024); ammonia (IEA, Ammonia Technology Roadmap; Argonne life-cycle study); methanol (IRENA, Innovation Outlook: Renewable Methanol; IEAGHG life-cycle studies).

A.11 Current CBAM certificate prices

Table 15 CBAM certificate prices by quarter, 2026

Corresponding import quarter	CBAM certificate price
Q1 2026	EUR 75.36/tCO_2e
Q2 2026	EUR 75.28/tCO_2e
Q3 2026	To be published by Oct 05, 2026
Q4 2026	To be published by Jan 04, 2027

A.12 China reference carbon prices

Table 16 China reference carbon prices

Indicator	Price
National ETS CEA closing price (17 August 2026)	RMB 97.60/tCO_2e
Closing price (14 August 2026)	RMB 98.21/tCO_2e
2025 annual average	RMB 62.36/tCO_2e
End-2025 closing price	RMB 74.63/tCO_2e
2025 national average CCER price	RMB 70.76/tCO_2e

Note: Historical reference values as of the dates shown; refresh before final release.

Historical reference values as of the dates shown; refresh before final release.

A.13 Boundary parameters for carbon border adjustment on ammonia and methanol landed costs

Table 17 Carbon-border-adjustment boundary parameters — ammonia routes

Ammonia route	Reference price excluding carbon (USD/t product)	Emission factor (tCO_2e/t product)	Corresponding FOB (USD/t product)
Coal-based	300.00	4.20	300
Natural-gas-based	497.95	2.20	400
Renewable-based	724.40	0.30	600
Ammonia-to-H_2 route	**Reference price excluding carbon (USD/kg H_2)**	**Emission factor ($kgCO_2e$/kg H_2)**	**Corresponding FOB (USD/t product)**
Coal-based	4.5	24	300
Natural-gas-based	3.99	11	400
Renewable-based	5.35	2.4	600

Note: Units: hydrogen-equivalent costs in USD/kg H_2; emission intensity in $kgCO_2e$/kg H_2; FOB prices in USD/t product.

Table 18 Carbon-border-adjustment boundary parameters — methanol routes

Methanol route	Reference price excluding carbon (USD/t product)	Emission factor (tCO_2e/t product)	Corresponding FOB (USD/t product)
Coal-based	370.00	3.20	370
Natural-gas-based	376.62	0.80	300
Renewable-based	1,055.00	0.40	1,000
Methanol-to-H_2 route	**Reference price excluding carbon (USD/kg H_2)**	**Emission factor ($kgCO_2e$/kg H_2)**	**Corresponding FOB (USD/t product)**
Coal-based	4.5	24	370
Natural-gas-based	3.17	11	300
Renewable-based	7.53	2.4	1,000

Note: Units as for the ammonia table above.

International Hydrogen Fuel Cell Association

IHFCA is an international non-profit organization dedicated to advancing global hydrogen energy and fuel cell collaboration, industrialization, and commercialization.

GLOBAL HYDROGEN NETWORK



Global Governance

KAMA 한국자동차모빌리티산업협회 · H2KOREA Korea Hydrogen Alliance · ahp African Hydrogen Partnership · AUSTRALIAN HYDROGEN COUNCIL · Ivoire Hydrogène · GH2

Research & Academic

Centre for Advanced Structural Materials · 上海氢能利用工程技术研究中心

Source: IHFCA

Websit: https://www.ihfca.net/

INTERNATIONAL HYDROGEN FUEL CELL ASSOCIATION

International Hydrogen Fuel Cell Association (IHFCA)

This work reflects the views of the IHFCA Secretariat but does not necessarily reflect those of IHFCA's individual member organizations or of any particular funder or collaborator. The work does not constitute professional advice on any specific issue or situation. The IHFCA makes no representation or warranty, express or implied, in respect of the work's contents (including its completeness or accuracy) and shall not be responsible for any use of, or reliance on, the work. For enquiries or corrections, please contact the IHFCA Secretariat.

International Hydrogen Fuel Cell Association (IHFCA)

Website: www.ihfca.net

IHFCA Secretariat: +86 (0)10 5091 1068 | IHFCA@ihfca.net

Address: Level 2, Xingzhi Building, No. 37 Rongxing North 3rd Street, Beijing Economic and Technological Development Zone, Beijing, China

Contact information:
www.ihfca.net/web/ContactUs.aspx



Download Report

UNITED NATIONS
INDUSTRIAL DEVELOPMENT ORGANIZATION

Vienna International Centre
Wagramerstr. 5, P.O. Box 300,
A-1400 Vienna, Austria
+43 1 26026-0
www.unido.org
unido@unido.org

INTERNATIONAL HYDROGEN FUEL CELL ASSOCIATION

Level 2, Xingzhi Building,
No.37 of Rongxing North 3rd Street, Beijing Economic and Technological Development Zone, Beijing.
+86 (0)10 5091 1068
www.ihfca.net
ihfca@ihfca.net

aramco

Floors 43/45, F20-26, China World Tower,
No.1 Jianguomen Outer Street, Chaoyang District, Beijing
+86 (0)10 8590 5900
china.aramco.com
+86 (0)10 8535 1875