



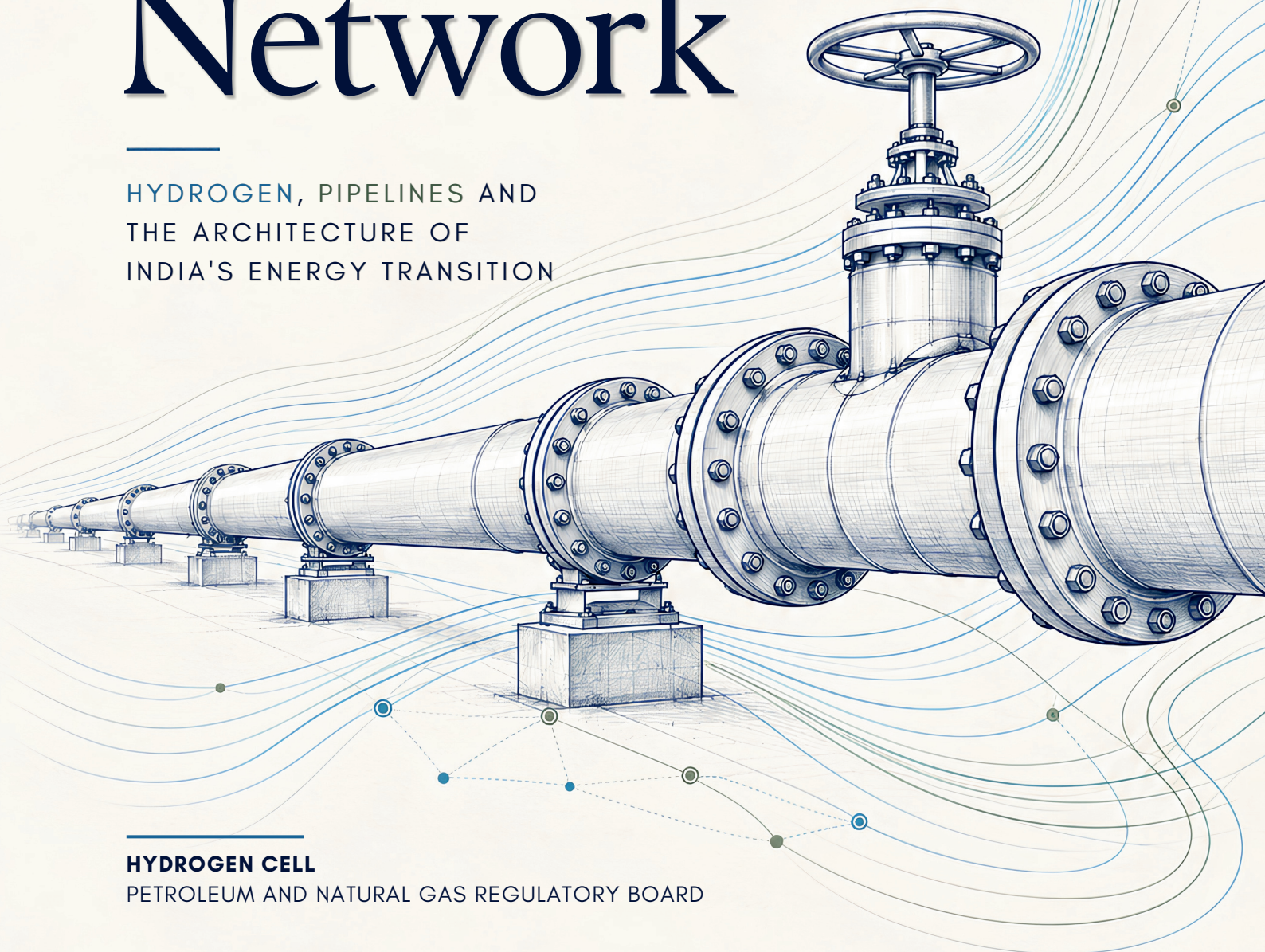
पेट्रोलियम एवं प्राकृतिक गैस
विनियामक बोर्ड
**PETROLEUM AND
NATURAL GAS**
REGULATORY BOARD

The Molecule and the Network

HYDROGEN, PIPELINES AND
THE ARCHITECTURE OF
INDIA'S ENERGY TRANSITION

HYDROGEN CELL

PETROLEUM AND NATURAL GAS REGULATORY BOARD







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Government of India
Ministry of New and Renewable Energy



Message

India stands at the threshold of a transformative energy transition driven by clean energy, innovation and self-reliance. The National Green Hydrogen Mission, launched with an outlay of ₹19,744 crore, seeks to position India as a global hub for the production, utilization and export of green hydrogen while contributing to decarbonization, energy security and sustainable economic growth. The Mission envisions the creation of a complete green hydrogen ecosystem encompassing production, storage, transportation, distribution, application and export.

As India advances towards its green hydrogen ambitions, development of safe, efficient and affordable transportation infrastructure will be critical. The ability to connect production centres with industrial, commercial and mobility applications through a robust hydrogen value chain will determine the pace and scale of adoption. In this regard, the efforts being undertaken to examine hydrogen transportation through pipelines and blending with natural gas are both timely and significant.

The publication provides a comprehensive perspective on the technical, regulatory and infrastructure dimensions of hydrogen transportation. It highlights the opportunities and challenges associated with integrating hydrogen into India's evolving energy system and contributes valuable insights for policymakers, regulators, industry and researchers.

I commend the Petroleum and Natural Gas Regulatory Board (PNGRB) and its Hydrogen Cell for their proactive efforts in advancing pilot projects, technical studies, regulatory preparedness and stakeholder engagement in this emerging field. Such initiatives will play an important role in enabling a safe, resilient and future-ready hydrogen ecosystem aligned with the objectives of the National Green Hydrogen Mission.

I am confident that this publication will serve as a useful reference for all stakeholders working towards building a sustainable hydrogen economy and realizing India's vision of becoming a global leader in clean energy.

(Santosh Sarangi)

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FOREWORD

India's energy transition will be shaped not only by the fuels it produces, but by the systems through which these fuels are transported, measured, priced and delivered safely to consumers. Green hydrogen has emerged as an important part of this transition, yet production targets alone cannot create a hydrogen economy. Between the point of production and the point of use lies an infrastructure question, and for a country with a large and expanding natural gas network, that question has direct relevance to the Petroleum and Natural Gas Regulatory Board.

The Molecule and the Network addresses this question with clarity. It neither treats hydrogen blending as an end in itself, nor assumes that existing pipelines can be converted simply because a molecule can physically enter them. It examines the network as a system. The practical limit of hydrogen in a network may not be set by the pipe alone, but by the least compatible component or consumer connected to it.

Hydrogen is expected to play a significant role in India's energy future. India aims to become energy independent by 2047 and achieve net zero by 2070, and the National Green Hydrogen Mission has provided direction and scale to this ambition. Across the world, hydrogen is increasingly being considered as a means to complement electrification, decarbonise hard-to-abate sectors, store renewable energy and strengthen energy security. India must therefore prepare not only to produce hydrogen, but also to move, store and use it safely and economically.

For PNGRB, this requires looking ahead. Networks, standards, metrology, safety systems and regulatory frameworks cannot be afterthoughts. They must evolve alongside technology and market development, supported by Indian evidence and anchored in clear legal authority. A transition is credible only when engineering, economics and regulation move forward together.

Such preparation does not mean attempting to predict the market in detail. It means reducing avoidable uncertainty, building evidence before decisions become urgent, and keeping sound options open as technology and markets evolve. Technical readiness cannot substitute for legislation, just as legislation cannot substitute for engineering evidence.

This publication is a timely contribution. I hope it will encourage informed discussion among policymakers, regulators, industry, academia and the technical community, and support the careful development of a hydrogen ecosystem that is safe, efficient, transparent and suited to Indian conditions.

I commend Shri Muktikam Phukan, Director (Admin/HR & Coordination/Hydrogen), and Shri Farhan Akhter, Assistant Consultant, Hydrogen Cell, for conceptualising and developing this publication. Their sustained work in bringing together technical evidence, regulatory questions and the institutional record has produced a document of lasting value to PNGRB and the wider energy sector.

(Jayanta Narayan Das)
Member (Technical), PNGRB





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Ministry of New and Renewable Energy

MESSAGE

India's energy transition will be defined not only by how clean energy is produced, but also by how effectively it is transported, integrated, and delivered to the sectors that need it most. The National Green Hydrogen Mission was launched with the vision of positioning India as a global hub for the production, utilization and export of green hydrogen, while accelerating industrial decarbonization, enhancing energy security, and fostering long-term economic growth. The success of this vision depends on the development of reliable infrastructure capable of connecting production centres with end users at scale.

In this context, hydrogen transportation assumes strategic importance. While green hydrogen production technologies are advancing rapidly, the challenge of moving hydrogen safely, efficiently and economically remains central to its widespread adoption. Existing natural gas infrastructure, hydrogen blending initiatives, dedicated pipeline development and supporting regulatory frameworks together constitute the foundation upon which a future hydrogen economy will be built.

The publication makes an important contribution to this discussion by examining the technical, commercial, regulatory and institutional dimensions of hydrogen transportation through pipelines and blending with natural gas. It highlights both the opportunities and the complexities associated with integrating hydrogen into existing energy networks and underscores the importance of evidence-based policymaking and regulatory preparedness.

I mention the efforts of the Petroleum and Natural Gas Regulatory Board, particularly its Hydrogen Cell, in undertaking pioneering work through pilot projects, technical studies, development of the Roadmap on Hydrogen Transportation and Blending with Natural Gas, international collaborations, and the creation of a broader ecosystem of stakeholders. These initiatives complement the objectives envisaged under the National Green Hydrogen Mission and contribute significantly towards building the institutional and technical readiness required for a hydrogen-powered future.

As India advances towards its green hydrogen ambitions, collaboration among ministries, regulators, industry, academia and technology providers will be essential. The pathway ahead will require innovation, rigorous safety standards, infrastructure investments and sustained stakeholder engagement. Equally important will be the ability to translate emerging knowledge into practical solutions that can be deployed at scale.

I am confident that this publication will serve as a valuable reference for policymakers, regulators, industry leaders, researchers and all those interested in shaping India's hydrogen ecosystem. I congratulate the authors and the PNGRB Hydrogen Cell for bringing together a thoughtful and timely work on a subject that will play a defining role in India's clean energy journey.

30.9.26
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MESSAGE

As PNGRB marks its twentieth year, it does so having worked for two decades to create an orderly, transparent and competitive framework for petroleum, petroleum products and natural gas infrastructure, while protecting consumer interests and supporting the development of a modern energy market. The next phase of India's energy transition will require the same institutional discipline to be applied to technologies and energy carriers that are still evolving.

Hydrogen is one such area. The National Green Hydrogen Mission has given the country a clear strategic direction, but achieving scale will depend on more than production. Hydrogen must reach users safely and economically; infrastructure must be compatible; technical standards must be tested; commercial arrangements must be transparent; and responsibilities among institutions must be clearly understood. Hydrogen is therefore as much a subject of coordination and governance as of technology.

The Molecule and the Network places these issues in one connected narrative. It begins with a simple question, "How will the molecule move?", and follows it through energy security, international experience, pipeline and end-use compatibility, blending, tariff treatment, infrastructure sequencing and the statutory framework. In doing so, it illustrates a principle central to good regulation: a technical decision rarely remains only technical once it enters a regulated network. Measurement becomes billing; equipment compatibility becomes safety; capital expenditure becomes tariff; and infrastructure planning becomes a question of access, investment and public interest.

Regulation for an emerging sector cannot assume that every uncertainty is already resolved, nor can preparation wait until a market has formed. Preparation, however, is only as durable as the institutional knowledge behind it. Studies, pilots, committee deliberations, international engagements and regulatory proposals are most useful when their lessons are organised, preserved and made accessible to those who will take the work forward. This publication therefore serves not merely as a record of activity, but as a bridge between experience already gained and decisions yet to be taken, and it should help younger professionals understand how regulatory institutions prepare for technological change.

I congratulate the Hydrogen Cell and all officers, experts, organisations and stakeholders whose work has contributed to the knowledge reflected in these pages. I trust that *The Molecule and the Network* will be read in the constructive spirit in which it has been prepared: as an invitation to examine difficult questions carefully, distinguish evidence from assumption, and build India's hydrogen infrastructure on the foundations of safety, sound regulation, institutional cooperation and consumer confidence.

(Anjan Kumar Mishra)

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(including Foreword by Dr. Anil Kumar Jain, Chairperson, PNGRB)

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About the Authors

Acknowledgement

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We acknowledge the Scientific Advisory Committee constituted by the Board on hydrogen blending, and its Chairman, Shri Mukesh Mohan, Executive Director, Indian Oil Corporation Limited. The Committee's deliberations, and the judgement its members brought from industry, research institutions and academia, shaped much of the evidence examined in this book.

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Finally, we acknowledge the officers, consultants and staff of PNGRB, whose work, experience and institutional knowledge provide the foundation on which much of this publication rests.

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Preface

India's green-hydrogen ambition is usually expressed in tonnes. This book begins with a different question: how will the molecule move from where it can be produced to where it will be used? Clause 6.4 of the National Green Hydrogen Mission places the Ministry of Petroleum and Natural Gas and PNGRB in the pathway for green-hydrogen uptake in refineries and city gas distribution. Yet the Board's statutory powers remain those conferred by the PNGRB Act, 2006, over petroleum, petroleum products and natural gas. The work is assigned; the full hydrogen-specific authority is not. The space between those two facts is what this book examines.

In July 2026, the Hydrogen Cell published a Knowledge Paper on hydrogen transportation through pipelines and blending with natural gas, and the Chairperson directed that the enquiry be carried further. What began as an expansion became a longer enquiry into what must exist before the molecule can reach a consumer at all.

Part I begins with movement, then turns to vulnerability and historical precedent. It asks what the March 2026 Gulf disruption revealed about a gas system meeting close to half its demand from imported LNG, and what the shock of 1973 built and failed to build. The evidence bears directly on self-reliance. Allocation between sectors could change within days; the physical network could not, and a household protected in its volume of gas was not protected in what it paid. Part II turns to evidence: how far operating experience abroad can be transferred to India, and where Indian materials and conditions require Indian testing.

Part III takes up three practical dilemmas. Where should hydrogen be blended? The answer depends not simply on the pipe, but on the assets and consumers downstream. Who should pay? Engineering can identify where a cost arises; tariff and funding rules determine where it ultimately falls. Who builds first? Infrastructure waits for demand, demand waits for infrastructure, and investment waits for confidence in both. At low blend ratios, hydrogen contributes only a small share of delivered energy. Its near-term value therefore lies less in large-scale decarbonisation than in providing early offtake, operational evidence and market formation while larger direct uses develop.

Part IV turns to what PNGRB has built since 2021: pilots, studies, a Roadmap, proposed guidelines, testbed programmes and an institutional process for converting evidence into regulatory preparation. It ends with the statutory boundary. Technical evidence can tell a regulator what may be safe or workable. It cannot enlarge the statute under which that regulator acts. That distinction between readiness and authority is where the argument concludes.

The evidence base is primarily the Board's record: pilot clearances, MIS and Bulletin data, the Pathways study, the Roadmap and the regulations in force, supplemented by international standards, operating experience and research. Quantitative claims are sourced, with derived calculations set out in Notes after the relevant chapter references. The book is current to September 2026. Other hydrogen carriers, underground storage and production economics appear only where they bear directly on transport. The earlier Knowledge Paper is reproduced as an Annexure.

This is a work of analysis prepared within the Hydrogen Cell. It draws on the Board's institutional record but is not a statement of Board policy, and nothing in it prejudices any proposal, authorisation or regulation the Board may consider. When a new molecule enters an existing network, the molecule and the architecture around it have to be settled together.

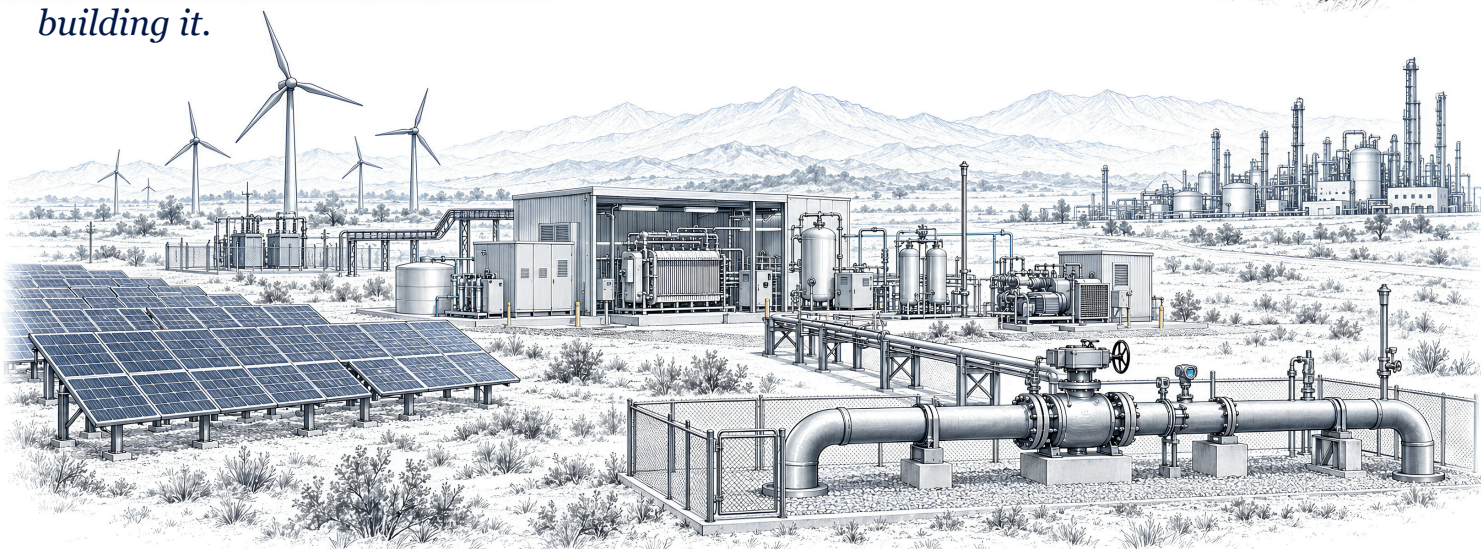
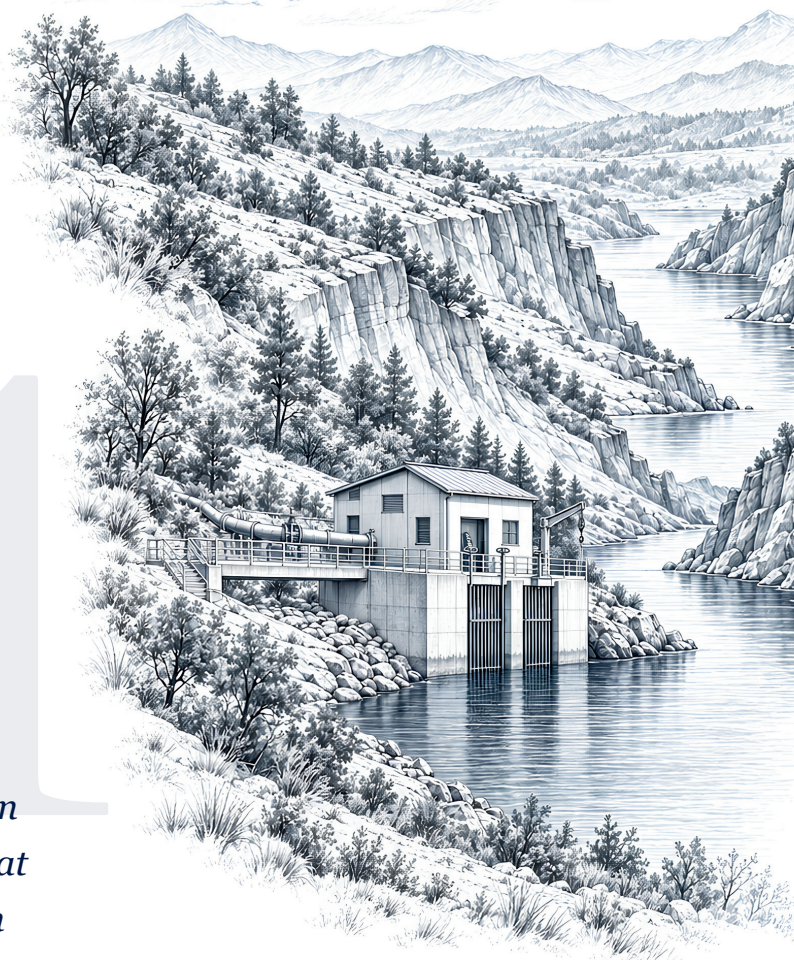
PART I

THE QUESTION



The Molecule With Nowhere To Go

Green hydrogen needs renewable power, water, and somebody who wants it. In India those three sit in different places. Clause 6.4 of the National Green Hydrogen Mission points to the regulatory bridge that must connect them and to PNGRB's role in building it.



The hard part of green hydrogen is not making it. It is moving it.

The National Green Hydrogen Mission, approved by the Union Cabinet in January 2023 with an outlay of ₹19,744 crore, commits India to at least five million tonnes a year of green hydrogen by 2030 (Ministry of New and Renewable Energy [MNRE], 2023). The Mission is broader than a production target: it combines the 2030 production ambition with demand creation, infrastructure, domestic manufacturing, standards, research, skills and measures intended to reduce dependence on imported fossil fuels and feedstocks. MNRE subsequently fixed the Green Hydrogen Standard at a well-to-gate emissions intensity of not more than two kilograms of carbon-dioxide equivalent per kilogram of hydrogen (Press Information Bureau, 2023a).

For refineries and city gas distribution, the Mission does not leave regulatory development unassigned. It routes that work through MoPNG and PNGRB. It assigns a task; it does not enlarge the statute. Clause 6.4 records that the Ministry of Petroleum and Natural Gas will facilitate the uptake of green hydrogen in refineries and city gas distribution, that new refineries and city gas projects will be planned and designed to be compatible with maximum possible green hydrogen deployment, and that the Ministry “will also enable development and facilitation of regulations through the Petroleum and Natural Gas Regulatory Board” (MNRE, 2023, cl. 6.4).

India does not begin this transition from zero. It already has a large industrial hydrogen market, an extensive natural-gas network, city-gas systems across hundreds of authorised geographical areas, operating blending pilots and institutions accustomed to regulating pipeline safety, access and tariffs. The challenge is therefore not whether India possesses a starting system, but how that system is adapted: where existing infrastructure can be used, which components need modification, where dedicated hydrogen transport becomes preferable, and how dependable demand is built around it.

The powers under which PNGRB acts come from the PNGRB Act, 2006, and they run to petroleum, petroleum products and natural gas. Carrying out Clause 6.4 inside those limits, and getting ready for the day they move, is what this book is about.

1.1 Three requirements, three geographies

Green power, water and a consumer are the three things an electrolyser ultimately needs around it. They need not begin in the same place. Renewable power may be cheapest in one geography, usable water easier to secure in another, while the industries that already consume hydrogen were built decades ago in a third.

Every electrolyser built in India is therefore a decision about which of the three to move: the electrons, the water, or the molecule.

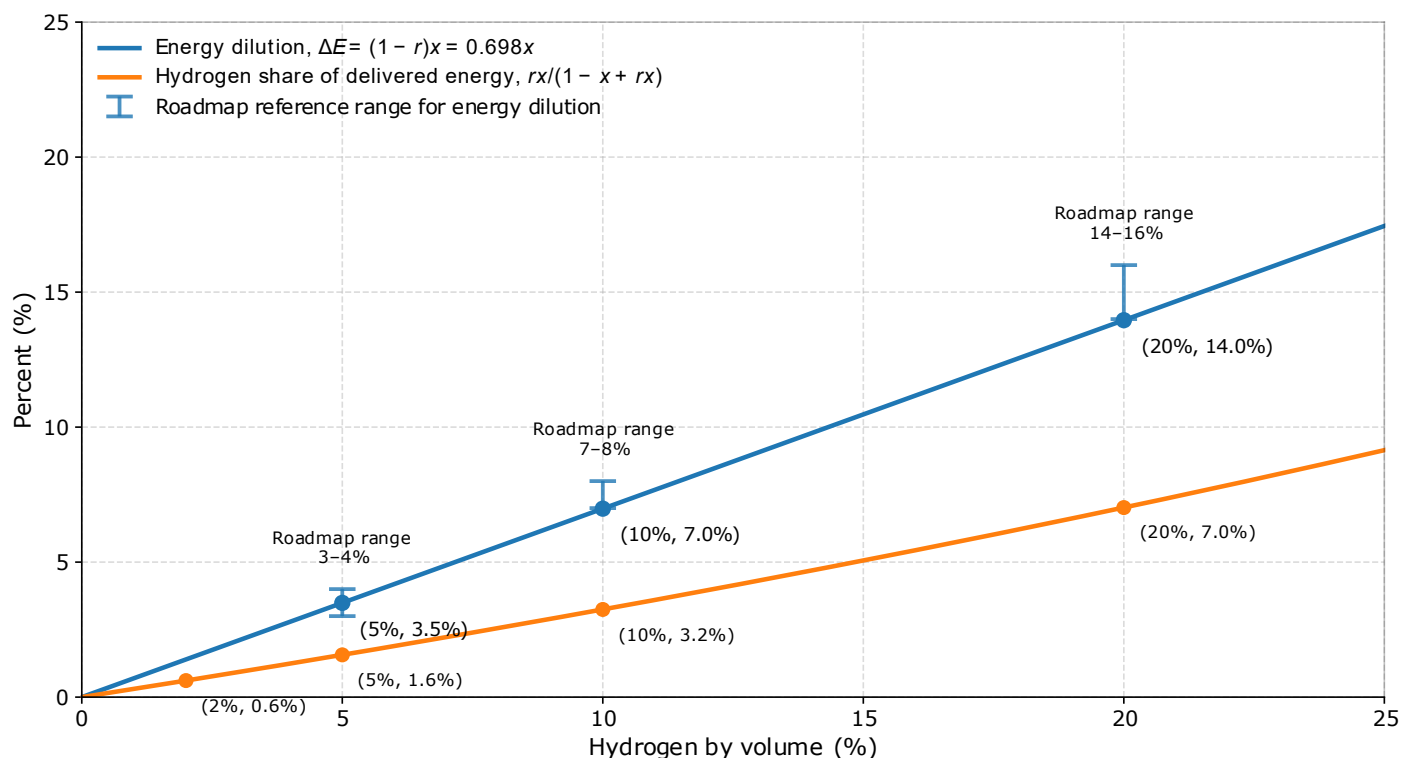
The renewable electricity can be cheapest where the sun is hardest and the land emptiest: Rajasthan, Kutch, the high desert of Ladakh. Many of those places are also short of water. Electrolysis alone requires about nine kilograms of water for every kilogram of hydrogen produced; a working plant requires more once demineralisation, cooling and other process needs are counted.

It is worth being careful here, because the water point is usually overstated. Every kilogram of hydrogen chemically consumes about nine kilograms of water. At five million tonnes a year, that is a reaction-floor of about forty-five million cubic metres. A plant requires more water than this stoichiometric minimum. The *Pathways for Transmission of Hydrogen in Natural Gas Pipelines and City Gas Distribution Network* study (PNGRB & ICF, 2025), hereafter referred to as the Pathways study, cites a gross water requirement of roughly 59–95 kilograms per kilogram of hydrogen once demineralisation and cooling are included. Not all of that additional water is chemically consumed; part of it is associated with treatment and cooling and may be returned to the environment. Even then, this is not fundamentally a national-volume problem. It is a siting problem. Much of India’s strongest solar resource lies in western, northern and interior regions where water stress can also be material. The overlap is important, but not exact. Water does not make the Mission impossible. It makes water-intensive production in some of the sunniest locations more difficult or expensive, and that affects where electrolysers are best located.

The Pathways study estimates that India was already consuming roughly 6.7 million tonnes of hydrogen a year by FY2022, overwhelmingly fossil-derived. Its sectoral dataset attributes approximately 3.208 million

FIGURE 1.1

Energy dilution against volumetric blend. (Refer Calculation Note 1)



tonnes to petroleum refining and 2.200 million tonnes to ammonia, about four-fifths of the total combined, with roughly 1.321 million tonnes in other uses (PNGRB & ICF, 2025). Those plants sit on coastlines and in inland industrial belts chosen decades ago for crude logistics, port access and feedstock supply. Solar irradiance did not come into it.

Every electrolyser built in India is therefore a decision about which of the three to move: the electrons, the water, or the molecule. Electrons belong to the power system. Water belongs to another set of institutions. Hydrogen has to find a network. That is the question this book follows.

1.2 How energy is counted here

A convention has to be settled first, because most disagreements about blending turn out to be disagreements about units. Energy here is a lower heating value throughout.

A kilogram of hydrogen carries more than twice the energy of a kilogram of methane, one reason it has long attracted rocket engineers. A cubic metre, however, carries less than a third of methane's energy. That is where gas engineers see the problem. Pipelines move volume, and their capacity is governed by hydraulics as much as by the energy in the gas.

The consequence is easy to calculate and widely misunderstood. Replace a twentieth of the methane in a pipeline with hydrogen and, at the same volumetric flow, the gas carries about three and a half per cent less energy than before. Replace a fifth and the reduction is about fourteen per cent. The loss is smaller than the hydrogen fraction, because hydrogen carries energy of its own: each percentage point of hydrogen by volume removes about 0.7 of a percentage point of energy. But the energy density still falls, which means more gas must be moved to deliver the same amount of energy. That difference eventually appears in hydraulics, metering, capacity and tariff design.

A household billed by the cubic metre pays for volume and cooks with energy. If the volumetric ₹/SCM charge were left unchanged, a household receiving a twenty percent hydrogen blend would pay the same amount per cubic metre while receiving roughly fourteen per cent less LHV energy in that cubic metre. The Roadmap addresses the problem directly by treating energy-based billing as the appropriate commercial basis as hydrogen blending increases (PNGRB, 2025), and Chapter 6 returns to metering as a question of consumer protection rather than engineering alone.

1.3 Two questions that have been taken for one

Almost every Indian discussion of hydrogen transportation runs two arguments together and

pulling them apart is the most useful thing a reader can carry into the chapters that follow.

The first is about transport. If production and consumption sit apart, the molecule has to be carried, and over land at volume the cheapest carrier is a pipeline. That is a real problem with a distant answer: no dedicated hydrogen transmission pipeline is presently authorised, and the power to authorise one has not been conferred.

The second is about offtake. A bankable hydrogen project ordinarily needs a credible buyer, and in the early years of a green-hydrogen market that buyer may be difficult to secure at the scale and price a project needs. Putting small quantities of hydrogen into an existing gas stream creates another route to offtake.

The **Chairperson, PNGRB**, put the point plainly in his Foreword to the July 2026 Knowledge Paper (PNGRB, 2026b):

“Blending hydrogen with natural gas offers a further advantage: it gives a nascent industry assured offtake in its most fragile years.”

CHAIRPERSON'S FOREWORD · PNGRB KNOWLEDGE PAPER · JULY 2026

That problem has a nearer answer, and it wants no new transmission pipeline but an injection point, a network that already exists, and a rulebook.

There are already instances of it. At NTPC Kawas township in Surat, green hydrogen produced using electricity from NTPC's 1 MW floating-solar project entered Gujarat Gas Limited's PNG network for domestic cooking under a PNGRB approved - pilot (PNGRB, 2026b). The operation was blending about five percent hydrogen in their domestic network. The pilot programmes, including its subsequent progression, is dealt with in Chapter 8.

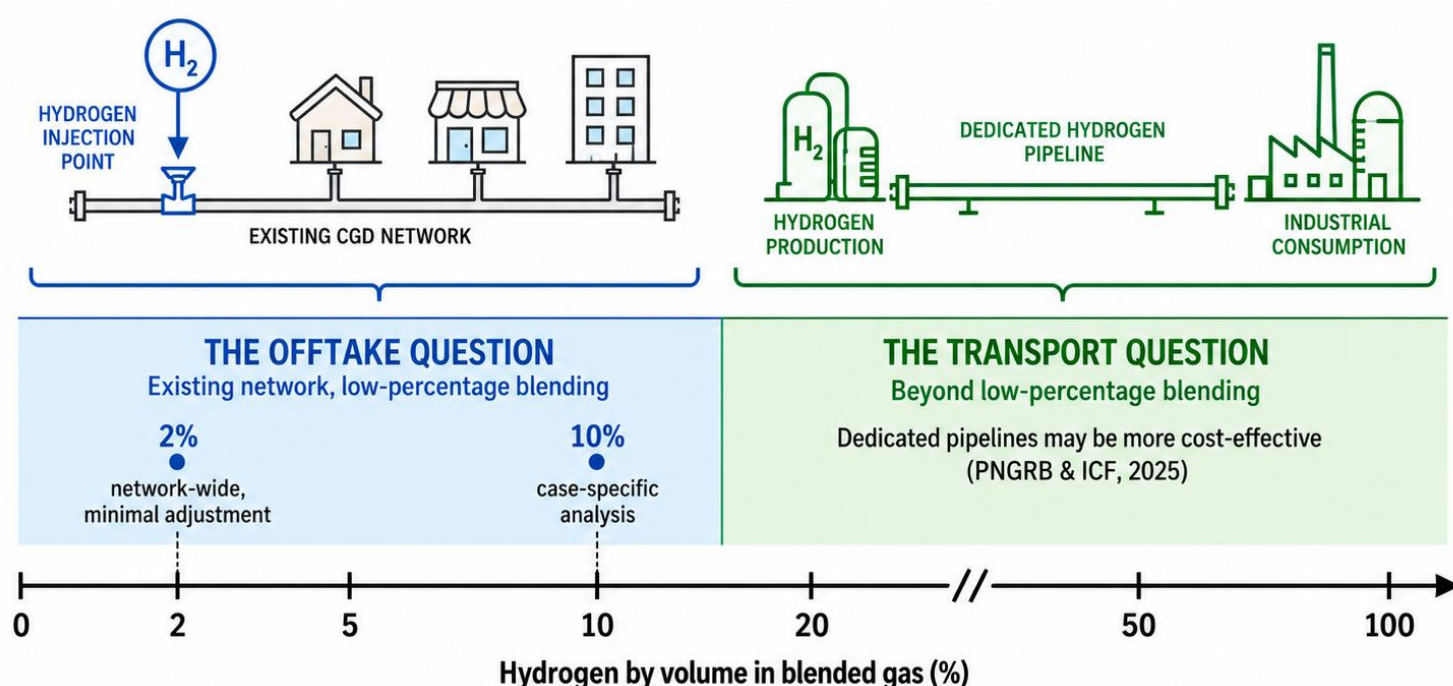
Blending moves hydrogen, but it does not solve the bulk transport problem. At low concentrations in an existing gas grid, its more immediate economic function is offtake.

1.4 Where the two arguments meet

PNGRB commissioned a detailed study during 2024 to assess what India's existing natural-gas infrastructure could physically accommodate, with support from the World Bank. The Pathways study reviewed nineteen published technical documents, examined seventeen international hydrogen-blending pilots, and drew on consultations with Indian pipeline operators, engineering organisations and technology providers. It organised the available evidence into four indicative blending ranges, providing a practical framework for understanding where hydrogen could be introduced with relatively limited intervention and where

FIGURE 1.2

Where the offtake question ends and the transport question begins.



progressively more detailed technical assessment would be required (PNGRB & ICF, 2025).

Blending up to two per cent by volume works across the network with minimal adjustment. Up to ten per cent is technically possible but wants case-specific analysis, pipeline by pipeline. Above ten per cent presents a significant challenge and needs substantial system changes. And then the finding that shapes this book: developing pure hydrogen pipelines and supporting infrastructure may be more cost-effective than implementing more than ten per cent blending.

So the ceiling on blending is economic before it is technical. Pathways study therefore identifies roughly ten per cent not as a physical cliff, but as an indicative techno-economic decision point. Below it, the case for using existing infrastructure is strongest. Beyond it, substantial system changes are required, and a dedicated hydrogen pipeline enters the economic comparison, potentially as the cheaper solution.

Beyond that range, the transport question returns: should the system continue modifying a shared network, or move the molecule through dedicated infrastructure?

One correction before that sentence is read too simply. A dedicated hydrogen pipeline need not necessarily mean a newly built line. The European Hydrogen Backbone estimated that, for the 1,200-millimetre case it modelled, repurposing an existing pipeline would require pipeline capital expenditure of roughly €0.5 million per kilometre, compared with about €2.8 million per kilometre for a new line (European Hydrogen Backbone, 2021). A technical article by Alok Sharma and S. S. Gupta, published in the Centre for High Technology's 2021–22 Annual Report, similarly noted that repurposing could cost roughly fifteen to twenty per cent of new-build pipeline cost and observed that constructing a new pipeline may take more than four years from concept to commissioning (Sharma & Gupta, 2022).

The Indian constraint is material rather than merely financial. Sharma and Gupta note that one approach to reducing susceptibility to hydrogen-related damage is to limit line-pipe grade to API 5L X52, while recording that a majority of Indian gas transmission pipelines use X70 steel and may therefore, in their words, be “at least theoretically” more vulnerable to hydrogen-related

damage. They also discuss operation at around forty per cent of specified minimum yield stress as a conservative approach for repurposed hydrogen service, which would imply lower operating pressure and potentially lower throughput (Sharma & Gupta, 2022). Those observations are screening considerations, not a finding that X70 pipe is unsuitable or that every repurposed Indian pipeline must operate at forty per cent SMYS. Whether a particular line can be repurposed depends on its steel, welds, defects, operating history, pressure cycle and the hydrogen conditions proposed. Chapter 4 returns to the evidence needed to answer that question.

A compressed natural gas cylinder built to Indian specification takes two per cent hydrogen by volume, and the limit lives in the cylinder standard rather than in the pipe that fills it. A urea plant loses efficiency in its reformer above the same two per cent. An existing compressor station absorbs about five per cent on the speed and power margins it was designed with; past that the compression equipment comes out (PNGRB & ICF, 2025; Sharma & Gupta, 2022). None of these is a line-pipe metallurgy limit. The CNG tank and reformer are downstream compatibility constraints that Pathways study addresses through deblending above two per cent. The gas-driven compressor is an infrastructure modification threshold: around two to five per cent without modification, higher where the equipment is suitably changed.

As a recommendation, the PNGRB roadmap turns this into a scoring rule: end-use compatibility is scored as the minimum of all downstream equipment scores, because the least tolerant device sets the system limit (PNGRB, 2025).

The least compatible connected equipment therefore sets the permissible blend for that network segment.

So the useful question is not how much hydrogen a pipeline can carry, but what sits at the far end of it, and what it costs either to replace that equipment or to take the hydrogen back out before it gets there.

Chapter 5 puts a number on the second and asks whether the hydrogen should have been turned into methane before it was ever injected.

1.5 A network built faster than it is used

India's gas transmission system runs at about a third of the capacity it was built to carry.

In May 2026, throughput across the authorised NGPL system was 32.6 per cent of its aggregate determined capacity: 247 MMSCMD against 758 MMSCMD. Taken across April and May together the figure is much the same (PNGRB, 2026c).

The shortfall is not spread evenly. Sorted by the route under which each line was authorised, the two legacy categories operated at about half to two-thirds of determined capacity in May. The seven pipelines authorised under Regulation 5 for which the May MIS reports both determined capacity and throughput operated at 4.56 per cent in May, and at 4.49 per cent across April–May (PNGRB, 2008b; PNGRB, 2026c).

Those seven are also part-built: 5,406 kilometres are operational out of 8,273 authorised, and two have less than half their authorised length in operation (PNGRB, 2026c). How much of the gap between determined capacity and throughput reflects unfinished pipeline, and how much reflects offtake, cannot be settled from the published returns. They record quantity, not cause.

Downstream the pattern is sharper. Across 309 authorised geographical areas at 30 June 2026, city gas entities had commissioned 8,983 CNG stations against a pro-rata Minimum Work Programme target of 7,328, laid 3,25,575 inch-kilometres of pipe against a target of 4,04,971, and connected 1,72,18,151 households against a target of 4,41,36,269 (PNGRB, 2026d). Stations at 123 per cent of schedule. Pipe at 80. Households at 39.

A CNG station is a single project site. A household connection is repeated last-mile work: a door knocked on, a household persuaded, a riser carried through a building.

Nor is the network finished. The authorisations already granted commit city gas entities to 12,65,41,862 domestic connections, 18,336 CNG stations and 5,47,158 inch-kilometres of pipe by September 2034 (PNGRB, 2026d). Whatever rules govern what may flow through that pipe have to exist before most of it is in the ground.

That frames the blending question in a particular way, and it cuts two ways. At system level, aggregate

capacity was not scarce in May 2026: throughput was only 32.6 per cent of aggregate determined capacity. That does not establish spare hydraulic capacity on every corridor, which remains a segment-specific question. Commercially, additional throughput through an under-utilised regulated asset can carry value, although the effect depends on the corridor, tariff framework and contractual structure. Hydrogen's claim is not that the network needs it. It is that the network will eventually need something that does not arrive by sea.

City gas took 63.3 million standard cubic metres a day through the transmission system in May 2026, the largest single sector at 26 per cent, ahead of fertiliser at 25 per cent (PNGRB, 2026c). That figure can be used as a gross reference stream, not as a forecast that every unit of CGD gas is technically eligible for blending. Holding delivered lower-heating-value energy constant, approximating natural gas as methane and using standard-volume conditions, the scale of hydrogen required at selected blending levels is shown below. The Pathways Study's Annexure separately projects 2030 CGD-blending demand of about 0.13–0.17 million tonnes a year under its own demand and blending assumptions (PNGRB & ICF, 2025). The two calculations are not competing forecasts. They use different baselines but point in the same direction: blending will not absorb the bulk of the Mission target, yet it can create a material early offtake market while larger refinery, ammonia, steel and transport demand is being built.

TABLE 1.1

Illustrative hydrogen requirement for selected blending levels.

Note: Illustrative calculation using 63.3 MMSCMD of CGD transmission offtake in May 2026 as the reference natural-gas stream. Hydrogen percentages are by volume. Delivered lower-heating-value energy is held constant; natural gas is approximated as methane. This is not an estimate of the volume of CGD gas technically eligible for blending.

Source: Author's calculations based on PNGRB (2026c). See Calculation Note.

H2 blend by volume	Illustrative H2 demand	Share of 5 Mt/y target	H2 share of blend LHV energy
2%	0.040 Mt/y (~39,900 t/y)	0.8%	0.61%
5%	0.102 Mt/y (~102,000 t/y)	2.0%	1.56%

H2 blend by volume	Illustrative H2 demand	Share of 5 Mt/y target	H2 share of blend LHV energy
10%	0.212 Mt/y (~211,600 t/y)	4.2%	3.25%

The legal position is narrower than the technical one. The PNGRB Act, 2006 expressly regulates natural gas but does not expressly name hydrogen as a distinct regulated commodity. Low-proportion hydrogen-natural-gas blends have therefore been handled case by case within the existing natural-gas framework, while dedicated hydrogen transport and a general hydrogen-specific regime for authorisation, access, capacity, tariff and safety require an explicit statutory footing. Chapter 9 returns to that boundary in detail.

There is a further reason, and it has nothing to do with hydrogen. The network described above carries a fuel for which India remains heavily import-dependent. Roughly 45 to 50 per cent of national gas demand is met by imported LNG, and more than sixty per cent of India's LNG shipments transit a single strait (Bakshi, 2026).

In March 2026 that stopped being a background condition.

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CALCULATION NOTES

Calculation Note 1

Illustrative hydrogen requirement for CGD blending

The calculation accompanying Table 1.1 uses the **63.3 MMSCMD** of gas delivered to the CGD sector through the transmission system in May 2026 as a gross reference stream (PNGRB, 2026c). It does not assume that the entire stream is technically suitable for hydrogen blending.

Let:

$Q = 63.3$ MMSCMD; where Q is the original natural-gas flow;

$$x = \text{hydrogen fraction by volume}$$

$$r = \frac{LHV_{H_2}}{LHV_{CH_4}} = 0.302$$

And $\rho_{H_2} = 0.0852$ kg/SCM

Because hydrogen has a lower volumetric heating value than methane, replacing a given volume fraction of methane with the same volume fraction of hydrogen would reduce the energy delivered at unchanged volumetric flow. For comparison of blending cases while **holding delivered lower-heating-value energy constant**, the required total blended-gas flow is:

$$Q_{\text{blend}} = \frac{Q}{(1-x) + rx}$$

The corresponding hydrogen volume is:

$$Q_{H_2} = \frac{Qx}{(1-x) + rx}$$

The annual hydrogen requirement is therefore:

$$M_{H_2} = \frac{Qx}{(1-x) + rx} \times 10^6 \times 365 \times 0.0852$$

where Q is expressed in MMSCMD and M_{H_2} is obtained in kilograms per year. Dividing by 1,000 gives tonnes per year.

Applying this basis gives:

- **2 vol% H₂**: approximately **39,900 tonnes/year**
- **5 vol% H₂**: approximately **102,000 tonnes/year**
- **10 vol% H₂**: approximately **211,600 tonnes/year**

Relative to the National Green Hydrogen Mission's annual production ambition of **5 million tonnes**, these quantities correspond to approximately **0.8%**, **2.0%** and **4.2%**, respectively.

Energy dilution at unchanged volumetric flow

The reduction in volumetric energy content shown in Figure 1.1 is calculated relative to an equivalent methane stream at the same total volumetric flow. With hydrogen comprising a volume fraction x of the blend and $r = 0.302$:

$$\frac{LHV_{\text{blend}}}{LHV_{CH_4}} = (1-x) + rx$$

Therefore, the fractional reduction in energy per unit volume is:

$$D = 1 - [(1-x) + rx] = x(1-r)$$

and, for $r = 0.302$:

$$D = 0.698x$$

This gives an energy dilution of approximately **1.4% at 2 vol% H₂**, **3.5% at 5 vol% H₂**, **7.0% at 10 vol% H₂** and **14.0% at 20 vol% H₂**.

H₂ share of blend LHV energy

Hydrogen's share of the delivered energy is lower than its volumetric share. Using the same lower-heating-value ratio:

$$S_{H_2} = \frac{xr}{(1-x) + xr}$$

gives hydrogen energy shares of approximately **0.61% at 2 vol%**, **1.56% at 5 vol%**, and **3.25% at 10 vol%**.

These values are illustrative system-scale calculations rather than forecasts of actual hydrogen uptake. The volume of CGD gas that could in practice accommodate hydrogen would depend on network configuration, downstream consumer and appliance compatibility, materials and equipment, gas-quality requirements, operating conditions, metering arrangements and the applicable regulatory framework.

What Hormuz Revealed

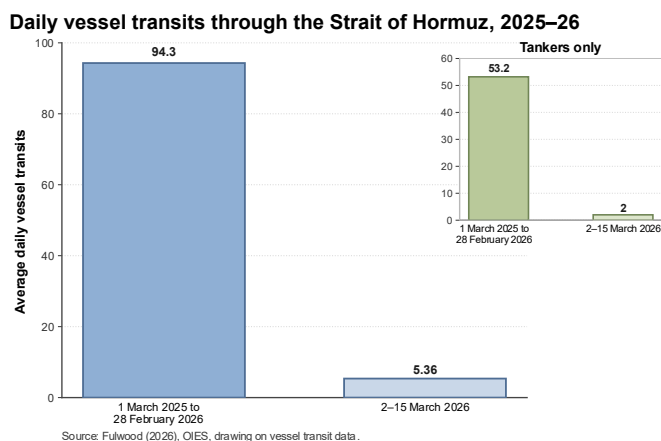
In March 2026 the Indian state put, in one instrument, an emergency hierarchy among its gas customers. The order is unusually explicit about what the network was expected to protect under stress.



On 30 March 2026, Fulwood reported that an average of 5.36 vessels a day passed through the Strait of Hormuz between 2 and 15 March, against 94.3 a day over the preceding twelve months. For tankers carrying oil and LNG, the corresponding figures were 2.0 and 53.2. (Fulwood, 2026).

FIGURE 2.1

Daily vessel transits through the Strait of Hormuz, 2025–26.



What that did to the Indian gas system is the subject of this chapter.

2.1 What arrives by sea

India is the world's third-largest importer of crude oil, the fourth-largest importer of liquefied natural gas, and the second-largest consumer of liquefied petroleum gas. Roughly 45 to 50 per cent of its natural gas demand is met through imported LNG, and Qatar has historically supplied around half of that, largely under long-term contract. About half of India's crude imports and more than sixty per cent of its LNG and LPG shipments transit the Strait of Hormuz (Bakshi, 2026).

Those are the figures usually quoted. What matters more is what sits behind them.

For crude, India built a shock absorber. The strategic petroleum reserve holds stock against exactly this, and crude suppliers have been diversified steadily over two decades. Gas has no equivalent large-scale strategic reserve. LNG requires specialised cryogenic storage and is generally held in operational rather than strategic inventories (Bakshi, 2026).

India built a strategic buffer for the barrel. It did not build an equivalent one for the molecule.

That gap had been there for years. March 2026 is when it became visible.

2.2 The order of March 2026

With gas availability tightening, the Government of India invoked the Essential Commodities Act, 1955. The order issued by the Ministry of Petroleum and Natural Gas allowed the Government to direct both domestically produced gas and imported LNG toward priority sectors and to curtail supply elsewhere. The allocations were expressed against each category's preceding six-month average consumption. PPAC was designated the nodal agency for information, while GAIL, in coordination with PPAC, was assigned to manage the pooled gas supplies required to implement the directions (Bakshi, 2026; Ministry of Petroleum and Natural Gas, 2026a).

The instrument is the Natural Gas (Supply Regulation) Order, 2026, made on 9 March under section 3 of the Act, and one feature of it matters more than the allocation percentages: it has overriding effect over any inconsistent provision in existing gas sales agreements and other commercial arrangements. A sector whose entire regulatory architecture rests on contracts, tariffs, access codes and capacity bookings watched inconsistent contractual terms yield to an emergency statutory order, inside a fortnight.

The framework set four priority categories. Priority I protected domestic PNG, CNG for transport, LPG production and the compressor fuel and other essential requirements needed to keep the pipeline system operating, each at 100 per cent of the preceding six-month average subject to operational availability. Second, agricultural inputs, with fertiliser production units receiving roughly seventy per cent of their average consumption over the preceding six months. Third, selected industrial sectors connected to the national grid, supplied at approximately eighty per cent of recent average consumption. Fourth, commercial and industrial customers of city gas distribution networks, also held to roughly eighty per cent.

Below the four categories, the reductions were sharper. Refineries received around sixty-five per cent of their average consumption. Gas-based power stations and petrochemical facilities faced partial curtailment (Bakshi, 2026).

Contracts ordinarily govern individual supplies. In March 2026 a statutory order placed a cross-sector hierarchy above inconsistent commercial arrangements and required the system to be operated accordingly. The kitchen and the bus sat in the first protected tier, alongside LPG production and the fuel needed to keep the pipeline system operating. Fertiliser followed. Industrial uses were rationed more deeply or drawn upon to balance the system.

That ranking says what the gas network is understood to be for, and few Indian instruments state that emergency hierarchy so explicitly.

2.3 Where the shock landed

The categories set out intent. What happened underneath them is a different matter.

Fertiliser was exposed at the feedstock. Thirty of India's thirty-two urea units use natural gas as feedstock, with roughly half of the LNG used in domestic urea manufacturing tied to Qatari supply. Allocation of lower-cost domestic gas has cushioned the sector since the early 2010s, but only the base of it: imported LNG does the balancing (Bakshi, 2026).

LPG produced the most visible reallocation. The LPG Control Order issued on 9 March 2026 directed refiners to maximise LPG yields and to channel the entire output of their C3 and C4 streams - propane,

FIGURE 2.2

The allocation order under the Essential Commodities Act, March 2026.

2. Regulation of production, supply and distribution. – The Central Government may, with a view to maintain supplies and securing equitable distribution and availability of natural gas for priority sector, hereby directs as under: -

(1) Priority Sector I

The supply of natural gas to the following sectors shall be treated as priority allocation and shall be maintained subject to operational availability to hundred per cent. of their average past six month average gas consumption:

- (a) Domestic Piped Natural Gas supply;
- (b) Compressed Natural Gas for transport;
- (c) LPG production including LPG shrinkage requirements;
- (d) Pipeline compressor fuel and other essential pipeline operational requirements.

(2) Priority Sector II

The supply of natural gas to the fertilizer plants shall ensure seventy per cent. of their past six month average gas consumption, subject to operational availability:

Provided that the units shall not use the gas supply for any other purpose except in the production of fertilizers and a certificate to this effect shall be furnished to the Petroleum Planning and Analysis Cell (hereinafter referred to as the "PPAC") through the Ministry of Fertilizer:

Provided further that allocation to a particular unit may not be diverted to any other unit.

(3) Priority Sector III

The gas marketing entities shall ensure that gas supply to tea industries, manufacturing and other industrial consumers supplied through the national gas grid is maintained at eighty per cent. of their past six month average gas consumption subject to operational availability.

Explanation.- For the purpose of gas allocation to this sector, the principles shall be evolved by the PPAC in coordination with the Industry Committee.

(4) Priority Sector IV

All City Gas Distribution (hereinafter referred to the "CGD") entities shall ensure that industrial and commercial consumers supplied through their networks receive eighty per cent. of their past six month average gas consumption subject to operational availability.

Explanation : For the purpose of gas allocation to this sector, the principles shall be evolved by the PPAC in coordination with the Industry Committee.

butane, propylene and butene - to LPG rather than to petrochemical production (Ministry of Petroleum and Natural Gas, 2026b). On 12 March the Government reported that LPG production had risen 28 per cent in the preceding five days (Press Information Bureau, 2026); by 18 March it put the increase at 40 per cent (All India Radio, 2026a). India had about 33.1 crore domestic LPG consumers on 1 July 2026, 10.6 crore of them under the Pradhan Mantri Ujjwala Yojana (All India Radio, 2026b). Bakshi estimated that the country would still require 29–34 LPG cargoes a month despite higher refinery output (Bakshi, 2026).

Smaller industry sat at the end of the queue. In Morbi, one of India's largest ceramic clusters, nearly one hundred units reportedly shut, with several hundred more at risk if conditions held (Bakshi, 2026). Nothing about ceramics is classified as essential, and the order did not classify it.

What separated the cases was a combination of statutory priority, substitutability and access to alternative supply. Where one of those was missing, the shock travelled quickly into output, price or both.

2.4 Price rather than volume

The shortage reached city gas consumers differently, and the distinction matters for what follows.

In May 2026, CGD accounted for 26 per cent of the gas moving through PNGRB-authorized transmission pipelines, slightly ahead of fertiliser at 25 per cent (PNGRB, 2026c). This is a measure of transmission-system throughput, not national gas consumption. It matters because city gas sits directly on the network whose response to the disruption is being examined.

The March allocation order then treated customers on that network differently. Domestic PNG was placed in Priority I, protected at 100 per cent of the preceding six-month average subject to operational availability. Commercial and industrial consumers supplied through CGD networks were placed in Priority IV, at roughly 80 per cent.

The same network could therefore deliver two different consequences from the same shortage.

For the household, the first-order effect was more likely to appear in price than in physical availability. CGD supply depends on a mix of domestic gas and imported LNG. When lower-cost domestic gas

becomes less available, more expensive LNG can enter the supply mix. The same effect had been visible in 2023 and 2024, when reductions in domestic allocation to CGD were followed by higher retail PNG and CNG prices (Bakshi, 2026).

Industrial and commercial consumers could face both effects: a higher gas price and a lower allocation.

Fulwood's modelling shows how large the price exposure could become. Under a relatively short disruption, with Gulf LNG supply returning around mid-year, the modelled average TTF price for 2026 was about USD 13.50 per MMBtu. A restart delayed into the fourth quarter raised the average to about USD 21; a full-year shutdown raised it to about USD 34, against a pre-disruption reference case of approximately USD 11.50 per MMBtu (Fulwood, 2026). At the higher price levels, the model anticipates demand destruction in price-sensitive markets including India.

Protection in volume is not protection in price. A household may continue to receive gas and still pay more for it. An industrial customer connected to the same network may pay more and receive less.

2.5 What was revealed

Everything the state reached for during the disruption worked on a short timescale. Allocation between sectors could be changed. Eligibility for a cylinder refill could be tightened. Approval windows for laying pipe could be shortened. Refiners could be directed to raise production. All of those decisions could be taken in days or weeks.

The physical network could not.

The response worked on both sides of the balance. Supply was pooled, diverted and augmented. On the demand side, one direction also became visible: where a gas network already existed, move eligible consumers away from recurring cylinder delivery and onto it. On 13 March an amendment to the Liquefied Petroleum Gas (Regulation of Supply and Distribution) Order, 2000 barred any household with a piped-gas connection from retaining a domestic LPG connection or taking refills (Ministry of Petroleum and Natural Gas, 2026c). A further amendment on 25 May gave such households 30 days from receiving piped gas to terminate the LPG connection, with a transfer voucher allowing it to be restored if they later moved to an area

without piped gas (Ministry of Petroleum and Natural Gas, 2026d).

That was not, by itself, a way of importing less. India imports more than sixty per cent of its LPG requirements and meets roughly 45 to 50 per cent of its natural-gas demand through imported LNG (Bakshi, 2026). A household that switches from LPG to PNG therefore moves between two fuel systems that both retain substantial import exposure.

But the logistics are different.

A household connected to a gas network no longer requires a cylinder to be filled, transported, delivered and replaced. In March 2026 that chain was rationed: the minimum interval between refill bookings stood at 25 days in urban areas and 45 days in rural areas, irrespective of connection type (Press Information Bureau, 2026b).

A pipe does not eliminate import dependence. It changes the infrastructure through which that dependence is managed. And a pipe can, one day, carry a molecule produced in India.

PNGRB's PNG Drive 2.0 campaign reflected the same infrastructure logic. Launched on 1 January and originally due to close on 31 March, it was extended to 30 June. Its closure report described the campaign as a national response to a structural vulnerability in India's household energy supply chain (PNGRB, 2026e).

By August, part of the emergency response had begun to acquire a more permanent form. On 13 August, the Central Government amended the Petroleum Products (Maintenance of Production, Storage and Supply) Order, 1999. The amendment inserted an operative clause and a Schedule specifying facility-wise maximum LPG production for twenty-one refineries and three upstream companies, totalling 63.81 thousand tonnes a day (Ministry of Petroleum and Natural Gas, 2026e).

The amendment went beyond setting production numbers. Every refiner was required to develop and maintain evacuation and storage infrastructure adequate for the scheduled quantities and to implement all technically and economically feasible measures to increase LPG output, including naphtha-to-LPG conversion. The Government could direct a

production ramp-up where it considered this necessary to ensure adequate availability at fair prices, including by restricting alternative uses of relevant input streams. The Centre for High Technology was assigned a compliance-monitoring role, contravention attracted the enforcement provisions of the Essential Commodities Act, and the Schedule was to be revised on 1 January and 1 July each year.

Those details matter. A Schedule designed for periodic revision, backed by monitoring and statutory enforcement, is no longer merely an emergency instruction. A temporary response had begun to harden into a standing mechanism.

That is one of the things the disruption revealed. A supply shock arrives; emergency measures follow; and if the underlying vulnerability persists, some of those measures acquire a life beyond the emergency that produced them.

But policy and infrastructure move on different clocks. The allocation framework of March 2026 could be drafted in days. The network through which it operated had been built over decades. An allocation order can therefore respond to a shortage almost immediately; a pipeline cannot. The interval between deciding that infrastructure is needed and being able to use it can run for years, on a timescale comparable to major institutional or legislative change.

Hormuz gives self-reliance a practical meaning. India becomes less exposed when a larger share of the energy and industrial feedstock on which it depends can be produced, stored and delivered from a broader set of sources, including domestic ones. Supplier diversification and strategic stocks still matter. Green hydrogen can add another option by turning Indian renewable electricity into an industrial feedstock and, in suitable networks, a share of delivered gas. That contribution depends on production, transport, storage and dependable demand developing together. The enduring response to a supply shock is therefore to build the capabilities that reduce exposure when the next one arrives.

The comparison is not yet with hydrogen technology. It is with what governments do after shocks. The United States responded to the petroleum disruption of 1973 with emergency allocation measures and then built institutions around a more permanent energy-security

problem. In the same decade, hydrogen attracted research, demonstrations and capital, but without a comparable market and infrastructure framework.

What endured, and what did not, is the subject of the next chapter.

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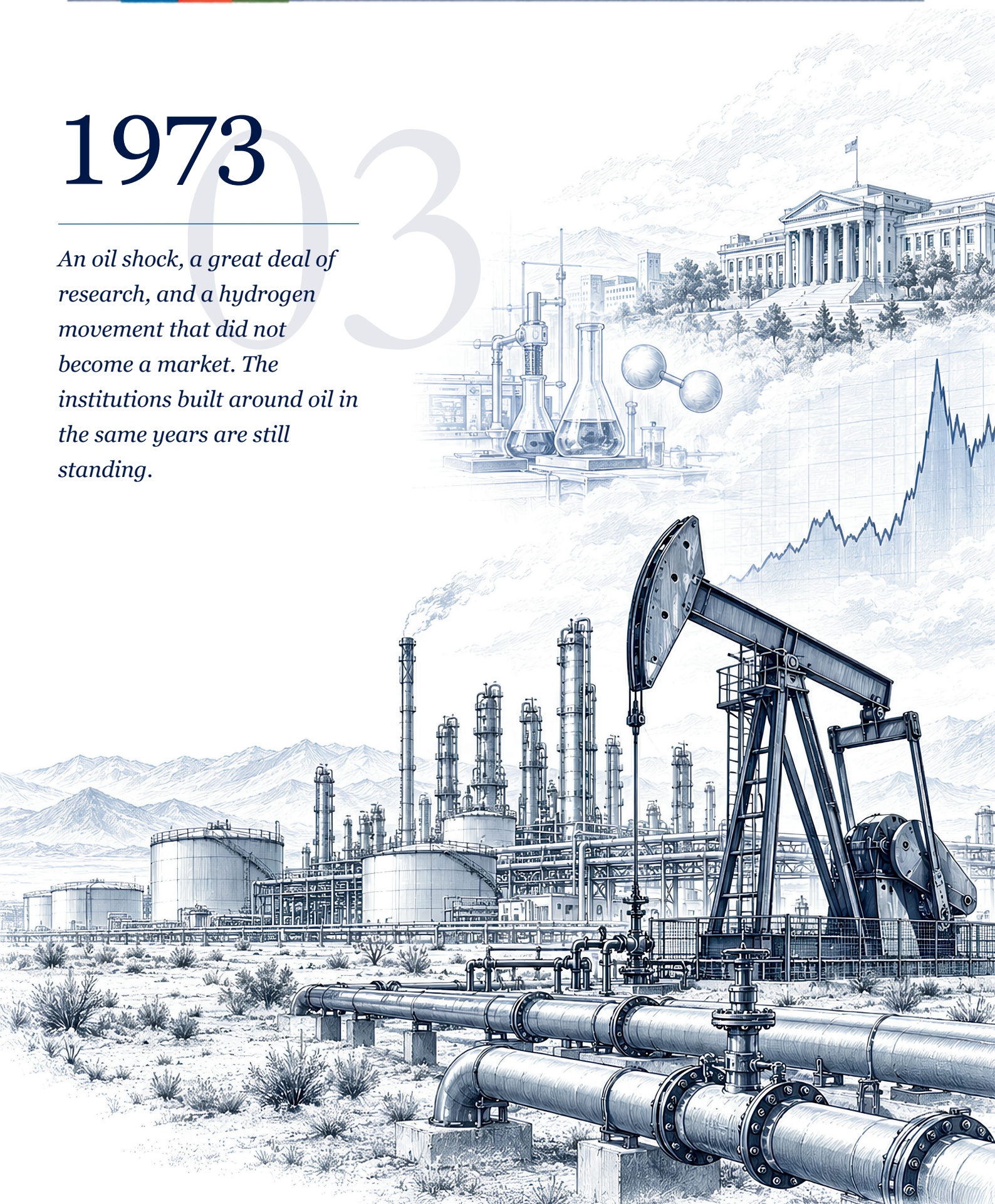
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1973

An oil shock, a great deal of research, and a hydrogen movement that did not become a market. The institutions built around oil in the same years are still standing.



In October 1973 Arab oil exporters imposed production cuts and an embargo on states they judged to have supported Israel in the Yom Kippur War. Between the eve of the embargo and January 1974, the benchmark price rose from about USD 2.90 a barrel to USD 11.65 (Yergin, 1991).

For countries dependent on imported fuel, the arithmetic changed almost overnight. What followed, in India and the United States, was institution-building that has lasted fifty years. Hydrogen received something different: research, demonstrations and extraordinary attention, but no comparable market.

3.1 The idea was already there, and it was about pipes

Hydrogen did not arrive with the embargo. It was waiting.

John Bockris, an electrochemist, gave the field its name in 1970 during a discussion at the General Motors Technical Center at Warren, Michigan, and published it two years later with A. J. Appleby under the title “The Hydrogen Economy: An Ultimate Economy?” (Bockris & Appleby, 1972). He did not claim the idea. Writing in 1981 he traced it to Franz Lawaczeck, a German turbine engineer who had proposed around 1930 that energy be moved as hydrogen through pipes, and whose work reached him through E. W. Justi’s book of 1965 and a letter from Justi in May 1974 (Bockris, 1981). In a memoir written near the end of his life he remembered it differently, as something said to him over dinner in 1968 (Bockris, 2013).

The founding proposition of the hydrogen economy, in other words, was the one this book is about.

By January 1974 the reasoning had been written down. A bibliography of the field compiled that month at the University of New Mexico and published through NASA opens by stating the case: hydrogen would need a large-scale transmission and distribution system, and a pipeline network similar to or partly integrated with the existing natural gas pipelines appeared the most practical solution. Hydrogen was to be preferred over electricity as the carrier for most purposes, on the grounds of ready substitution across every energy use and low transmission cost. Nuclear plant could then be sited far from cities, which its author called one of the most pressing problems of the day. And hydrogen would supply the storage needed to meet daily and

seasonal peaks, most economically in depleted natural gas formations underground (Cox, 1974).

Derek Gregory of the Institute of Gas Technology had gone further two years earlier, in a report for the American Gas Association. Hydrogen would come from remote, possibly offshore, stations through underground high-pressure pipelines like those already carrying natural gas, and - the sentence is worth reading twice, in many instances the same lines could be used, with modifications to the compressor stations. He saw no insurmountable problems in doing it (Gregory, 1972).

The objection was recorded at the same time. A systems study run at the Johnson Space Center over the summer of 1973 concluded that a pipeline system like the natural gas system appeared practical, provided design factors were included to avoid hydrogen environment embrittlement of the pipeline metals (Savage et al., 1973). The 1974 bibliography gives permeation and embrittlement their own section.

Bockris describes the idea spreading from a concern about vehicle exhaust to the thought that hydrogen might be put into industry in place of natural gas as the gas ran out. Publications on the subject were running at about a hundred a year by 1973 (Cox, 1974). The case for blending, and the case for reusing gas infrastructure, were therefore being made before either became part of a modern gas-network transition programme.

When the embargo came, the field had a name, a literature and a first conference already scheduled.

It also, within months, had the New York Times. On 12 May 1974 the paper’s business section carried a full page by Victor K. McElheny under the headline “Hydrogen — A Way Out of the Energy Crisis?”, subtitled with the question of whether this light, plentiful gas was an alternative to the all-electric economy in the year 2000. The illustration ran in three panels. Yesterday: the Hindenburg burning at Lakehurst in 1937. Today: liquid hydrogen tanks at a rocket facility, marked no smoking. Tomorrow: a note on the American natural gas pipeline network, with the note that this network could be used to carry hydrogen when the gas runs out (McElheny, 1974).

That is the proposition this book is about, printed in a newspaper fifty-two years ago beside a headline asking

about the year 2000, which came and went with the pipelines still carrying gas.

FIGURE 3.1

The New York Times, 12 May 1974.



3.2 What the shock built

The American response came in three pieces. The Emergency Petroleum Allocation Act of 1973 put petroleum under federal price and allocation controls and required a mandatory allocation programme guided by national defence, essential public services, agriculture, independent refiners and equitable distribution. The regulations made under it used historical base-period volumes (often 1972) as the reference for individual allocations, while protecting specified priority uses. The Federal Energy Administration was created in 1974 to administer the programme; in 1977 its functions were transferred into the new Department of Energy (Department of Energy Organization Act, 1977; Emergency Petroleum Allocation Act, 1973; Federal Energy Administration Act, 1974).

A reader who has come through Chapter 2 will recognise the architecture, though not the formula. A historical consumption base, protected uses, mandatory reallocation and an emergency public-interest standard sit behind both instruments. India's March 2026 Order used the preceding six months rather than a 1972 base year, but the regulatory instinct is recognisable.

India's legislation of the period ran towards supply and finance rather than rationing. Parliament enacted the Oil Industry (Development) Act in 1974, and the Oil Industry Development Board was constituted on 13 January 1975. The Act's stated rationale expressly

referred to the successive steep increases in international crude and petroleum-product prices since early 1973 and the resulting need for greater petroleum self-reliance. Its answer was to create a statutory development fund and a Board able to finance exploration, production, refining, transport and research (Oil Industry (Development) Act, 1974). In March 1974 the Government also constituted the Oil Prices Committee under Dr K. S. Krishnaswamy of the Reserve Bank of India to reconsider petroleum-product pricing. The Act itself makes the price-shock rationale explicit.

Both institutional lineages outlived the shock. The Department of Energy continues under the Act that created it in 1977, having absorbed the functions of the Federal Energy Administration, and the Oil Industry Development Board remains in operation under the Act of 1974 (Department of Energy Organization Act, 1977; Oil Industry (Development) Act, 1974).

3.3 What the shock did not build

Hydrogen got its moment in the same eighteen months. By then hydrogen had a small society and a first conference behind it: the H₂indenburg Society, founded at Boston in 1972 and dedicated to the safe utilisation of hydrogen as a fuel, and the Cornell International Symposium and Workshop on the Hydrogen Economy, which had met in August 1973 with some scientists. What opened at Miami Beach on 18 March 1974 was larger than either. T. Nejat Veziroglu of the University of Miami had organised it on a seventy-thousand-dollar grant from the National Science Foundation, and he and Harold Harrenstein, the university's dean of engineering, had given it a name they thought catchy: The Hydrogen Economy Miami Energy Conference, THEME. Seven hundred and fifty people came, from eighty countries. In Veziroglu's later recollection, eleven of them met that evening in the penthouse of the Playboy Plaza hotel and agreed that an association should be founded. The International Association for Hydrogen Energy was established on 21 October that year. Veziroglu, who was in the room, recorded that those present agreed the hydrogen energy system was an idea whose time had arrived (Veziroglu, 2015).

The International Energy Agency was established in November of the same year, another institutional response to the energy-security problem exposed by

the oil shock (International Energy Program Agreement, 1974).

FIGURE 3.2

The Playboy Plaza Hotel on Collins Avenue in Miami.



What faded was not hydrogen research. It was the prospect of turning that research into a hydrogen economy on the timetable its advocates had imagined.

Later assessments do not offer a single cause. The technology was expensive, several conversion steps were inefficient, infrastructure had to precede demand, and policy support weakened when the energy-price signal weakened. What matters here is that technical progress alone was not enough. Three constraints kept meeting each other (National Research Council, 2004).

The first was the absence of a common infrastructure rulebook. The National Academies would later warn that hydrogen codes and standards need to be established well ahead of the market because permitting, safety and infrastructure design otherwise become barriers of their own (National Research Council, 2004). That observation came thirty years later; the 1970s literature had already identified the underlying technical questions but had not turned them into a national market framework.

The second was infrastructure sequencing. Hydrogen could not become a consumer fuel without production, transport, storage and refuelling appearing together. Building any one of them without the others created an asset with nothing to connect to. The technical literature already knew that a gas-like pipeline system brought material constraints, including hydrogen-environment embrittlement; what it did not supply

was a market mechanism for building the whole chain together.

The third was continuity. Energy R&D expanded after the oil shocks and contracted sharply when oil prices fell again in the 1980s. Hydrogen research did not disappear, but its position in federal energy priorities weakened with the pressure that had helped create it.

As oil prices fell, federal priority and funding contracted. The research survived; a self-sustaining hydrogen market did not.

3.4 The cars

Two vehicles from the period are worth naming, because they show how far the engineering had got and how little that settled.

In 1970 Karl Kordesch, an Austrian chemist at Union Carbide who had co-invented the alkaline battery, took his own Austin A40 and put a six-kilowatt alkaline hydrogen-air fuel cell where the boot had been. Lead-acid batteries went under the bonnet. Six hydrogen cylinders were strapped to the roof. The car kept room for four passengers and had a range of about three hundred kilometres, and Kordesch drove it on public roads as his personal transport for more than three years, commuting, shopping, and being tolerated by his neighbours as a man with bottles on his car (Kordesch & Simader, 1996).

It worked. It did not become a market. In Japan a series of hydrogen vehicles was built across the same period at what was then the Musashi Institute of Technology, several of them running on liquid hydrogen, and they

FIGURE 3.3

The Austin A-40 Hybrid car of K.V. Kordesch. (Kordesch et al., 2008).



too remained demonstrations rather than a market (Furuhama, 1989).

A working car answered an engineering question. It did not solve the cost of the fuel, the cost of the conversion, the absence of refuelling infrastructure or the problem of supplying hydrogen at scale. A demonstration is not a market.

3.5 The pattern

Set the two records side by side and the difference is not in how much money was spent or how good the technology was.

Oil got statutory machinery: allocation rules, pricing machinery, a development fund, an agency and a defined set of responsibilities. Hydrogen got research programmes, technical studies, demonstrations, conferences and scientific institutions. What it did not get was a comparable market-and-infrastructure framework: no national mechanism for building a network, no stable system of offtake, and no institution responsible for joining production, transport and end use into a market.

When the price signal weakened, hydrogen research continued, but there was no comparable market structure to carry deployment forward.

There is an obvious objection to that. Oil collapsed in the mid-1980s, and hydrogen made from expensive electricity could not compete with cheap petroleum whatever the rulebook said. On this reading hydrogen died of arithmetic, and the search for a regulatory explanation is the kind of thing done by people who wanted the technology to succeed, which describes most of the authors cited above.

The objection is partly right. A statute would not have made expensive hydrogen competitive with cheap oil. The narrower point is institutional. Rules can allocate responsibility, preserve capability and give investment somewhere to attach; research and demonstrations cannot create a market by themselves. American petroleum price and allocation controls were removed by Executive Order 12287 in January 1981 (Executive Order 12287, 1981). By then the Federal Energy Administration had already been absorbed into the new Department of Energy. The controls disappeared; the broader institution did not. India's Oil Industry

Development Board also remains in operation under the Act of 1974.

That does not prove that regulation could have saved the hydrogen economy of the 1970s. It shows something narrower: an emergency instrument can be stood down while institutional capability built around the problem survives it.

None of which settles the harder question, which is when the rules should be written. They cost money to draft and to comply with and drafting them for a market that does not yet exist spends public attention on something nobody has asked for. Joan Ogden set the problem out in 1999 as a chicken-and-egg: investment waits for demand, demand waits for infrastructure, and neither moves (Ogden, 1999). Chapter 7 returns to it.

India's path was different. It did not try to build a hydrogen economy in the immediate aftermath of the 1973 shock, but it did not ignore hydrogen for long. A later status report records that Government-supported hydrogen-energy research began in 1976, covering production from water, liquid-hydrogen and metal-hydride storage, engine and thermal applications, and other parts of the technology chain (Sastri, 1989).

What India did not build was a hydrogen market or a hydrogen transport regime. Its durable institutional response to the energy shock went instead into petroleum security, pricing and development finance. Hydrogen remained a research subject. Oil became an institutional one.

There was reason for that sequencing. India's immediate problem was the cost and security of the fuels it was already consuming, not the construction of an economy around a secondary energy carrier whose economics were still unresolved. The judgement was not that hydrogen had no future. It was that other problems came first.

The first hydrogen-economy wave did not disappear. Its conferences, research programmes and technical literature survived, and some of the engineering questions now being asked were already on paper by 1973. What did not emerge was a market architecture capable of turning that knowledge into infrastructure at scale. Oil received institutions because governments had an immediate problem to solve. Hydrogen remained principally a research problem.

The difference in 2026 is therefore not that India has finally discovered hydrogen. India was researching it fifty years ago. The difference is that a real gas network, a regulator already responsible for the gas network, pilots, a Roadmap and actual end users now exist around the transport question.

The question is therefore no longer whether hydrogen can be imagined in a gas network. It is how much of the evidence accumulated elsewhere can safely be transferred to ours.

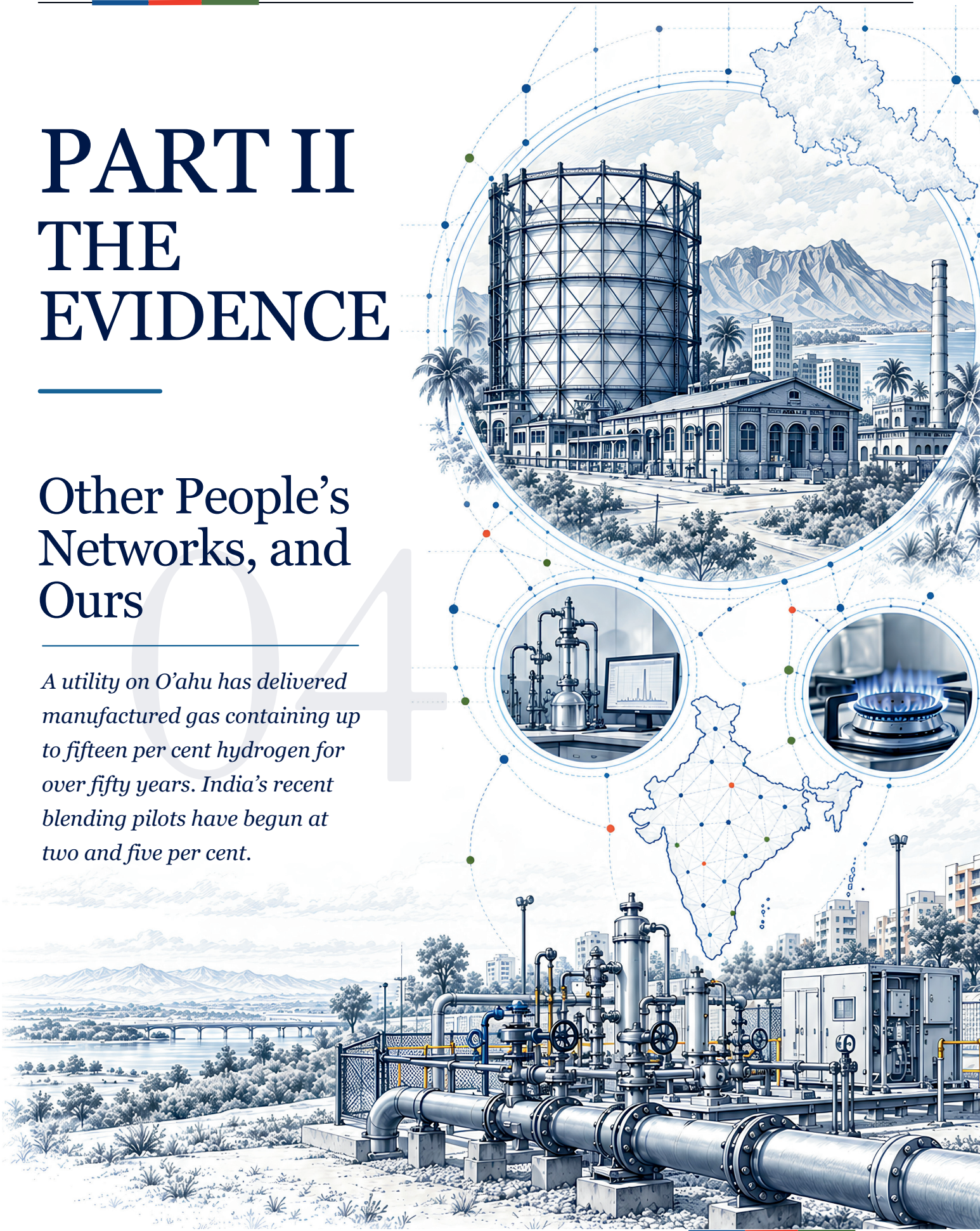
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PART II THE EVIDENCE

Other People's Networks, and Ours

A utility on O'ahu has delivered manufactured gas containing up to fifteen per cent hydrogen for over fifty years. India's recent blending pilots have begun at two and five per cent.



Hawaii has no natural gas of its own. The Honolulu Gas Company got round that in 1904 by cracking ships' bunker fuel oil at a plant in Iwilei, and its successor got round it again in 1974 by building a plant in West O'ahu that makes gas out of naphtha, a by-product of the refinery next door. It is the only plant of its kind in the United States (Hawaii Business Magazine, 2024; Hawai'i Gas, n.d.-a).

The product is mostly methane, with up to fifteen per cent hydrogen in it. The hydrogen is there because the process puts it there. From the plant a sixteen-inch transmission line runs into the island distribution system, and from there some 1,100 miles of pipe carry the gas from Kapolei to Hawai'i Kai, to the kitchens of downtown Honolulu and Waikiki (Hawai'i Gas, n.d.-b; Hawai'i State Energy Office, n.d.).

That has been going on for fifty-two years, which makes it one of the longest-running utility operating records involving hydrogen-containing gas. The company says that it carries more utility hydrogen than any other in the United States (Hawai'i Gas, n.d.-a).

Nobody set out to prove anything by it. There was no trial protocol, no control group and no reporting requirement, and for most of the fifty-two years the hydrogen was an incidental component of a manufactured fuel rather than a subject of study. It nonetheless answers the question pilot projects are still being built to answer whether a distribution network

can carry a substantial hydrogen fraction to ordinary domestic customers, for decades, without the thing becoming unmanageable. On the evidence of Honolulu, it can, and nobody had to be told to try.

Hawai'i is not a fifty-year controlled hydrogen experiment. It is a long operating record from one particular network, fuel composition and equipment population. That makes it evidence, not a transferable limit.

So the obvious question is why India is testing at two / five.

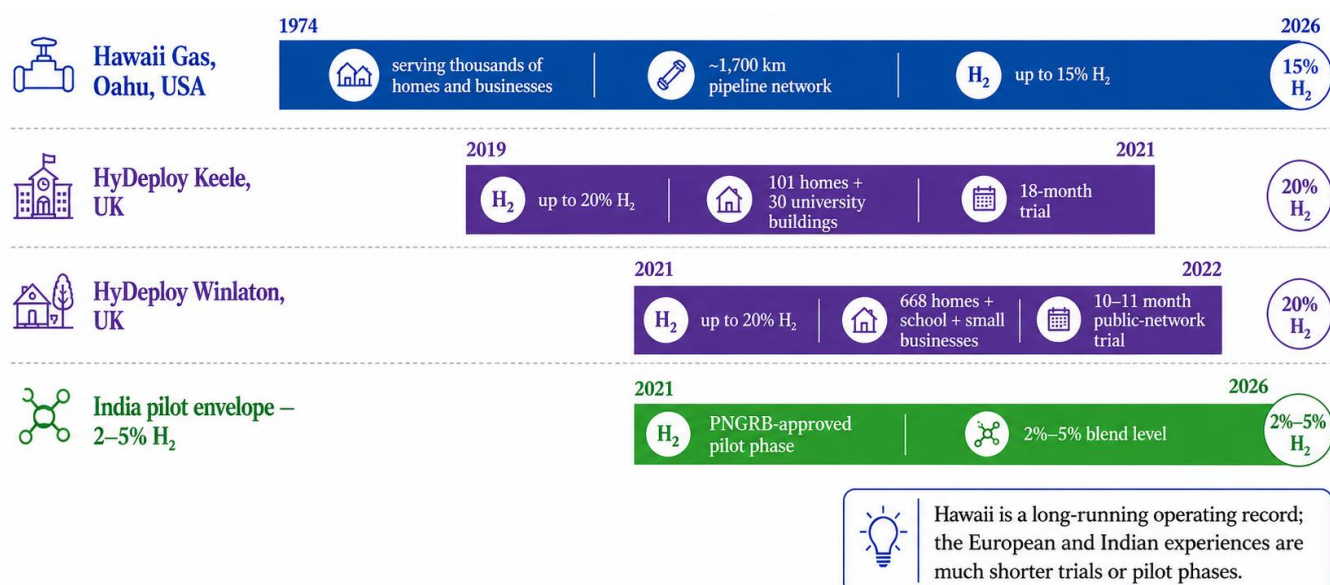
4.1 What was measured on purpose

The deliberate evidence came later, and from Britain.

HyDeploy ran on the private gas network at Keele University from 2019 to 2021 - a £7 million project funded through Ofgem's Network Innovation Competition, led by Cadent with Northern Gas Networks, Progressive Energy, the Health and Safety Executive's science division and ITM Power. A half-megawatt electrolyser and a grid entry unit injected up to 20 mol per cent hydrogen into a network serving a hundred homes and thirty campus buildings. Blending began in October 2019 and ran at full operation through 2020; by the end of the trial more than 42,000 cubic metres of hydrogen had gone into the pipe (Isaac, 2019; Keele University, 2021).

FIGURE 4.1

Hydrogen in operating distribution networks: Hawai'i, the UK trials and Indian pilots.



Sources: Hawaii Gas; HyDeploy / Cadent; PNGRB Knowledge Paper and Roadmap.

The control logic is worth noting, because it is the same problem Chapter 6 is about. The grid entry unit measured the Wobbe index of the incoming natural gas and calculated how much hydrogen could be added while staying inside the range permitted by the Gas Safety (Management) Regulations, that is, the blend was set by what the gas had to look like at the burner, not by a policy number (Isaac, 2019).

The finding was that customers used the blended gas with no changes to their appliances, and that no incremental degradation of materials was expected up to 20 mol per cent on that network. The evidence generated at Keele helped underpin the subsequent safety case and HSE approval for the Winlaton public-network demonstration, where 668 houses, a school and some small businesses began receiving blended gas in August 2021 (Cadent Gas, 2021; Isaac, 2019).

Two qualifications travel with that result and both matter here. The Keele network is predominantly polyethylene, which §4.5 shows tolerates far more hydrogen than steel does. And the material conclusion was expressly reached for the purposes of the trial on the Keele network, not as a general finding about pipe.

Germany — When Evidence Has Somewhere to Go

Germany is useful here not because its blend percentages should be copied into India, but because it shows what can exist around a percentage once research, rules, certification and infrastructure begin to connect.

The physical programme is already visible. In October 2024 the Bundesnetzagentur approved a hydrogen core network of 9,040 kilometres, to enter service progressively through 2032. Around sixty per cent of the approved network is based on conversion of natural-gas pipelines and the rest on new construction. That is an approved infrastructure programme, not a statement that all 9,040 kilometres are already carrying hydrogen (Bundesnetzagentur, 2024).

By August 2026 part of the system had begun to operate as a chain rather than as isolated demonstrations. The GET H₂ Nukleus partners reported that initial renewable hydrogen produced during commissioning of RWE electrolyzers in Lingen had reached the Marl Chemical Park through roughly 120 kilometres of pipeline. Commercial operation of

the electrolyzers was still being completed. What matters here is the sequence: production, transport and an industrial offtake had begun to work together under real network conditions (Nowega, OGE, RWE & SYNEQT, 2026).

The rule system is equally important. Germany's 2024 Standardization Roadmap for Hydrogen Technologies was developed jointly by DIN, DKE, DVGW, NWB, VDA, VDI and VDMA through a nationally coordinated process. It organised the work across production, infrastructure, application, quality infrastructure, and training, safety and certification. Its published database contained more than 850 standards and technical rules already available or applicable to hydrogen, while the exercise identified around 180 needs and recommendations for further action. The number itself is not the lesson. The lesson is the method: inventory the existing rules, identify the gaps, turn priority gaps into implementation projects, and revise the technical rule set as research and field experience accumulate (Project partners Standardization Roadmap for Hydrogen Technologies, 2024).

DVGW sits inside that process as more than a publisher of worksheets. Its research programme spans hydrogen pipelines, fitness of steels, distribution networks, gas quality, component readiness, safe operation, odourisation and real-world laboratories; its testing and certification functions provide routes by which evidence can become an accepted component or operating practice (DVGW, 2024). German law also gives that technical-rule system a defined legal significance. Section 49(2) of the Energy Industry Act provides a presumption of compliance with generally recognised technical rules for gas and hydrogen installations where the DVGW technical rules are followed (Energiewirtschaftsgesetz, 2005, § 49(2)).

The HIGGS project shows what the evidence side looks like. Its high-pressure test platform examined representative transmission-network components and API 5L steels from X42 through X70 at 80 bar under 20 and 30 mol per cent hydrogen blends and under 100 per cent hydrogen. The campaign examined valves, couplings, regulators, filters and flow measurement as well as steel specimens. No hydrogen-induced cracking was detected in the constant-displacement steel

specimens under the stated campaign conditions, while the project remained careful not to convert that result into a universal material certificate. That qualification is the important part: a result becomes transferable only when the material, pressure, composition, duration, weld condition and test method are known (European Research Institute for Gas and Energy Innovation, 2023).

That is the capability relevant to India. India does not need to repeat two decades of European work, and it should not import European conclusions detached from the conditions that produced them. It needs the institutional chain that tells an operator which evidence is acceptable, where an Indian difference must be tested, who validates the result, and how that result enters an approval, certificate or operating rule. The PNGRB–DVGW cooperation described in Chapter 8 is therefore more useful than access to a foreign rulebook alone. Properly used, it is a way of building that chain.

4.2 What a standard is evidence of

Caution is part of the answer and not the whole of it. Honolulu is a particular network, and what it demonstrates is a proposition about that network.

The O'ahu system runs at distribution pressures, in a climate that barely varies, on an island, serving a customer base and an appliance population that grew up alongside the gas. Its pipe was laid for the gas it carries. Its burners were sold into a market where that gas was the only gas on offer. When somebody in Honolulu buys a water heater, it is a water heater for the fuel Hawai'i Gas sells, because there is nothing else to buy it for.

None of that is true of a segment of Indian transmission pipe built to API 5L X-70 and running at seventy or ninety bar, or of a household in Ahmedabad whose stove was bought to burn natural gas from a network authorised in 2012.

This is the general point and it governs everything that follows. A technical standard is not a statement about hydrogen. It is a record of what was found out about a particular set of materials, pressures, temperatures, appliances and operating practices, written down in a form that can be applied to other things that resemble them. The German rulebook is a description of German networks. ASME B31.12 is a description of what

American practice concluded about hydrogen piping. Each is evidence, and each is evidence about somewhere else.

Which does not mean it cannot be borrowed. It means the borrowing has to be justified case by case, and that the justification is an engineering judgement about resemblance rather than an administrative act of adoption.

4.3 What happens to steel

Hydrogen embrittlement is often used as though it described a single phenomenon. It does not. In a 1978 NASA-sponsored study, Rocketdyne engineer W. T. Chandler separated hydrogen embrittlement into three forms. They behave differently enough that putting them under one label can obscure what a pipeline assessment actually has to look for.

The first is reaction embrittlement, in which hydrogen reacts with the metal or with a constituent in it to form an embrittling product: hydrides in titanium, zirconium, columbium and tantalum; methane where hydrogen reacts with carbon in steel; water vapour where it reacts with oxygen in copper. Where gaseous reaction products form inside voids or discontinuities, their pressure can drive further damage. This form is permanent once the material has been damaged, and temperature and pressure influence the reaction (Chandler, 1978).

The second is internal embrittlement, caused by hydrogen already absorbed into the metal, the delayed failure of hydrogen-charged high-strength steel is the classic case. Before cracking occurs, removal of the hydrogen can restore much of the lost ductility; once a crack has formed, removing the hydrogen does not remove the crack. The effect is particularly important around ambient temperature (Chandler, 1978).

For an operating steel pipeline, gaseous hydrogen-environment effects (including their interaction with defects, welds and cyclic loading) are among the principal integrity concerns. Hydrogen-environment embrittlement describes degradation while a material is exposed to a hydrogen environment, conventionally assessed by comparison with its behaviour in a non-embrittling environment.

In the test evidence Chandler reviewed, elastic properties and tensile yield strength were

comparatively little affected. The larger effects appeared in ductility, notch behaviour and crack propagation. In Chandler's description, hydrogen-environment embrittlement initiates at an exposed, susceptible region under tensile strain; once a crack forms, the problem becomes one of fracture and crack growth. Threshold stress intensities for crack growth can fall and crack-growth rates can rise in hydrogen (Chandler, 1978).

A pipeline is not a laboratory tensile specimen, but it contains welds, notches, dents, corrosion features and other discontinuities from which failure may initiate. That is why the Roadmap does not stop at nominal steel grade. Its screening framework also examines weld hardness and flaw density (PNGRB, 2025), because an integrity assessment has to ask not only what the pipe was specified to be, but where a crack could begin and how it might grow. A hydrogen-pipeline integrity assessment is therefore as much about welds, flaws, microstructure and operating stress as it is about the grade stamped on the pipe.

Two further findings set the limits of the argument.

The first is about pressure. Much of Chandler's comparative evidence was generated for rocket-engine service, at hydrogen pressures around 68.9 meganewtons per square metre (ten thousand pounds per square inch). Indian transmission and city-gas systems operate at pressures well below that test pressure, with the low-pressure distribution tiers lower still. That does not make the older evidence quantitatively transferable to an Indian pipeline. It does, however, rule out the easy assumption that hydrogen effects disappear merely because operating pressure is lower: Chandler records significant environmental effects at pressures of one atmosphere or below (Chandler, 1978).

The second is about grade. Rocketdyne classified alloys according to their behaviour in hydrogen at ten thousand pounds per square inch. Plain carbon and low-alloy steels including AISI 1020, A-533-B, HY-80 and A-515 were classified as severely embrittled under those test conditions, with notch-strength ratios in hydrogen of roughly three-quarters to four-fifths of their values in helium. Within the same dataset, several higher-strength alloys showed substantially larger reductions: 4140 at 0.40, Inconel 718 at 0.46, H-11 at 0.25 and maraging steel at 0.12. A short group of

austenitic stainless steels, aluminium alloys and copper alloys was classified as negligibly affected under those test conditions (Chandler, 1978).

The older data help explain why strength became a screening variable. They do not make grade a verdict. Modern pipeline testing is less tidy. NIST tested two X52 and two X70 pipeline steels in pressurised hydrogen and found the X70 materials performed on par with the X52 materials in fatigue under the conditions tested (Slifka et al., 2018). Hydrogen nevertheless increased fatigue-crack growth relative to air, and subsequent NIST work on welds and heat-affected zones showed why local microstructure, crack path and residual stress also matter. Strength grade alone did not determine the result.

Material grade is therefore a sensible conservative screening variable. It is not a substitute for testing the steel, welds, defects and operating conditions actually in the ground.

4.4 What Indian regulation currently says about hydrogen

Nothing, in the strict sense, and the way in which it says nothing is instructive.

The technical standards for natural gas pipelines were notified in November 2009 under section 61 of the Act. Regulation 3(2) provides that design, materials, welding, fabrication, installation, testing, commissioning, operation, maintenance and corrosion control shall follow ASME B31.8, except where the Indian regulation specifically cancels, replaces or modifies it. The city gas regulation of August 2008 does the same. Two annexures then list further codes - API 5L for line pipe, API 1104 for welding, ASME Section VIII and IX, NACE recommended practices, a run of Indian Standards, without stating an edition for any of them (PNGRB, 2008a; PNGRB, 2009).

ASME B31.8 is the American standard for gas transmission and distribution piping. The hydrogen counterpart is ASME B31.12, and it appears in neither regulation's annexures (PNGRB, 2008a, Annexures II; PNGRB, 2009, Annexures II and VI).

The present regulations incorporate standards that were adopted for the natural-gas network and do not themselves create a hydrogen-specific integrity and operating framework equivalent to the one

contemplated in the Roadmap. ASME B31.8 is the principal referenced gas-transmission and distribution code, while API 5L specifies line pipe. ASME B31.3 is a general process-piping code rather than a natural-gas-specific code and is used in facilities including hydrogen plants; its presence therefore does not fill the network-level hydrogen questions addressed by B31.12 and hydrogen-specific integrity guidance. ISO 6976 provides the calorific-value calculation once composition is known. The remaining network questions include hydrogen-assisted fatigue and fracture assessment, blend-ratio injection control, leak detection, gas-quality management, metrology and odourisation.

None of which amounts to an oversight. Every one of those standards was adopted for a network carrying

natural gas, and each does its job for that gas. Nor has the rulebook been left to age: the city gas regulation has been amended fourteen times since 2008, most recently in December 2025, and the pipeline regulation six times since 2009 (PNGRB, 2008a; PNGRB, 2009). The machinery for revision exists and runs.

What it is, is a set of instruments that describe a different fluid, kept scrupulously up to date.

4.5 The ladder

Against that background the Board commissioned an assessment of what published evidence indicated different components of an Indian gas network could accommodate. ICF Consulting India examined eighteen classes of component against blending limits, as installed and after modification, and the result reads

FIGURE 4.2

Component tolerance to hydrogen, as installed and after modification (PNGRB & ICF, 2025).

S. No.	Element	Blending limit (without modifications)	Blending limit (with modifications)	Key remarks / retrofit solution
1	Compressor	2%–5%	15%–20%	Swapping gas turbines or internal combustion engines with electric motors
2	Electrically driven compressor	15%–20%	–	–
3	Valve	10%	–	Requires new equipment
4	Gas filter	10%	–	Requires new equipment
5	Fuel filter	10%	–	Requires new equipment
6	Odorant	15%	–	–
7	Insulation joint	10%–20%	–	–
8	Volumetric meters	10%	–	Requires new equipment
9	Process gas chromatograph	≤0.2%	10%–20%	Replace helium cylinders with argon cylinders
10	Gas meters	10%–50%	–	–
11	Gas turbine	1%–2%	15%–20%	Modifications to increase limit to 15%–20%
12	Feedstock / reformer	2%	–	Lower efficiency. Requires debinding solution
13	Burner / gas stove	10%	20%–100%	–
14	CNG vehicle fuel tank	2%	–	Requires debinding solution
15	Domestic appliances	20%	–	–
16	Transmission pipeline (steel)	5%–10%	–	Requires changes in the operating pressure. Needs to be evaluated for each specific pipeline with its P&ID diagrams
17	Distribution pipeline (PE)	25%–100%	–	–
18	Condensing and steam boilers	5%–10%	20%–100%	–

as a ladder. Every threshold and every modification cost in this section comes from that assessment (PNGRB & ICF, 2025).

At the bottom are components whose as-installed limits occur at very low blends but which can be modified relatively simply. A process gas chromatograph tolerates 0.2 per cent hydrogen as configured and reaches ten to twenty per cent once its helium carrier gas is swapped for argon, which is an operating expense with no capital component at all.

In the middle sit the components that can be bought up the ladder. A gas-driven compressor is limited to two to five per cent by its drive rather than by the machine and reaches fifteen to twenty per cent when the drive is replaced with an electrical one, at six and a half to eleven per cent of capital cost. A gas turbine tolerates one to two per cent and reaches fifteen to twenty with combustion system, instrumentation and fuel-blending upgrades at around ten per cent of capital cost.

At the top are the components that need nothing done to them, and it is worth pausing on why. Adding hydrogen to natural gas raises the fundamental flame speed, which ought to push a flame back into the burner. For fully premixed appliances, THyGA notes that the rise in fundamental flame speed caused by hydrogen can be counterbalanced by the accompanying rise in excess air. Its standards work therefore considers both existing propane-rich limit gases and hydrogen-containing test gases, depending on the appliance and the test purpose (Dörr et al., 2023). A domestic burner tolerates ten per cent as installed and twenty to a hundred with modification. Distribution pipework in polyethylene tolerates twenty-five to a hundred. Domestic appliances as a class are placed at twenty per cent (PNGRB & ICF, 2025, Table 1). On this evidence, domestic end-use is not the first limiting case on the network, which is not where most readers would expect to find it.

And outside the ladder altogether sit two components with no modification path stated: the compressed natural gas cylinder in a vehicle, and the reformer in a plant that uses gas as feedstock. Both stop at two per cent. Chapter 5 is about what that costs and who pays it.

4.6 From a ladder to a rulebook

A ladder of equipment limits says what a network can bear. It does not, by itself, say who may operate at what level, on what evidence, or with what obligations attached. The September 2025 Roadmap tries to supply that second layer.

It does so through four proposed service classes, designated BG for blended gas. BG-1 covers up to two per cent hydrogen by volume: minimal asset change, a metrology check, and volumetric billing with a compensation factor or a move to energy-based billing. BG-2 covers up to five per cent, adds Safety Case approval and minimum instrumentation. BG-3 extends to ten per cent on post-testbed evidence, catalogued OEM certifications and debblending guidance wherever purity-critical offtakes exist downstream. BG-4 extends to twenty per cent only in limited domains where pilot and testbed evidence, certified appliance cohorts, enhanced safety and metrology, and a robust debblending scheme support it (PNGRB, 2025).

The obligations rise with the class rather than siting fixed. Under the Roadmap's proposed operating procedures, leak surveys move from quarterly at BG-1 to bi-monthly at BG-2 and monthly at BG-3 and BG-4, or as PNGRB directs. Elastomer and seal change-out intervals are likewise to be set by class. The detailed metrology provisions move the framework towards energy-based billing from BG-2 upward, supported by on-site composition analysis and calorific-value correction. (PNGRB, 2025).

Movement up the ladder would itself be controlled. The Roadmap proposes blend changes of no more than one percentage point of hydrogen by volume per hour unless another rate is approved, with hold points at two, three and five per cent. A Wobbe-index excursion, analyser failure, odorant low-flow alarm, leak alarm, pressure-relief-valve chatter, compressor surge warning or emergency-shutdown trip would halt further increase. Every service-class upgrade would be subject to Hydrogen Cell clearance after the readiness screen and end-use evidence had been satisfied, and the proposed framework reserves to PNGRB the ability to impose a lower cap for a particular corridor or customer. (PNGRB, 2025).

That last reservation matters. It gives administrative form to the siting principle developed in Chapter 5: the

appropriate blend is determined not only by the pipe that carries it, but by what is connected to the pipe.

4.7 The screen

Under the proposed framework, progression is not left to an unstructured judgement. A pipeline segment would reach a service class by passing a weighted screen of nine parameters as proposed in the Roadmap, applied to sections of one to five kilometres (PNGRB, 2025).

Material compatibility and weld integrity carry fourteen per cent each. Component readiness, end-use compatibility and pipeline age carry twelve each. Gas losses and location class carry ten. Corrosion, and capacity utilisation taken together with maximum allowable operating pressure, carry eight each. Each parameter is scored from one to five, and the weights sum to a hundred (PNGRB, 2025).

The decision gate is a floor rather than the weighted total: a segment proceeds only if it scores at least four out of five on every parameter taken individually.

Two of the scoring conventions carry the logic of the whole framework. Component readiness is taken as the minimum of all individual component scores, on the stated ground that the least compatible element limits overall readiness, and end-use compatibility is treated the same way (PNGRB, 2025). The screen is built on weakest-link reasoning rather than on averages, which is the correct construction for a safety instrument, and the reason a single intolerant device downstream can hold an entire segment at BG-1.

4.8 The parameter that binds

Of the nine parameters, material compatibility is the one most likely to narrow the field at the first pass.

The Roadmap scores material compatibility initially by steel grade. API 5L X42 to X52 scores five, reflecting lower strength and comparatively favourable fracture behaviour. X52 to X60 scores four. X60 to X70 scores three. X70 to X80 scores two, and X80 and above scores one. Since the proposed gate requires a score of at least four on every parameter, the generic matrix places the dividing line within the lower-strength grades (PNGRB, 2025).

That matrix is a screen, not a material verdict. The distinction matters because the Roadmap did not apply

the complete nine-parameter framework across the national transmission network. Its preliminary operator exercise covered four systems and used the two variables available consistently enough for an initial comparison: material grade and pipeline age. Under that preliminary filter, API 5L Grade B was marked no; X42 yes; X52 yes; X56 no; X60 no; X65 no; X70 no; and the reported X70/X80 category no.

There is a useful tension between the two tables. The generic material matrix gives the X52–X60 band a score of four, which is the minimum material score required by the proposed gate. The preliminary pilot filter is more conservative: it uses X52 or below and marks X56 and X60 unsuitable at that first pass. The two should therefore not be read as the same decision rule. The latter is an early-candidate filter for pilot selection, not a finding that every X56 or X60 pipeline is hydrogen-incompatible.

The preliminary exercise nevertheless says something important about where the easiest Indian candidates may lie. Two of the four operator systems were reported as predominantly X65. In the other two, sections meeting the grade-and-age filter were identified. In one system the Roadmap lists eight X52 sections, largely short spur and connectivity lines, ranging from 0.03 to 21.7 kilometres and together amounting to about fifty-five kilometres (PNGRB, 2025). Most are six-inch lines. The point is not the fifty-five kilometres as a proportion of the national network, the exercise did not screen the national network. It is the type of asset that emerged from the first filter: relatively young, lower-grade and mostly short sections rather than an obvious cross-country hydrogen corridor.

The Roadmap makes that preference explicit. Its summary of the screening module lists high-strength steels of X70 and above among the red flags and identifies early candidate sections as API 5L X42 to X52 aged ten years or less (PNGRB, 2025). Sharma and Gupta, writing in the Centre for High Technology's 2021–22 Annual Report, make the Indian context more difficult: they record that the majority of Indian gas transmission pipelines are API 5L X70 (Sharma & Gupta, 2022).

That still does not make an X70 stamp a disqualification.

The older material evidence discussed in §4.3 explains why strength entered the screen in the first place. Modern pipeline testing is less tidy. NIST tested two X52 and two X70 pipeline steels in pressurised hydrogen and found the tested X70 materials performing on par with the X52 materials in fatigue. Hydrogen still accelerated fatigue-crack growth relative to air, but grade alone did not determine the result. Welds, heat-affected zones, microstructure, flaws, residual stress and the operating cycle all matter (Slifka et al., 2018).

The preliminary screening therefore shows why the Roadmap's higher service classes cannot simply be assumed available across the existing transmission network. It does not show that the network is incapable of carrying them. For a major steel segment that does not meet the Roadmap's early-candidate filter, progression towards higher blends would require one or more of three responses: asset-specific evidence establishing acceptable behaviour under the intended hydrogen and operating conditions; operating changes or targeted retrofit, including derating where required; or a decision to introduce hydrogen further downstream into a compatible distribution network.

The first is the evidence gap the Indian testbed is intended to narrow. Generic literature can identify what should be tested; it cannot establish the fatigue and fracture behaviour of every Indian pipe, weld and defect population.

The second route - operating at lower stress - needs a qualification. Sharma and Gupta (2022) discuss operation at around forty per cent of specified minimum yield strength as one conservative approach to repurposed hydrogen service. Separately, the European Hydrogen Backbone estimates discussed in Chapter 1 put repurposing cost at roughly fifteen to twenty per cent of new-build pipeline cost (European Hydrogen Backbone, 2021; Sharma & Gupta, 2022). The two figures describe different aspects of repurposing and should not be read as a single bargain in which a particular expenditure purchases a particular operating stress.

ASME B31.8 makes the pressure relationship clearer. Its design-pressure equation is:

$$P = \frac{2StFET}{D}$$

where P is design pressure, S is specified minimum yield strength, t is nominal wall thickness, D is nominal outside diameter, and F , E and T are the applicable design, longitudinal-joint and temperature factors. Where the applicable E and T factors are unity, an F of 0.40 corresponds to a design-stress ceiling of forty per cent of SMYS. The numerical correspondence is real; it is not a universal equivalence independent of the other terms in the equation.

Reducing operating stress can also reduce transport capability, but there is no single percentage consequence that can be applied to every line. Diameter, inlet and outlet pressure, compression, network configuration and flow conditions determine how much capacity is actually lost. Chapter 5 returns to the places where the Indian natural-gas design framework already applies a 0.40 design factor and to what that might mean for where blending is least expensive to accommodate.

One parameter runs in the opposite direction, and the contrast is instructive. In the Roadmap's proposed screen, capacity utilisation above 98.5 per cent receives a score of one, while utilisation between 87 and 90 per cent receives five. The published scale does not extend below 87 per cent. India's authorised transmission network as a whole operated at 32.6 per cent of aggregate determined capacity in May 2026 (PNGRB, 2026c).

That system-wide average cannot simply be inserted into a segment-level screening table. Individual corridors may run far above or below it, and the Roadmap considers utilisation together with pressure margin. The contrast nevertheless exposes an implementation question. A screening framework intended for Indian assets eventually has to say how a segment below its lowest published utilisation band is to be scored.

4.9 A blend cannot be regulated as a volume

One more consequence follows from the service classes, and it changes what regulating a gas network consists of.

Indian gas regulation already lives in two units. Physical quantities are measured and reported in standard cubic metres, while natural-gas transmission tariff is denominated in rupees per MMBtu. The bridge between the two is heat value. Existing regulatory

reporting formats require entities to state average heat value in MMBtu per SCM and, where quantities are expressed in both units, to state the basis used for energy equivalence. The city-gas technical standards also include the American Gas Association's fuel-gas energy-metering guidance and treat gas measurement, billing and energy balance as part of ordinary network operation (PNGRB, 2008a; PNGRB, 2008b).

Hydrogen does not change that principle. It makes the bridge between volume and energy more important because the calorific value of a hydrogen–natural-gas blend depends on its composition. Once composition becomes an operating variable, the commercial account depends more directly on knowing what gas was actually delivered.

That is the significance of the Roadmap's proposed metrology architecture. From the higher service classes it couples composition analysis with calorific-value and Wobbe-index measurement, meter verification and increasingly explicit energy accounting. Its detailed metrology provision moves to energy-based billing from BG-2 upward through composition and calorific-value correction based on on-site gas analysis, although the BG-2 service-class summary itself describes energy-based billing only as recommended (PNGRB, 2025). The Roadmap should therefore be read here as indicating the direction of the proposed framework, not as a notified billing rule.

The same framework proposes automatic analyser checks, periodic multi-point validation, meter-bias verification and the reporting of composition, heating value, Wobbe index, pressure, flow, alarms, odorant dose, leak records and downtime. Assembled, those measurements describe a continuously updated picture of the network's operating state; the Roadmap's testbed specification uses the language of a digital twin.

The importance is commercial rather than technological. Energy is already part of the regulatory unit of account. Hydrogen makes the composition behind that energy value something that has to be measured and auditable. A regulator cannot independently verify composition-sensitive settlement merely from a volumetric meter reading. Chapter 6 returns to that problem as one of consumer protection.

4.10 What the screen asks for

The framework set out in this chapter is unusually specific. It fixes thresholds by component, ties them to graded operating envelopes, gates movement between envelopes on a nine-parameter screen with a floor rather than an average, and requires instrumentation sufficient to settle bills on energy rather than volume. The Roadmap is unusually prescriptive in bringing component thresholds, operating classes, screening, metrology and reporting into one proposed framework.

What it does not yet have in sufficient depth is Indian material and system evidence across the range of assets to which that framework would eventually have to apply. The steel grade matrix, the hardness thresholds, the flaw density bands, the permeation scores for polyethylene grades, the component tolerances, all are drawn from international codes and published research, principally American and European. The screen asks a segment whether it resembles the pipe those codes were written about.

A substantial part of India's transmission system may not fit the Roadmap's preferred early-candidate profile. Which leaves the question of where blending should happen instead, and who bears the cost of putting it there.

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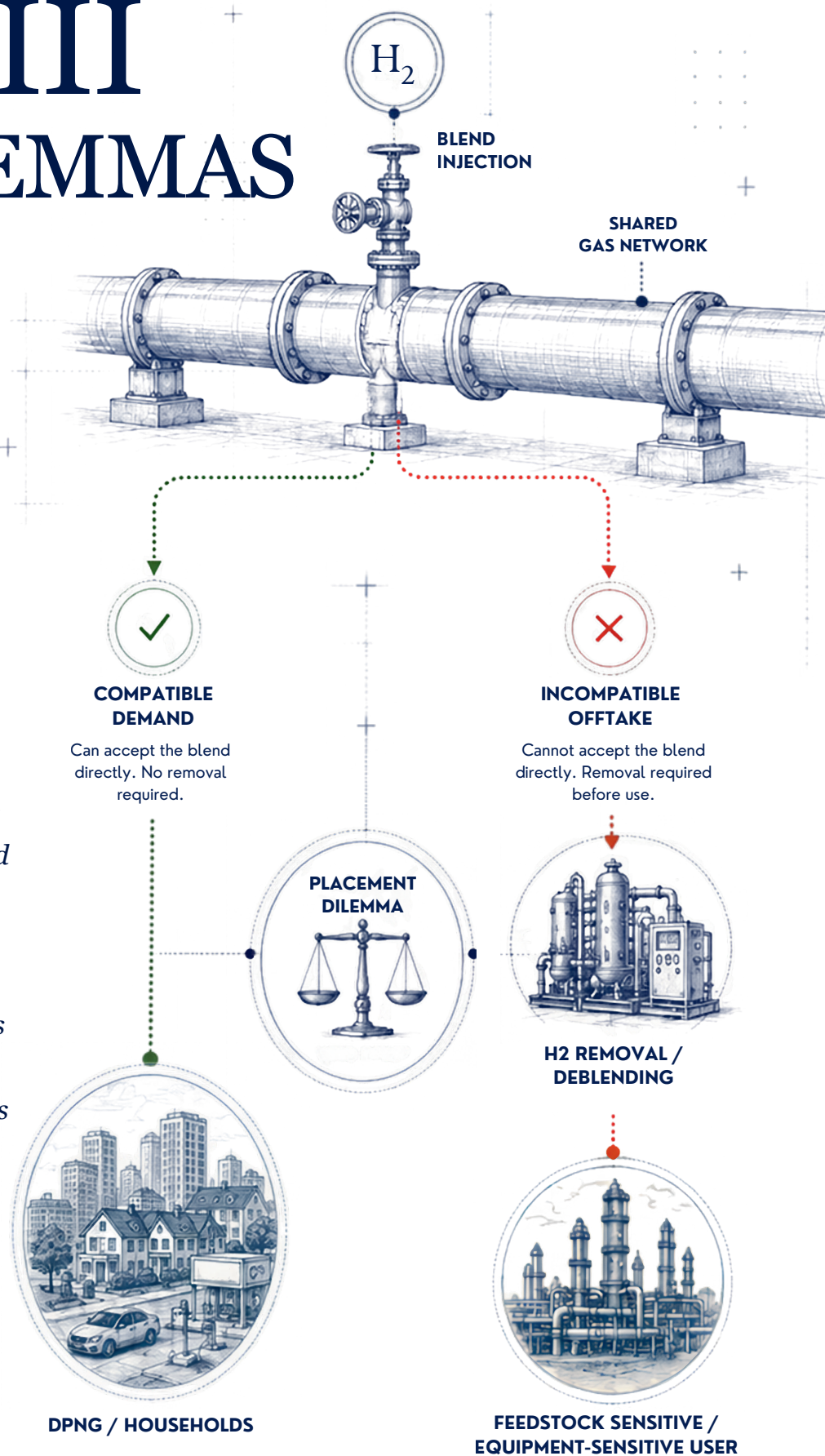


PART III

THE DILEMMAS

Where Blending Belongs

Hydrogen put into a shared gas network may have to be reduced or removed before an offtake whose equipment or feedstock specification cannot accept the blend. The cost of taking it out is borne by someone who never asked for it, and that determines where blending can sensibly be done.



Green hydrogen does not stay green in the eyes of the plant at the far end of the pipe. It arrives there as an off-specification component of a feedstock, and the question that plant has to answer is not what the molecule cost to make but what it costs to remove.

The Pathways study uses roughly USD 2.50 per kilogram as a benchmark for grey hydrogen and about USD 1.50 per kilogram as an indicative large-scale cost for recovering hydrogen through pressure swing adsorption (PNGRB & ICF, 2025). At ₹87 to the dollar, those figures are about ₹218 and ₹130 per kilogram respectively.

The ratio is striking: the stated separation cost is around sixty per cent of the grey-hydrogen benchmark. But that is not yet a net-cost calculation. Hydrogen recovered from a blended stream is not necessarily valueless. At a fertiliser complex it could, in principle, displace part of the hydrogen otherwise produced on site if its purity, pressure and process integration permit; elsewhere it would require a separate use or offtake.

That changes the regulatory question. It is not simply who pays to remove hydrogen that an offtaker did not ask for. It is who pays for separation, who owns the hydrogen recovered from it, and who receives whatever value that hydrogen retains.

Whether that question arises at all depends on who is standing at the far end of the pipe.

5.1 The two-per-cent problem

Chapter 4 set out the equipment ladder. Two entries on it do something the others do not.

A compressed natural gas cylinder built to Indian specification tolerates two per cent hydrogen by volume, as per IS 15490 (Bureau of Indian Standards, 2004). A steam methane reformer in a urea plant loses efficiency above the same figure, because a reformer is a chemical process designed around a feed composition rather than a piece of equipment with a tolerance band. Most other components on the ladder can be modified: a gas chromatograph needs its helium carrier replaced with argon, an operating expense rather than a capital one; a gas-driven compressor can be re-driven electrically for six and a half to eleven per cent of its capital cost; a gas turbine can be upgraded to fifteen per cent for around ten per cent of capital cost.

Valves, gas and fuel filters and volumetric meters are rated to about 10 per cent as installed and need new equipment above that level (PNGRB & ICF, 2025).

The reformer case deserves explaining rather than asserting, because at first sight it should not arise at all. A urea plant is already a hydrogen-making installation: natural gas is reformed to produce hydrogen-rich synthesis gas, the hydrogen is combined with nitrogen to make ammonia, and ammonia is then reacted with carbon dioxide to make urea. Hydrogen arriving in the natural-gas feed might therefore look like a useful addition.

But the plant is designed around a feed composition, not around hydrogen concentration alone. Replacing part of the methane with molecular hydrogen changes the material and energy balance entering the reformer. Methane is not merely the source of hydrogen; through the reforming process it also supplies the carbon-containing stream used elsewhere in an integrated ammonia–urea complex. The relevant chemistry therefore changes when hydrogen displaces methane rather than being introduced at the point where hydrogen is actually required (Alfian & Purwanto, 2019).

That is why the Pathways study treats feedstock/reformer service differently from an appliance or a meter. It assigns a two-per-cent hydrogen limit and identifies debblending above that level (PNGRB & ICF, 2025). The two-per-cent figure is the study's threshold; the chemistry explains why such a threshold can exist.

The CNG vehicle tank and the feedstock/reformer therefore sit differently from most of the equipment on the ladder. For each, the Pathways study gives a two-per-cent limit and does not identify a modification pathway that raises it; instead, it identifies debblending above that level (PNGRB & ICF, 2025, Table 1).

The reasons are different. The CNG tank is part of a dispersed vehicle fleet rather than a stationary network asset, so changing the permissible blend would engage the compatibility of the installed vehicle population. The reformer is not merely a component through which gas passes: the gas is its process feedstock, and changing that composition changes the process it was designed to run.

That makes these limits different from the compressor, turbine or chromatograph cases. For many network components, a higher blend can be accommodated by modification or replacement. At these two offtakes, the Pathways study instead moves the problem downstream into separation.

5.2 What separation costs, and who pays it

The Pathways study worked the arithmetic through two representative cases.

For fertiliser, the Pathways study presents a representative deblending case for a plant producing 35.68 lakh tonnes of urea a year and consuming 9.51 lakh tonnes of natural gas. The study associates a ten-per-cent hydrogen blend with a downstream separation requirement and applies an assumed hydrogen-separation cost to illustrate the resulting burden (PNGRB & ICF, 2025).

That commercial example should be treated with caution because hydrogen blending percentages are ordinarily expressed by volume, while the example is presented through mass quantities. A direct conversion between the two depends on the composition and flow basis of the gas, as well as separation recovery, required hydrogen purity and pressure, compression duty and process integration. The more durable point is regulatory rather than numerical: once a purity-sensitive plant has to treat a blended feed, a downstream cost appears that may not have arisen if the hydrogen injection point had been located differently.

For transport, the Pathways study similarly identifies a deblending requirement above its two-per-cent CNG vehicle-tank threshold. Its detailed commercial case shows the effect on delivered energy cost. CNG at ₹74.09 per kilogram is expressed as USD 17.99 per MMBtu; a ten-per-cent hydrogen blend raises the modelled value to USD 18.67 per MMBtu; after the deblending step it reaches USD 21.28 per MMBtu (PNGRB & ICF, 2025).

The proportions in that sequence are more useful than any single station-capital figure. In the Pathways case, the blend itself raises the modelled value by about 3.8 per cent. The subsequent deblending step adds a further 14.0 per cent, taking the total increase over the base case to about 18.3 per cent. The increase associated with deblending is therefore materially

larger, in this case, than the increase attributed to the blend itself.

The incidence is what turns this from an engineering question into a regulatory one. The upstream hydrogen producer obtains an additional route to offtake. A downstream consumer may inherit a treatment requirement created by a change in the common gas stream. But the hydrogen recovered through separation is not necessarily without value: at some sites it may be usable or saleable, while at others it may have no ready outlet. A complete commercial rule therefore has to answer three questions together: who funds the separation equipment, who owns the recovered hydrogen, and how any value recovered from it is credited.

Both affected sectors also sat high in the emergency allocation hierarchy introduced in March 2026. CNG for transport was placed in Priority I at one hundred per cent of the reference quantity, subject to operational availability. Fertiliser followed in Priority II at about seventy per cent, while refinery supply could be reduced, to the extent feasible, to around sixty-five per cent (Ministry of Petroleum and Natural Gas, 2026). The hierarchy did not insulate either sector from shortage; fertiliser was itself rationed. It did, however, give both an explicit priority. A blending framework should therefore avoid creating an unnecessary downstream treatment burden at offtakes whose continuity of supply the same state has chosen to protect.

5.3 The published separation cost comes from a different concentration range

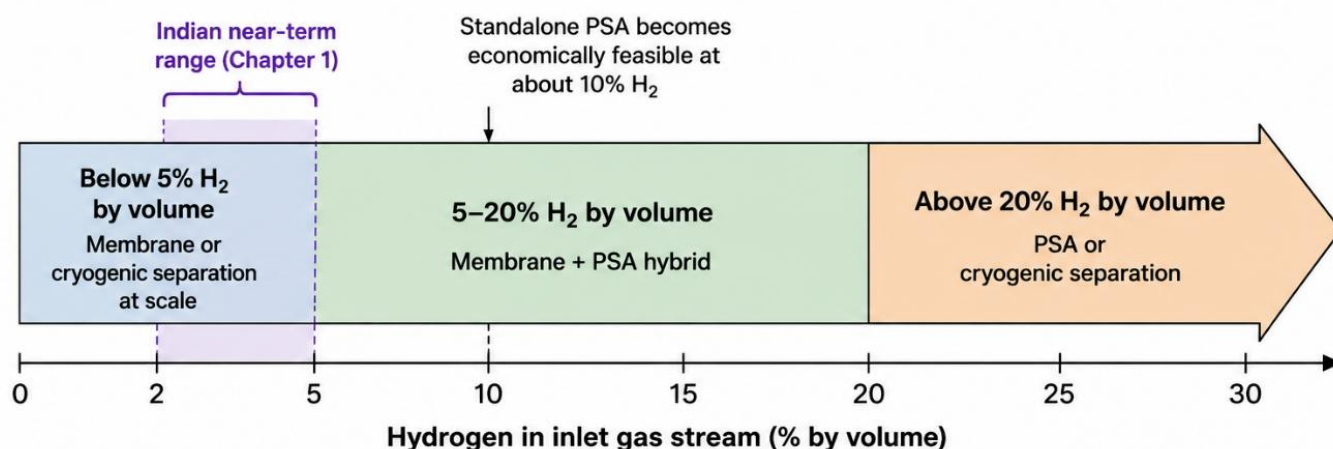
One qualification has to be entered before the USD 1.50 figure is carried into a low-blend Indian case.

The Pathways estimate is for large-scale pressure swing adsorption. The September 2025 Roadmap subsequently places PSA in a different operating range: it describes the technology as economically feasible above roughly ten per cent hydrogen, where recovery can exceed seventy per cent, and as less effective at very low inlet concentrations. For streams below five per cent it identifies membrane separation, or cryogenic separation where scale justifies it; between five and twenty per cent it proposes a membrane, PSA hybrid as

FIGURE 5.1

Separation technology by inlet hydrogen fraction, with the Indian near-term range marked.

Separation technology by inlet hydrogen fraction, with the Indian near-term range marked.



Indicative CAPEX benchmarks (excluding land and civil works)

Technology	CAPEX
PSA (10 TPD)	₹40–60 Cr
Cryogenic (20 TPD)	₹100–120 Cr
Membrane + PSA hybrid (5 TPD)	₹25–35 Cr

Source: Roadmap, Module B.8. Indicative technology-selection ranges and CAPEX benchmarks; CAPEX excludes land and civil works.

the preferred technology family (PNGRB, 2025). The low-blend range examined in the early part of this book, roughly two to five per cent therefore sits outside the concentration range for which the Roadmap regards standalone PSA as the natural economic choice. The USD 1.50-per-kilogram estimate should not simply be transferred into that range. The relevant cost becomes technology-, scale-, purity- and site-specific.

The Roadmap provides indicative capital benchmarks for the candidate technologies, but not a field-validated Indian cost per kilogram of hydrogen recovered from a two-to-five-per-cent network stream. That is a measurement problem for the testbed, rather than an argument against blending.

5.4 The siting rule

Put the two findings together and a rule falls out of them.

The cost of blending is a function of what lies downstream of the injection point rather than of the percentage injected. A blend of five per cent injected

into a distribution zone serving domestic burners, which the Pathways study places at ten per cent without modification, and between twenty and a hundred with, imposes no separation cost on anybody (PNGRB & ICF, 2025). The same five per cent injected upstream of a CNG mother station or a urea plant imposes one on both.

The roadmap already carries the formal version of this, though it is expressed as a scoring convention rather than a siting principle: end-use compatibility is scored as the minimum of all downstream equipment scores, because the least tolerant device sets the system limit (PNGRB, 2025). Read as a rule for where to inject rather than how much to inject, it says something stronger. Blending belongs where the downstream offtake profile can accept the intended blend, or where purity-critical offtakes can be isolated from it.

There is a separate point about distribution steel. Schedule 1D of the CGD technical standards (PNGRB, 2008a) applies a Location Class 4 design factor of 0.40 to steel mains. In the B31.8 pressure relationship, where the longitudinal-joint and temperature factors

are unity, that corresponds numerically to a design-stress ceiling of forty per cent of SMYS. Sharma and Gupta discuss operation at around forty per cent SMYS as one approach to repurposing natural-gas pipelines for hydrogen service (Sharma & Gupta, 2022). The numerical convergence is worth noticing, but it is not a hydrogen-compatibility finding. Steel grade, welds, flaws, pressure cycling, material toughness and the integrity assessment remain relevant. The existing design factor therefore gives distribution steel a comparatively conservative starting point; it does not by itself qualify a CGD steel main for hydrogen service.

That distinction reinforces rather than replaces the siting argument. The pipe may have engineering headroom while an offtake connected to it does not. A distribution segment can therefore be a better candidate for blending than a transmission corridor serving purity-sensitive consumers, but the answer still depends on the assets and customers downstream of the injection point.

Which makes hydrogen blending a question about maps as much as percentages. A single national blending percentage, applied uniformly, would ignore differences between network segments. Set low enough

to accommodate the least tolerant downstream use, it could leave usable headroom elsewhere untouched. Set higher, it could create treatment or separation requirements at offtakes that cannot accept the resulting composition.

The more useful regulatory unit is therefore the bounded network zone: an injection point, the assets downstream of it, the offtakes supplied from it and the concentration those assets and offtakes can collectively accept. The permissible blend would follow that downstream profile, with the boundary of the zone itself forming part of the regulatory decision.

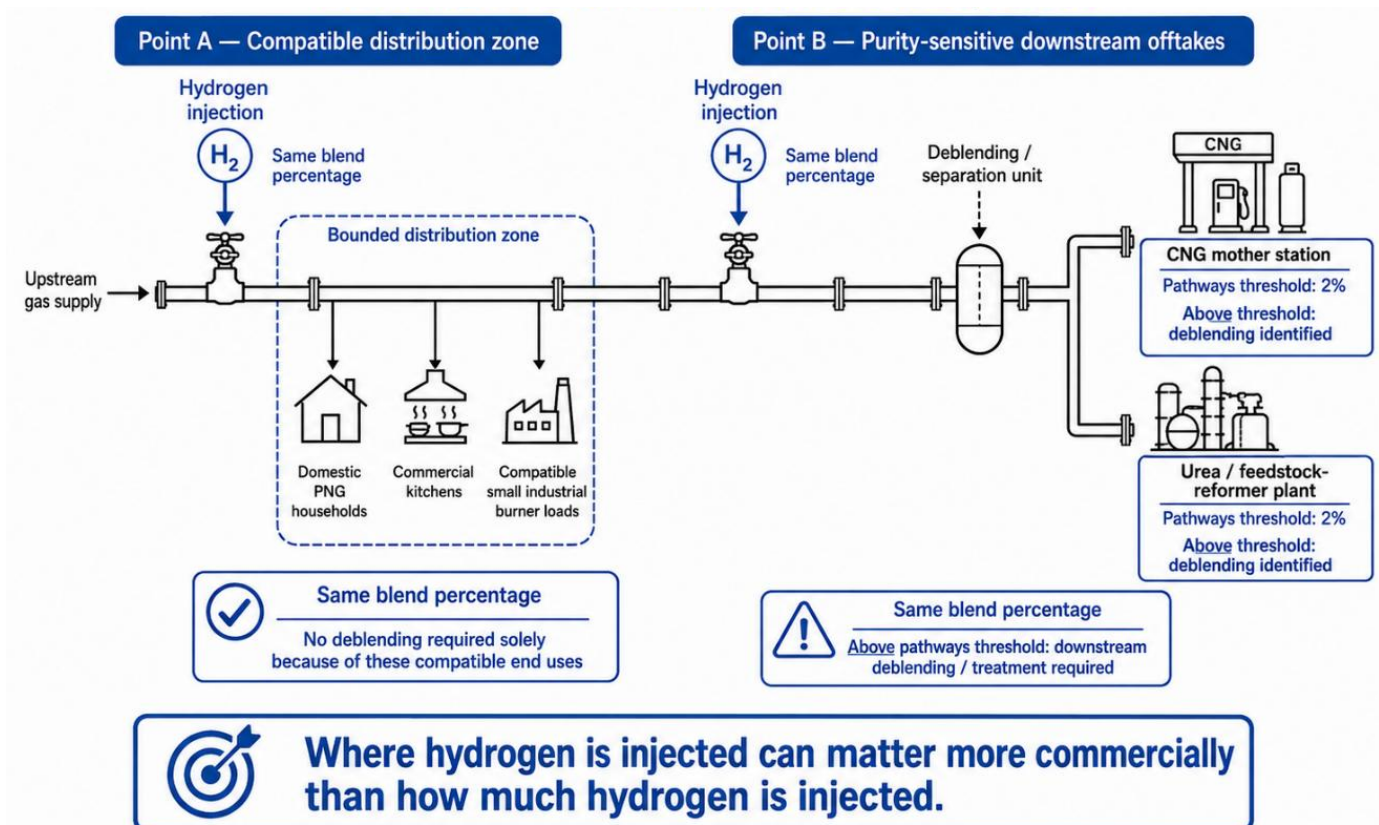
That is more demanding to administer than a single percentage. It is also more faithful to where the cost actually arises: not simply where hydrogen enters the network, but where the changed gas composition meets a consumer that cannot use it.

5.5 Two ways around direct hydrogen blending

There are two routes that avoid much of the downstream problem described in this chapter, and a book arguing for hydrogen blending has to confront both rather than wait to be asked about them.

FIGURE 5.2

Two injection points, two consequences.



The first is methanation. Hydrogen and carbon dioxide can be reacted over a catalyst to produce methane and water before injection, so that the network does not carry hydrogen as a blend component at all. The resulting methane can be conditioned to the applicable pipeline gas-quality requirements. The hydrogen-specific questions considered in this chapter (material tolerance, appliance compatibility and deblending at purity-sensitive offtakes) are then largely moved out of the network and into the conversion plant upstream.

India also has a possible source of carbon dioxide alongside its expanding biogas industry. Upgrading raw biogas to biomethane removes carbon dioxide and other constituents, producing a CO₂-rich separated stream that may, depending on the plant and its configuration, be available for capture or utilisation. Methanation offers one possible use for such a stream.

Against that stand two costs. The conversion carries an energy penalty on top of electrolysis, so less of the original renewable electricity ultimately reaches the consumer as useful gaseous energy. It also adds another piece of capital equipment upstream: instead of injecting hydrogen directly, the project first has to make methane from it.

There is a statutory qualification as well. Methanation solves the hydrogen problem technically; it does not automatically solve it legally. Section 2(za) of the PNGRB Act defines natural gas by reference to gas obtained from bore-holes together with specified inclusions. Synthetic methane produced from hydrogen and carbon dioxide is not expressly named. Its treatment under the present Act should therefore not be assumed merely because the finished molecule is methane.

Methanation is nevertheless important for the argument of this chapter. It shows that there is another way to use the gas network as an outlet for renewable hydrogen: **change the molecule before it enters the pipe**. The price of doing so is paid at the injection end rather than through hydrogen-specific modifications and separation further downstream.

The second route is biomethane itself. The closure report of the National PNG Drive makes the market argument directly: as piped-gas consumption rises and city-gas networks reach higher utilisation, they provide a wider and more stable market for compressed biogas,

supporting the integration of indigenous renewable gas into the gas system (PNGRB, 2026c).

That integration has already moved from principle towards operating practice. In February 2026 PNGRB approved guidelines for injection of biogas and biomethane into natural-gas pipelines and city-gas networks. The guidelines require the injected gas to meet prescribed quality, technical and safety requirements and connect the injection facilities to the existing CGD and NGPL regulatory architecture (PNGRB, 2026a).

But the statutory position deserves the same care as it does for hydrogen. The present Act does not explicitly include biogas or CBG within the definition of natural gas. Biomethane can therefore be technically compatible with an existing gas network without that fact, by itself, settling the reach of the parent statute.

That parallel is useful. Technical readiness can run ahead of explicit legislative wording. It has happened with another low-carbon gas before the hydrogen question is settled.

Biomethane and hydrogen should not, however, be treated as competing claims on the same percentage of blending headroom. Biomethane is methane-rich gas conditioned to network-quality requirements; it does not consume the two-, five- or ten-per-cent hydrogen tolerance discussed elsewhere in this book. The two molecules can still compete at particular locations for injection capacity, offtake, project capital and policy attention, but those are different constraints.

Nor does one make the other unnecessary. Biomethane is ultimately constrained by the quantity, location and economics of suitable biological feedstock. Renewable hydrogen is constrained by a different chain of electricity, water, electrolyser capacity and transport. Their sensible roles in the gas system therefore need not be identical.

The choice is not between reserving a network for biomethane or reserving it for hydrogen. It is between putting each molecule into the part of the system that can absorb it at the lowest additional cost.

5.6 What remains

None of this makes blending unattractive. It makes it specific. Blending belongs where the downstream network and its offtakes can accept the intended

concentration, with the permissible level determined by the assets and consumers actually connected to that part of the system.

Specificity does not make the cost disappear. Injection equipment, analysers, protective systems, metering changes and, where required, deblending all have to be paid for. In a regulated network, the question is not only what those measures cost, but who should bear that cost and who should receive any value they create.

That is a tariff question.

And it is the subject of the next chapter.

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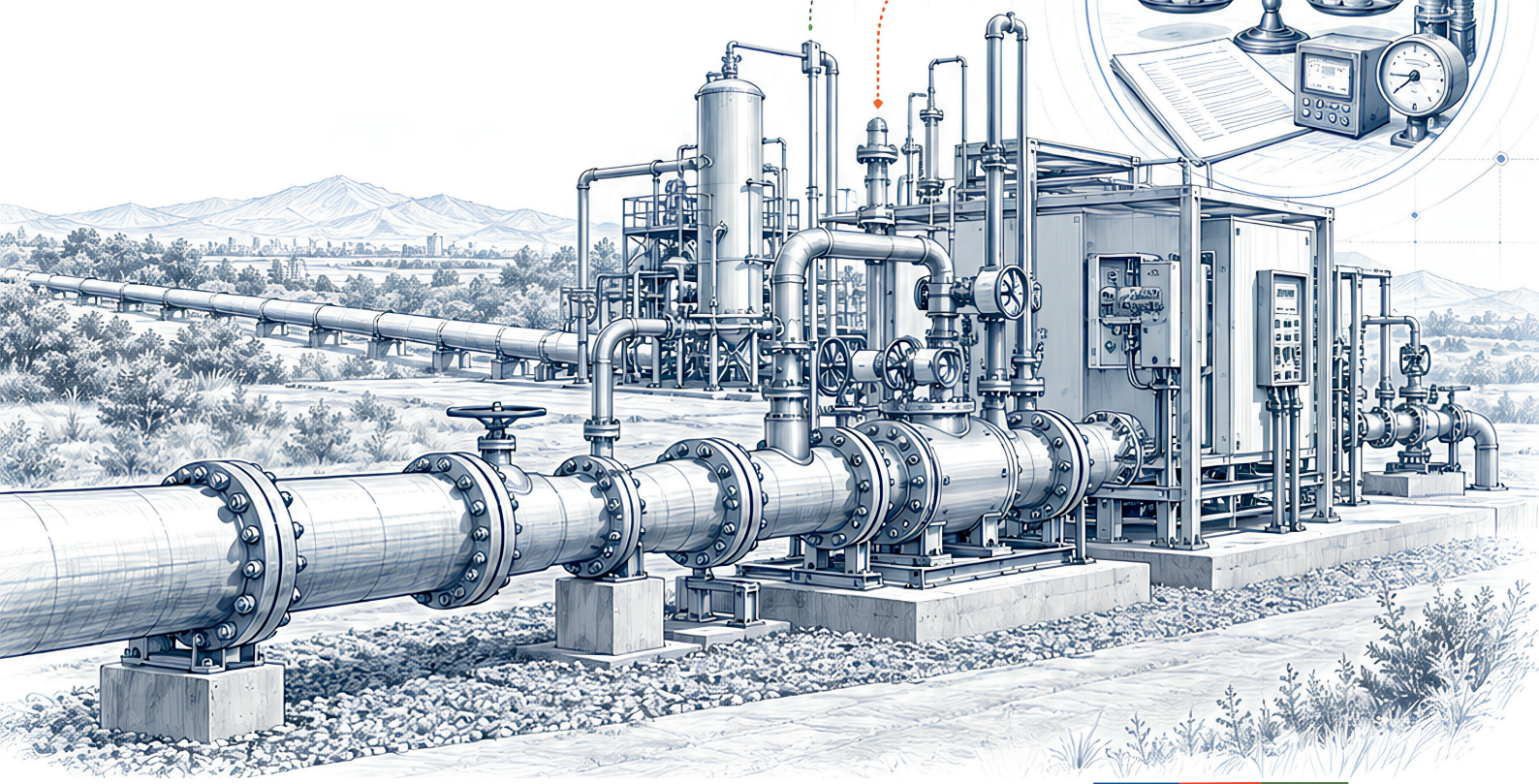
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Who Pays

Blending costs money before it saves any carbon. In a regulated network those costs do not lie where they fall: they are allocated, by a regulator, under a tariff.



One feature of India's pipeline tariff framework becomes particularly important when hydrogen enters the gas stream.

Regulation 2(1)(g) of the natural gas pipeline authorisation regulations defines the pipeline tariff as a unit rate in rupees per million British thermal units. Not per cubic metre. Schedule F requires a transport bill to state volume in both MMBtu and standard cubic metres. Schedule E requires the entity to report its average heat value in MMBtu per SCM, and Schedule H requires the basis of energy equivalence to be stated where volumes are expressed in both units (PNGRB, 2008b).

Indian transmission regulation therefore already works in two measures at once: physical flow in volume and commercial settlement in energy.

Hydrogen makes the connection between the two more consequential. A cubic metre of hydrogen carries much less energy than a cubic metre of methane. As the hydrogen fraction changes, so does the energy represented by a measured volume of blended gas. The September 2025 Roadmap responds to that problem through progressively tighter composition measurement, calorific-value correction and energy-based settlement as blend classes rise (PNGRB, 2025).

Everything in this chapter follows from that conversion: who measures it, who pays for the equipment that makes it measurable, and who carries the cost when the same physical flow delivers less energy.

6.1 The pipe carries less

Before any new equipment is bought, blending changes what a given volume of gas delivers.

Chapter 1 established the physical reason. On a lower-heating-value basis, hydrogen carries a little under a third of methane's energy for the same volume. The Roadmap therefore estimates that a five per cent hydrogen blend reduces volumetric energy content by roughly three to four per cent; at ten per cent the reduction is about seven to eight; and at twenty per cent, fourteen to sixteen (PNGRB, 2025).

That should not be confused with an equivalent percentage loss of hydraulic pipeline capacity. How much gas a line can physically move depends on pressure, compression, diameter, network

configuration and operating conditions. What can be said directly is narrower: at the same volumetric flow, the pipe delivers fewer units of energy as hydrogen replaces natural gas.

That distinction matters because the regulated transmission tariff is expressed in rupees per MMBtu. If the recoverable cost of a pipeline were held constant while its energy throughput fell, the cost per unit of energy would rise unless the effect were offset by greater volumetric throughput, higher utilisation or another recovery mechanism.

Hydrogen therefore creates a second capacity question alongside the hydraulic one: how authorised, contractual and open-access capacity should be reconciled with a stream whose energy content per unit volume changes with blend ratio. The Roadmap identifies the underlying derating issue (PNGRB, 2025). The regulatory treatment of it is not yet settled.

No new blending skid has been paid for at this point. This is the arithmetic that arrives before the expenditure does.

6.2 What blending costs

The Roadmap groups the additional costs associated with blending under four heads, and the classification is more useful here than the indicative tariff numbers attached to it.

First is the capital associated with injection and control: blending skids, gas analysers and protective interlocks. Second is additional operation and maintenance, including composition analysis, monitoring and upkeep of the control system. Third is the incremental safety and leak-detection architecture required for blended service. Fourth is shrinkage, quality assurance and quality control (PNGRB, 2025).

Not every activity in that list is new. A natural-gas network already measures gas, monitors leaks, operates SCADA and maintains safety systems. Hydrogen changes the specification, frequency or extent of some of those activities and adds equipment to others. Nor does every cost sit physically at the injection skid; measurement and surveillance obligations can extend to downstream nodes.

The tariff question is therefore not whether gas networks had these functions before hydrogen. It is what incremental expenditure is attributable to

blending, whether it was prudently incurred, and from whom it may properly be recovered.

The Roadmap also publishes indicative cost-model outputs. This chapter does not use those outputs; it uses only the cost taxonomy and the financing proposals. Nothing that follows requires a precise blending surcharge to be assumed.

6.3 The premium is not where the money goes

The commodity arithmetic is worth doing, but the prices first have to be put on the same energy basis. At five per cent hydrogen by volume, hydrogen contributes about 1.56 per cent of the blend's lower-heating-value energy; at ten per cent, about 3.25 per cent.

Let C_{H_2} and C_{NG} be the hydrogen and natural-gas commodity prices per unit of energy, expressed on the same LHV basis, and let s_E be hydrogen's share of the blend energy. Relative to natural gas alone, the fractional increase in commodity cost is then:

$$s_E \left(\frac{C_{H_2}}{C_{NG}} - 1 \right)$$

A quoted LNG price in USD per MMBtu should therefore not be compared directly with a hydrogen price derived on an LHV basis unless both have first been normalised to the same heating-value convention. The precise increase changes with the

price inputs, but the underlying result is robust: even a large hydrogen price premium has a relatively small effect on the commodity cost of a low hydrogen-volume-fraction blend, because hydrogen supplies only a small share of its energy.

This is a commodity-price comparison only. It does not capture non-commodity costs associated with compression, injection, metering, network adaptation, storage or downstream treatment.

These are illustrative commodity effects, not estimates of the final retail bill. Taxes, distribution margins, network charges and the entity's pricing structure determine how much of the change eventually appears there.

The capital, metrology, safety and downstream-treatment costs follow a different arithmetic. They depend on the assets that must be installed or modified, where those assets sit in the system, who owns them and how the applicable tariff or funding framework allocates their cost.

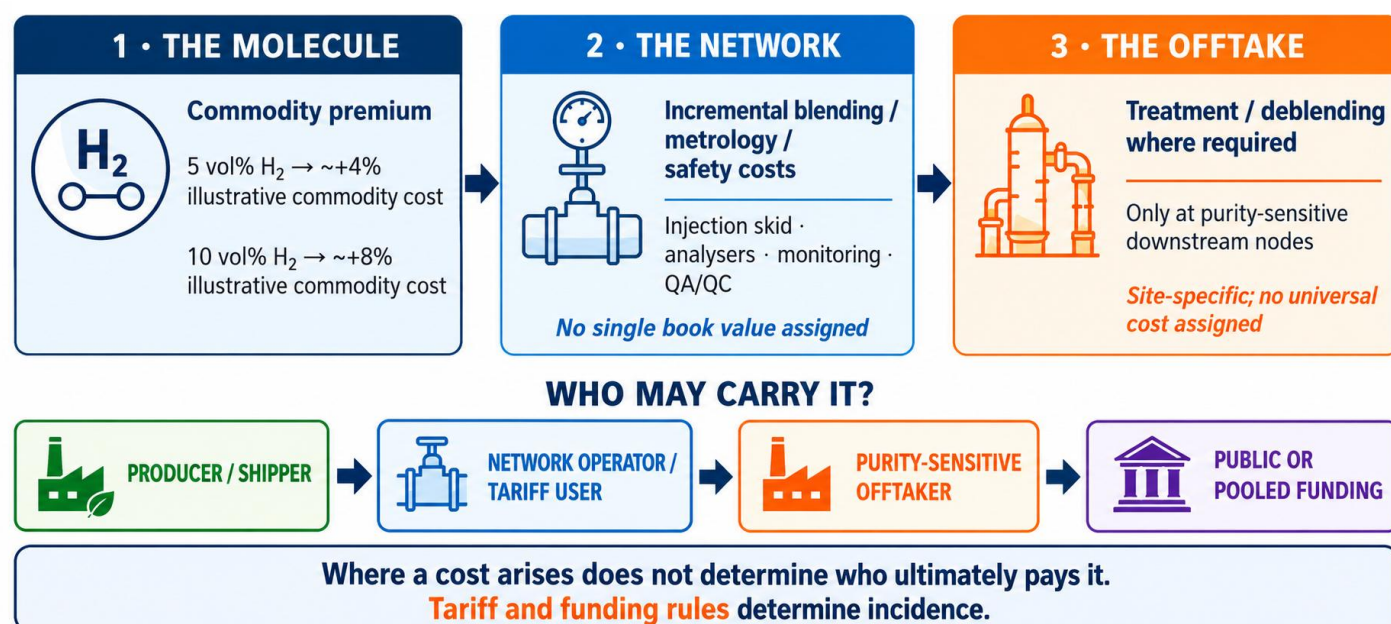
The molecule's price therefore does not, by itself, answer who pays.

6.4 On whom

The Roadmap proposes a hydrogen-infrastructure clause for CGD tariff treatment, intended to recover expenditure on blending skids, sensors and safety systems, and envisages recovery from industrial and commercial consumers. It also proposes differentiated

FIGURE 6.1

Where a cost arises does not determine who ultimately pays it. Tariff and funding rules determine incidence.



treatment between consumers receiving blended gas, consumers requiring deblending and users of pure hydrogen (PNGRB, 2025).

These are proposals, not existing tariff rules. Their importance is that they make explicit a question that engineering cannot answer: which customer class should carry an expenditure that was incurred to introduce hydrogen into a shared network?

One possible logic is to keep early transition costs away from consumer categories that public policy has chosen to protect. But that does not settle the matter. Cost causation and ability to pay are different tests, and an industrial consumer that neither requested a particular blending investment nor receives its principal benefit may reasonably be treated differently from one for which the investment creates a direct decarbonisation service.

The same difficulty appears internationally. Poudineh describes early hydrogen transport and storage as infrastructure being committed before the market it is intended to serve has fully formed. The resulting market-creation risk cannot be removed by a tariff design; it has to be allocated among users, investors and public support (Poudineh, 2026).

Chapter 5 added another party. Where a purity-sensitive offtake lies downstream of an injection point, that customer may require treatment or deblending even though the hydrogen was introduced elsewhere. The magnitude of that cost is site-specific, but its incidence is real.

The relevant parties are therefore wider than a single tariff class: the network user charged through a tariff, the purity-sensitive offtaker required to treat the gas, the operator or its investors where expenditure is not recoverable, and the public or pooled funding source where transition support is provided.

Cost allocation is a distributive choice expressed through a tariff. The engineering tells the regulator where the expenditure occurs; it does not tell the regulator who should bear it.

6.5 The funds

The Roadmap proposes two broader ways of carrying expenditure that may not be suited to immediate recovery from a particular customer.

The first is a proposed Hydrogen Innovation Fund. The Roadmap envisages it as a broader source of support for early-stage hydrogen R&D, pilot implementation and OEM certification, rather than as a fund for the national testbed alone. Its proposed applications include the national testbed and mobile laboratories, field pilots, appliance-retrofit support, certification laboratories and hydrogen-compatible digital monitoring systems. Its proposed sources include a contribution linked to the annual net profits of major pipeline operators, a share of corporate social responsibility allocations, viability-gap support under the National Green Hydrogen Mission, and climate or multilateral development finance. The proposed uses include the national testbed, field pilots, appliance retrofits, certification facilities and digital monitoring, with competitive and performance-linked disbursement (PNGRB, 2025).

The second is an alternative proposal for a one per cent cess on the natural-gas pipeline tariff, ring-fenced for hydrogen research and pilot support (PNGRB, 2025).

The difference is not merely administrative. The first approach spreads the funding requirement among corporate, mission and external-finance sources rather than placing it immediately on a unit of gas transportation. A pipeline cess would put the charge first onto transportation through the regulated network. Whether, and to what extent, that charge was then passed through to particular classes of final consumer would depend on the downstream pricing and tariff arrangements.

A dedicated levy may offer a more predictable recurring source than project-by-project grants. But durability does not answer the prior legal question: whether the Board may impose such a levy, for what purposes, and on which regulated users.

The Roadmap proposes the mechanism. It does not settle the statutory authority for it.

That question belongs to Chapter 9.

6.6 What the customer can check

There is one party to the arrangement that does not negotiate the network's metrology rules: the customer.

Chapter 4 described the Roadmap's proposed measurement architecture. Here its commercial purpose matters. A household on a piped connection

sees volume at the meter but consumes energy at the burner. Hydrogen blending lowers the energy contained in a given volume of gas: on the lower-heating-value basis used in this book, the reduction is about three and a half per cent at a five-per-cent blend, seven per cent at ten, and fourteen per cent at twenty.

That creates a consumer-protection issue. If a volumetric billing arrangement simply carried over the same per-unit treatment without correcting for the lower calorific value of the blend, a customer receiving the same measured volume could be charged as though that volume still contained the energy of unblended natural gas. Calorific-value adjustment corrects for that difference. For the same measured volume, the billable energy falls as the measured calorific value falls.

The Roadmap therefore proposes increasingly composition-sensitive settlement as the blend class rises. Its detailed metrology provisions move towards energy-based billing from BG-2 upward, using on-site composition analysis and a composition/calorific-value correction factor. Where volumetric billing continues during transition, the proposed framework provides for a compensation factor reflecting measured energy dilution. It also provides for publication of average lower heating value, Wobbe index and the conversion factors applied in billing, supported by analyser and meter verification (PNGRB, 2025).

The calculation of calorific value itself is not a standards gap. BIS already adopts IS 14504:2021 / ISO 6976:2016 (Bureau of Indian Standards, 2021) for calculating calorific value, density, relative density and Wobbe index from a known gas composition. What is not presently identified in the Indian standards framework is a dedicated BIS methodology for applying a composition or calorific-value correction specifically to the billing of hydrogen–natural-gas blends. The Roadmap's CVCF therefore goes beyond determining the properties of the gas: it proposes how those measured properties should enter the commercial account.

(The Roadmap's BG-2 service-class summary describes energy-based billing as “recommended”, while its detailed metrology provisions state that it is mandatory from BG-2 upward. This chapter records the direction of the proposed framework; it does not treat either formulation as a notified billing rule.)

That correction should not be confused with the final price effect of blending. A more expensive hydrogen fraction can raise the commodity cost per unit of energy, while blending equipment, metrology and safety systems may add recoverable network costs. Calorific-value adjustment does something narrower: it prevents a lower-energy cubic metre from being treated commercially as though it still contained the reference energy of unblended natural gas.

Read as engineering, these are measurement and calibration requirements. Read as consumer regulation, they preserve the evidentiary chain between the gas that passed through the meter and the energy for which the customer was charged. Once settlement depends on composition, the volumetric meter reading alone is not enough to reproduce the commercial calculation. The composition and calorific-value data behind the conversion must also be auditable, and the customer should be able to see the factor that was applied.

The bill therefore has two sides to it. Hydrogen can add costs elsewhere in the chain; calorific-value adjustment ensures that the customer is credited for the corresponding reduction in energy contained in a given volume of blended gas.

That is why energy-basis settlement is not merely a hydrogen instrumentation problem. It is a billing-transparency and consumer-protection problem.

6.7 What is not yet decided

The pieces are now visible. Natural-gas transmission tariff is already denominated in energy. Blending reduces the energy carried by a given volume of gas. The Roadmap identifies additional network costs and proposes mechanisms through which some of them might be recovered or funded. Chapter 5 showed that further treatment costs can arise at particular downstream offtakes.

What remains undecided is incidence: which costs belong to the network, which belong to a particular customer, which remain with the investor, and which (if any) should be carried through public or pooled support. Alongside that sits the regulatory test of prudence: which expenditure should be recoverable at all.

Those are tariff questions, and ultimately questions of statutory authority.

But even a well-designed tariff cannot recover the cost of infrastructure from a market that has not yet formed.

The next question is therefore one of sequence: who builds first?

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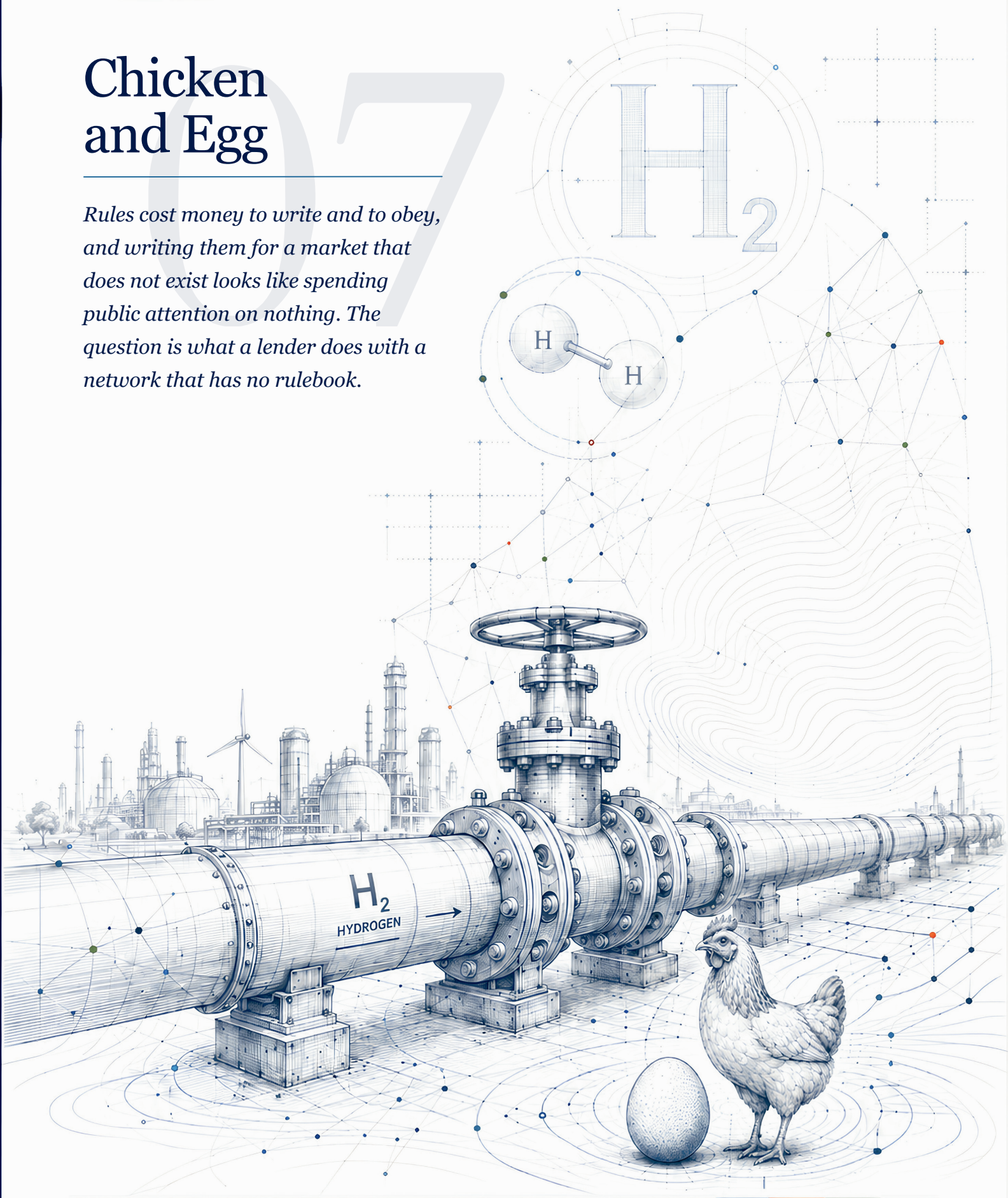
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Chicken and Egg

Rules cost money to write and to obey, and writing them for a market that does not exist looks like spending public attention on nothing. The question is what a lender does with a network that has no rulebook.



Joan Ogden described the start-up problem in 1999, and its structure has changed remarkably little. Infrastructure becomes economical only when demand is large enough; demand is difficult to create before infrastructure exists; and investors hesitate to build either without confidence in the other (Ogden, 1999).

Nobody wants to go first.

The regulator's version has an extra turn in it. Rules could go first, but rules written before a market exists are written on guesses, and a regulator who guesses wrong imposes cost on an industry for no benefit. Better, on this view, to let the market form and then regulate what it turns out to be.

That argument is respectable and this chapter is against it. Not because anticipation is virtuous, but because of what happens in a room where somebody is deciding whether to lend.

7.1 What a lender is actually looking at

Project finance for energy assets works on a narrow principle: the lender is repaid from the project's own cash flows and has little or no claim on the sponsor beyond the project's collateral and its contracted revenues. Everything else follows from that. Bankability is the assessment of whether a project's risk-return profile, legal and contractual framework and revenue certainty are enough to attract capital on reasonable terms (Rushton & Patonia, 2026).

Oil, gas and mature renewables have a template for this, worked out over decades: take-or-pay obligations, price indexation, delivery flexibility, liquidated damages, step-in rights. Each of those apportion a risk to whichever party can manage it. Hydrogen projects have to borrow that template, and where hydrogen differs the borrowing does not fit.

The most important place it does not fit has a name. A hydrogen plant depends on the simultaneous completion of things it does not own - pipelines, storage, transport networks, and a customer able to receive what it makes. Where those are built by different entities, a plant can be finished and idle. Where distribution is not synchronised with production, the producer cannot deliver and may breach a supply contract it has already signed.

The financiers' term for this is synchronisation risk, and the finding that matters for this book is what

lenders do about it: they size, or even time-limit, debt to the weakest link in the chain rather than to the standalone construction risk of any single asset (Rushton & Patonia, 2026).

Read that sentence carefully. An electrolyser can be technically sound and still have its financing constrained by an asset outside its fence. If the pipeline, storage system or offtake arrangement on which it depends is uncertain, that uncertainty enters the lender's assessment of how much debt the project can carry and on what terms.

Regulation can become one of those dependencies. If access to the network, permissible operating conditions or the treatment of hydrogen under the governing framework is unresolved, the lender does not need to decide the legal question itself. It prices the uncertainty or refuses to rely on the uncertain revenue.

That is why regulatory clarity has to arrive early. Not because every rule can sensibly be finalised before evidence exists, but because the rules on which an investment depends cannot all be left until after the investment has been made.

7.2 How thin the offtake actually is

The scale of the revenue problem is worth seeing.

Rushton and Patonia, drawing on BloombergNEF data, report that only a small share of planned clean-hydrogen capacity has an identified offtaker at all. Their Figure 4 shows about six per cent of total planned capacity with some form of offtake, and within that offtake capacity only around thirteen per cent classified as binding (Rushton & Patonia, 2026).

That does not mean capital is unavailable. It means that much of the announced project pipeline still lacks the revenue certainty on which conventional limited-recourse debt depends.

This is where a blending obligation can matter, but the distinction is important. A mandate is not an offtake agreement. It can create a defined source of demand and reduce uncertainty over whether somebody will be required to buy or use the molecule. Bankability still depends on translating that requirement into an enforceable commercial arrangement: quantity, price, duration, counterparty credit and the allocation of non-performance risk.

Blending therefore does something important for a young hydrogen market even if Chapter 1 was right that it is not the long-term answer to bulk transport. It can create a route to early demand through an existing gas system. If that demand is then converted into creditworthy long-term contracts, it can also support financing.

The pipe provides the route. The rule can create the demand signal. The contract is what turns the two into bankable revenue.

7.3 What LNG actually teaches

LNG provides the cleaner precedent.

The first LNG project financings date to the mid-1970s. They did not wait for a liquid global spot market to appear. Long-term sales and purchase agreements allocated price and volume risk to identified counterparties and created cash flows against which lenders could advance debt.

What took more than three decades was something different: lender willingness to give meaningful credit to merchant revenue. Even today, Rushton and Patonia note, merchant exposure is commonly haircut or excluded from the base case on which debt is sized (Rushton & Patonia, 2026).

That is the useful comparison for hydrogen. An infrastructure market does not have to be mature before it can be financed. But where the market is immature, the contract has to do work that the market cannot yet do.

Hydrogen therefore need not wait for a liquid commodity market. It does need credible rules, counterparties and contractual arrangements capable of converting future demand into predictable revenue.

7.4 The argument that is not about money

Everything above is an efficiency argument: earlier regulatory clarity can reduce financing uncertainty. It is true, and it is not the strongest thing that can be said.

The stronger argument is about what happens if hydrogen-specific rules arrive after the assets and commercial arrangements they are intended to govern.

Existing natural-gas pipelines and city-gas networks do not cease to be regulated merely because a low proportion of hydrogen is introduced into the gas

stream. The natural-gas safety and operating framework continues to matter. The difficulty is narrower: the present PNGRB Act does not expressly provide a complete hydrogen-specific basis for matters such as dedicated hydrogen pipeline authorisation, capacity, access, tariff treatment and the full set of technical requirements that a hydrogen regime would eventually need.

If that framework arrives only after assets have been built or customer-facing arrangements established, later requirements may have to be applied to equipment, contracts and operating practices designed before those requirements existed. Some will fit. Others may require modification.

The issue is therefore not that the network would be unregulated. It is that hydrogen-specific obligations should not depend indefinitely on stretching instruments written for another gas beyond the purpose for which Parliament enacted them.

That is an accountability argument before it is a financing one.

7.5 What the record shows

The financiers have looked at which hydrogen projects reached financial close and which stalled, and the pattern is consistent enough to be worth stating plainly.

Those that closed combined stable policy support, strong offtake agreements and integrated infrastructure development, they turned political ambition into investment signals through transparent risk allocation and revenue certainty. Those that faltered suffered from policy ambiguity, regulatory inconsistency, or weak coordination along the value chain (Rushton & Patonia, 2026).

Policy ambiguity. Regulatory inconsistency. Weak coordination along the value chain. Chapter 3 found an earlier echo of the same pattern in the wreckage of the American hydrogen programme of the 1970s, described in different words by people who were not thinking about project finance at all.

The financiers' own conclusion is that bankability is less a question of technological viability than of financial structure, policy coherence and market formation, an ecosystem outcome, secured not within the boundaries of a project but through the interplay of

technology readiness, policy frameworks, market confidence and institutional innovation (Rushton & Patonia, 2026).

A regulator cannot create technological maturity, bankable demand or market confidence by itself. What it can do is remove one avoidable source of uncertainty: the rules under which infrastructure may be connected, operated, accessed and paid for.

7.6 Where India stands

Set the pieces out and the Indian position is unusual, in a way that is easy to miss from inside it.

There is a network, built and underused. There is a regulator with five years of pilot and preparatory work behind it, a published Roadmap, a nine-parameter readiness screen, proposed service classes and operating procedures (PNGRB, 2025), and transmission and distribution testbed programmes at different stages of development. There is a Mission that assigns the work. There is also already a mandatory blending obligation for a different indigenous gas: CBG in the CNG (Transport) and PNG (Domestic) segments (Press Information Bureau, 2023b). It does not answer the hydrogen question, but it demonstrates that demand creation through a blending obligation is already an instrument of Indian gas policy.

The familiar chicken-and-egg problem therefore looks slightly different in India. The physical network already exists. Pilot evidence exists. A proposed technical architecture exists. Testbed development is under way. What remains incomplete is the express and enforceable hydrogen-specific framework within which those pieces would eventually operate.

That does not require the rulebook to outrun the evidence. It requires the two to be built together. Technical testing can narrow what the rules should say; regulatory preparation can reduce the uncertainty against which investment is judged. Waiting for either side to finish before beginning the other simply recreates the sequencing problem.

The point does not depend on an estimate of how long Parliament will take. The testbeds themselves have engineering, commissioning and evidence-generation horizons. Legislative clarification, standards development and technical testing can therefore proceed in parallel, with the evidence progressively

informing the framework that will eventually depend on it.

Anticipatory regulation is therefore less a claim that the regulator knows what the market will become than a way of preserving options while it forms.

What has actually been built in those five years is the subject of the next chapter.

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PART IV

THE ARCHITECTURE

What Has Been Built

Five pilots, a set of guidelines, an advisory committee, three foreign cooperations and a roadmap to 2033.



In June 2021 the Board cleared a request from GAIL (India) Limited, working with Avantika Gas, to put two per cent hydrogen into a steel line upstream of a city gate station at Indore. It was a small thing: one operator, one section of network, one clearance letter dated 23 June (PNGRB, 2026b).

Everything in this chapter followed from it.

8.1 The order things happened in

The sequence matters more than the inventory, because the sequence is the argument.

The Indore clearance made obvious that a framework was needed, and Typical Guidelines for hydrogen blending were drafted the following year. They were then held. They were not notified, not published and not put out for comment.

That is not a failure and it deserves recording as a choice. A framework issued in 2022 would have rested on one completed pilot at two per cent in one city. Four further pilots, a commissioned study and a roadmap have happened since, and the guidelines now being revised rest on all of them.

So the sequence runs: a pilot, a draft held back, four more pilots cleared case by case, a study, a roadmap, an advisory committee, and only then a framework put to the public. The order was chosen, and the choosing is the part worth noticing. Regulatory programmes more often accumulate than build, a study here, a committee there, a pilot because somebody asked.

8.2 The five pilots

Five blending pilots have been cleared, and they were not chosen to be similar (PNGRB, 2026b).

One thing has to be said about how the pilots are described. The register records the point at which hydrogen enters each pilot network, and that point determines what equipment the blended gas can actually test. A pilot injected upstream of a city gate station can expose downstream station equipment and the distribution system to blended gas; a pilot injected into an MDPE distribution main does not, by itself, test the upstream steel transmission line or city gate station in hydrogen service. Each pilot should therefore be read against the assets and offtakes located downstream of its own injection point rather than as a test of the entire CGD chain.

Indore, Madhya Pradesh. The first clearance went to GAIL (India) Limited with Avantika Gas on 23 June 2021, at two per cent, injected into a steel line upstream of a city gate station; it was completed with no adverse reports. A second clearance followed to Avantika Gas on 23 October 2022, at five per cent, injected into distribution polyethylene. Assessment is under way.

Jorhat, Assam - Assam Gas Company, cleared 31 March 2023. Two per cent, injected into distribution polyethylene, serving township domestic connections.

NTPC Kawas, Gujarat - Gujarat Gas Limited, cleared 3 November 2023. Five per cent, injected into distribution polyethylene, supplying households in the NTPC township at Adityanagar in Surat, with the hydrogen made by electrolysis from a one-megawatt floating solar plant.

Ahmedabad, Gujarat - Adani Total Gas Limited, cleared 30 May 2024. Five per cent, injected into distribution polyethylene.

Gorakhpur, Uttar Pradesh - Torrent Gas Limited, cleared 29 November 2024. Two per cent, injected into steel at a city gate station and carried on into the distribution network beyond it. Assessment is expected at the end of 2026.

Read as a set, they vary the things worth varying: six clearances across five locations, two blend levels, injection at both city gate stations and distribution mains, four states, six operators, and consumers ranging from a township to a city network. Every pilot carries mandatory third-party assessment.

What they do not vary is scale. These are sections and townships, not networks, and Chapter 4 explained why the evidence they produce cannot answer the question about Indian transmission steel. That is what the testbed is for.

8.3 The groundwork

Alongside the pilots, three lines of regulatory preparation have run.

The Typical Guidelines have been rewritten. The 2022 draft was never issued; what exists now is a document built from the ground up and narrowed deliberately to domestic piped natural gas, reviewed by the Scientific Advisory Committee, and scheduled to be put out for

public comment at the National Conference on Transportation of Hydrogen and Blending with Natural Gas at the Indian Institute of Technology Ropar on 09 and 10 October 2026.

It will be the first thing this programme has published for the public to argue with. It will also still be guidelines rather than regulations, and the distinction is the subject of Chapter 9.

Eight of the hydrogen standards recommended by the Ministry of New and Renewable Energy have been adopted. Chapter 4 set out what adoption means in this context and where it stops.

And amendments to the PNGRB Act have been proposed, in the terms Chapter 9 describes.

8.4 From study to roadmap

The analytical work came in two stages and they did different jobs.

The Pathways study, conducted by ICF Consulting India under the Board's mandate and in association with the World Bank, established what an Indian network can physically take: the thresholds at two, ten and above ten per cent, the component tolerances, the deblending economics, and the finding that dedicated pipelines may be more cost-effective than blending beyond ten per cent. Chapters 1, 4 and 5 rest on it. (PNGRB & ICF, 2025).

The roadmap turned that into a programme. Nine modules, a nine-parameter screening framework, four service classes with an operational rulebook, a testbed specification, a deblending assessment, a financing mechanism, and a two-phase horizon - capacity building and foundational readiness to 2028, scale-up and commercialisation to 2033. It was reviewed by NITI Aayog on 9 July 2025 in a session chaired by Dr V. K. Saraswat (PNGRB, 2025; PNGRB, 2026b).

The two-phase structure is worth a sentence of its own, because it sequences regulation to what can be demonstrated rather than to what would be convenient. Nothing in the second phase is scheduled to begin before the evidence from the first is in.

8.5 The testbed

The pilots produce field data from operating networks. The testbed is meant to produce something the pilots cannot: controlled experimental evidence on Indian

steel, Indian welds, Indian polymers and Indian operating conditions - the tensile and fatigue behaviour, the threshold stress intensities, the crack growth rates, the permeation scores and the meter biases that Chapter 4 showed the screening matrix currently borrows from foreign codes.

Two nodal designations were made in November 2025. Indraprastha Gas Limited holds the nodal role for the city gas testbed. GAIL (India) Limited holds it for the transmission side, with IIT Roorkee as academic partner for in-situ testing at Vijaipur.

Both remain at the stage of institutional arrangement rather than operation. GAIL has informed the Board that its revised proposal for the transmission test loop is under consideration by the Ministry of New and Renewable Energy. No commissioning date is stated here, because none has been sanctioned.

That is worth saying plainly rather than glossing. The single most important piece of evidence the Indian programme needs, the material data that would tell the Board whether Indian X-70 behaves as the generic matrix assumes, does not yet exist, and the facility that would produce it has not been built.

8.6 The committee

Data does not translate itself into regulation. Somebody has to decide what a test result means for a rule, and that decision is technical, contestable and better made in public than in a file.

The Scientific Advisory Committee on Hydrogen Initiatives was constituted by Board order dated 12 February 2026 and met for the first time on 24 February at the Board's office in New Delhi. It is chaired by Sh. Mukesh Mohan, Executive Director at Indian Oil, and convened by Sh. Muktikam Phukan, Director (Coordination & Hydrogen), with the Hydrogen Cell as secretariat. Its membership runs across the ecosystem the questions come from: GAIL and Indraprastha Gas from transmission and distribution, Gujarat Gas from city gas, Engineers India as consultants, Welspun from pipe manufacture, the Indian Institutes of Technology at Ropar, Roorkee and Bombay, the National Green Hydrogen Mission, the Bureau of Indian Standards, and the American Society of Mechanical Engineers (PNGRB, 2026b).

Its membership is worth setting out, because the composition is the point. Gas transmission and distribution: GAIL, Gujarat Gas, Indraprastha Gas. Engineering and manufacture: Engineers India Limited, Welspun. Academic: the Indian Institutes of Technology at Ropar, Roorkee and Bombay. Standards: the Bureau of Indian Standards, and ASME. Policy: the National Green Hydrogen Mission. In the chair, an Executive Director of Indian Oil.

Chapter 4 observed that Indian technical standards adopt ASME B31.8 as the governing code, subject to Indian modifications, and that its hydrogen counterpart, B31.12, appears in neither regulation's annexures. ASME sits on this committee. Whatever else the membership was assembled for, the body whose gas code India has adopted, and whose hydrogen code it has not, now advises on the question.

The remit recorded in the constituting order is India-specific guidance on hydrogen transportation through pipelines, on blending, and on the associated safety protocols. The deliverables are correspondingly concrete: blending guidance, validated safety protocols, assessment of the testbed design, structured technical review of the testbeds and the five pilots, and evidence-based recommendations for amendments, operational rulebooks and tariff frameworks.

The pattern is not Indian. Germany constituted a National Hydrogen Council in June 2020, twenty-five members from industry, science and civil society. The United Kingdom constituted what is now the Hydrogen Delivery Council in July 2020. Regulators reach for expert advisory bodies because there is a class of question they cannot answer alone, and the questions in this book are mostly of that class.

8.7 Borrowing time

Three memoranda have been signed with European technical institutions since April 2025, and the reasoning behind them is stated in the Board's own record: standards, test methodologies, simulation tools and safety frameworks that took Germany and Britain two decades to develop can be adopted and adapted in a fraction of that time, provided an institutional pathway exists (PNGRB, 2026b).

The Institution of Gas Engineers and Managers, April 2025.

IGEM is Britain's professional body for gas engineering and publishes hydrogen-specific additions to its transmission and distribution rule set. Relevant instruments include IGEM/TD/1 Edition 6 Supplement 2 for high-pressure hydrogen pipelines and repurposing above 7 bar; IGEM/TD/3 Supplement 1 for natural-gas/hydrogen blends in distribution pipelines at up to 7 bar; IGEM/TD/22 for repurposing natural-gas distribution mains and services to hydrogen; IGEM/TD/23 for hydrogen pressure-regulating installations at up to 7 bar; and hydrogen supplements to TD/13 for pressure-regulating installations. The memorandum provides a structured route to technical standards cooperation, training and certification.

SGN, August 2025

Signed during a study visit to the United Kingdom. SGN is developing H100 Fife, an end-to-end 100 per cent green-hydrogen production, storage and distribution-to-homes demonstration in Fife. The first phase is designed for up to 300 homes in Buckhaven and Denbeath, supplied by a 5 MW electrolyser. The network was completed in December 2024; commissioning of the production and storage site has since begun, with homes to be connected on a rolling basis. The memorandum covers blending pilots, integrity management and pathways for hydrogen in city-gas networks.

And the Deutscher Verein des Gas- und Wasserfaches, (DVGW) exchanged on 12 January 2026 at Mahatma Mandir in Gandhinagar in the presence of the Prime Minister of India and the German Federal Chancellor. DVGW maintains the Regelwerk, the German technical rule set for gas, including the worksheets on gas quality, on conversion of steel and plastic pipelines for hydrogen, and on fracture mechanical assessment.

Chapter 4 argued that a standard is evidence about the network it was written for, which might read as an argument against all of this. It is not. Borrowing a standard is a judgement about resemblance, and a cooperation agreement is how you find out what the standard actually assumes, which is precisely what an Indian regulator cannot learn by downloading the document.

8.8 The domestic side

Three lines of domestic engagement have run alongside.

Industry, principally through the pilots themselves, each one a structured collaboration with an authorised city gas entity and through the two testbed designations of November 2025, which brought GAIL and Indraprastha Gas into technical partnership with the Board. Workshops have widened the conversation: the Indian Oil workshop at Panipat Refinery on hydrogen transportation through pipelines on 4 November 2025, and the first Hydrogen Pilot Project Forum, held alongside a stakeholder consultation at the India Habitat Centre on 1 August 2025.

Academia and research, through IIT Roorkee as testbed partner, the Gujarat Energy Research and Management Institute, and Indian Oil's research centre at Faridabad.

And cross-ministerial coordination: MoPNG as parent ministry, under whose Mission clause the Board is designated; MNRE as nodal ministry for the Mission, with the Board's Director serving on the National Hydrogen Safety Panel; NITI Aayog, which reviewed the draft roadmap; and the Bureau of Indian Standards and the explosives regulator, with whom coordination is flagged in the roadmap's regulatory review module (PNGRB, 2025; PNGRB, 2026b).

8.9 Safety

Three institutional layers govern safety in the programme, and they do different things.

The Scientific Advisory Committee has a dedicated safety assessment remit covering hydrogen risks across production, transport, blending and end use, with explicit emphasis on high-pressure blending and residential use. The National Hydrogen Safety Panel, constituted under the Mission and on which an official of the Board serves, supplies the inter-ministerial coordination. And mandatory third-party assessment of every blending pilot is the operational safeguard, the mechanism by which what happens on a pilot becomes externally verified evidence rather than an operator's account of its own work (PNGRB, 2026b).

The third of those is the one that will matter most, and for a reason the first two do not cover. A regulator without statutory power over hydrogen cannot compel

much. What it can do is make external verification a condition of the clearance it does have power to grant, which is what has been done, and which is why the pilot record can be relied on at all.

8.10 What it adds to

Set out end to end, the five years produced: five pilots authorised and one completed; a set of guidelines drafted, withheld, and rewritten; eight recommended standards adopted; a commissioned study published; a roadmap to 2033 reviewed by NITI Aayog; an advisory committee constituted and convened; two testbed nodal designations; three international memoranda; and a proposal for statutory amendment.

Not one of those is a regulation.

The Typical Guidelines are guidelines. The service classes are a framework. The screening matrix is a method. The operational rulebook is a proposal. The tariff clause is a recommendation. Every element of the architecture described in this chapter exists as preparation for an instrument that cannot yet be made, and the Board's own summary of its position says so: the bottleneck is statutory rather than technical.

Which is where this book ends up, and where the next chapter begins.

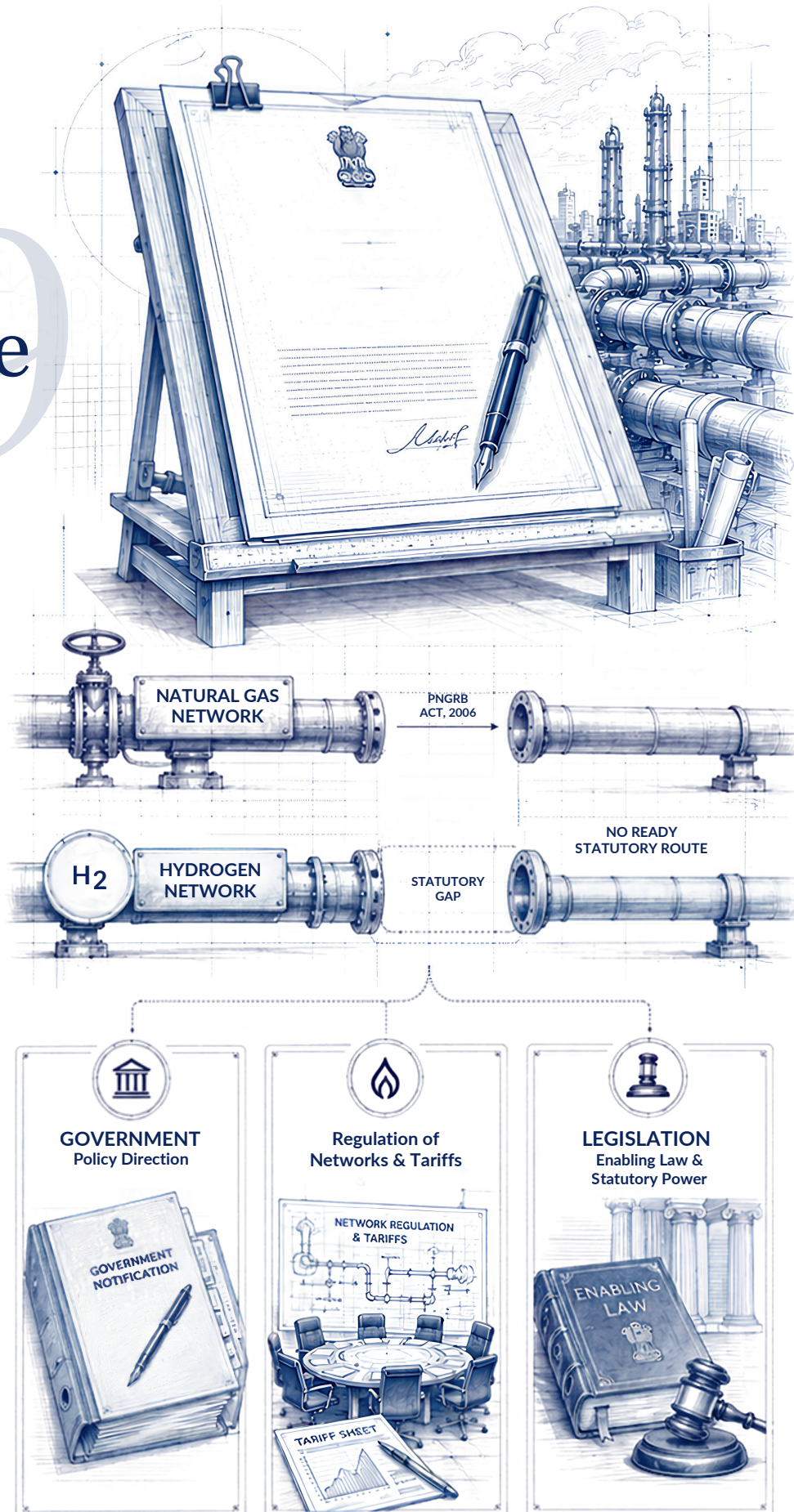
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The Statutory Gap, and the Three Roles

On 13 August 2026 the Government amended a supply order from 1999 by publishing a notification. PNGRB has no equivalent route for hydrogen, and the reason is the subject of this chapter.



On 13 August 2026 the Government amended a supply order from 1999 by publishing a notification. The contrast with hydrogen is the subject of this chapter.

The order was the Petroleum Products (Maintenance of Production, Storage and Supply) Order, 1999. As Chapter 2 described, the amendment inserted a new operative clause and a schedule specifying refinery and upstream-company LPG production quantities, required adequate storage, evacuation and transport infrastructure, empowered the Central Government to direct production increases when public interest required them, provided for monitoring, and required the schedule to be updated twice each year (Ministry of Petroleum and Natural Gas, 2026e).

No amendment to the parent statute was required. Section 3 of the Essential Commodities Act, 1955 already supplied the authority under which the subordinate instrument could be changed.

Hydrogen presents the opposite problem for this Board. PNGRB can amend regulations only within the subject matter Parliament has already placed inside the PNGRB Act. The difference is not institutional capacity or willingness. It is the location of the legal power.

9.1 What the Act reaches

The Petroleum and Natural Gas Regulatory Board Act, 2006 is built around three statutory categories: petroleum, petroleum products and natural gas. The Board's powers - to authorise infrastructure, regulate access and tariff, prescribe technical standards and exercise its other statutory functions - operate within that subject matter.

Hydrogen is not expressly included as a regulated substance. Section 2(ze) defines petroleum by reference to liquid hydrocarbons and petroleum products by derivation from petroleum. Section 2(za) defines natural gas as gas obtained from bore-holes and consisting primarily of hydrocarbons, together with specified inclusions such as LNG, CNG, transnational pipeline gas, gas hydrates and coal-bed methane. Hydrogen appears in none of those express inclusions.

A low-proportion hydrogen blend presents a harder question. The natural-gas component remains natural gas, and the resulting stream may still be capable of

being regarded as natural gas while hydrocarbons remain predominant. But the Act does not say that expressly. Nor does it prescribe a hydrogen percentage below which the classification is preserved.

That distinction is enough for the argument here. A predominantly natural-gas stream containing a small hydrogen fraction is legally different from hydrogen as a fuel in its own right or from a dedicated hydrogen pipeline. But the statute supplies no numerical boundary between the two.

Economics can produce an indicative percentage. Engineering can produce a safe percentage. The Act does not produce a percentage at all.

9.2 Two doors that do not open

There are two provisions that look, at first sight, as though they might close the gap without an amendment to the Act. Neither is enough.

The first is section 2(zc). Strictly speaking, it is not a free-standing power to declare any substance to be natural gas. It defines “notified petroleum, petroleum products and natural gas” as such petroleum, petroleum products and natural gas as the Central Government may notify from time to time for maintaining or increasing supply, securing equitable distribution or ensuring adequate availability.

The grammar matters. Notification operates on a substance already falling within one of the statutory categories; it does not itself enlarge those categories. If a low-proportion blended stream is already capable of being treated as natural gas, section 2(zc) may operate on that natural gas. It cannot, by notification alone, make hydrogen in its own right natural gas.

Australia faced a comparable definitional problem and dealt with it legislatively. Its National Gas Law and National Energy Retail Law had been built around natural gas and processable gas; hydrogen did not fall within the existing conception of naturally occurring gas. The 2023 reforms therefore extended the national gas framework to a broader category of covered gases, expressly encompassing hydrogen and blends containing it. Taylor describes the amendment as the step that allowed the national gas framework to reach low-level hydrogen blends rather than requiring hydrogen to be treated as though it were natural gas already (Taylor, 2024).

The Australian solution is useful because of what it did not do. It did not rely on an administrative power to deem hydrogen natural gas. It changed the statutory vocabulary so that the law could expressly accommodate a new gas.

The second is section 11(j). It permits the Board to “perform such other functions as may be entrusted to it by the Central Government to carry out the provisions of this Act.” The limiting words do the work. Section 11(j) can enlarge the functions entrusted to the Board for carrying out the Act; it cannot enlarge the subject matter of the Act itself.

Neither provision therefore supplies an administrative substitute for an express hydrogen mandate.

9.3 What cannot be given effect

The consequence is specific rather than general, and listing it is more useful than describing it.

Pipeline authorisation. The Board cannot authorise a dedicated hydrogen pipeline, because the authorisation power runs to natural gas pipelines and city gas networks.

Technical and safety standards. The Board cannot make binding technical standards for hydrogen service, because the regulation-making power under section 61 runs to petroleum, petroleum products and natural gas.

Integrity management. The obligations that keep a pipeline safe over its life attach to assets the Act recognises.

Capacity determination, access and tariff. The apparatus by which capacity is determined, third-party access secured and tariffs set is available for natural gas and for a natural gas stream carrying a low blend. It is not available for hydrogen as such, which means Chapter 6’s questions about who pays cannot be answered by a tariff order for a fuel the Act does not name.

Existing natural-gas obligations do not disappear merely because a low proportion of hydrogen is introduced into an authorised natural-gas network. The statutory gap is therefore not an absence of regulation around the existing asset. It is the absence of an express basis for a general hydrogen-specific regime beyond the natural-gas category.

That distinction becomes decisive for dedicated hydrogen pipelines, hydrogen-specific capacity and access rules, hydrogen transportation tariffs, and technical requirements intended to govern hydrogen service as such. Those are the points at which the existing machinery runs out of statutory subject matter.

9.4 The machinery is already built

Here is the part that makes the gap frustrating rather than merely inconvenient.

The instruments that would carry hydrogen material specifications, blend limits, odourisation requirements and metering obligations already exist. They are the technical standards regulations, one for natural gas pipelines, notified in November 2009, and one for city gas networks, notified in August 2008. Both are made in exercise of the powers conferred by section 61.

Both incorporate international codes by reference. Regulation 3(2) of the pipeline standards requires design, materials, welding, fabrication, installation, testing, commissioning, operation, maintenance and corrosion control to follow ASME B31.8 except where the Indian regulation says otherwise; the city gas regulation does the same. Their annexures list some sixty further codes without freezing an edition (PNGRB, 2008a; PNGRB, 2009).

And both are kept current. The city gas regulation has been amended fourteen times since 2008, most recently on 17 December 2025, when a standard for domestic gas stoves was added. The pipeline regulation has been amended six times since 2009. Each regulation reserves to the Board the power to effect appropriate modifications at any time. Amendments are worked up by technical committees drawn from industry, academia and other stakeholders, put to the Board, exposed to public consultation and open house, and then notified.

So there is a functioning apparatus for keeping technical standards current, with a committee structure, a consultation process and twenty amendments in seventeen years to show for it. What it cannot do is take hydrogen as its subject, because section 61 does not reach the substance.

The absence of ASME B31.12 from the present framework illustrates the boundary rather than

proving it. PNGRB can continue updating technical requirements for assets and streams that fall within the Act. What subordinate regulation cannot do is create, by itself, a complete technical regime for hydrogen pipelines as hydrogen pipelines when the parent statute does not expressly place that subject within the Board's remit.

9.5 What the commissioned study proposed changing

The Pathways study examined the Act provision by provision and recommended amendments to five sections (PNGRB & ICF, 2025).

Section 2: notify hydrogen–natural-gas blends under clause 2(zc), widen the definition of natural gas in clause 2(za) to include blended natural gas, and add a separate definition of blended natural gas.

Section 11, to include the blending of hydrogen in natural gas expressly among the Board's functions.

Section 14, so that the statutory register can accommodate hydrogen-related activities and infrastructure.

Section 17, so that the procedure for applying for authorisation expressly covers hydrogen.

Section 61, so that the Board's regulation-making power can support hydrogen-specific technical, safety, quality, monitoring and certification requirements (PNGRB & ICF, 2025).

That is the commissioned study's legislative map, not draft legislation and not necessarily an exhaustive list of every consequential amendment that a final Bill would require. The study does not name section 16, which contains the authorisation requirement itself; a Bill would need to consider it alongside section 17.

The two routes mentioned in the study should not be treated as substitutes. Notification under section 2(zc) can operate only on petroleum, petroleum products or natural gas already falling within the Act. A definitional amendment does something different: it changes the statutory category itself. A low-proportion stream already capable of being characterised as natural gas may be amenable to notification; hydrogen in its own right cannot be brought within the Act merely by calling it notified natural gas.

9.6 Not an Indian peculiarity

All of which could be read as a specifically Indian oversight. The comparative record suggests something more general.

When Liv Malin Andreasson compared Denmark and the Netherlands in 2024, both were trying to fit hydrogen into gas statutes written for an earlier system. Denmark had moved further on dedicated hydrogen infrastructure and injection into the gas network but still faced questions over permissible hydrogen content. The Netherlands had addressed permissible content in the natural-gas network while its then Gas Act did not provide the same basis for dedicated hydrogen transport (Andreasson, 2024).

The comparison has already begun to date, which is itself the point. The Netherlands' Energiewet, brought into force in 2026, expressly defines hydrogen gas and addresses infrastructure for its transport (Energiewet, 2024).

The lesson is therefore not that the positions Andreasson described in 2024 are fixed. It is that jurisdictions built around natural gas have had to rewrite the legal vocabulary as hydrogen moved from policy ambition towards infrastructure.

India is confronting the same kind of transition: not a failure peculiar to its statute, but the ordinary consequence of asking an older gas law to govern a molecule it did not expressly name.

9.7 The rest of the chain

Across the rest of the hydrogen value chain, responsibility is distributed. Green-hydrogen policy, the Mission and the Green Hydrogen Standard sit with the Ministry of New and Renewable Energy. Hazardous-chemical requirements engage the Ministry of Environment, Forest and Climate Change; environmental and waste controls engage the Central Pollution Control Board and the corresponding state authorities; compressed-gas storage and cylinders engage PESO under the applicable pressure-vessel and cylinder framework; and vehicle regulation engages the Ministry of Road Transport and Highways (PNGRB & ICF, 2025).

Coordination mechanisms do exist. Chapter 8 described the National Hydrogen Safety Panel and the cross-ministerial work already under way. But

coordination is not the same thing as a single statutory interface regime. A hydrogen project still crosses legal boundaries at physical points - production to pipeline, pipeline to storage, storage to dispensing, dispensing to vehicle or end user - and the obligations on either side may originate in different statutes and regulators.

This book does not propose who should own that interface, and the omission is deliberate. Describing the boundary is analysis. Naming a new institutional owner would answer a different question.

9.8 Enabler, facilitator, regulator

The Board has described its role in hydrogen under three headings: enabler, facilitator and regulator. The Knowledge Paper (PNGRB, 2026b) presents them as simultaneous rather than sequential, and that distinction should be preserved.

As enabler, PNGRB has supported pilots, commissioned analytical work, advanced standards alignment, established technical reference frameworks and proposed the statutory changes that would give the programme firmer legal footing.

As facilitator, it has brought operators, manufacturers, standards bodies, researchers and ministries into the same technical process through pilots, testbed development, the Scientific Advisory Committee, domestic consultation and international cooperation.

As regulator, the position is different. The work is presently one of regulatory readiness: building the evidence base, safety logic, institutional mechanisms and proposed regulatory pathways from which enforceable hydrogen-specific rules could later be made if Parliament supplies the necessary statutory authority.

The missing element is therefore not a regulatory role. It is the express statutory footing needed to convert regulatory preparation into general hydrogen-specific regulation.

That is the gap between readiness and authority, and it is the gap on which this book ends.

9.9 What the amendment is for

What an amendment would and would not achieve is worth stating plainly, because the case for legislation is easily overstated.

It would not create demand for hydrogen. It would not make green hydrogen cost-competitive with the gas it displaces; commodity economics remain a separate question from statutory authority. It would not decide where blending belongs, which Chapter 5 showed depends on the network and its downstream offtakes. And it would not establish what concentration Indian pipelines, welds, equipment and consumers can safely accept; Chapter 4 showed that those answers still depend on evidence.

What an amendment could do is give legal effect to those answers when they arrive.

A screening framework not yet incorporated into generally applicable hydrogen regulation, a proposed service-class ladder, a metering architecture not yet notified as a hydrogen billing regime, and tariff provisions that cannot presently operate for hydrogen transportation as such remain preparation rather than a complete enforceable hydrogen rulebook.

The technical programme can generate evidence. It can identify limits, test materials, construct tariff models and design operating procedures. What it cannot do is enlarge its own parent statute.

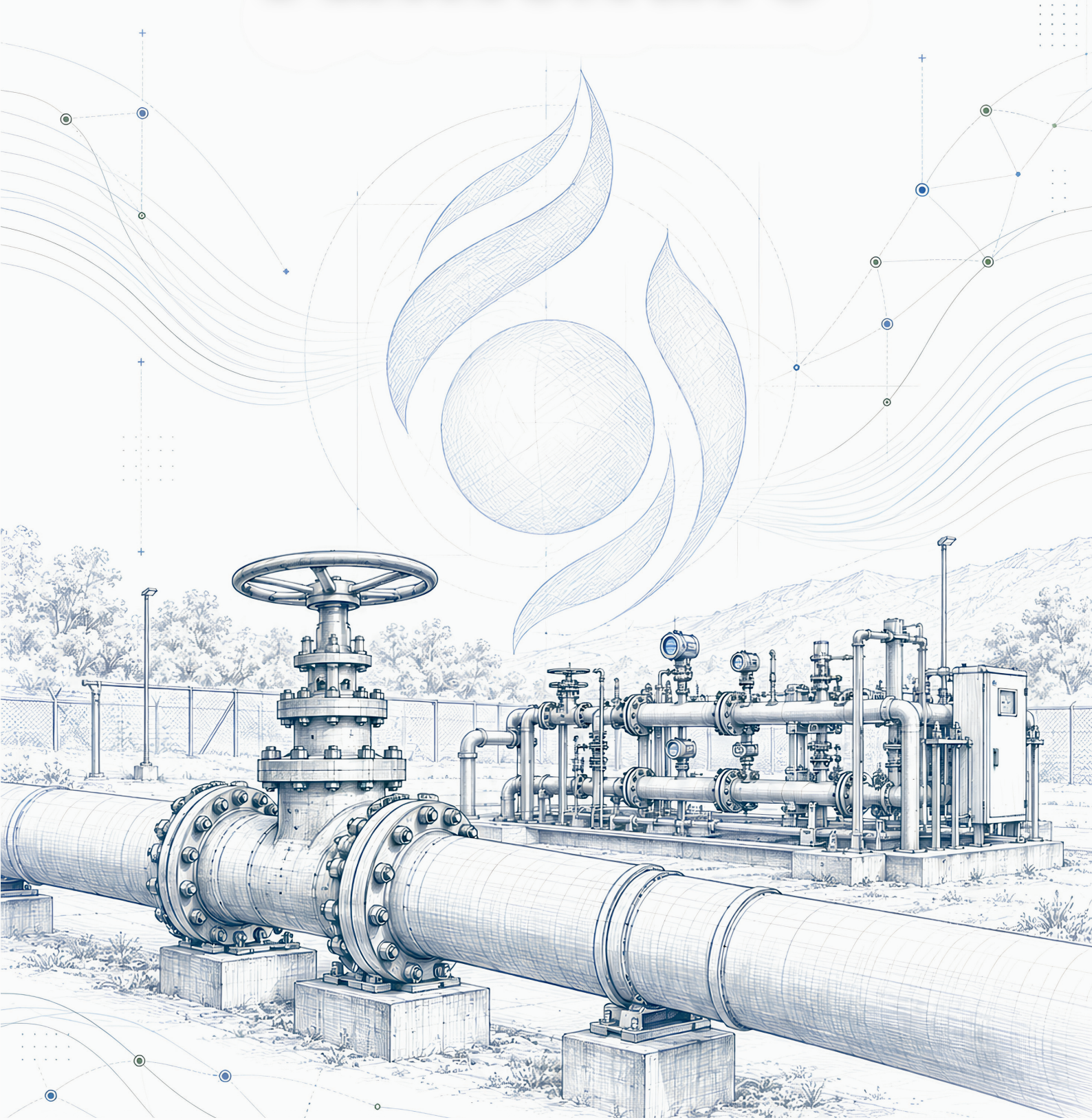
On 13 August 2026, the Government could change a twenty-seven-year-old LPG supply instrument through delegated legislation because the parent Act already supplied the power. Hydrogen exposes the reverse condition.

The gap this book has been describing is the gap between having the analysis and having the authority to give that analysis legal effect.

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Annexure





PETROLEUM AND NATURAL GAS REGULATORY BOARD
HYDROGEN CELL - COORDINATION DIVISION

Hydrogen Transportation as Natural Gas Blend

PNGRB's Work on Hydrogen Transportation
through Pipelines and Blending with Natural Gas

*An account of the institutional, technical
and evidentiary hydrogen transportation
architecture built by India's downstream
petroleum and natural gas regulator*



A KNOWLEDGE PAPER

July 2026 • New Delhi



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FOREWORD

India has set itself on the path of becoming a global hub for green hydrogen. While high ambitions are announced in missions and outlays, however, they are realised in infrastructure, standards, and institutions. Somewhere between the electrolyser and the burner tip lies a question that receives far less attention than it deserves: how will hydrogen actually move?

For a molecule that is produced where renewable power and water are abundant, and consumed where industry and cities are, the answer will substantially run through pipelines and India's natural gas pipeline network, built over decades and regulated by this Board, is the most credible carrier available. Blending hydrogen with natural gas offers a further advantage: it gives a nascent industry assured offtake in its most fragile years. But a pipeline network is not made hydrogen-ready by declaration. It is made ready by evidence.

A question arises as to whether regulatory oversight ought to precede this new technology. Often, there is a suspicion on the role of Regulators. PNGRB combines multiple roles – technical, legislative and developmental. Hydrogen needs all three. It is a highly inflammable and diffusive molecule for which technical and safety solutions have to be developed and mandated. Framing of Regulations to authorise pipelines, permit its co-mingling with natural gas and assuring access rights to consumers is a part of legislative jurisdiction. And, the high cost of both the hydrogen molecule and specialised infrastructure involves the developmental role. Therefore, the nature of Regulation ought to determine its requirement which is quite manifest in this case.

Two convictions have governed this Knowledge Paper. The first is that safety is not a chapter in the hydrogen story; it is the binding on which every page depends. Hydrogen will earn its place in India's energy system only through a record of incident-free operation, and every element of our programme - controlled pilots, independent assessment, expert scrutiny and testbed validation. The second is that no Regulator can do this alone. What has been built is the joint work of the Ministries of Petroleum and Natural Gas and of New and Renewable Energy, NITI Aayog, the Office of the Principal Scientific Adviser, our pilot entities, our academic partners, and our international counterparts.

The bridge that remains is legislative. The inclusion of hydrogen within the PNGRB Act, 2006 will convert readiness into authority. When that moment comes, this Board intends to be found prepared.

I commend the Hydrogen Cell for this paper, and I commend the paper to policymakers, industry, and researchers alike - as a record of what has been done, and a statement of intent for what must follow.


(Dr. Anil Kumar Jain)
15-7-2026

Genesis & Mandate

Anticipatory regulation — the discipline of building the institutional, technical, and evidentiary architecture for a regulatory mandate before it is statutorily conferred. This paper records what India's downstream petroleum and natural gas regulator has built, since 2021, in service of that idea.

Hydrogen sits at the centre of India's long-term energy transition. The National Green Hydrogen Mission, launched by the Government of India in January 2023 with an outlay of ₹19,744 crore, aims to make India a global hub for the production, use, and export of green hydrogen. The Mission's ambition is well-defined; its implementation, however, rests on a question the policy documents largely leave open, how will hydrogen actually move, at scale, from the points where it is produced to the points where it is consumed?

Pipelines are the answer. They are the lowest-cost mode of bulk gaseous-fuel transport over land, and in India a substantial network already exists. The Petroleum and Natural Gas Regulatory Board (PNGRB), constituted by an Act of Parliament in 2006, today oversees 27,905 km of operational natural gas transmission pipeline out of 34,803 km authorised, 3,25,575 inch-kilometres of City Gas Distribution pipeline serving 309 authorised geographical areas. It is the regulatory custodian of the infrastructure that will, in time, carry hydrogen.

The PNGRB Act, 2006, however, does not currently extend to hydrogen. Its remit covers petroleum, petroleum products, and natural gas, not hydrogen as a fuel in its own right, nor hydrogen blended with natural gas. The National Green Hydrogen Mission anticipates precisely this gap. Clause 6.4 of the Mission Document records that the Ministry of Petroleum and Natural Gas "will also enable development and facilitation of regulations through the Petroleum and Natural Gas Regulatory Board (PNGRB)."

Green hydrogen has three requirements that may not be available at the same place - **green power, water and consumer**. Natural Gas Pipeline can prove to be the solution by **blending hydrogen**. In a way, the blended supply can also provide **purchase support**, especially if natural gas prices remain low. This calls for development of a suitable regime that also includes safety aspects looking to the highly inflammable properties of hydrogen.

NGHM, Clause 6.4

MoPNG will facilitate uptake of Green Hydrogen in refineries and City Gas Distribution through both Public Sector Entities and private sector. MoPNG will also enable development and facilitation of regulations through the Petroleum and Natural Gas Regulatory Board (PNGRB). New refineries and CGD projects will be planned and designed to be compatible with maximum possible Green Hydrogen deployment.

Regulating hydrogen transport in India will therefore require two things in sequence: a legislative amendment to the PNGRB Act, 2006, and a regulator that is ready to act from the moment that amendment is notified. The lesson of past energy transitions is that regulation must precede the market, not follow it. Where regulatory direction has been absent, most starkly in the fragmented American hydrogen research efforts of the 1970s, which faded for want of consistent standards and sustained policy signalling, caused an initially well-funded effort to collapse investment, infrastructure, and public confidence have failed to take hold. The Hydrogen Cell was constituted within PNGRB to ensure that India does not repeat that pattern. Its remit is to build, in advance of statutory mandate, the evidence base, the technical standards, the institutional partnerships, and the regulatory depth that hydrogen will demand from day one.

The Cell's core objective is to establish PNGRB's preparedness to regulate the transportation of hydrogen through pipelines including its blending with natural gas, in a manner that protects consumers, ensures supply, brings energy security and promotes competitive markets, from the moment statutory authority is conferred.

What follows is the record, since inception, of what has been built in service of that objective.



2

A Five-Year Build

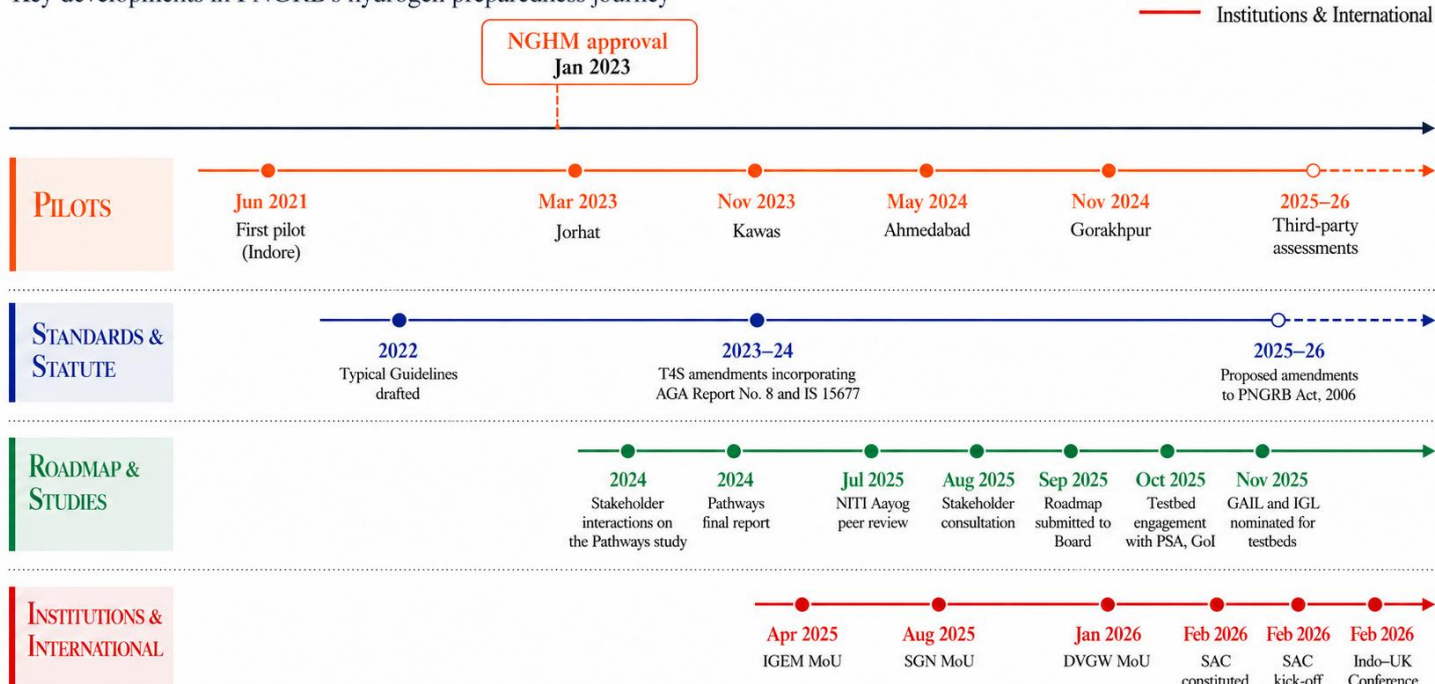
Since June 2021, PNGRB's work on hydrogen has advanced along four parallel tracks — field pilots, technical guidelines and statutory groundwork, a phased national roadmap, and a network of domestic and international partnerships. The coherence of the sequence is its strongest claim to readiness.

The first pilot in Indore in 2021 created the operational rationale for the Typical Guidelines drafted the following year. Those Guidelines created the framework within which four further pilots were authorised between 2022 and 2024. The pilots, together with the World Bank-ICF Pathways study, created the empirical foundation for the PNGRB Roadmap. The roadmap, in turn, prescribed the Scientific Advisory Committee, the National Hydrogen Testbed, and the structured international cooperations.

What began as a single approval has become a regulatory architecture. The timeline below records its construction.

Milestone Timeline 2021–2026

Key developments in PNGRB's hydrogen preparedness journey



The Regulatory Groundwork

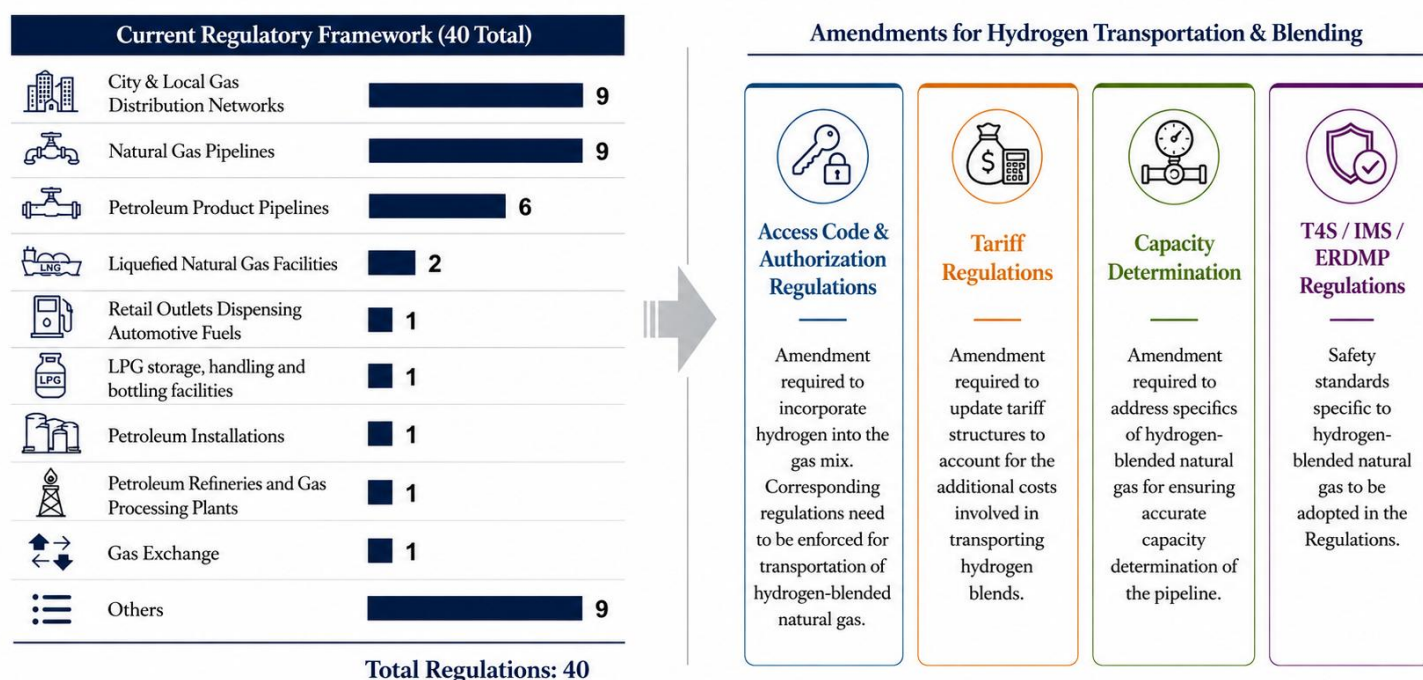
Hydrogen lies outside the current scope of the PNGRB Act, 2006. The regulatory machinery that would give effect to its inclusion has been under preparation since 2022.

The Typical Guidelines for Hydrogen Blending with Natural Gas were drafted in 2022 by a PNGRB technical committee with industry representation. They establish a common technical and safety reference for hydrogen blending pilots.

Of twenty hydrogen-relevant standards recommended by MNRE, eight have been adopted into PNGRB's regulatory framework. Six were already in force through existing T4S provisions covering natural gas pipelines and CGD networks. The **other two, AGA Report No. 8** (compressibility factors for hydrogen–natural gas mixtures) and **IS 15677** (metering protocols for blended streams) were added through the T4S (CGD) amendments notified in the Gazette of **25 April 2024**. One further standard, **ASME B31.12**, the principal international standard for hydrogen pipelines remains under review, with adoption contingent on the inclusion of hydrogen in the PNGRB Act, 2006.

The proposed amendments to the PNGRB Act, 2006 lift the legislative ceiling on the rest of this work. PNGRB has formally proposed amendments to bring hydrogen - both as a fuel in its own right and as a blend with natural gas - within its statutory remit. Once notified, they would close the gap on which everything else depends. None of what follows - tariffs, access rules, capacity determination, dedicated hydrogen pipelines - can be regulated by an Act that does not name hydrogen.

Transitioning to Hydrogen: Regulatory Landscape & Required Amendments



The scale of regulatory adaptation required becomes visible when one surveys PNGRB's existing rulebook.

Forty notified regulations are currently in force. Four classes - Access Code & Authorization, Tariff, Capacity Determination, and T4S/IMS/ERDMP - will require substantive amendment to accommodate hydrogen blending. A further set will be required for dedicated 100% hydrogen pipelines once those become operational.

What this paper records is a regulator that has done what it can - Guidelines, T4S amendments, standards adoption, an Act amendment proposal - within the constraints of a statute that does not yet name the molecule it is preparing to regulate.

4

India's First Hydrogen Blending Pilots

Five PNGRB-approved pilots - across four states, and two pipeline materials - are generating the India-specific evidence base on which hydrogen regulation will rest.

Borrowed evidence has limits. International blending trials demonstrate what is possible in German, British, or American networks; they do not establish what is safe and operable in Indian ones. India's natural gas pipeline grades, MDPE specifications, climatic envelope, odorization practice, and consumer end-use mix differ enough that PNGRB has chosen to build its regulatory evidence from Indian field data.

That decision has translated into a structured pilot programme. The first, at Indore, has run in two phases: an initial 2% injection (upstream of CGS) in 2021, followed by a 5% blend (MDPE) through from 2022; four more have since been authorised across Gujarat, Assam, and Uttar Pradesh. Together they span the operational range PNGRB will eventually have to regulate.

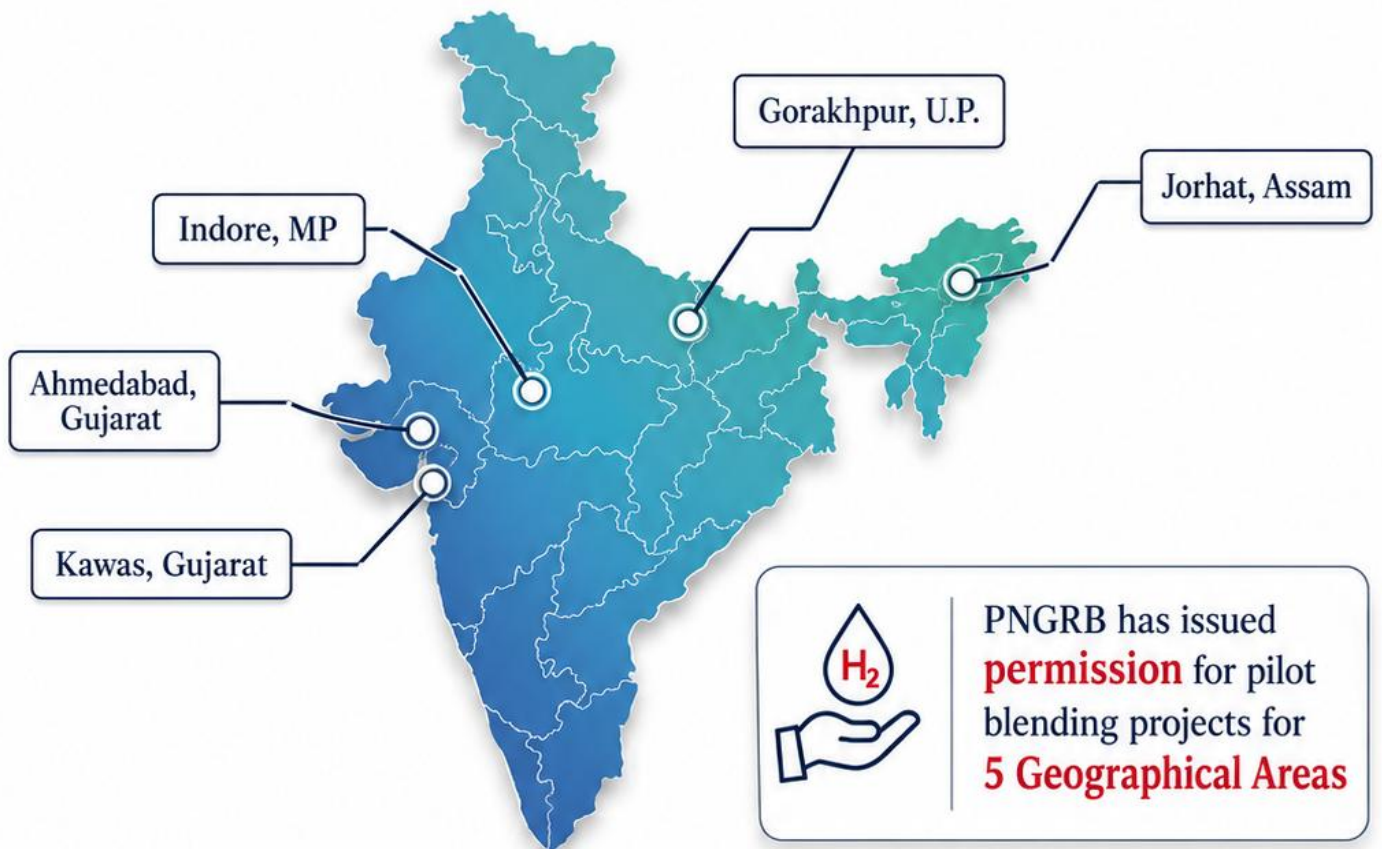
- **Pipeline materials.** Hydrogen has been injected into both MDPE pipelines — the predominant CGD material — and steel: at Indore in Phase 1 (CGS) and Gorakhpur (CGS).
- **Customer segments.** The five cover domestic PNG, commercial, industrial, and CNG customers.
- **Blend percentages.** Tested levels range from 2% to 8% by volume.

Each pilot ends with mandatory third-party assessment, the regulatory mechanism by which field data becomes evidence usable in regulation. Ahmedabad, Indore, and Kavas have completed their blending phases, with assessments now underway; Jorhat and Gorakhpur will complete blending by the end of 2026.

Parameters under assessment across all five pilots include MDPE and steel pipeline behaviour, stratification characteristics, leakage profiles, metering performance under blended flow, and end-use compatibility at the consumer interface.

INDIA'S FIRST HYDROGEN BLENDING PILOTS

Five pilot geographies approved for hydrogen blending in CGD networks



SOME KEY PARAMETERS UNDER ASSESSMENT



MDPE & Steel
Pipeline Behaviour



Stratification
Characteristics



Leakage
Profiles



Metering
Impacts



Consumer-End
Performance

The findings will feed two regulatory destinations: the Scientific Advisory Committee, which will validate the data and recommend technical thresholds; and the operational rulebook that will, in due course, govern the routine authorisation of hydrogen blending across India's CGD networks.

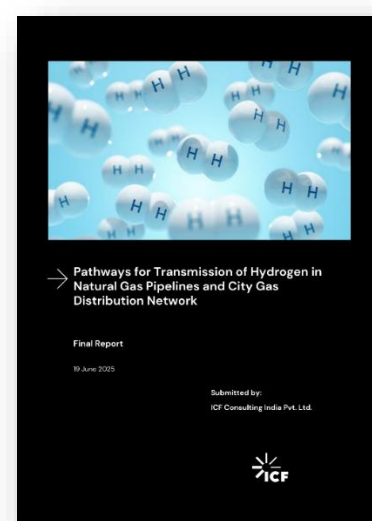
Location	Indore / MP (1st Pilot Study)	Indore / MP	NTPC Kawas / Gujarat	Jorhat / Assam	Ahmedabad / Gujarat	Gorakhpur / UP
Operator	GAIL(India) Ltd. (with Avantika Gas)	Avantika Gas Ltd.	Gujarat Gas Ltd.	Assam Gas Co.	Adani Total Gas Ltd.	Torrent Gas Ltd.
Injection Point	Steel (Upstream of CGS)	MDPE	MDPE	MDPE	MDPE	Steel (CGS)
Blend %	2% → 5%	5%	5%	2%	5%	2%
Customers	Dom · Ind · Com · CNG	Dom · Ind · Com	Domestic (township)	Domestic (township)	Dom · Com	Dom · Ind · Com · CNG
Clearance	23.06.2021	23.10.2022	03.11.2023	31.03.2023	30.05.2024	29.11.2024
Status	Completed (No Adverse reports)	Assessment underway	Assessment underway	Assessment underway	Assessment underway	Blending; assess end-2026

5

From Pathways to Roadmap

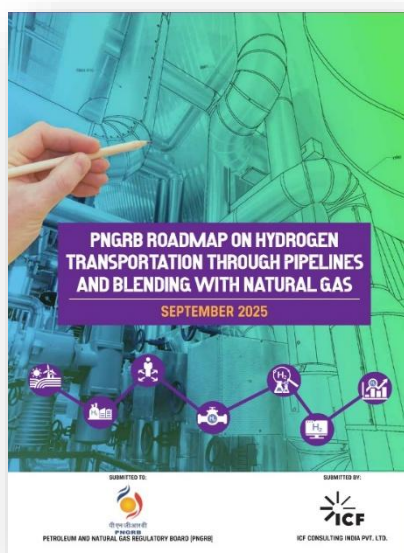
The Pathways study, completed in 2024, established what was technically feasible. The PNGRB Roadmap, published in September 2025, translated that feasibility into a phased programme to 2033, India's first published institutional plan for hydrogen transportation through pipelines.

The Pathways study. Conducted by ICF Consulting India under PNGRB's mandate and in association with the World Bank, the study *Pathways for Transmission of Hydrogen in Natural Gas Pipelines and CGD Networks* was structured around five tasks: demand–supply mapping for low-carbon hydrogen, technical and commercial assessment of the existing pipeline sector, regulatory assessment against international practice, and a phased roadmap. Its final report, completed in 2024 and web-hosted on PNGRB's website since 19 June 2025, set the operating envelope. On a network-wide level, blending **up to 2%** is feasible with minimal adjustments; **up to 10%** is technically possible subject to case-specific pipeline and network assessment; **beyond 10%**, system-level changes are required, and dedicated pure-hydrogen pipelines may be the more cost-effective option. The study's twelve-month action set, addressed to PNGRB, **prioritised statutory amendment of the Act**, detailed technical assessments, and standards alignment.



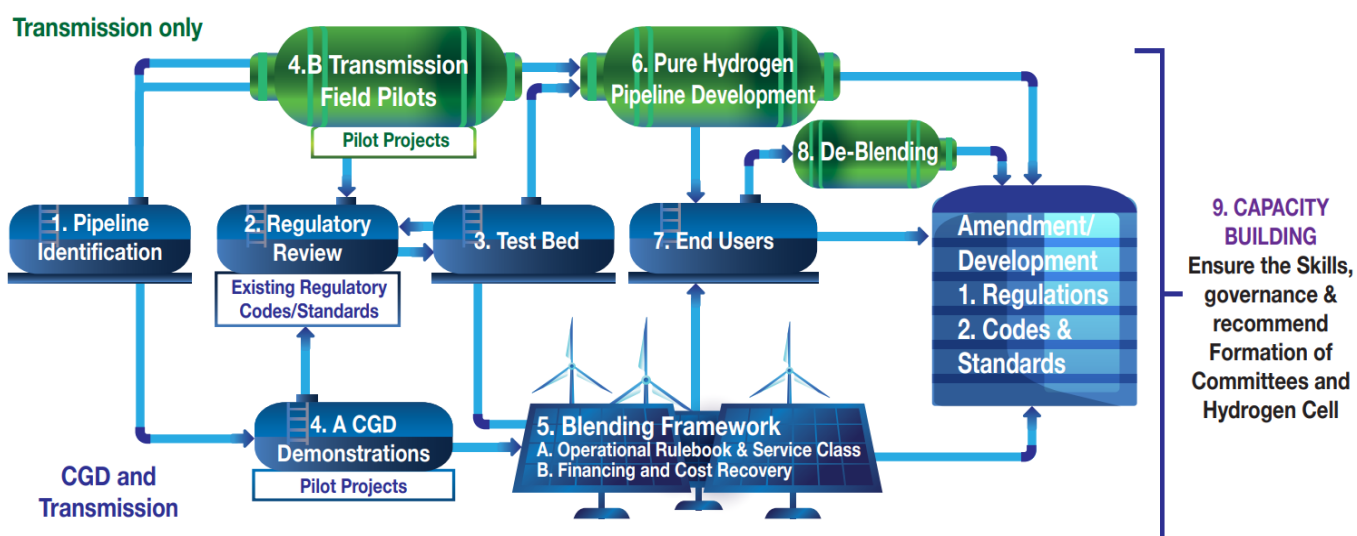
The roadmap. submitted to the PNGRB Board on 24 September 2025, web-hosted shortly thereafter, and circulated to over 130 stakeholders, including **Dr. V.K. Saraswat (Member, NITI Aayog), the Secretary, MoPNG, and the Secretary, MNRE**, the roadmap is structured as a phased, module-based pathway. The Pathways study's recommendations were translated into nine modules organised across two phases: **Phase I (2025–2028)** focused on capacity building and foundational readiness, pipeline identification, the National Hydrogen Testbed, foundational standards, and pilot demonstrations; **Phase II (2029–2033)** on scale-up and commercialisation, the blending framework, dedicated pure-hydrogen pipelines, end-user appliance compatibility, debinding technologies, and continued capacity building.

The institutional process behind the roadmap mattered as much as its content. The draft was reviewed at NITI Aayog on 9 July 2025 in a session chaired by Dr. V.K. Saraswat under the guidance of Dr. Anil Kumar Jain, Chairperson, PNGRB. A focused stakeholder consultation and the inaugural Hydrogen Pilot Project Forum was held on 1 August 2025 at the India Habitat Centre, New Delhi. Both shaped the final document.



PNGRB also engaged with the Office of the Principal Scientific Adviser to the Government of India on 28 October 2025. The meeting, chaired by **Prof. Ajay Kumar Sood, PSA to the GoI**, was convened to apprise the PSA of PNGRB's ongoing and proposed initiatives on hydrogen transportation through pipelines and blending with natural gas, including the World Bank-supported Pathways study, the PNGRB Roadmap, testbed creation, safety coordination mechanisms and the need for legislative amendments. The PSA appreciated the comprehensiveness of the roadmap and indicated that funding support under NGHM may be explored.

A central innovation of the roadmap is its **Readiness Assessment Module** - a nine-parameter scoring framework for evaluating which pipeline segments are technically suitable for initial blending. The framework converts "which pipelines can take hydrogen?" from a discretionary judgement into an evidence-based regulatory question.



The roadmap's two structural prescriptions - the National Hydrogen Testbed and the Scientific Advisory Committee - are taken up in the sections that follow.

6

The National Hydrogen Testbed

Field pilots establish what works at one site. A National Testbed establishes what works at scale — under controlled conditions, across the full range of components, materials, and operating regimes that regulation will eventually need to cover.

The roadmap's most consequential prescription is institutional rather than regulatory. It calls for the establishment of a National Hydrogen Testbed, a permanent, instrumented infrastructure for full-scale testing of hydrogen transportation and blending in Indian conditions. Without such a facility, regulation would have to depend on extrapolation from limited pilot sites and on borrowed evidence from German, British, and American test programmes. With it, India can generate its own.

The architecture is bifurcated. Two nodal entities were designated on 19 November 2025:

- **GAIL (India) Limited** - nominated as the Central Nodal Agency for the **transmission (NGPL) hydrogen testbed**. GAIL has submitted a proposal to MNRE under the National Green Hydrogen Mission for a **Centre of Excellence at its Vijaipur facility** (Guna district, Madhya Pradesh), with **IIT Roorkee** as the academic partner for in-situ testing.
- **Indraprastha Gas Limited (IGL)** - nominated as the nodal entity for the **CGD/distribution hydrogen testbed**, covering low-pressure network applications including CNG and domestic PNG systems.

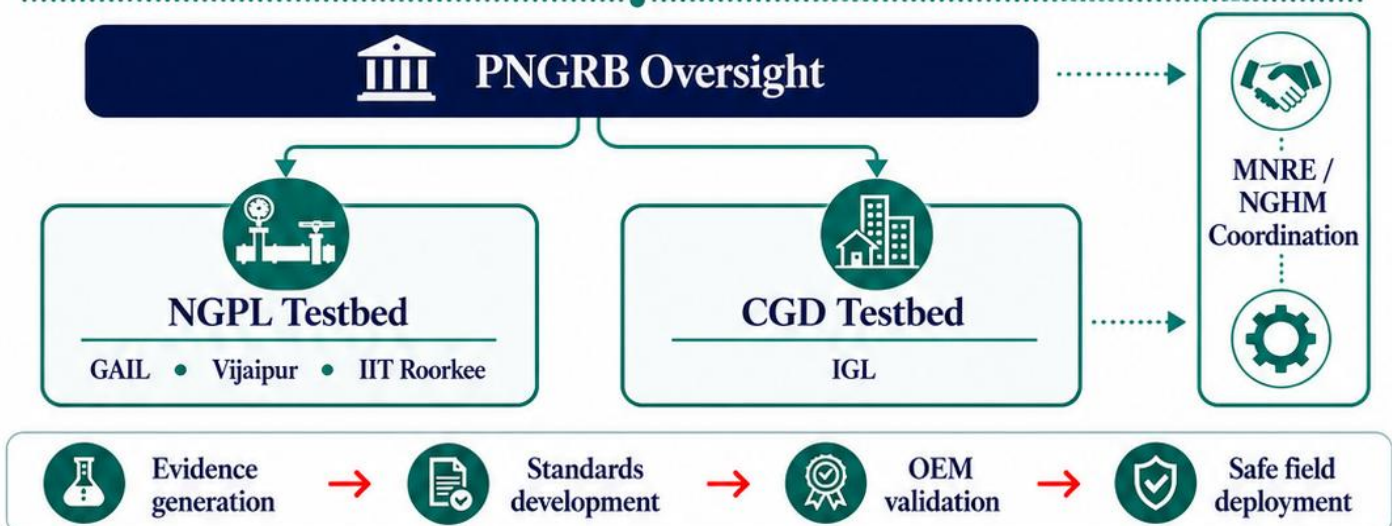
The split reflects a structural distinction in PNGRB's regulatory remit: transmission and distribution are technically and operationally different problems, and the Testbed mirrors that division. Both nodal facilities will operate under PNGRB oversight in coordination with MNRE/NGHM.

Six lines of work are envisaged across the Testbed system: full-scale test loops covering high-pressure transmission and low-pressure CGD/MDPE systems; material testing for hydrogen embrittlement, fatigue, elastomer compatibility, and weld performance; component assessment of valves, meters, compressors, and regulators under hydrogen service; operational safety testing for pressure cycling, leakage characteristics, and stratification behaviour; instrumented monitoring with SCADA-integrated real-time flow and integrity evaluation; and OEM certification - standards validation that allows Indian manufacturers to certify hydrogen-ready components.

The causal sequence is direct: **Testbed → National Standards → OEM Certifications → Safe Field Deployment**. Evidence generated in the loops becomes the technical basis for the regulations PNGRB will, once empowered, issue. PNGRB's study visits to DNV Spadeadam and SGN H100 Fife in the United Kingdom have provided design references for how comparable testbeds operate abroad, informing both the technical scope and the governance arrangements being developed for the Indian facilities.

National Hydrogen Test Bed

The scientific backbone for India-specific evidence generation



The Scientific Advisory Committee

Pilots generate data. The Testbed will generate more. But data does not translate itself into regulation. The Scientific Advisory Committee is the technical forum constituted to make that translation — under expert scrutiny, against international benchmarks, in Indian conditions.

The Scientific Advisory Committee on Hydrogen Initiatives was constituted by PNGRB Order **PNGRB/Coordination/1-H2Roadmap/(1)/2025 (E-6041)** dated **12 February 2026** and met for the first time on **24 February 2026** at the PNGRB office, New Delhi. It is chaired by **Sh. Mukesh Mohan**, Executive Director, IOCL, and convened by **Sh. Muktikam Phukan**, Director



(Coordination) and Officer-in-Charge of the Hydrogen Cell, with the Hydrogen Cell functioning as Secretariat. Its membership is drawn from across the relevant ecosystem — gas transmission and distribution entities, refineries, IITs and other academic institutions, MNRE, pipeline manufacturing entities and EPC Consultants as well as standards making bodies.

The SAC is constituted as the apex advisory body, providing evidence-based inputs to PNGRB. Its remit, as recorded in the constituting order, is to deliver India-specific guidance on hydrogen transportation through pipelines, hydrogen–natural gas blending, and associated safety protocols.

The deliverables are correspondingly concrete: **India-specific blending guidance, validated safety protocols, assessment of the National Testbed design, structured technical review reports on the GAIL and IGL testbeds and the five field pilots**, and **evidence-based regulatory recommendations** for PNGRB amendments, operational rulebooks, and tariff frameworks.

The SAC fits a pattern visible across every country building a hydrogen economy at scale: regulators reach for expert advisory bodies to do what they cannot do alone. Germany's National Hydrogen Council, established in June 2020, sits at the centre of that country's hydrogen strategy with twenty-five experts drawn from industry, science, and civil society. The United Kingdom's Hydrogen Delivery Council - originally the Hydrogen Advisory Council, constituted in July 2020 - is the joint government–industry forum

that informs UK hydrogen policy. The European Union runs the Clean Hydrogen Partnership; the United States its Hydrogen and Fuel Cell Technical Advisory Committee under the Department of Energy. The logic is consistent across jurisdictions: regulating an emerging energy technology demands depth in materials science, pipeline engineering, safety analysis, and end-use compatibility that no single regulator can hold in-house, and expert bodies provide that depth without diluting regulatory authority.

The SAC reflects this pattern but is more sharply specified. Where Germany's and the UK's councils advise on the full hydrogen economy, the SAC's remit is targeted to a specific regulatory perimeter - transportation through pipelines, blending with natural gas, and the associated safety architecture - which is precisely the perimeter PNGRB will be asked to regulate. Its outputs are operational, not deliberative: technical guidance documents, validated safety protocols, structured pilot review reports, and concrete regulatory recommendations. The intent is that when PNGRB eventually issues hydrogen regulations, those regulations will already have been stress-tested against expert scrutiny - Indian conditions verified, international benchmarks applied, multi-stakeholder consensus reached.

SAC Structure

Structured Technical Oversight Architecture of the Scientific Advisory Committee



The SAC is, in effect, the validation layer between the evidence base PNGRB has been building since 2021 and the regulations it will eventually need to issue. Its work over the coming year will determine the quality of those regulations.

8

International Cooperation

PNGRB has signed three Memoranda of Understanding with leading European technical institutions since April 2025. Each one shortens the time between an Indian regulatory question and a defensible answer.

The argument for international cooperation in hydrogen regulation is straightforward. Standards, test methodologies, simulation tools, and safety frameworks that have taken Germany and the United Kingdom two decades to develop can be adopted and adapted in a fraction of that time - provided the institutional pathway exists. Three Memoranda have been signed since April 2025 to build that pathway.

PNGRB × IGEN (United Kingdom) — April 2025. The Institution of Gas Engineers and Managers (IGEM) is the United Kingdom's principal technical body for gas engineering and standards. Its hydrogen series, IGEN/TD/1, TD/3, TD/13, and SR/25, covers high-pressure hydrogen pipelines, the repurposing of natural gas pipelines for hydrogen service, pressure-regulating installations for hydrogen and blended mixtures, and hydrogen safety. The MoU gives PNGRB structured access to these standards and to IGEN's training and certification programmes, with the explicit objective of strengthening India's hydrogen standards and certification ecosystem.

PNGRB × SGN (United Kingdom) — August 2025. SGN, one of the United Kingdom's principal gas distribution network operators, runs the H100 Fife project, the world's first 100% hydrogen domestic distribution pilot, supplying around 1,000 homes in Scotland [designed to supply up to 300 homes in its first phase]. The MoU, signed during the Secretary, PNGRB's UK study visit, is focused on knowledge exchange in blending pilots, integrity management, and pathways for hydrogen adoption in CGD networks. Joint research and pilot projects fall within scope.

PNGRB × DVGW (Germany) — January 2026. The MoU with the Deutscher Verein des Gas- und Wasserfaches (DVGW) - Germany's technical and scientific association for gas and water - was exchanged on 12 January 2026 at Mahatma Mandir, Gandhinagar, in the presence of the **Hon'ble Prime Minister of India and the Federal Chancellor of Germany.** DVGW's *Regelwerk*, including **G 260** (gas quality), **G 407/G 408** (conversion of steel



and plastic pipelines for hydrogen), **G 409** (hydrogen suitability of steel components), **G 463** (new steel hydrogen pipelines), and **G 464** (fracture mechanical assessment) is among the most comprehensive hydrogen technical rule sets in the world. The MoU provides PNGRB with access to these rules and test principles (with translation support), the **Hydrogen Readiness Testing Scheme (HRTS)** for materials and components, hydrogen-ready certification methodology, and network simulation tools for blends up to twenty percent and beyond. The operationalisation kick-off was held on 9 February 2026.

A fair question follows from all of this: if Europe's hydrogen standards are this mature, why can they not simply be adopted wholesale? The answer is that a technical standard is not a free-standing document; it is the codified evidence of the network it was written for. DVGW's rules assume German gas qualities as defined in G 260, German pipeline steels and vintages, and German operating temperatures; IGEM's assume the material stock and pressure regimes of the British grid. Indian conditions differ at almost every one of those parameters, a gas basket that blends domestic production with regasified LNG of varying composition, pipeline steel grades and MDPE specifications procured to Indian standards, a climatic envelope that ranges from sub-zero winters to soil temperatures European polymer standards never contemplated, distinct odourisation practice, and a consumer appliance base never certified against European norms. A blending threshold that is safe on a German network is a hypothesis, not a conclusion, on an Indian one. There is also a legal dimension: to be enforceable, standards must be adopted into India's own regulatory framework through T4S notification, in coordination with BIS and PESO, rather than referenced from a foreign rulebook. What the MoUs therefore provide is not a shortcut around Indian evidence but a head start toward it: European test methodologies, certification schemes, and simulation tools, adapted and validated against Indian field data from the pilots and, in time, the National Testbeds. The inheritance is curated, not copied - built without compromising Indian regulatory authority, and structured to feed Indian standards, Indian testbeds, and Indian regulations.

Study visits. Alongside the formal MoUs, PNGRB has undertaken structured study visits to **DNV Spadeadam** - the United Kingdom's principal hazardous-trials facility, operated by the Norwegian risk-management firm DNV - and to **SGN H100 Fife**. These visits have provided design references for the National

Hydrogen Testbed and have informed the governance arrangements being put in place around it.

What the three MoUs and the associated study visits give PNGRB is, in effect, a curated technical inheritance, built without compromising Indian regulatory authority, and structured to feed Indian standards, Indian testbeds, and Indian regulations.



Domestic Engagement & Capacity Building

Hydrogen regulation cannot be built in isolation. PNGRB has been deliberately constructing the domestic ecosystem — industry partners, academic institutions, and the cross-ministerial coordination on which coherent national action depends.

Three lines of engagement have advanced in parallel with the international cooperation set out on the previous page.

Industry. The five blending pilots are the most visible engagement, each one a structured collaboration with a CGD authorised entity (GAIL/Avantika Gas, Adani Total Gas, Gujarat Gas Ltd., Assam Gas Company, Torrent Gas). Beyond the pilots, the two testbed designations of November 2025 brought **GAIL** and **Indraprastha Gas Limited** into structured technical partnership with PNGRB. Industry workshops have broadened the conversation: most recently, the **IOCL Panipat workshop on hydrogen transportation through pipelines** (4 November 2025), and the **inaugural Hydrogen Pilot Project Forum** held alongside the stakeholder consultation at the India Habitat Centre on 1 August 2025.

Academia and research. The Testbed at GAIL Vijaipur is being developed with **IIT Roorkee** as academic partner for in-situ testing. Engagement with the **Gujarat Energy Research and Management Institute (GERMI-Gujarat)** is active. **IOCL R&D Faridabad** has been a technical interlocutor on multiple workstreams. The roadmap envisages widening this network, its capacity-building module is explicitly dedicated to skills, governance, and the institutional infrastructure needed for sustained engagement.

Cross-ministerial coordination. Hydrogen regulation requires coherent action across a constellation of central institutions. PNGRB's structured engagement covers:

- **MoPNG** as the parent ministry, with PNGRB designated for hydrogen regulation under NGHM Clause 6.4;
- **MNRE**, the nodal ministry for the National Green Hydrogen Mission, with PNGRB's Director (Coordination) serving on the **National Hydrogen Safety Panel** constituted under NGHM, and PNGRB's systematic adoption of MNRE-recommended hydrogen standards as set out earlier;
- **NITI Aayog**, which reviewed the draft Roadmap on 9 July 2025 in a session chaired by Dr. V.K. Saraswat;
- **BIS and PESO**, the principal Indian standards and explosives-safety bodies, with coordination flagged in the Roadmap's Regulatory Review module.





The apex engagement in this constellation came on 28 October 2025, when a PNGRB delegation led by the Chairperson was received by **Prof. Ajay Kumar Sood, Principal Scientific Adviser to the Government of India**. The Pathways study and the Roadmap were formally presented, and the Chairperson laid before the

PSA the regulatory questions that hydrogen blending will pose in practice: tariff methodology, since natural gas tariffs are determined on an energy basis and hydrogen's lower energy density could translate into higher effective tariffs post-blending; the treatment of pipeline authorisations issued for specific end-use segments once blended gas is supplied; and the absence of a dedicated R&D funding mechanism for testbed creation, PNGRB not being a scientific body per se.

Two requests were placed before the PSA: recognition of PNGRB as an essential stakeholder in national scientific and technical coordination on hydrogen safety and infrastructure, and support under the National Green Hydrogen Mission for regulatory studies and the National Hydrogen Testbed. The PSA appreciated the comprehensiveness of the Roadmap and concurred that funding support under NGHM may be explored, noting existing Mission allocations for sectors such as fertiliser, shipping, and mobility.

The final Roadmap document, on publication in September 2025, was circulated to **over 130 stakeholders**: government, industry, academia, etc., to ensure the regulatory direction was visible to every actor whose work it would touch.

The picture that emerges is of a regulator that has chosen, deliberately, to do its work in the open and in partnership rather than in isolation, and to build, in advance of statutory mandate, the relationships on which future regulation will depend.

10

Safety is Non-Negotiable

The single largest determinant of whether India's hydrogen pipeline architecture succeeds is whether it remains safe. Public trust, once lost, is exceptionally difficult to rebuild — and the entire economic case for hydrogen rests on a record of incident-free operation.

The Hindenburg disaster of 6 May 1937, when a hydrogen airship erupted in flames, captured on newsreel and radio recordings heard by millions within a day, ended commercial hydrogen aviation overnight. It took three decades, until the Apollo programme, for hydrogen to recover public confidence as a fuel. The root

cause of the disaster, later analyses have argued the airship's incendiary skin coating, rather than the hydrogen itself, was the primary culprit - the attribution remains debated, but hydrogen bore the blame regardless. The lesson is institutional: an emerging energy technology cannot afford a single visible incident in its formative years, and the safety regime that prevents such incidents is therefore not a cost on the system, it is the precondition for the system existing at all.

For PNGRB, safety has therefore been treated as a design principle rather than a downstream compliance requirement. The hydrogen programme has been built around controlled pilots, mandatory third-party assessment, SAC scrutiny, testbed-based validation, standards alignment, and coordination with national safety mechanisms. Each layer is intended to ensure that technical feasibility is converted into regulatory confidence only after evidence has been generated and independently reviewed. The principal technical and operational risks being considered for hydrogen transportation and hydrogen-natural gas blending may be summarised as follows:

Concern	Engineering response
Hydrogen embrittlement	Material selection, fracture-mechanics assessment under ASME B31.12, pressure management
Leak detection	Hydrogen-specific sensor arrays; SCADA-integrated monitoring; lower-explosive-limit alarms at critical points
Odourisation	Conventional mercaptan-based odorants interfere with fuel cells; novel odorants or alternative detection strategies required for hydrogen networks
Blending-ratio control	Precision injection systems, flow metering, and real-time compositional monitoring
Pipeline integrity	In-line inspection tool compatibility; modified cathodic protection protocols for hydrogen service
Emergency response	Protocols recognising hydrogen's wider flammability range (4–75%), rapid dispersion behaviour, and distinct ignition characteristics

PNGRB's existing safety regulatory architecture, the **Technical Standards and Specifications (T4S)**, **Integrity Management System (IMS)**, and **Emergency Response and Disaster Management Plan (ERDMP)** regulations, provide the structural foundation. These are precisely the regulations identified earlier as requiring amendment to accommodate hydrogen blending; the underlying safety logic is already present and well-established for natural gas, and the amendments will extend it to hydrogen.

Institutionally, three layers govern safety in PNGRB's hydrogen programme. The **Scientific Advisory Committee's** dedicated Safety Assessment terms of reference cover hydrogen risks across the value chain - production, transport, blending, end-use - with explicit emphasis on high-pressure blending and residential use. The **National Hydrogen Safety Panel** under NGHM, on which PNGRB serves as a member, provides the inter-ministerial coordination mechanism. The **upcoming Testbeds & mandatory third-party assessment** of every blending pilot is the operational safeguard that converts pilot-stage learning into validated, externally verified safety evidence.

Safety is not a constraint on ambition — it is the foundation on which ambition can be built.

Key Takeaways

If the work of the past five years has a single organising principle, it is anticipation — the deliberate construction of a regulatory architecture in advance of statute authorising its use.

Six observations summarise what has been built, and what its construction implies.

- 1. Anticipation, not reaction.** Since June 2021, PNGRB has progressed hydrogen-relevant work in advance of statutory mandate: five pilots authorised, Typical Guidelines drafted, eight MNRE-recommended standards adopted, three international MoUs signed, a National Hydrogen Testbed designated, a Scientific Advisory Committee constituted, and a Roadmap to 2033 published. This is the institutional record of a regulator choosing not to wait.
- 2. Evidence-based prescription, not borrowed prescription.** Every regulatory recommendation that PNGRB will issue rests on a defensible empirical foundation, Indian field data from five pilots, technical inheritance through three structured European cooperations, and reviewed analytical work in the Pathways study and the roadmap.
- 3. Institutional architecture, not just rules.** The Scientific Advisory Committee, the National Hydrogen Testbed, the international partnerships, the National Hydrogen Safety Panel - these are the institutions that will sustain hydrogen regulation across the multiple regulatory cycles a thirty-year energy transition will demand. Rules age; institutions endure.
- 4. A phased horizon, sequenced to capability.** The roadmap's two-phase structure - capacity building and foundational readiness (2025–2028), followed by scale-up and commercialisation (2029–2033) - sequences hydrogen regulation to what can be demonstrably done, not to what would be politically convenient.
- 5. The bottleneck is statutory, not technical.** Nearly every component of the architecture described in this paper — from the regulations that would replace the Typical Guidelines, to the adoption of ASME B31.12, to PNGRB's ability to issue dedicated hydrogen-pipeline tariffs and access rules - is contingent on a single legislative action: the inclusion of hydrogen within the scope of the PNGRB Act, 2006.
- 6. Safety underwrites everything.** The economic case for hydrogen, the investor confidence behind ₹19,744 crore of NGHM commitments, and the public acceptance on which residential blending will eventually depend, all rest on a safety record that has yet to be built. PNGRB's safety architecture is the load-bearing wall of the entire structure.

Enabler · Facilitator · Regulator

A regulator's role is conventionally understood as the issuance and enforcement of rules. In emerging energy sectors, that understanding is insufficient. PNGRB sees its role in India's hydrogen pipeline future as a triad — enabler, facilitator, and regulator — and the work described in this paper is the institutional expression of that view.

As Enabler. PNGRB has prepared technical reference frameworks, advanced standards alignment, commissioned analytical work, supported the development of the roadmap, and proposed statutory amendments that would give the hydrogen architecture formal legal footing.

As Facilitator. PNGRB has coordinated pilots, testbed development, the Scientific Advisory Committee, domestic stakeholder consultations, cross-ministerial engagement and international technical cooperation with institutions such as IGEM, SGN and DVGW. This connective role is indispensable because hydrogen transportation cannot be built by one institution alone.

As Regulator. PNGRB is preparing the evidence base, safety logic, institutional mechanisms and draft regulatory pathways that can support enforceable regulations once hydrogen is expressly brought within the PNGRB Act, 2006. The paper therefore records not the completion of regulation, but the creation of regulatory readiness.

The three roles are not sequential. They are simultaneous. The work since 2021 has been the work of all three at once - enabling, facilitating, and preparing to regulate. This is what an anticipatory regulator looks like in practice.

Hydrogen will move at the pace of trust. Trust will be earned through evidence, partnership, and uncompromising attention to safety. PNGRB's task — across all three of its roles — is to keep that pace honest.

About the Authors



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DIRECTOR (ADMIN & HR / COORDINATION & HYDROGEN)

Muktikam Phukan is a chemical engineer and energy-sector professional with over three decades of experience in oil and gas operations, safety, energy efficiency and regulation. As Director (Admin & Coordination) and Officer-in-Charge of PNGRB's Hydrogen Cell, he leads the Board's work on hydrogen regulatory preparedness, safety and infrastructure development. He has previously served as Director (Technical), PNGRB, and held senior technical roles at Oil India Limited and PCRA.



Farhan Akhter

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Farhan Akhter is part of the PNGRB's Hydrogen Cell, working on hydrogen transportation, blending, pipeline readiness and safety regulation. He has contributed to PNGRB's Hydrogen Roadmap, blending pilots, testbeds, Scientific Advisory Committee and the PNGRB-DVGW cooperation programme. An Electronics & Instrumentation engineer from R.V. College of Engineering, he previously worked with Jio-bp and Nutanix.



पीएनजीआरबी
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