The Cambridge Handbook of HYDROGEN AND THE LAW

EDITED BY

Ruven Fleming

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THE CAMBRIDGE HANDBOOK OF HYDROGEN AND THE LAW

The Cambridge Handbook of Hydrogen and the Law is the first comprehensive reference work on the regulation of this key area. It is global in scope, featuring chapters that explain the legal situation on hydrogen in Europe, the USA, Latin America, Oceania, the Middle East/North Africa and Southeast Asia. It includes chapters covering all relevant legal aspects of the hydrogen value chain from production to end use, making it the first in-depth work on the interplay of hydrogen and the law. Leading scholars and practitioners discuss the creation of hydrogen markets, the role of local authorities, sustainability and public participation in hydrogen regulation, offshore hydrogen, the regulation of hydrogen transportation and storage, indigenous perspectives on hydrogen, the regulation of hydrogen in the heating sector and the regulation of electricity storage in the form of hydrogen. This title is also available as Open Access on Cambridge Core.

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1

Introduction

Ruven Fleming

1.1 INTRODUCTION

Werner Franz, a fourteen-year-old German cabin attendant, was off to a good start on 6 May 1937. At midday he saw New York passing by beneath his feet – the Big Apple. Despite a detour of three hours to avoid a thunderstorm, the airship embarked on an early evening landing at Lakehurst, New Jersey. Passengers were already able to see friends and relatives on the landing field, awaiting their arrival.[1] But all of a sudden Werner Franz witnessed a 'huge bang and strong vibration in the airship'.[2] As the Hindenburg burst into flames, Werner Franz jumped off the airship from about four or five metres, walked under the ship and ran out the other side.[3] Magically he, together with sixty-one of the ninety-seven people aboard the airship, survived the disaster. But he remained traumatized for months to come. What caused the explosion of the Zeppelin Hindenburg was, most likely, sparks from a static charge that loaded the newly repainted outer cover of the airship. The sparks occurred when the landing rope was dropped, igniting 200,000 cubic metres of hydrogen.[4]

Fast forward eighty-six years: by the end of September 2023, the Director of IRENA, the International Renewable Energy Agency, Francesco La Camera, underlined in a speech on the future of renewables that 'rapid green hydrogen scale-up lies on a systemic innovation approach beyond technology, which means we need innovative regulatory and policy frameworks, finance, and business models'.[5] Be clear about the significance – this is the Director of the World's Agency on renewables strongly advocating for a comprehensive and holistic roll-out of hydrogen – the very substance that lay at the heart of one of the biggest disasters in civil aviation. How did we end up here?

One could have expected a ban on hydrogen after the Hindenburg disaster, but instead, we kept using hydrogen over the following eighty-six years. In the 1970s, a hype around hydrogen as

Parts of this chapter benefited from the research done by Ms. Kelsey Pailman, to whom I am indebted for her help.

[1] Focus 'Am 6. Mai 1937 wird der Zeppelin LZ 129 "Hindenburg" bei einer Landung zerstört' <https://focus.de/wissen/videos/1937-die-katastrophe-der-hindenburg-am-6-mai-1937-wird-der-zeppelin-lz-129-hindenburg-bei-einer-landung-zerstoert_id_5272588.html> accessed 8 February 2024 (hereinafter: Focus).

[2] Ibid.

[3] Ibid.

[4] Ibid.

[5] IRENA 'Removing Barriers for Green Hydrogen Development' <https://irena.org/News/articles/2023/Nov/Removing-Barriers-for-Green-Hydrogen-Deployment> accessed 8 February 2024.

the next 'big thing in energy' developed.[6] One tangible result was cars, running on fuel cells, developed with competitive examples like the Kordesch passenger car in 1970 and the Japanese Musashi cars.[7] But until today hydrogen remains hugely important to our daily lives. No refining of crude oil into petroleum, which we need for our cars, planes and many other everyday applications, would be possible without hydrogen.[8] Thus, hydrogen was never gone entirely, but it vanished a bit from the public eye.

This changed significantly during the 2010s, when hydrogen was rediscovered, this time as driver for the decarbonization of our lifestyle.[9] Since the 2020s, arguably, another hype around hydrogen developed and by the time of writing this book it is even possible to (provocatively) conclude (again): a spectre is haunting Europe and the world – the spectre of hydrogen.

Today there are fierce proponents and staunch opponents of hydrogen – people who love and those who loathe the molecule. Some stakeholders view hydrogen as a saviour for the decarbonization of the gas industry and others consider it to be a smoke screen by the gas industry to keep operating for decades to come.[10]

And much like the communist manifesto that was launched 175 years ago, the aim of this book is two-fold: first, it wishes to take away the mist surrounding hydrogen, enabling a clear and sober view of law and regulation concerning this energy carrier. Second, the book also contains an element of appeal and urgency, just as the manifesto did. This book is not neutral. It explains hydrogen regulation from around the globe, but at the same time also makes various concrete suggestions on how to improve the regulatory system and speed up the phase-in of hydrogen as a carrier to be used in our energy systems. The reason for this normative view is simple: hydrogen is important to help with the decarbonization of certain sectors, those (heavy industry, heavy duty transport, and so on) where emissions are hard to abate.[11]

Over the last 150 years, hydrogen has been produced technically via various methods, but also several types of hydrogen developed. With a view to production there is the traditional method of steam methane reforming,[12] producing hydrogen via electrolysis,[13] the production of hydrogen from biofuels[14] or biomass,[15] to name some of the important

[6] Peter Hoffmann *The Forever Fuel: The Story of Hydrogen* (Westview Press 1981) 1; Jeremy Rifkin The Hydrogen Economy (Tarcher 2002) 9 (hereinafter: Rifkin); John Bockris 'The Origin of Ideas as a Hydrogen Economy and Its Solution to the Decay of the Environment' (2002) 27 International Journal of Hydrogen Energy 731–740; Joseph J Room *The Hype about Hydrogen: Fact and Fiction in the Race to Save the Climate* (Island Press 2004) 3.

[7] Hydrogen Cars Now '1807–1986 Hydrogen Fuel Cars 1807–1986' <https://hydrogencarsnow.com/index.php/1807-1986/> accessed 8 February 2024.

[8] Martha Roggenkamp 'The Use of Power-to-Gas in Refineries: Regulatory Challenges from EU and German Perspective' in Martha M. Roggenkamp, Catherine Banet (eds.) *European Energy Law Report Vol. XII* (Intersentia, Cambridge 2018) 251–269 at 256.

[9] The European Union, for instance, started spending significant amounts of money into hydrogen research projects such as Store & Go <https://storeandgo.info/index.html> accessed 8 February 2024.

[10] Goda Naujokaitytė 'Clean Hydrogen: Smoke Screen or the Future of Energy?' (Science Business 3 September 2021) <https://sciencebusiness.net/news/clean-hydrogen-smoke-screen-or-future-energy> accessed 12 February 2024.

[11] International Energy Agency (IEA) 'Tracking Hydrogen' <https://iea.org/energy-system/low-emission-fuels/hydrogen> accessed 12 February 2024.

[12] Adolfo Iulianelli et al. 'Advances on Methane Steam Reforming to Produce Hydrogen through Membrane Reactors Technology: A Review' Vol. 58 (2016) Catalysis Review 1–35; for Steam Methane Reforming based on renewable feedstocks see: Mahin Basha Syed, 'Technologies for Renewable Hydrogen Production' in Abul Azad, Mohammad Khan (eds.) *Bioenergy Resources and Technologies* (Academic Press 2021) 158.

[13] For more information on this see Chapter 13 by Elena Tissari in this book.

[14] For more information on this see Chapter 7 by Piti Eiamchamroonlarp in this book.

[15] Alexandre Soares dos Santos, Lílian de Araújo Pantoja 'Microbial Conversion of Biomass' in Sabu Thomas et al. (eds.) *Handbook of Biomass* (Springer 2023) at 1–23.

ones.[16] This book touches upon these techniques in different chapters and appraises them from a legal perspective.

1.2 WHICH HYDROGEN ARE WE TALKING ABOUT?

Concerning the diverse types of hydrogen, terminology differs around the globe. Some regions use the 'colour book of hydrogen'[17] for their regulation and legislation. While the details are subject to debate, at least the three fundamental colours 'grey', 'blue' and 'green' hydrogen are distinguished from each other (with many more colours and shades – details can be found in the overview in Chapter 2 of this book). Hydrogen is often considered 'grey' when it is produced using fossil fuels (for example, through steam reforming).[18] When the CO_2 – which is a by-product of hydrogen production from fossil fuels – is captured and permanently stored, the hydrogen is often referred to as 'blue'.[19] Hydrogen that is produced from renewable sources is frequently labelled 'green'.[20]

Others created their own terms, such as low-carbon hydrogen, renewable hydrogen. Since there is no general agreement on terminology around the globe, this book will make the respective terminology used in the individual jurisdiction as transparent as possible. An overview of the different 'types' of hydrogen and terminologies features in Chapter 2 of this book. In any case, a unified approach to terminology is highly desirable and much needed, as meaningful regulation and the interlinkage of different regions of the world is only possible if we have common standards that are referring to the same things.

As diverse as the types of hydrogen and its production are, the academic literature on the subject is just as extensive. There is no shortage of books on hydrogen – the technicalities, physics, chemics and economics behind it have been described well. One of the most notable contributions over recent decades was published by Cambridge University Press[21] and it aptly demonstrates why the current *Handbook of Hydrogen and the Law* is needed. While the book by Ball and Wietschel is a comprehensive scientific publication on hydrogen and its various applications, covering all major aspects related to hydrogen, there is one omission: regulation and law. The lack of regulation and the fact that more needs to be done in that respect is mentioned in various chapters of the book, but it does not feature a chapter solely on hydrogen regulation.

This is characteristic of the regular treatment of hydrogen in recent debates. While technicians have solutions for various hydrogen-related issues, the legal framework is currently still under development, which might be part of the reason it is not frequently discussed. Some notable exceptions to this exist, of course. Particularly over the past few years, there has been a gradual increase in academic discussion and debate regarding the legal implications of a hydrogen economy. Section 1.3 highlights some of these, structured along the hydrogen value

[16] US Department of Energy 'Hydrogen Production and Distribution' <https://afdc.energy.gov/fuels/hydrogen_production.html> accessed 14 February 2024.

[17] More details on that can be found in Chapter 2 of this book.

[18] Grey hydrogen is produced from natural gas, which generates smaller amounts of CO_2 emissions than what is sometimes classified as 'black' or 'brown' hydrogen where coal is used as a source in the production process, see IEA 'The Future of Hydrogen – Seizing Today's Opportunities' (2019) at 34 <https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf> accessed 12 June 2024.

[19] Robert Howarth, Mark Jacobson 'How Green Is Blue Hydrogen?' (2021) 9 Energy Science & Engineering 1676, 1677.

[20] IEA (2007), table 1; IEA (2019), 34.

[21] Michael Ball, Martin Wietschel (eds.) *The Hydrogen Economy Opportunities and Challenges* (Cambridge University Press 2009).

chain, namely production, transportation and supply to end-use customers, which will also serve as a structuring element in general for the organization of this book. The fourth aspect structuring this book, the development of hydrogen markets, will not be considered separately in this overview but is integrated into the discussions on hydrogen transportation.

1.3 CURRENT LEGAL LITERATURE ON HYDROGEN

1.3.1 *Hydrogen Production*

The classification of hydrogen – the 'colour book' of hydrogen[22] – is discussed critically to some extent by the current literature, due to the fact that classification determines the energy production methods which would catalyse the uptake of hydrogen, as Banet argues.[23] Riemer identifies two key challenges for such a classification, in particular with a view to sustainability.[24] First, clarity in legislative frameworks is required when ascertaining which hydrogen production methods (for example, methods for producing green and/or blue hydrogen) would be compatible with a climate-neutral system from a legal and policy perspective.[25] Second, once the forms of hydrogen are selected, the actual content of the sustainability criteria will need to be evaluated, particularly in light of decarbonization targets and lessons learned from certifying biofuels.[26]

Classification plays a significant role in the certification of hydrogen, when produced, but also in the context of certain legal vehicles like guarantees of origin.[27] This can have repercussions for the import of hydrogen into certain regions from other regions. To give an example: for the EU, imports of renewable and low-carbon hydrogen are anticipated to complement domestic production.[28] The balance that, according to the literature, needs to be found here is between allowing flexibility for diverse hydrogen pathways, while considering that certified fuels need to be climate neutral by 2050.[29] Despite certain improvements in defining renewable hydrogen, as noted by Banet, there is a need to ensure consistency across legislative acts, as there remains a risk of divergence in definitions.[30] Such divergence may impact the commodity market, as well as the scale and speed of infrastructure development.[31]

With regard to the second challenge, namely the content of the sustainability criteria for hydrogen, lessons may be drawn from the sustainability of biofuels which preceded that of

[22] Ruven Fleming 'The Hydrogen Revolution and Natural Gas: A New Dawn in the European Union?' in D. Olawuyi, E. Pereira (eds.) *The Palgrave Handbook of Natural Gas and Global Energy Transitions* (Palgrave MacMillan 2022) 123–140 at 125 <https://doi.org/10.1007/978-3-030-91566-7_5> accessed 22 January 2024 (hereinafter: Fleming).

[23] Catherine Banet 'Building Europe's Hydrogen and Renewable Gas Markets' (2023) Centre on Regulation for Europe, 24 (hereinafter: Banet).

[24] Matia Riemer, 'Lessons Learnt from Certifying Biofuels for a Future Hydrogen Certification Scheme' (2022) 18th International Conference on the European Energy Market (EEM), Ljubljana, Slovenia, 1–7 <https://doi.org/10.1109/EEM54602.2022.9921171> accessed 19 January 2024 (hereinafter: Riemer).

[25] Ibid.

[26] Ibid.

[27] Ibid.

[28] European Commission 'Directive (EU) 2023/2413 of the European Parliament and of the Council amending Directive (EU) 2018/1999 and Directive 98/70/EC as regards the promotion of energy from renewable sources and repealing Council Directive (EU) 2015/652' OJ L, 2023/2413, Recital 9(B).

[29] Banet 38.

[30] Ibid. 25.

[31] Ibid.

renewable gases in areas like the EU.[32] In this regard, biofuel certification has had more than a decade of practical experience which can serve as a guideline for certification of hydrogen. This topic will be discussed further in various chapters of the current book.[33] The regulation of hydrogen production as such depends very much on national law and has been investigated from a legal perspective in particular jurisdictions.[34] However, there are no legal assessments as yet concerning other jurisdictions or offshore production of hydrogen, which is why some chapters of the current book are dedicated to these aspects.

1.3.2 *Hydrogen Transmission and Distribution*

The next step in the hydrogen value chain after production is the transport of hydrogen, namely transmission and distribution.[35] As noted by Tanase and Herrera Anchustegui, there are, depending on the regional context, regulatory principles applicable to hydrogen in the context of, for example, the transmission of hydrogen through pipelines.[36] These principles have mostly been adapted from existing frameworks within the natural gas and electricity sectors.[37]

Scheibe and Poudineh opine that the system of hydrogen transmission through pipelines possesses characteristics akin to natural monopolies, particularly due to the high costs of developing and repurposing infrastructure.[38] With the experience of the electricity and natural gas sectors in mind, the importance of ensuring a competitive market through unbundling measures as well as ensuring non-discriminatory third-party access to pipeline networks is emphasized.[39] At the same time, exceptions to these rules are required to stimulate more private investments in the sector.[40] Barnes highlights a chicken-and-egg dilemma: regulation of competition will only become practically effective upon the development of a hydrogen market and associated infrastructure.[41] Yet it is essential for the regulatory framework to be in place, so as to facilitate this development.[42]

32 European Council Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC art 17 and 18.

33 For example, in Chapter 10 by Mauger, Villavicencio Calzadilla and Fleming as well as in Chapter 5 by Taylor.

34 For the United Kingdom see Dalia Majumder-Russell 'Hydrogen Projects: Legal and Regulatory Challenges and Opportunities' (2021, Globe Law and Business Ltd); for Germany see Marlon Koralewicz et al. 'PORTAL GREEN – Genehmigungsrechtlicher Leitfaden für Power-to-Gas-Anlagen' <https://dvgw.de/medien/dvgw/forschung/berichte/g201735-portalgreen-finaler-genehmigungsleitfaden-bd1.pdf> accessed 15 February 2024.

35 Fleming 125–126.

36 Lavinia Tanase, Ignacio Herrera Anchustegui 'EU Hydrogen and Decarbonised Gas Market Package: Unbundling, Third-Party Access, Tariffs and Discounts Rules at the Core of Transport of Hydrogen' in Íñigo del Guayo Castiella, Lorenzo Mellado Ruiz (eds.) *Retos Regulatorios de los Gases Renovables en la Economía Circular* (Marcial Pons 2023) at 8 (hereinafter: Tanase and Herrera Anchustegui).

37 Ibid.

38 Alexander Scheibe, Rahmatallah Poudineh, 'Regulating the Future European Hydrogen Supply Industry: A Balancing Act between Liberalization, Sustainability, and Security of Supply?' (2023) OIES Paper: ET, No. 26, ISBN 978-1-78467-218-8, Oxford Institute for Energy Studies, Oxford at 1 (hereinafter: Scheibe and Poudineh).

39 Tanase and Herrera Anchustegui 7.

40 Ibid.

41 Alex Barnes 'The EU Hydrogen and Gas Package: Help or Hindrance for the Development of a European Hydrogen Market?' (2023) OIES Paper ET22, Oxford Institute for Energy Studies at 21 <https://oxfordenergy.org/wpcms/wp-content/uploads/2023/03/The-EU-Hydrogen-and-Gas-Decarbonisation-Package-ET22.pdf> accessed 23 January 2024.

42 Ibid.

In the development of a hydrogen market, questions arise as to who will own and operate hydrogen distribution and transmission networks. This might be different regarding distribution networks and transmission networks.[43]

According to Barnes, a strict ownership unbundled model for the regulation of hydrogen transmission, but also in particular distribution, can dissuade further private investment.[44] Barnes provides an example in this regard that the strict ownership unbundling model prevents the risk sharing that was common in the gas pipeline and liquid natural gas (LNG) markets, where producers and purchasers of gas took equity stakes in common infrastructure for the purposes of sharing risks related to the development of a market.[45]

Baumgart and Lavrijssen note that where a hydrogen transmission network operator is part of an undertaking active in transmission or distribution of natural gas or electricity, it should undergo at least legal unbundling, as well as accounting unbundling.[46] Horizontal unbundling has been subject to the criticism that it may hamper synergies between gas and hydrogen networks, and may also result in an inefficient duplication of structures.[47] Tanase and Herrera Anchustegui, however, note that a lighter version of unbundling can be employed, given that the risks of conflicts of interests stemming from combined operatorship is less likely than in vertical integration.[48] Any remaining risks could, in their opinion, be mitigated through monitoring and approval by regulatory authorities.[49]

Further to unbundling, another key component of the legislative landscape for hydrogen transport is the third-party access regime for hydrogen pipelines. As noted by Tanase and Herrera Anchustegui, third-party access implies that states must ensure non-discriminatory third-party access to transport infrastructure.[50] The rationale for providing third-party access is that hydrogen networks are capital intensive to build and risk becoming natural monopolies. De Wildt notes that two types of third-party access to hydrogen pipelines can be accommodated: regulated and negotiated third-party access.[51] These and other aspects will be dealt with in this book with a view to the transmission,[52] but also the distribution[53] level of hydrogen networks and in particular legal conditions for making investments into both will be discussed.[54]

1.3.3 *Hydrogen End Use*

Hydrogen consumption is currently low all around the globe, but how to regulate the end use of hydrogen has been the topic of some discussion in literature, particularly about the key themes of customer protection, hydrogen end-use sectors as well as hydrogen blending.

43 For an example from the EU context see rGD, art. 42.
44 Barnes 16.
45 Ibid.
46 Max Baumgart, Saskia Lavrijssen 'Exploring Regulatory Strategies for Accelerating the Development of Sustainable Hydrogen Markets in the European Union' (2023) Journal of Energy and Natural Resources Law <https://doi.org/10.1080/02646811.2023.2257528> accessed 20 January 2024.
47 Ibid.
48 Tanase and Herrera Anchustegui 11.
49 Ibid.
50 Ibid. 8.
51 Bo de Wildt, Adriaan van der Welle, Marcel Weeda, Sebastiaan Hers 'Towards Decarbonised Gas Markets: An Analysis of the Current and Future Market Design for Gaseous Fuels Based on EU Legislation' (2022) at 8 <https://repository.tno.nl/SingleDoc?find=UID%20ea2d301f-a8ee-4654-8902-a8e13b728cb9> accessed 12 June 2024.
52 For example, Chapter 15 by Jansen in this book.
53 For example, Chapter 17 by Broersma, Holwerda and Jaeger in this book.
54 For example, Chapter 16 by Zerde in this book.

Heidecke and others note that emphasis on consumer protection rules, concerning for example supplier switching, price comparisons and obtaining accurate data on consumption, is crucial.[55] With regard to supplier switching, customers could be equipped with an inherent right to change suppliers for natural gas and hydrogen, and protective caps on pricing could be set.[56]

With a view to relevant sectors for hydrogen use, some parts of the world identified early adopter sectors in which a 'switch' to renewable or low-carbon hydrogen may take place soon.[57] These sectors include the industrial sector involving hydrogen in the production of ammonia, methanol and steel making to replace fossil fuels.[58] Another early adopter of renewable or low-carbon hydrogen is the heavy-duty transportation sector, including road, rail, maritime and aviation.[59]

As noted by Scheibe and Poudineh, however, the debate on usage of hydrogen in the heating sector, in particular for heating in buildings, is quite fierce.[60] The primary reservation to the use of hydrogen in the heating sector is based on the assertion that hydrogen is comparatively inefficient compared to its use in other sectors, and will only be available in low quantities at high cost.[61] As a result, Scheibe and Poudineh noted that hydrogen strategies across member states differ in respect of their treatment of heating in buildings.[62] The topic will be discussed in more depth in a separate chapter of this book.[63]

Lastly the percentage of hydrogen allowed for blending in the natural gas system, both for those customers connected directly to the transmission system and those connected to the distribution system, has also increasingly become a point of discussion regarding hydrogen and consumers. At a transmission level, gas transmission networks transmit gas from border interconnection points to gas distribution networks as well as large (for example, industrial) consumers connected directly to the transmission network. It has been argued that a cap, rather than a fixed blending target, would give room for discrepancies in blending percentages at interconnection points between different countries.[64] Furthermore, Zemite and others note that, in any case, there should be harmonization of standards between interconnected countries.[65]

Most customers, such as household customers, are supplied currently via the gas distribution network. Tests are currently underway to ensure hydrogen compatibility with certain appliances. For example, in 2023 a German blending trial was conducted to test whether households could

55 L. Heidecke et al. 'The Revision of the Third Energy Package for Gas' (2022) Publication for the Committee on Industry, Research and Energy (ITRE) at 26 <https://europarl.europa.eu/RegData/etudes/STUD/2022/734009/IPOL_STU(2022)734009_EN.pdf> accessed 17 January 2024.

56 Ibid.

57 For the example of the EU see European Commission, 'EU Strategy on Hydrogen' COM (2020) 301 final, 17 (hereinafter: EU Hydrogen Strategy).

58 Ibid. at 10.

59 Ibid.

60 Scheibe and Poudineh 2–3.

61 Hydrogen Europe Position Papers 'Hydrogen Technologies Can Boost the Energy Performance of Buildings' (May 2022) 6 <https://hydrogeneurope.eu/wp-content/uploads/2022/05/220516-EPBD_hydrogen-Europe-Position-paper-1.pdf> accessed 6 June 2024.

62 Scheibe and Poudineh 2–4.

63 See Chapter 20 by Jansen and Reins.

64 Ruven Fleming 'Green Hydrogen Developments in the EU: Cross-Border Cooperation between Germany and the Netherlands' in Martha Roggenkamp, Catherine Banet *European Energy Law Report Volume XIV* (Intersentia, Cambridge 2021) 267–293 at 291.

65 L. Zemite et al. 'Blending Hydrogen with Natural Gas/Biomethane and Transportation in Existing Gas Networks' (2023) 60 Latvian Journal of Physics and Technical Sciences 33–45 at 34–35.

be supplied 20 per cent of blended hydrogen as opposed to the 10 per cent currently provided by German law.[66] After sampling 100 households, the trial showed that following six months of the test, the households in the sample did not experience any technical difficulties in respect of the 20 per cent hydrogen blend.[67] Allowed blending levels of hydrogen at a household level differ in accordance with different technical standards in different countries. But they also depend on the individual end-use purposes, as demonstrated by some chapters in this book.[68]

1.4 CONCLUSION

Having sketched the legal debate on hydrogen, the observed immature status and currently underdeveloped knowledge on hydrogen regulation can wreak havoc on business cases and new hydrogen projects. The hydrogen economies of the future depend on the development of clear legal frameworks, but also on comprehensible explanations about the current situation. Remember the speech by Francesco La Camera? He mentioned 'innovative regulatory and policy frameworks' as the first of several preconditions for rapid green hydrogen scale-up.

This *Handbook* takes the reader along on its mission to fill the knowledge gap on hydrogen and the law. It is the first comprehensive book on hydrogen regulation, not only featuring an overview of the status quo on all permanently inhabited continents, but also looking in-depth at regulatory issues for the four most important aspects of hydrogen economies from a legal perspective: market creation, production, transport and end use. Accordingly, the book features a range of chapters discussing the topic of hydrogen regulation in breadth and depth. This is necessary as, on the one hand, it is the first to provide a truly global overview of hydrogen regulation from the most relevant regions for hydrogen in the world. On the other hand, there are many countries and regional organizations that may provide best-practice examples for certain elements of the hydrogen chain, the knowledge about which can be beneficial for other countries. Finding and discussing these best practices constitutes a particular focal point of this book.

The book addresses several questions, both systematic and pragmatic. Systematic questions include (but are not limited to): if hydrogen is an energy carrier that couples the gas and electricity sectors, how much legal system integration is required to follow up? How can natural gas exporting countries transition to hydrogen? Which types of hydrogen are desired in these transitions and how does law currently steer decisions on that? What are the regulatory criteria to establish sustainability of hydrogen supplies? Should a support mechanism be designed (subsidies, blending quotas or other means) and can/should it be done in such a way as not to distort nascent markets? Which stakeholder perspectives are covered by current law and where are possibilities for improvement?

Besides these issues there are also practical questions that need to be answered. How can current natural gas infrastructure be repurposed for hydrogen and which authorizations are required for that? How may gas quality standards for hydrogen be harmonized to facilitate cross-border trade and export/import of hydrogen? How should permitting regimes for electrolyzers be designed and could proper design provide efficiency gains in the process? Moreover, what are the possibilities for people to participate and have their say in the hydrogen transition? And with

[66] DVGW 'Gasgeräte bereit für 20% Wasserstoff' <https://dvgw.de/medien/dvgw/leistungen/publikationen/gasgeraete-bereit-fuer-20_-h2-factsheet-dvgw-avacon.pdf> accessed 15 February 2024.

[67] Ibid. 4.

[68] See for example Chapter 18 by Cocciolo and Chapter 19 by Huhta and Sairanen in this book.

a view to end use, where should we first focus efforts, as hydrogen will not be readily available in the required quantities and qualities anytime soon? Should, e.g., the transport sector or the housing/heating sector be decarbonized first? Is energy storage the solution for the future?

The chapters have all been specially commissioned for this book and written by leading experts in the field of energy regulation. This includes academics, industry lawyers, lawyers working for non-governmental organizations (NGOs), as well as those working for international institutions. The result is a multitude of perspectives on 'hydrogen and the law', not only (but also) from an academic perspective. All experts obtained knowledge on hydrogen regulation via research projects, daily work, previous publication projects or involvement in commercial hydrogen projects and they all are experts on a particular region or a particular element of the hydrogen value chain. The central idea behind producing this *Handbook* as an open-access publication is to provide everyone with access to the knowledge encapsulated in this reference work. That way, all actors and stakeholders of the 'hydrogen revolution' can gain crucial insights – citizens, the private sector, investors, law firms, but also regulators and governmental and non-governmental organizations. Having said all of that: let the fun begin!

PART I

Current Hydrogen Regulation on the Continents

2

Hydrogen Regulation in Europe

The EU's 'Hydrogen and Decarbonised Gas Market' – Best Practice or Missed Opportunity?

Leigh Hancher and Simina Suciu

2.1 INTRODUCTION

The EU's path towards net-zero carbon was triggered with the launch of the European Green Deal,[1] a comprehensive policy roadmap adopted in 2019 to transform the Union's economy[2] and align it with the goals of the Paris Agreement of 2015.[3] Major importance is attached to hydrogen (H2) in the ongoing energy transition and for the realisation of the EU's ambitious and legally binding net-zero target.

Consequently, one of the two strategic pillars aimed at reaching the targets in the Green Deal's roadmap focuses on H2.[4] This roadmap spans twenty action points, including the design of the enabling market rules for the deployment of H2, based on a review of the EU's existing gas legislation.

Hydrogen can be used as a direct energy carrier, it can support storage and transport, it can function as an alternative fuel for e-mobility and it can be used as a feedstock – that is, an input for oil refining/petrochemicals, ammonia and steel production.[5] Today, renewable and low-carbon H2 gases are not yet cost competitive compared to fossil-based H2 gas. By 2050, the European Commission (EC) estimates that gaseous fuels, largely H2 and biogases, will make up a fifth of final energy consumption, and by 2030 Europe is expected to have a 'pure' H2 market in place.[6]

Building on the promise to make the EU's climate, energy, transport and taxation policies fit for reducing net greenhouse gas (GHG) emissions by at least 55 per cent by the Green Deal's intermediate target date of 2030, in July 2021 the EC adopted its first series of more targeted

The views expressed in this chapter are personal and do not represent the position or and/views of any organisation.

[1] COM(2019) 640 final, issued on 11 December 2019, European Green Deal.

[2] By reducing GHG emissions to 55 per cent compared to 1990 levels by 2030 and to net zero by 2050, aiming to decouple economic growth from GHG emissions; Ibid., p. 2.

[3] United Nations, Paris Agreement (2015).

[4] Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of Regions: A Hydrogen Strategy for a Climate-Neutral Europe, Brussels, 8 July 2020, COM(2020) 301 final (EU Hydrogen Strategy).

[5] Martin Lambert, *Clean Hydrogen Roadmap: Is Greater Realism Leading to More Credible Paths Forward?*, OIES, September 2023, pp. 2–3 and 8.

[6] Euractiv, *EU's Future Hydrogen Grid Takes Shape after Parliament Vote*, 9 February 2023.

proposals (the 'Fit for 55' initiative). This promotes, inter alia, demand for and production of renewable and low-carbon gases, including H2.[7]

2.1.1 The Gas Package

In December 2021, the EC released its 'Hydrogen and Gas Market Decarbonisation Package' (Gas Package).[8] This package, also sometimes referred to as the 'Fourth Gas Package', includes a proposal for a gas directive (GD) and a regulation (Regulation) establishing common internal market rules for renewable and natural gases and for H2, to foster decarbonisation, create the conditions for a more cost-effective transition and reach the EU's goal of climate neutrality by 2050. It is a recast of the 'Third Gas Package' and extends its scope to cover H2 networks.

Both the GD and the Regulation contain provisions (set out in separate chapters) applicable to natural gas systems and to dedicated H2 networks. More specifically, the GD includes provisions on the unbundling of H2 network operators and their certification. It also addresses topics that are common to both natural gas and H2, including: (i) consumer protection; (ii) third-party access (TPA) to infrastructure and integrated network planning; (iii) rules for transmission, storage and distribution system operators; and (iv) rules on independent regulatory authorities.

Read in conjunction with the GD, the Regulation lays down rules on the organisation of the decarbonised gas and H2 markets, on H2 blends for natural gas systems and cross-border coordination on H2 quality. It also elaborates principles and rules concerning: (i) tariffs for network access and discounts; (ii) the separation of regulated asset bases (RAB), TPA services, principles of capacity-allocation mechanisms and congestion-management procedure; and (iii) the duties of regulatory authorities and regional cooperation between them.

With this Gas Package and the ambition to adopt a comprehensive system of regulation for H2 and decarbonised gases, the EU aimed at the time to be one of the world's jurisdictions, along with the United States, to lead on H2 policy development.[9] Belgium, probably one of the most developed H2 markets, adopted specific H2 transport legislation in July 2023.[10] Some countries (such as Australia) have amended their existing regulations to include H2, while other countries (China, Republic of Korea) are developing H2-specific technical guidelines.[11]

The launch of the Gas Package in 2021 was subsequently overtaken in March 2022 by the 'RepowerEU' Plan, which was triggered as a response to the global energy crisis. This initiative called for an acceleration of the roll-out of renewable energy to complete the energy transition and replace the use of fossil fuels, contributing to the further reduction of dependence on energy supply from Russia. This means, inter alia, building more renewable energy generation capacity

7 European Commission, 'Hydrogen and Decarbonised Gas Market Package' <https://energy.ec.europa.eu/topics/markets-and-consumers/market-legislation/hydrogen-and-decarbonised-gas-market-package_en> accessed 15 February 2024.

8 Ibid. Extensive public consultations took place prior to the initial publication of the EC's Gas Package in December 2021: European Commission, 'Public Consultation Launched on Hydrogen and Decarbonising the EU Gas Market' <https://commission.europa.eu/news/public-consultation-launched-hydrogen-and-decarbonising-eu-gas-market-2021-03-26_en> accessed 15 February 2024.

9 International Energy Agency (IEA) 'Hydrogen' <https://iea.org/energy-system/low-emission-fuels/hydrogen> accessed 15 February 2024.

10 Belgian Act on the transport of hydrogen <https://economie.fgov.be/en/themes/energy/sources-and-carriers-energy/hydrogen/regulation-hydrogen-transport> accessed 15 February 2024.

11 OECD, 'Risk-Based Regulatory Design for the Safe Use of Hydrogen', p. 9 <www.oecd.org/governance/risk-based-regulatory-design-for-the-safe-use-of-hydrogen-46d2da5e-en.htm> accessed 30 May 2024; The Hydrogen Regulatory Landscape (2023) <www.oecd.org/gov/risk-based-regulatory-design-for-the-safe-use-of-hydrogen-46d2da5e-en.htm> accessed 30 May 2024.

and faster, as well as ensuring the enhanced integration of renewable energy sources into final energy uses.[12]

Nevertheless, a major pillar of the RepowerEU plan is the 'Hydrogen Accelerator', which sets out an ambitious strategy to double the previous EU renewable H2 target to ten million tonnes of annual domestic production, plus an additional ten million tonnes of annual H2 imports. Meeting these targets requires the EU to significantly upscale its manufacturing capacities, speed up development and retrofit infrastructure to allow for future H2 readiness.

There is increasing scepticism that these targets are realistic.[13] This uncertainty impacts on the transportation, distribution and storage of domestically produced H2 and imported H2 from countries with adequate renewable energy resources.

This chapter will first describe certain concepts in the Gas Package, which – as we explain – have proved controversial in the ongoing EU legislative process. We question whether these concepts are 'fit for purpose' in the H2 market context given two main differences between the regulatory framework applied to natural gas versus H2.

2.1.2 *Natural Gas and H2: The Main Differences and Challenges in Regulation*

A first key difference between the implementation of the current natural gas regulatory framework (as enacted through the gas packages of 1998, 2003 and 2009) and the provisions in the new Gas Package is that the former rules were intended to regulate an existing, profitable and mature natural gas market with well-developed infrastructure. By contrast, there is currently no real H2 market, let alone any well-developed infrastructure, and the high costs of H2 production together with a lack of means for transporting renewable H2 have become a challenge for the development of this market.[14]

A second key difference between natural gas (methane) and H2 is that, while the former must be transported from point of production (an onshore or offshore gas field) to the point of use, the latter can be produced near input sources and then transported to the point of use. H2 is also more difficult and more expensive to transport over long distances compared to natural gas; thus, a European-wide H2 pipeline network or 'H2 backbone' may not necessarily materialise. This seems to have partially made its way into EU policy given the references to EU 'H2 hubs' and 'H2 valleys'.[15] With current technologies, transport often doubles the price of H2 for the end user. It is more logical to start with H2 clusters around Europe's key port areas and experiment with different transport modes and carriers between them and production centres in third countries.

In view of these differences, this chapter analyses the key instruments to be deployed in the proposed regulatory exercise. We first focus (in Section 2.2.2) on the 'regulatory holiday' concept in the H2 market context, and whether, as developed in the Gas Package, this approach facilitates the inception of an H2 market.

[12] Communication on REPowerEU: Joint European Action for More Affordable, Secure and Sustainable Energy, COM (2022) 108 final, 8 March 2022, with Annexes.

[13] International Energy Agency (IEA), *Global Hydrogen Review*, 2023 <https://iea.org/reports/global-hydrogen-review-2023/executive-summary> accessed 15 February 2024.

[14] Camilla Palladino, 'Lex in Depth: The Staggering Cost of a Green Hydrogen Economy', *Financial Times*, 28 May 2023; European Parliamentary Research Service, Briefing towards Climate Neutrality, *EU Rules for Renewable Hydrogen. Delegated Regulations on a Methodology for Renewable Fuels of Non-biological Origin*, 2023, p. 4.

[15] European Commission, Directorate-General for Research and Innovation, *REPowering the EU with Hydrogen Valleys*, Publications Office of the European Union, 2023.

Next, we turn to a detailed critique of three of the principal regulatory building blocks of the new Gas Package: unbundling (Section 2.3), tariff regulation (Section 2.4) and TPA (Section 2.5).

In conclusion, we question in Section 2.6 whether the ambitious timelines and targets envisaged by the new Gas Package, the mirroring of some parts of the existing framework for natural gas regulation in a dedicated H2 network and in renewable and low-carbon H2 used for injection into the natural gas systems, as well as the EC's approach to a nascent EU H2 market, are realistic and appropriate to pursue its decarbonisation goals.

2.2 OVERVIEW AND HISTORY OF THE HYDROGEN AND DECARBONISED GAS MARKET PACKAGE

2.2.1 *Scope and Definitions*

In its 2021 Impact Assessment accompanying the Gas Package, the EC anticipated: (i) an H2-based infrastructure, which will complement and partly replace the current natural gas infrastructure and (ii) a methane-based infrastructure, which will evolve from the current natural gas-based system to one which uses primarily biomethane and synthetic methane.[16]

These two separate infrastructures are to be subject to similar but not identical regulatory principles. It is, therefore, immediately evident that certain definitions and regulatory concepts are central to understanding how these different sets of infrastructure will be developed and regulated.

The expansion in the new Gas Package to include other types of gas besides natural gas and liquefied natural gas (LNG) is already an improvement given the increasing lack of clarity around the scope and applicability of the Third Package to H2 or blended H2 – it is no longer reflecting market developments.

In this regard, the EC confirmed that 'the Third Gas Package applies to all gases that can be safely injected into the gas network, which include hydrogen blended safely into the natural gas system' but the Third Gas Package 'does not apply to dedicated hydrogen infrastructure'.[17]

Pure Hydrogen What Is It?

Hydrogen is lighter than air, and can be transported, stored and transformed into other carriers. Based on the energy source and the means used for its production,[18] as well as its greenhouse emissions, H2 is often categorised based on a colour code. Figure 2.1 matches the coloured H2 types (mainly green, grey and blue H2) with terms from the EU legislation to the extent possible.

Even if the EC proved reluctant to embrace this colour code, it could not totally avoid the controversy of whether H2 could really prove to be 'the silver bullet' for decarbonisation. The EU Hydrogen Strategy refers to different H2 categories, such as 'electricity-based H2' (which encompasses all categories of H2 produced with electricity irrespective of its source) and 'low-carbon H2' (which includes blue H2 and electricity-based H2 with reduced greenhouse gas

[16] Brussels, 15 December 2021, SWD(2021) 455 final.

[17] European Commission Staff Working Document, Evaluation Report, SWD(2021) 457 final, 15 December 2021, p. 41.

[18] It is produced essentially through two means: (i) by splitting water into H2 and oxygen molecules with the support of extensive energy input. This split can be performed in various ways, including with electricity (a process called electrolysis). After splitting, H2 can be stored or transformed into methane, similarly to natural gas; and (ii) by steam-methane reforming, which separates H2 from carbon in methane. See US Energy Information Administration, *Hydrogen Explained. Production of Hydrogen* <www.eia.gov/energyexplained/hydrogen/#:~:text=Elemental%20hydrogen%20is%20an%20energy,source%20of%20energy%20or%20fuel> accessed 15 February 2024.

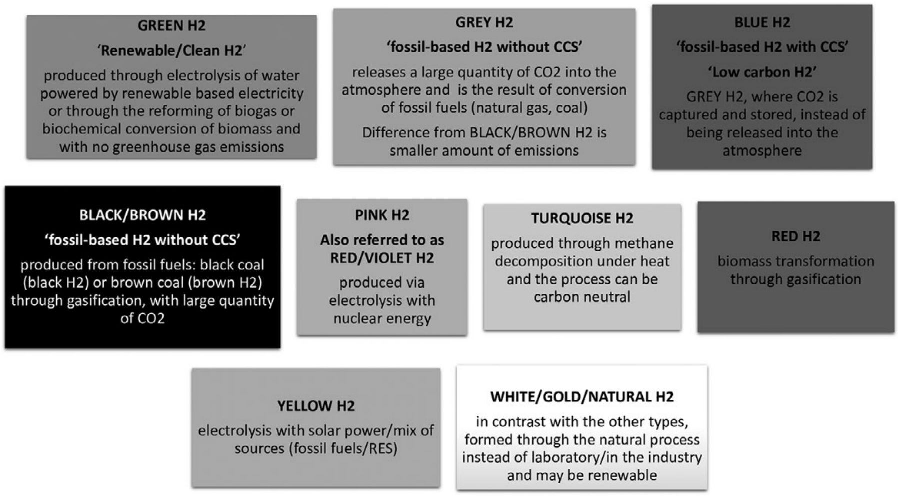

FIGURE 2.1 The coloured H2 types[19]

emissions).[20] This categorisation reflects the EC's 'stepwise' approach at the heart of the document.

Hence, the EC acknowledged that

> *"renewable hydrogen is the most compatible option with the EU's climate neutrality and zero pollution goal in the long term and the most coherent with an integrated energy system. In the short and medium term, however, other forms of low-carbon hydrogen are needed, primarily to rapidly reduce emissions from existing hydrogen production and support the parallel and future uptake of renewable hydrogen."*[21]

In any event, and for a nascent market to take off, clear definitions for the types of gases that are to be regulated must be applied consistently throughout the Gas Package. In addition, given Europe's H2 import dependency, a comprehensive terminology for different types of gases for inclusion in an EU-wide certification system will be necessary.[22]

The Necessity for Clearer and More Comprehensive Definitions and Concepts

The preamble of the GD[23] makes a distinction between 'low-carbon H2' and 'renewable H2' produced mainly from wind and solar energy, but the latter concept is not defined in the

[19] *Sources*: authors based on corroboration of different sources: (1) European Parliamentary Research Service, *EU Rules for Renewable Hydrogen: Delegated Regulations on a Methodology for Renewable Fuels of Non-biological Origin*, p. 3 <www.europarl.europa.eu/thinktank/en/document/EPRS_BRI(2023)747085>; (2) World Nuclear Association, *Hydrogen Production and Uses* <https://world-nuclear.org/information-library/energy-and-the-environment/hydrogen-production-and-uses> 1 May 2024; (3) US Energy Information Administration, *Hydrogen Explained. Production of Hydrogen*, section 2, pp. 3–4 <www.eia.gov/energyexplained/hydrogen/#:~:text=Elemental%20hydrogen%20is%20an%20energy,source%20of%20energy%20or%20fuel>; (4) *EU Hydrogen Strategy*, <https://energy.ec.europa.eu/topics/energy-systems-integration/hydrogen_en>; (5) 'Is Hydrogen Colourless or Colourful?' Ramboll <https://ramboll.com/net-zero-explorers/hydrogen-colours-explained>, all accessed 15 February 2024.

[20] EU Hydrogen Strategy, section 2.

[21] Ibid.

[22] CEER response to the European Commission's Public Consultation on the Hydrogen and Gas Market Decarbonisation Package, Ref: C21-GWG-171-03, 22 June 2021, p. 2 <www.ceer.eu/wp-content/uploads/2024/04/CEER-Response-to-the-EC-public-consultation-on-the-Hydrogen-and-Gas-Market-Decarbonisation-Package.pdf> accessed 15 February 2024.

[23] Recital 13 GD.

GD – which only states that 'renewable H2' produced using biomass energy is captured under the term 'biogas'.[24]

'Low-carbon H2' is defined in the GD as H2 derived from 'non-renewable' sources producing at least 70 per cent less greenhouse gas emissions than fossil natural gas across its full lifecycle.[25] To ensure compliance with this threshold, the GD includes certification rules.[26]

Although 'low-carbon gases', including 'low-carbon H2', are not all 'renewable', they are equated with 'renewable gas' in several provisions of the Gas Package. As 'renewable fuels' they could not be included in the proposal for the revision of the Renewable Energy Directive.[27] Their inclusion in the Gas Package is aimed to fill in that gap.

The definitions of 'low-carbon H2' and 'renewable H2'are contained in two interrelated EU Delegated Acts (DA), as foreseen under Articles 27(3) and 28(5) of the Renewable Energy Directive.

The 'Additionality DA'[28] defines under which conditions H2 and H2-based fuels produced from electricity can be qualified as renewable (or renewable fuels of non-biological origin – RFNBOs).

In the same DA, 'low-carbon H2' refers to H2 derived from non-renewable resources meeting a greenhouse gas emission reduction threshold of 70 per cent.[29] The Renewable Energy Directive requires RFNBOs to reduce emissions by at least 70 per cent compared to fossil fuels such as gasoline and diesel. This threshold is also captured under the terms 'low-carbon gases' and 'low-carbon fuels'.[30]

The calculation of the 70 per cent threshold is further clarified in the Methodology DA.[31] This DA lists what emissions need to be captured under the lifecycle GHG emissions and what rules need to be considered for determining the emissions associated with each input.

To meet the 70 per cent threshold, operators need to provide information supporting its achievement to the national regulators through a voluntary certification process.[32]

The methodology for calculating the 70 per cent threshold remains controversial and, as part of the public consultation process on the Gas Package, multiple stakeholders requested more clarity on the relationship among guarantees of origin (GO), certification and carbon intensity for renewable and low-carbon gases.[33]

[24] Ibid.

[25] In view of the fossil fuel comparator for renewable fuels of non-biological origin set out in the methodology adopted according to Article 29a(3) of Directive (EU) 2018/2001, as well as Article 2(10) of the GD.

[26] Article 9 GD.

[27] EU Directive 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources (recast), PE/48/2018/REV/1, [2018] OJ L 328.

[28] European Commission Delegated Regulation (EU) 2023/1184 of 10 February 2023 supplementing Directive (EU) 2018/2001 of the European Parliament and of the Council by establishing a Union methodology setting out detailed rules to produce renewable liquid and gaseous transport fuels of non-biological origin, [2023] OJ L 157/11.

[29] Ibid., Article 2, first paragraph, point (10).

[30] Ibid., Article 2, first paragraph, point (11)–(12).

[31] European Commission Delegated Regulation (EU) 2023/1185 of 10 February 2023, [2023] OJ L157/20.

[32] Article 9 GD. The Renewable Energy Directive (RED III) updates this process with, e.g., the obligation of gas suppliers to use guarantees of origin when demonstrating the RED share to consumers (the original Article 19(8) for electricity in RED II is now extended to gas); verification criteria regarding compliance with the sustainability and greenhouse gas emissions saving criteria for renewable fuels and recycled carbon fuels that are accounted to targets set in RED III. Articles 19(8), and 30–31 contain the concept of a Union database for tracing of liquid and gaseous transport fuels that are eligible for counting towards RED III targets.

[33] ENTSOG, 'High-Level Position on Hydrogen and Decarbonised Gas Market Package' (2022) p. 3 <www.entsog.eu/sites/default/files/2022-02/ENTSOG%20High%20Level%20Position%20on%20Hydrogen%20and%20Decarbonised%20Gas%20Market%20Package.pdf> accessed 19 February 2024 (hereafter: ENTSOG)

The rules on 'blue' H2 have not yet been finalised in the EU, although some progress is being made. The trilogue agreement on the new Package refers at Article 8(5)A to a further Commission DA on the methodology for assessing greenhouse gas emissions savings from low-carbon fuels. The proposed DA would include minimum carbon capture rates and upstream methane emissions performance standards. However, there are persistent doubts on whether carbon capture technology can consistently deliver capture rates of more than 70 per cent, as foreseen in the definition of low-carbon gas in the Gas Package. Although the first two DAs have met criticism,[34] they do bring further regulatory certainty. The provisional agreement on the Gas Package reached at the end of 2023 also recognises the EU's focus to increase biomethane production.[35]

Having established these distinctions between clean or pure H2 and low-carbon gas and fuels which may contain some H2, but which can still be co-mingled with natural gas, it is now possible to consider the different regulatory frameworks for dedicated H2 and natural gas networks.

2.2.2 *The Gas Package in Detail*

The Gas Package went through the EU ordinary legislative procedure. Multiple trilogue discussions[36] between the EC, the European Parliament (EP) and the Council of the European Union (Council) have taken place, and in the last trilogue[37] a provisional agreement was reached.[38] The Gas Package was formally adopted on 21 May 2024,[39] it was published in the EU Official Journal on 15 July 2024 and entered into force 20 days later.

Regulatory Objectives and Principles

The stated aim of the Gas Package is to prepare for the shift away from conventional fossil or methane gas to renewable and low-carbon gases, in particular biomethane and H2.[40] More specifically, in the EC's views,[41] this means the decarbonisation of gas consumption, the creation of cost-effective, cross-border H2 infrastructure and a competitive H2 market. This would also require the removal of barriers to decarbonisation, as well as the establishment of

34 Dave Keating, 'EU Sets Out Rules for Green Hydrogen – Inviting Promise and Peril', Energy Monitor (20 February 2023) <www.energymonitor.ai/hydrogen/eu-sets-out-rules-for-green-hydrogen-inviting-promise-and-peril/#:~:text=New%20EU%20green%20hydrogen%20rules&text=The%20act%20requires%20proof%20that,no%20older%20than%2036%20months> accessed on 30 May 2024.

35 European Council, 'Gas Package: Council and Parliament Reach Deal on Future Hydrogen and Gas Market' <https://consilium.europa.eu/en/press/press-releases/2023/12/08/gas-package-council-and-parliament-reach-deal-on-future-hydrogen-and-gas-market/> accessed 15 February 2024 (hereafter: Council Gas Package).

36 A 'trilogue' or a 'tripartite meeting' represents the informal interinstitutional negotiation between the EP, the Council and the EC.

37 November–December 2023.

38 Recital 6 GD (14 December 2023, interinstitutional file 2021/0425(COD) and Regulation (15 December 2023, interinstitutional file 2021/0424(COD)).

39 <https://data.consilium.europa.eu/doc/document/PE-105-2023-INIT/en/pdf>. The Gas Directive was published in the Official Journal L2024/1788 on 15.07.2024 and the Gas Regulation was published in L2024/1789 on 15.07.2024.

40 European Commission, 'Hydrogen and Decarbonised Gas Market Package' <https://energy.ec.europa.eu/topics/markets-and-consumers/market-legislation/hydrogen-and-decarbonised-gas-market-package_en> accessed 15 February 2024.

41 Ibid.

cost-effective conditions for the transition period – that is, to 2049.[42] For instance, the GD foresees that long-term contracts for unabated fossil natural gas should not be extended beyond 2049 to avoid locking in fossil fuels.[43]

The Gas Package provides several mechanisms to achieve these broad regulatory objectives.

First, 'the main objective of this Directive is to enable and facilitate [the] transition by ensuring the ramp up of a hydrogen market and an efficient market for natural gas'.[44] As a result, the Gas Package includes separate provisions and chapters for (i) dedicated H2 systems (H2 networks, terminals and storage), which contain a 'hydrogen of a high grade purity',[45] and (ii) natural gas systems, which refer to gas composed mainly of methane and other gases that can be technically and safely injected into the natural gas system (such as biomethane, H2).[46]

The creation of a new market design for (pure) H2 is based on the mirroring of some of the regulatory principles applicable to natural gas infrastructures. The various mechanisms provided for achieving this overall goal are linked specifically to the operation of dedicated H2 infrastructure networks, the repurposing of existing gas infrastructure for H2 blends and its transportation, and the designation of H2 network, storage and terminal operators. The Gas Package includes exceptions from some of its regulatory requirements in the shape of 'regulatory holidays' for H2.

Second, a new European Network of Network Operators for Hydrogen (ENNOH) would be created to promote a dedicated H2 infrastructure, cross-border coordination and interconnector network construction, and elaborate on specific technical rules. ENNOH's tasks are therefore identical to those conferred on the European Network of Transmission System Operators (ENTSO)-E (electricity) and ENTSO-G (gas). ENNOH will be a separate entity from ENTSO-E and ENTSO-G.[47]

Fourth, the scope of the Security of Gas Supply Regulation[48] is extended to H2 and to renewable and low-carbon gases.

Regulatory Holidays

The Gas Package contains several transitional provisions in the shape of 'regulatory holidays'. During the initial roll-out period, dedicated H2 networks can enjoy temporary derogations from the default regulatory regime. This includes regulatory holidays from the obligation of granting TPA to the network, ownership unbundling and regulated tariffs. Historically, ad hoc derogations from these provisions provided in the earlier packages have been used to incentivise merchant investment in the natural gas and electricity sectors.[49] These derogations are usually

42 Ibid.
43 Recital 144 and Articles 31(3) and 71(1)(s) GD.
44 Recital 6 GD.
45 Article 2(4) GD.
46 Article 2(3) GD and CEER and ACER, 'When and How to Regulate Hydrogen Networks?' (2021), footnote 6 <https://acer.europa.eu/sites/default/files/documents/Official_documents/Position_Papers/Position%20papers/ACER_CEER_WhitePaper_on_the_regulation_of_hydrogen_networks_2020-02-09_FINAL.pdf> accessed 30 May 2024 (hereafter: CEER and ACER).
47 Council Gas Package.
48 Regulation (EU) 2017/1938 of the European Parliament and of the Council of 25 October 2017 concerning measures to safeguard the security of gas supply and repealing Regulation (EU) No 994/2010 published in (2017) OJ L 280/1.
49 J. Papsch, 'Chapter 11 Derogations and Exemptions' in Christopher Jones (ed.) *EU Energy Law Volume I the Internal Energy Market*, 5th ed. (Edward Elgar 2020) p. 528 (hereafter: Jones, *EU Energy Law*).

granted for a period of up to twenty-five years by relevant national energy regulatory authorities, as endorsed by the EC, through an 'Exemption Decision'.[50]

Ad hoc exemptions are, however, not considered to be sufficient for creating a major impetus for the ramping up of an H2 market. For example, the exemption mechanism[51] cannot be used for H2 networks within Member States, but only for pipelines which cross borders (interconnectors), for storage facilities and for import terminals. This exemption regime has been very successful in delivering new investments in the gas sector in the last twenty years. Nevertheless, a more structural approach to exemptions for H2 seems to be called for.

First, compared to electricity and gas, the H2 value chain will continue to be far more fragmented, with far more actors and with very different business models. Second, that market may be geographically dispersed. H2 could be piped, either blended with natural gas or through dedicated H2 pipelines, or it could be shipped, either in a condensed or liquefied state or via another molecule such as ammonia, methanol or liquid organic hydrogen carrier (LOHC). Third, with current H2 technologies, transport often doubles the price of H2 for the end user.

In the coming years, H2 transport from a terminal, an industrial facility or a cluster is likely to be made up of several different approaches, models and options, including transport by truck or rail. There is likely to be a mix of local H2 networks in industrial clusters and privately owned 'direct lines' serving to connect a single industrial user, H2 terminal or H2 storage facility to the nearest H2 transport network. A 'national H2 grid' linking key clusters might eventually make sense to benefit from economies of scale. However, it cannot be assumed that either supply of H2 or demand for it will evolve such as to justify the roll-out of national H2 networks in the coming years. Hence, and for all these reasons, the traditional approach to monopoly gas grid regulation cannot be transposed to the emerging H2 transport market. These essential differences between natural gas and H2 infrastructure are especially relevant in considering how to balance regulation versus investment incentives.

It is evident that over-regulation can therefore undermine investment in the H2 value chain during a period when the EU needs billions of euros in investment. But equally, 'under-regulation', or at least inadequate transparency on how the future regulatory regime will be applicable to a given investment, can have the same effect.

But 'under-regulation', the lack of effective TPA when an 'essential facility' exists, can also stifle investment in new H2 facilities. H2 suppliers or users will not be able to invest in new production or in decarbonisation of existing production unless they know that they will be able to access transport for H2. If an essential facility exists in this context – such as access to a central H2 grid – transparency with respect to if, when and how it will have access will be essential.

An additional advantage of the 'regulatory holiday' approach is that regulatory certainty can be provided. Investments in H2 would be undertaken on the assumption that regulated third-party access and unbundling, for instance, would be applied post-2032, again providing certainty.[52]

To prevent an 'over-' or 'under-regulation' framework for H2, a solution could have been a 'dynamic regulation' as a basis, as proposed by the European energy regulators body, Council of European Energy Regulators (CEER), together with European Union Agency for the Cooperation of Energy Regulators (ACER) in 2021.[53] This included more intensive levels of

[50] Article 36 of Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC (Text with EEA relevance) [2009] OJ L 211 (hereafter: Third Gas Directive).

[51] Article 60 Regulation – Recasting Article 36 Third Gas Directive.

[52] EU Hydrogen Strategy.

[53] CEER and ACER, p. 2.

regulation depending on the state of market development. The governance of this dynamic regulatory approach was inspired by the concept used in the existing EU regulation of the telecommunications sector, which gives regulators the power to intervene in a flexible and timely manner as a reaction to market dynamics. Regulators routinely assess if an operator is found to be dominant – that is, has significant market power (either individually or jointly) – in which case a specific regulatory obligation, proportionate to remedy the identified problem, must be imposed ex ante.[54]

Furthermore, CEER/ACER argued that this would enable regulation to be implemented in an appropriate manner to the evolution of the H2 sector. The approach in the Gas Package is less nuanced. Article 6 of the Regulation mandates a specific deadline for the expiry of the regulatory holiday period, as from January 2033, without first allowing national regulators to assess the development of the H2 market to justify the imposition of full/default regulation.

The rationale for this approach was in part to provide legal certainty and to tackle 'the expected disadvantages of the proposed approach of ex post regulation, in particular the lack of legal certainty for the required investments in hydrogen facilities and infrastructures with long life cycles and depreciation periods'.[55] But importantly the EC identified the 'risk of regulatory fragmentation across different Member States [having] a detrimental effect on network interconnectivity and the integration of national hydrogen markets and, thereby, on cross-border trade and market development'.[56]

The design of regulatory holidays for H2 investments must nonetheless be viewed alongside the introduction of rules to pursue the additional, parallel objectives of facilitating integration of renewable and low-carbon gas into the existing (methane) gas network. H2 can also be blended with natural gas up to a certain percentage at the interconnection points between EU Member States in the natural gas system.[57] As the transmission of all these gases are subject to full regulation, some form of competition between the existing and new gas networks may emerge. ACER and CEER also recalled that H2 and electricity transport companies are potential competitors, as both means could be used to transport energy from one place to another. This requires careful calibration of certain rules – for example to prevent cross-subsidisation by the users of existing system to the users of the new system. This also implies that potentially competing entities should not have decisive influence over certain investment decisions.[58]

The next sections will assess several of the key building blocks of the Gas Package: unbundling, tariff setting and TPA. We will also consider the controversy surrounding the 'regulated asset base' or RAB, a controversy which has arisen in the context of the regulation of a market in which existing and new infrastructural assets will coexist.

2.3 HOW MUCH TO UNBUNDLE?

The 'unbundling' concept has been one of the main regulatory tools used by the EU institutions in the liberalisation of its gas and electricity markets, leading to the break-up of former vertically

[54] EU Directive 2018/1972 establishing the European Electronic Communications Code (Recast) [2018] OJ L 321.

[55] European Commission staff working document, Impact assessment report accompanying the Gas Package, Brussels, 15 December 2021, SWD(2021) 455 final.

[56] Ibid.

[57] Blended flows will trigger additional cooperation among the TSOs to prevent the occurrence of restrictions due to gas quality (Recitals 6 and 43, Article 19(1) Regulation).

[58] CEER and ACER, p. 7.

integrated monopolies.[59] The evolution of unbundling took several decades in the natural gas and electricity sectors and the adoption of three consecutive EU legislative packages.[60] The EC's energy sector enquiry of 2007, together with the settlement of several competition key cases,[61] had shown that competition concerns related to incumbents' refusals to grant access to their networks to third-party suppliers persisted.[62]

Each successive legislative package introduced different types of functional, management, legal and accounting unbundling of transmission and distribution assets in a vertically or horizontally integrated undertaking. In a 'vertically integrated undertaking', there is a combination of at least one of the functions of transmission, distribution, H2 transport, H2 terminal operation, LNG or natural gas or H2 storage activity, with at least one of the functions of production or supply of natural gas or of H2,[63] in one undertaking/group of undertakings. Therefore, 'vertical unbundling' is the separation of production and supply activities (areas of the market open to competition), on the one hand, from monopolistic network functions such as transmission and distribution, on the other. Under the current rules for transmission assets, Member States may opt for one of three models: independent system operator (ISO[64]), independent transmission system operator (ITO[65]) and ownership unbundling (OU) models.[66] Ownership unbundling is the default rule and the strictest form of unbundling for gas and electricity as network owners must relinquish any form of control over their production and supply assets and sell their shareholder rights to third parties.[67] In addition to the rules on 'vertical unbundling', the GD maintains the 'horizontally integrated undertaking' concept.[68] In a 'horizontally integrated undertaking', at least one of the activities of production, transmission, distribution, supply or storage of natural gas is combined with a non-natural gas activity.[69]

This section focuses on the vertical and horizontal unbundling of dedicated H2 systems and the approach taken in the GD in order to avoid potential conflicts of interest and to promote competition along the value chain.[70] Yet it must be acknowledged that strict OU can prevent

[59] European Commission, *Energy Sector Competition Inquiry – Final Report – Frequently Asked Questions and Graphics* (10 January 2007) <https://ec.europa.eu/commission/presscorner/detail/de/MEMO_07_15> accessed 30 May 2024.

[60] These were dated 1998, 2003 and 2009.

[61] For example, see EC website <https://ec.europa.eu/commission/presscorner/detail/de/MEMO_07_15> accessed 15 February 2024; U. Scholz, S. Purps, 'The Application of EC Competition Law in the Energy Sector', vol. 1, no. 1, Journal of European Competition Law & Practice (2010), pp. 37–51 (hereafter: Scholz, Purps).

[62] EC website; Scholz, Purps.

[63] Article 2(43) GD.

[64] The operation of the asset is outsourced to a third-party independent from the vertically integrated undertaking, while ownership of the asset remains with the latter.

[65] The asset operation and ownership remain within the vertically integrated undertaking, but certain certification requirements are put into place to ensure that shareholders active in production/supply of natural gas do not influence the day-to-day activities of the asset. While it is the most flexible model of unbundling, it requires an extensive regulatory oversight in practice. There is also the ITO+ option, also referred to as 'unbundling à la carte': it does not provide for specific obligations on the TSOs, but allows Member States to maintain their own unbundling; see Jones, *EU Energy Law*, p. 109.

[66] It requires a complete separation of production/supply activities from transmission/storage/distribution.

[67] European Commission, 'Hydrogen and Decarbonised Gas Market Package' <https://energy.ec.europa.eu/topics/markets-and-consumers/market-legislation/hydrogen-and-decarbonised-gas-market-package_en> accessed 15 February 2024.

[68] Undertakings performing at least one of the functions of production, transmission, distribution, supply or storage of natural gas, and a non-natural gas activity (Article 2(38) GD).

[69] Article 2(44) GD.

[70] Article 68 GD onwards.

risk-sharing of the type that was common in the early days of the pipeline and LNG industries, when producers and buyers of gas and LNG took equity stakes in common infrastructure to share risk associated with the development of the market.[71]

2.3.1 *Vertical Unbundling*

Natural Gas Systems

For natural gas systems (pipelines, LNG terminals, storage facilities), the unbundling rules and models provided in the Gas Package remain essentially the same as those contained in the Third Package.

Dedicated Hydrogen Systems

The vertical unbundling rules as applicable to natural gas systems are to be expanded to dedicated H2 systems in the Gas Package.

Chapter IX of the GD in its Article 62 indicates that OU is to be the default rule for dedicated H2 systems and needs to be complied with by two years following the entry into force of the GD. There are two exceptions from this default rule in the GD.

The first is the ISO model, which may be applied by Member States if H2 networks belonged to vertically integrated undertaking (VIU). In earlier versions of the draft GD, the availability of this model was conditioned on its implementation at 'the entry into force [of the GD]'[72] or if applied to H2 networks 'completed before 1 January 2031'.[73] These conditions have been removed.[74] This means that the ISO model may be applied for an H2 asset belonging to a VIU after the entry into force of the GD.

The second is the ITO model, which, if applied to H2 assets by Member States, was initially proposed as an option that would have expired by the end of 2030.[75] This cut-off date was removed in the provisional agreement on the GD at the end of 2023 and in the last adopted version of the GD.

Three main observations are noteworthy here.

First, the cut-off dates that were envisaged to be applied to the unbundling models applicable to H2 dedicated networks were considered unworkable. As the European Network of Transmission System Operators for Gas (ENTSOG) has flagged,[76] the unbundling options cannot be effectively utilised by H2 operators if subject to various restrictions. This approach could have prevented or delayed investment in H2 infrastructure (especially in retrofitted infrastructure).[77]

Second, the possibility given to certified gas network operators to own and operate a H2 network is a significant improvement. An already ITO certified (natural gas or electricity) transmission system operator (TSO) can be certified under the same model and therefore

[71] Alex Barnes, 'The EU Hydrogen and Gas Decarbonisation Package: Help or Hindrance for the Development of a European Hydrogen Market?' OIES Paper (2023) No. 22, p. 14 <www.oxfordenergy.org/wpcms/wp-content/uploads/2023/03/The-EU-Hydrogen-and-Gas-Decarbonisation-Package-ET22.pdf> accessed 30 May 2024.

[72] Article 62(3) in earlier versions of the GD.

[73] Ibid.

[74] Ibid.

[75] Article 62(3a) first paragraph in previous versions of the GD.

[76] ENTSOG, p. 3 .

[77] As highlighted by ENTSOG (p. 3), retrofitting is fundamental for the development of H2 infrastructure.

operate as a dedicated H2 operator, and presumably this would be applicable to gas infrastructure assets ready for retrofitting as dedicated H2 networks.[78]

Third, although the combination of natural gas system-related activities together with H2 supply/production activities in the same VIU has already been allowed, this has been subject to certain conditions. An OU unbundled natural gas TSO has been allowed to have passive investments, minority shareholding, purely financial rights (for example, rights to receive dividends) only, and no voting or appointment rights for the selection of members to company boards or other bodies legally representing a company active in H2 production/supply.[79]

This outcome is now confirmed in Article 68 of the GD, with an additional clarification: if an undertaking engages in H2 production/supply, the OU-certified natural gas TSO shall comply with the same ITO requirements as for a certified H2 transmission network operator.

This clarification brings more flexibility. An OU-certified natural gas TSO can now apply an ITO regime to a dedicated H2 system and be part of the same VIU, with links to production or supply of H2 activities, but not with links to natural gas or electricity production or supply activities and therefore cannot circumvent the OU certification of the natural gas asset.

2.3.2 *Horizontal Unbundling*

Under horizontal unbundling, combining the activities of natural gas systems with the operation of dedicated H2 systems is allowed if two conditions are met: first, a dedicated H2 transmission network operator should be established in a separate legal entity from the activities of natural gas/electricity transmission/distribution and, second, to ensure transparency, there should be separate accounts applicable to different infrastructures.[80]

The main regulatory concern related to horizontal unbundling is the eventual cross-subsidisation between different activities (such as natural gas activities subsidising H2 activities), to the advantage of the integrated undertaking.

However, criticism has been voiced that the requirement of legal unbundling went too far.[81] Accounting unbundling through separation of RABs (monitored and approved by the national regulators) should be sufficient to monitor cross-subsidisation.[82] It was argued that legal unbundling might create too much red tape.[83] In the final version of GD the regulatory approach is softened: legal unbundling could be realised through establishing a subsidiary/separate legal entity in the group of entities controlled by the natural gas TSO without further functional

78 ACER, 'Report on Future Regulatory Decisions on Natural Gas Networks: Repurposing, Decommissioning and Reinvestments' (4 November 2022) <www.acer.europa.eu/sites/default/files/documents/Media/News/Documents/Future%20Regulation%20of%20Natural%20Gas%20Networks%20-%20Final%20Report%20DNV.pdf> accessed 30 May 2024.

79 EC Opinion of 3 February 2023 pursuant to Article 3 of the Regulation (EC) No. 715/2009 and Articles 10(6) of Directive 2009/73/EC – Italy – Certification of Snam Rete Gas S.p.A., C(2023) 914 final and EC Opinion of 6 June 2022 pursuant to Article 3 of the Regulation (EC) No 715/2009 and Article 10(6) of Directive 2009/73/EC – Spain – Certification of Enagás Transporte S.A.U. as transmission system operator for gas, C(2022) 3750 final.

80 Articles 69, 70 and 75 GD. Regarding accounting, the Regulation provides for detailed rules on separation.

81 Hydrogen Europe Position Paper, 'A Regulatory Framework Fit for a European Hydrogen Market' <https://hydrogeneurope.eu/wp-content/uploads/2022/06/220609-A-regulatory-framework-fit-for-a-European-h2-market-Final-2.pdf> accessed 15 February 2024.

82 ENTSOG, p. 3.

83 Ibid.

unbundling and separation of management/staff.[84] In addition, a limited derogation from legal unbundling could be granted if there is positive cost–benefit analysis and impact assessment, and separation of accounts and regulatory asset base.[85]

The GD also confirms that the exchange of commercial information between the H2 network/terminal/storage operators and natural gas transmission or distribution operators, as part of the same VIU, is allowed given the synergies and benefits that may result.[86]

2.3.3 *Cross-Subsidisation from Existing to New Infrastructure Assets*

Repurposing existing natural gas networks may prove to be the most cost-efficient option for the development of a dedicated H2 network on the assumption, amongst others, that the supply and demand of H2 will at least partially follow the current supply and demand for natural gas.[87]

Given that the use of natural gas networks is expected to decrease only gradually so that the need for gas-only networks will remain, and that not all the existing gas infrastructure can be converted to H2, construction of new H2 infrastructure will be necessary. The required financing of H2 infrastructure investment cannot come from revenues from user tariffs alone as these will be insufficient during the initial years of the transition to H2 or would put overly high costs on the initial users. If natural gas tariff revenue were to be used to finance H2 infrastructure this could lead to households financing the decarbonisation of industry.[88] This has given rise to extensive debate on the merits of cross-subsidisation and the need to separate out relevant assets.

Unsurprisingly, the gas TSOs favour a common RAB since operating both gas and H2 networks in a joint asset base would support repurposing, and 'network operators would have the option to finance and de-risk networks across users of both natural gas and H2 infrastructure'.[89] This common RAB 'would enable operators to spread these costs to the larger group of network users and enable them to offer more attractive tariffs to early H2 network users, neutralising investment risks'.[90]

The Gas Package facilitates limited cross-subsidies between the natural gas and H2 sectors. In principle, H2 networks must have separate regulated asset bases from gas and electricity networks. Cross-subsidies between regulated asset bases are allowed so long as they are via dedicated charges at offtake points in the same Member State as the beneficiary of the cross-subsidy. Cross-subsidies can only be for a limited period, cannot exceed one-third of the depreciation period for the subsidised infrastructure and must be approved by regulators.[91]

84 Recital 83 GD.
85 Ibid.
86 Articles 40(1), 54(1) GD.
87 ACER 'Repurposing Existing Gas Infrastructure to Pure Hydrogen: ACER Finds Divergent Visions of the Future' (16 July 2021) <www.acer.europa.eu/news-and-events/news/repurposing-existing-gas-infrastructure-pure-hydrogen-acer-finds-divergent-visions-future> accessed 30 May 2024.
88 Laura Heidecke et al., 'The Revision of the Third Energy Package for Gas' (2022), p. 10 <www.europarl.europa.eu/RegData/etudes/STUD/2022/734009/IPOL_STU(2022)734009_EN.pdf> accessed 30 May 2024.
89 Clifford Chance, 'Focus on Hydrogen: Proposal on the EU Hydrogen and Decarbonised Gas Market Package' (2021) <www.cliffordchance.com/briefings/2021/12/focus-on-hydrogen–proposal-on-the-eu-hydrogen-and-decarbonised-gas-market-package.html> accessed 30 May 2024.
90 Ibid.
91 The RAB represents the value of the net invested capital for regulatory purposes, calculated based on the rules defined by laws followed by the national regulatory authorities for determining base revenues for the regulated businesses and thus is used as the basis for the network tariffs setting. Regarding separation of RAB, see Recital 82, Article 69(3) GD and Article 5 Regulation.

Transfers between RABs may be allowed if the national regulators established that, subject to certain conditions, the 'financing of networks through network access tariffs paid by its network users [was] not viable'.[92]

2.4 TARIFF SETTING

The current EU gas market is organised based on entry/exit zones, where the gas TSOs guarantee transmission and support its costs. There are general principles set at EU level regarding transparency of tariff setting, revenue collection, cost drivers and cost reflectivity[93] (through the EU Network Code on tariff structures – TAR NC).[94]

2.4.1 *Tariffs and Discounts for Natural Gas Systems*

The Gas Package facilitates the integration of renewable and low-carbon gases into the existing natural gas network through (i) the reduction of injection costs and (ii) the access granted to the natural gas market.

Renewable and low-carbon gases will benefit from a 100 per cent and 75 per cent discount respectively at the entry points from renewable and low-carbon production facilities[95] and a 100 per cent discount at injection and withdrawal points into and out of gas storage facilities.[96] Until the end of 2025, the national regulators may in principle apply a discount of up to 100 per cent to capacity-based transmission and distribution tariffs at entry points from, and exit points to, underground gas storage facilities and LNG terminals.[97]

2.4.2 *Tariffs for Dedicated H2 Systems*

The applicability of cross-border tariffs to dedicated H2 systems is probably one of the most debated points related to the Gas Package. From the beginning of 2033 (or even earlier if rTPA is applied) certain principles related to tariffs for access to natural gas systems apply to dedicated H2 systems.[98]

2.5 THIRD-PARTY ACCESS REGIME

The introduction of TPA has been a fundamental regulatory instrument for liberalising the energy sector, and one which has evolved throughout the EU gas legislative packages. The new TPA-related provisions in the GD should also be read together with the justification of when refusals to provide access can take place.[99]

[92] Recital 8, Article 5(4) Regulation.
[93] Tariffs should reflect the actual costs incurred 'insofar as such costs correspond to those of an efficient and structurally comparable network operator and are transparent, whilst including an appropriate return on investments' (Article 17(1) Regulation).
[94] Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas, published in (2017) OJ L72/29.
[95] Article 18(1) Regulation.
[96] Idem.
[97] Article 17(3) first paragraph Regulation.
[98] Article 7(7) Regulation. Only Article 15(1), (2), 2b and 2c are applicable, but not Articles 16–17, which apply to natural gas systems.
[99] Article 6–8 Regulation onwards.

2.5.1 *Dedicated Hydrogen Systems*

The Gas Package gives the flexibility to Member States to rely on regulatory holidays to apply negotiated third-party access (nTPA) to dedicated H2 networks up until the end of 2032.[100] After this date, the default rule shall be the regulated, non-discriminatory and objective rTPA.[101]

Access to H2 storage is based on similar TPA rules as for H2 networks, with more flexibility until the end of 2032.[102] This regulatory approach contrasts with the regime applicable to gas storage, whereby either rTPA or nTPA can be applied and without a cut-off date.[103] For H2 terminals, however, the default rule is negotiated TPA.[104]

At the same time, long-term H2 capacity contracts are permissible[105] and can have (i) maximum twenty years for infrastructures completed by 1 January 2028 and (ii) fifteen years for infrastructure completed after that date.[106]

Hence the main differences are rTPA for H2 storage as opposed to nTPA for gas storage, and nTPA instead of rTPA for H2 import terminals. These differences are justified on the basis that H2 storage is likely to be more limited than gas storage for technical reasons but is also more crucial for the H2 system because of the intermittency of renewable electricity generation. H2 import terminals have more potential for competition because of the different means of transporting H2 (for example, ammonia, methanol, LOHCs, hydrogen).

2.6 CONCLUSION

An important starting point for making decarbonisation a reality is to have an appropriate regulatory governance system put in place that incentivises the uptake of renewable and low-carbon gases, but at the same time does not distort the already existing and well-functioning gas market, which is still seen as an essential 'bridge' to the energy transition. Replacing natural gas will be costly and will take time and effort, while the production of renewable H2 will require vast amounts of renewable electricity.

The Gas Package provides a framework to enable renewable and low-carbon gases to enter the market and contribute to decarbonisation, as well as security of supply. This package, which was introduced before the war in Ukraine, had received quite broad support in terms of its overall goals and ambitions, albeit that it has attracted criticism for its overly ambitious approach to an EU-wide H2 market that is yet to develop.

There is growing scepticism as to whether the Gas Package can deliver the desired decarbonisation objectives. Timing does not seem to be on its side. The legislative process was derailed by the war in Ukraine, which triggered an energy crisis in Europe and the EU co-legislators focused attention on emergency legislation to address security of supply issues, as well as rising gas prices.

It is questionable whether the ambitious timelines and targets provided are realistic given the Gas Package, even if now formally adopted, must still be transposed into national legislation of the Member States, which will take another 1–2 years. Based on the experience with the implementation of the 2009 Third Package, none of the Member States achieved the

[100] Section II access to hydrogen infrastructure, Article 35 GD.
[101] Idem.
[102] Article 37 GD.
[103] Article 33 GD.
[104] Article 36 GD.
[105] Contracts concluded between the user and operator of an asset for the booking of capacity in the asset.
[106] Article 7(3) Regulation.

deadline of eighteen months for transposition at national level. It took another three years for nearly all Member States to have the package implemented. Seen in this light, the intended deadlines for the expiry of the various regulatory holidays in the Gas Package do not appear generous. It is highly debated whether the exercise of mirroring the regulation of a mature natural gas regulation to dedicated H2 networks and renewable and low-carbon gases is the right way forward for a nascent market.

Given the early stage of the H2 market and the growing uncertainties around its future development, why would stricter regulation be applied to the initial stages of the new H2 sector when compared with the regulation of the Third Gas Package? Unlike natural gas at the time of liberalisation, there is no well-established, mature H2 market and infrastructure.

Towards the finalisation of the Gas Package legislative process, some of its H2-related provisions have become more flexible in comparison with the EC's initial proposal. Nevertheless, given the targets and cut-off dates in the light of the time required for national transposition, that flexibility may prove insufficient.

FURTHER READING

ACER, *Internal Gas Market in Europe: The Role of Transmission Tariffs*, 2020

Report on Future Regulatory Decisions on Natural Gas Networks: Repurposing, Decommissioning and Reinvestments, November 2022

Repurposing Existing Gas Infrastructure to Pure Hydrogen: ACER Finds Divergent Visions of the Future, 2021

ACER-CEER *Reaction to the European Commission's Hydrogen and Decarbonised Gas Market Package*, 2022

CEER, *Response to the European Commission's Public Consultation on the Hydrogen and Gas Market Decarbonisation Package*, June 2021

CEER and ACER, *When and How to Regulate Hydrogen Networks?* 2021

European Commission, Third Gas Package: (1) Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 Concerning Common Rules for the Internal Market in Natural Gas and Repealing Directive 2003/55/EC and (2) Regulation (EC) No 715/2009 of the European Parliament and of the Council of 13 July 2009 on Conditions for Access to the Natural Gas Transmission Networks and Repealing Regulation (EC) No 1775/2005, OJ L 211, 14.08.2009 as further amended

Fourth Gas Package: (1) Proposal for a Directive of the European Parliament and of the Council on Common Rules for the Internal Markets in Renewable and Natural Gases and in Hydrogen (recast), Brussels, 14 December 2023 16516/23 and (2) Proposal for a Regulation of the European Parliament and of the Council on the Internal Markets for Renewable and Natural Gases and for Hydrogen (recast), Brussels, 15 December 2023 16522/23

European Commission Staff Working Document, Evaluation Report, SWD (2021) 457 final, 15 December 2021

Jones, Christopher (ed.), *EU Energy Law Vol. I: The Internal Energy Market*, 4th ed. (Edward Elgar 2016)

3

Hydrogen Regulation in the United States

Will Government Financial Incentives Outweigh Regulatory Hurdles?

Donna M. Attanasio and Meghan Briggs

3.1 INTRODUCTION

The United States' support for hydrogen shifted in 2021 and 2022. Rather than focusing primarily on research, development, and demonstration projects, as in past decades, laws passed in 2021 and 2022 authorized $8 billion in grants plus lucrative tax credits to stimulate private investment in clean hydrogen. Another $1.5 billion will continue to support research. Under this approach, costs of production and adaptation for new uses will be reduced by government support while market development will be strongly influenced by private investors' decisions and interests.

In 2021, Congress also directed the US Department of Energy (DOE), the lead federal agency for hydrogen market development, to establish a national strategy and roadmap for hydrogen.[1] This was the first hydrogen strategy directive required by Congress since 2005.[2] The US National Clean Hydrogen Strategy and Roadmap (Roadmap), identifying the US government's goals for the production and use of hydrogen and the strategies for achieving those goals, was released in May 2023.[3]

Implementation of the 2021 and 2022 legislation is proceeding, but as of the date of this writing, there are still substantial regulatory gaps, including with respect to four discussed in this chapter: the definition of 'clean hydrogen' as applied to the tax credits; permitting reforms; regulation of the construction and operation of interstate hydrogen pipelines; and safety laws and harmonization of standards. This uncertainty as to if, how, and when various regulatory gaps will be resolved, and the impact that uncertainty will have on costs and sector growth, is unknown.

This chapter focuses primarily on the 2021 and 2022 federal legislation due to its potentially profound impact on the development of the hydrogen market. Section 3.2 will introduce the recent laws and the complex regulatory challenge of defining 'clean hydrogen'. Section 3.3 sets forth in more detail the policies and key laws through which the federal government intends to stimulate the hydrogen market. The private sector response to date to the hydrogen hub program

[1] 42 USC § 16161b.
[2] 42 USC §§ 16153, 16154.
[3] US Department of Energy, 'US National Clean Hydrogen Strategy and Roadmap' (energy.gov, May 2023) <www.hydrogen.energy.gov/pdfs/us-national-clean-hydrogen-strategy-roadmap.pdf> accessed November 4, 2023 (hereinafter: Roadmap).

is described in Section 3.4. Section 3.5 will discuss the regulation of hydrogen, with a focus on three areas of regulatory uncertainty that could impede market development.

Additionally, states can act independently from the US federal government to provide incentives or regulate in areas not pre-empted by the federal government. California, for example, has been a leader in promoting hydrogen use.[4] However, state actions are beyond the scope of this chapter.

3.2 WHAT IS 'CLEAN HYDROGEN'?

As referenced above, legislation passed in 2021 and 2022 provided significant financial support for clean hydrogen market development in the United States. The 2021 Infrastructure Investment and Jobs Act (IIJA, also called the Bipartisan Infrastructure Law) directed $9.5 billion to the DOE for hydrogen programs. The 2022 Inflation Reduction Act (IRA) included generous tax credits that could reduce the cost of investing in hydrogen production facilities or producing hydrogen by providing investors with a reduction in the income taxes they owe.[5] The tax credits are administered through the Internal Revenue Service, which is part of the US Treasury Department.

These financial incentives are intended for 'clean hydrogen'. But defining 'clean hydrogen' is not straightforward. The popular color-based hydrogen taxonomy has become increasingly complex as different technologies and fuel sources have sought their own hue, creating a rainbow of green, blue, grey, pink, brown, and turquoise hydrogen. The US government has eschewed the rainbow (or coloring-book) approach in favor of defining 'clean' by the kilograms of carbon dioxide equivalent emitted during production of a kilogram of hydrogen. This approach has the benefit of being both fuel and technology neutral, thus more easily accommodating new production methodologies. However, the statutes have different definitions for clean hydrogen.

The IIJA specifies that the terms 'clean hydrogen' and 'hydrogen' (as used in the IIJA) mean 'hydrogen produced in compliance with the greenhouse gas emissions standard' established by the DOE.[6] Through the IIJA, the US Congress instructed the DOE to set 'an initial standard for the carbon intensity of clean hydrogen production'[7] that would:

- support clean hydrogen production from 'fossil fuels with carbon capture, utilization, and sequestration; hydrogen-carrier fuels (including ethanol and methanol); renewable energy resources, including biomass; nuclear energy; and any other methods the Secretary [of DOE] determines to be appropriate',[8]
- define 'clean hydrogen' as 'hydrogen produced with a carbon intensity equal to or less than 2 kilograms of carbon dioxide equivalent produced *at the site of production* per kilogram of hydrogen produced', and
- 'take into consideration technological and economic feasibility'.[9]

[4] LegiScan, 'California Senate Bill 1075' (legiscan.com) <https://legiscan.com/CA/text/SB1075/2021> accessed December 1, 2022.
[5] Pub L 117–169 (2022), codified in relevant part, generally, at 26 USC §§ 45V, 48.
[6] 42 USC §16152(1).
[7] 42 USC § 16166.
[8] 42 USC §16154(e)(2) (internal subsection numbers omitted).
[9] 42 USC §16166(a)–(b)(1) (emphasis added).

Within five years after the initial standard for the carbon intensity of hydrogen production is set, the DOE must determine whether to lower the standard.[10]

The IRA defines 'qualified clean hydrogen' for use under the tax code as hydrogen produced in such a way as to result in *lifecycle greenhouse gas emissions* of no more than 4 kilograms of CO_2e (equivalent) per kilogram of hydrogen.[11] The IRA requires lifecycle emissions to be determined using the GREET (Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation) model developed by Argonne Laboratories.[12]

After receiving public comments, in June 2023 the DOE set the initial production standard for 'clean hydrogen' (often referred to simply as 'hydrogen') for the purposes of the programs it administers in a manner intended to harmonize with the IRA definition. The DOE's Clean Hydrogen Production Standard (CHPS):

> establishes a target for well-to-gate lifecycle greenhouse gas emissions of ≤4.0 kgCO2e/kgH2. The establishment of a well-to-gate target aligns with statutory requirements to consider not only emissions at the site of production but also technological and economic feasibility and to support clean hydrogen production from diverse energy sources . . . This target is also consistent with the IRA's definition of 'qualified clean hydrogen'. This target is likely achievable by facilities that achieve ≤2 kgCO2e/kgH2 at the site of production, which potentially have additional emissions from upstream and/or downstream processes.[13]

The well-to-gate boundaries, as illustrated in the DOE's guidance document, includes the emissions at each step, from feedstock extraction through production, including fugitive emissions, plus those related to sequestration (if applicable), but excludes component manufacturing and end use.[14] The DOE's endorsement of the GREET model is consistent with the IRA definition and is 'aligned with international best practices' as established through the International Partnership for Hydrogen and Fuel Cells in the Economy's Hydrogen Production Analysis Task Force.[15]

At the time of this writing, the Treasury Department, within which the Internal Revenue Service resides, has not yet issued its final regulations implementing a definition of 'qualified clean hydrogen' for use in the tax provisions it administers, although the IRA required it to do so by August 2023. Like the DOE, the Treasury has engaged in a notice-and-comment rulemaking procedure in which the public participates. A point of contention in the rulemaking is whether 'qualified clean hydrogen' that is produced from renewable resources must rely only on new renewable resources (referred to as 'additionality'), renewable resources that generate power during the same hours ('time matching'), and resources near the point of production. The underlying concern is that absent these constraints, the lucrative tax incentives will divert use of existing clean energy resources to hydrogen production, and thereby increase reliance on fossil

[10] 42 USC §16166(b)(2).

[11] 26 USC §45V(c)(2)(A) (emphasis added). The IRA requires that lifecycle greenhouse gas emissions 'shall only include emissions through the point of production (well-to-gate), as determined under the most recent [GREET] model'. 26 USC §45V(c)(1)(B).

[12] *See* US Department of Energy, GREET: The Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model (energy.gov, May 16, 2019) <www.energy.gov/eere/bioenergy/articles/greet-greenhouse-gases-regulated-emissions-and-energy-use-transportation> accessed November 4, 2023.

[13] US Department of Energy, 'Clean Hydrogen Production Standard (CHPS) Guidance' (June 2023) 2–3 <www.hydrogen.energy.gov/pdfs/clean-hydrogen-production-standard-guidance.pdf> accessed November 4, 2023.

[14] Ibid 4.

[15] Ibid 5.

fuels to meet other demands on the grid.[16] Other details also need to be resolved by the regulations, such as the method for determining if a project started construction and became operational within the period to which the tax credits apply. Once all the regulations implementing the tax benefits in the IRA are decided, investors will be better able to assess the financial viability of their planned projects.

3.3 US POLICY AND LAW PROMOTING PRODUCTION AND USE OF HYDROGEN

3.3.1 *The Big Picture*

The Biden administration's hydrogen policy is part of its broader effort to stimulate the US economy through investment and job growth across a wide range of clean energy sectors. Concurrently, the Biden administration is implementing its Justice40 initiative, which promotes energy justice and economic equity.[17] These cross-cutting themes of job growth, justice, and equity are reflected in the DOE's Roadmap and its criteria for awarding grants and other government funding. They are also evident in the structure of the IRA laws, which provide enhanced tax incentives for investing in lower-income communities or communities that have lost jobs due to recent reductions in fossil fuel production and for paying 'fair wages' (typically union wages) and providing job training.

3.3.2 *The DOE Roadmap: Hydrogen Goals and Strategies*

The US National Clean Hydrogen Strategy and Roadmap, published by the DOE in 2023, states how the federal government foresees sector growth over the coming decades, obstacles that need attention, and goals and strategies to guide further government actions. The Roadmap projects that 'clean hydrogen' production and use will contribute 10 percent of the emissions reductions required by the US Long-Term Climate Strategy by 2050.[18] Specific goals include: an increase in annual clean hydrogen production and use to 10 million metric tons (MMT) by 2030, 20 MMT by 2040, and 50 MMT by 2050; and creation of 100,000 new jobs by 2030 and 450,000 new jobs cumulatively by 2050.[19] For context, as of 2022, the United States produced only about 10 MMT of hydrogen per year.[20] Ninety-five percent of that was produced with steam-methane reforming processes using natural gas.[21]

[16] Adithya Bhashyam, 'US Hydrogen Guidance: Be Strict or Be Damned', Bloomberg NEF (September 21, 2023) <https://about.bnef.com/blog/us-hydrogen-guidance-be-strict-or-be-damned/#:~:text=Most%20prominent%20among%20these%20is,in%20the%20US%20by%202030> accessed November 3, 2023. On December 26, 2023, the IRS issued proposed regulations addressing these points, the definition, and other implementation details. US Internal Revenue Service, 'Notice of Proposed Rulemaking: Section 45V Credit for Production of Clean Hydrogen; Section 48(a)(15) Election to Treat Clean Hydrogen Production Facilities as Energy Property (REG-117631-23)', 88 FR 89220 (26 December 2023) <https://federalregister.gov/documents/2023/12/26/2023-28359/section-45v-credit-for-production-of-clean-hydrogen-section-48a15-election-to-treat-clean-hydrogen> accessed January 11, 2024.

[17] The White House, 'Justice40' (whitehouse.gov) <www.whitehouse.gov/?environmentaljustice?/justice40/> accessed November 4, 2023.

[18] Roadmap 1.

[19] Ibid.

[20] US Department of Energy, 'Hydrogen Production' (energy.gov) <www.energy.gov/eere/fuelcells/hydrogen-production> accessed November 4, 2023.

[21] US Department of Energy, 'Hydrogen Production: Natural Gas Reforming' (energy.gov) <www.energy.gov/eere/fuelcells/hydrogen-production-natural-gas-reforming> accessed November 4, 2023.

The Roadmap also sees the United States playing an 'important role' in creation of a global hydrogen market having 'the potential for $2.5 trillion in annual revenue and 30 million jobs . . . along with 20 percent global emissions reductions by 2050'.[22] Advances in the cost-effective production and deployment of hydrogen in the United States would provide leadership for other countries.

To facilitate the growth needed to meet the goals set forth in the Roadmap, the DOE offers three strategies:

1. 'Target Strategic, High-Impact Uses of Clean Hydrogen.' These uses are primarily industries that require high-temperature processes that cannot be electrified, and thus are otherwise difficult to decarbonize, such as steelmaking and chemical manufacturing.[23]
2. 'Reduce the Cost of Clean Hydrogen.' Cost reductions are sought throughout the supply chain.
3. 'Focus on Regional Networks.' Using IIJA funding (described below), the DOE's strategy is to develop multiple clusters or 'hubs' of hydrogen producers and users in diverse regions of the country that over time would scale up and then spread into a nationwide network.[24] By clustering, participants would be better positioned to share infrastructure, and the region would offer multiple opportunities for job seekers in the hydrogen field at multiple companies.[25] Hubs would also help develop understandings at a regional level of potential synergies (or lack) between hydrogen and electrification, and electric sector evolution that takes into account regional resources and needs.[26]

As envisioned in the Roadmap, industrial uses of hydrogen could expand to include steel and cement manufacturing, industrial heat, and production of bio or synthetic fuels.[27] In addition to hydrogen's current use for forklifts, buses, and light-duty vehicles, the Roadmap points to potential uses for hydrogen in the transportation market for medium- and heavy-duty vehicles, rail, maritime, aviation, and offroad equipment used in mining, construction, and agriculture. Hydrogen could also be used for long-term storage of renewable energy[28] and to integrate renewable intermittent resources into the grid.[29] Blending hydrogen with other fuels in greater amounts than today opens other potential uses in power generation and buildings.[30] The Roadmap asserts that the potential for a significant use of electrolysis in hydrogen production would also simulate growth in clean energy.[31] Cost-competition from dirtier fuels (in the absence of mandates to use clean fuels) remains a concern[32] as does additionality.[33]

The primary obstacles to market growth identified in the Roadmap, based on data collected in September 2021, are the cost to end-users and infrastructure development. The tax incentives in the IRA were not known at the time this data was collected, and therefore are not factored in. Specific issues with expansion identified by the DOE are the compatibility of hydrogen with

22 Roadmap 5.
23 Ibid 1, 29–38.
24 Ibid 48–57.
25 Ibid 1.
26 Ibid 26.
27 Ibid 17.
28 Ibid 6.
29 Ibid 17.
30 Ibid 17.
31 Ibid 5.
32 Ibid 31.
33 See above, text at n 16.

materials and existing fuel transportation methods, such as pipelines and tube trailers, and delays in permitting[34] (which is of general concern in the energy sector). National standards for blending limits, and harmonization of codes and standards, are also important to establishing a national market.[35] Multiple other concerns were identified by the DOE that could affect market growth, including the need for technology advancement; competing technologies; safety concerns; and a lack of suitable end uses.[36] The Roadmap calls for a 'whole of government approach' to address these concerns and asserts the federal agencies will coordinate an efficient response[37] without specifying how that will be accomplished.

Importantly, demand for hydrogen must increase along with production. The Roadmap points to several demand-side measures needed to achieve the DOE's goals for hydrogen, including standard terms for offtake agreements, price transparency,[38] and certainty of supply.[39]

3.3.3 *Research, Development, and Commercialization Programs*

The US government has supported research and development for hydrogen since the 1970s.[40] Building on this history, the 2021 IIJA authorized several new programs encouraging development of hydrogen as an alternative energy source. While authorizations vary by program, generally the DOE is authorized to provide grants, contracts, loans, or cooperative agreements to eligible entities to carry out the work under its major initiatives,[41] subject to the DOE's standard cost-sharing requirements.[42]

The centerpiece of the IIJA's hydrogen support is a four-year, $8 billion grant program for Regional Clean Hydrogen Hubs.[43] These hubs would link hydrogen producers and consumers through connective infrastructure (for example, pipelines, truck routes) to demonstrate the potential for a national clean hydrogen network and accelerate its development. Each funded hub is expected to produce clean hydrogen as defined in the IIJA. The IIJA requires funding of at least four hubs and specifies that production facilities at the four initial hubs must include one fueled by nuclear energy, one from renewable fuels, and one from fossil fuels. End-use demonstrations must also be diversified across industry use, electric power generation, residential and commercial heating, and transportation, and the hubs are to be geographically diverse.[44] In September 2022, the DOE put out its first call for hydrogen hub proposals. The request and response are discussed in Section 3.4.

34 Roadmap 25, 69.
35 Ibid 69.
36 Ibid 24.
37 Ibid 28.
38 Ibid 50.
39 Ibid 24, 50.
40 See US Department of Energy, 'Hydrogen Program: Background' (energy.gov) <www.hydrogen.energy.gov/about/background> accessed 4 November 2023; Kim Talus, Maxwell Martin, 'A Guide to Hydrogen Legislation in the USA: A Renewed Effort', J of World Energy Law & Business (September 24, 2022) <https://academic.oup.com/jwelb/article/15/6/449/6713813> accessed November 4, 2023; Michael Connolly, 'United States: Development in Hydrogen Production, Technology and Use under the Energy Policy Act of 2005', Thelen LLP (January 3, 2006) <https://mondaq.com/unitedstates/chemicals/36954/developments-in-hydrogen-production-technology-and-use-under-the-energy-policy-act-of-2005?signup=true> accessed November 4, 2023.
41 See, *e.g.*, 42 USC § 16161c, 42 USC § 16161d(f).
42 42 USC § 16164; 42 USC § 16352.
43 42 USC § 16161a; US Department of Energy, 'Regional Clean Hydrogen Hubs' (energy.gov) <www.energy.gov/oced/regional-clean-hydrogen-hubs> accessed November 4, 2023.
44 Ibid.

Another important DOE program that was revitalized with IIJA funding is the Clean Hydrogen Research and Development Program (formerly the Hydrogen Program Plan).[45] The IIJA provided $500 million for research, development, and demonstration of 'clean hydrogen production, processing, delivery, storage, and use equipment manufacturing technologies and techniques', including recycling of fuel cells[46] and a four-year $1 billion program for the commercialization and deployment of electrolyser for production of clean hydrogen.[47] The research enabled by the new IIJA funding complements the DOE's work under another program, administered by the DOE in tandem with the Clean Hydrogen Research and Development Program but adopted as part of the 2021 American Rescue Plan, called Clean Hydrogen Energy Shot. Its objective is to reduce the cost of clean hydrogen production by 80 percent, to achieve the goal of $1 per 1 kg of hydrogen in one decade.[48] The IIJA also included funding for training programs for the hydrogen workforce.[49] Another IIJA allocation, directed to the Department of Transportation for alternative fueling infrastructure, could support hydrogen development, but is not earmarked exclusively for hydrogen.[50]

3.3.4 *Tax Incentives to Attract Private Investment*

The Inflation Reduction Act of 2022 supports clean hydrogen by creating a new tax credit for hydrogen production and expanding existing tax credits for investment in clean hydrogen production facilities.[51] Tax incentives to invest in complementary technologies, such as carbon capture and storage, are also included in the IRA. There is no limit to how many qualifying investments can be supported by the tax credits, although there are limits on stacking credits on a single project.

The new production tax credit (PTC) applies to 'qualified clean hydrogen produced by the taxpayer ... at a qualified clean hydrogen production facility'.[52] The PTC is available for a period of ten years after the date the facility is placed in service. Construction of the facility must begin before January 1, 2033. The hydrogen must be produced in the United States (or its possessions) in the ordinary course of business, for sale or use, to qualify for tax credits. The maximum available credit is $0.60/kg (subject to adjustment for inflation),[53] but the applicable percentage a taxpayer may claim is scaled, as shown in Table 3.1.

Thus, lower emissions will result in a higher credit. The credit can be increased by a factor of five if construction of the facility complies with certain labor and wage requirements and Justice40-related criteria.[54]

[45] US Department of Energy, 'Hydrogen Program Plan' (energy.gov, November 2020) <www.hydrogen.energy.gov/pdfs/hydrogen-program-plan-2020.pdf> accessed November 4, 2023.
[46] 42 USC § 16161c.
[47] 42 USC § 16161d.
[48] US Department of Energy, 'Hydrogen Shot' (energy.gov) <www.energy.gov/eere/fuelcells/hydrogen-shot> accessed November 4, 2023.
[49] US Department of Energy, 'DOE Announces $1.5 Million to Train the Next-Generation Hydrogen Workforce' (energy.gov, November 10, 2022) <www.energy.gov/eere/fuelcells/articles/doe-announces-15-million-train-next-generation-hydrogen-workforce> accessed November 5, 2023.
[50] 23 USC §151.
[51] 26 USC §45V, §48.
[52] 26 USC § 45V.
[53] 26 USC § 45V(b).
[54] 26 USC § 45V(e).

TABLE 3.1 *Applicable clean hydrogen production tax credit by emissions level*

Kilograms of CO2e per kilogram of hydrogen		Applicable percentage of credit
Equal to or not greater than 4 kg	Not less than 2.5 kg	20
Less than 2.5 kg	Not less than 1.5 kg	25
Less than 1.5 kg	Not less than 0.45 kg	33.4
Less than 0.45 kg		100

TABLE 3.2 *Applicable clean hydrogen investment tax credit by emissions level*

Kilograms of CO2e per kilogram of hydrogen		Applicable percentage of eligible investment
Equal to or not greater than 4 kg	Not less than 2.5 kg	1.2
Less than 2.5 kg	Not less than 1.5 kg	1.5
Less than 1.5 kg	Not less than 0.45 kg	2.0
Less than 0.45 kg		6.0

This PTC may not be combined with credits under 26 USC §45Q, which incentivizes carbon capture and storage.[55] However, investors may combine the PTC with a tax credit for clean energy or zero-emission nuclear power production.[56] Certain other limitations apply.

As an alternative to the PTC, investors in a hydrogen production facility can elect to take an Investment Tax Credit (ITC) under 26 USC §48(a)(15) of the tax code. This credit allows the taxpayer to reduce its taxes based on its initial investment in the production facility rather than on the annual production of hydrogen. Like the PTC, the ITC incentive uses a tiered approach, tying the tax incentive received to the level of lifecycle greenhouse gas emissions (Table 3.2).

The statutory language further indicates that energy properties are eligible for certain multipliers and additions, which, if made available, would increase the value of the investment tax credit substantially, potentially to a level of 50 percent of the investment.[57] Those multipliers and additions are granted if construction of the facility complies with certain labor and wage requirements;[58] meets certain domestic content requirements;[59] or is located in an 'energy community'.[60] An 'energy community' is, generally speaking, a community adversely affected by the transition away from fossil fuels.[61] These provisions promote the Biden administration's Justice40 and US economic growth policies. The project may not claim the ITC and the PTC for the same facility or combine it with the credit for carbon capture and storage.

Subject to various limitations, the entity entitled to receive the PTC or ITC may transfer the credit for value, tax-free,[62] or treat it as a direct payment of taxes.[63] This flexibility to monetize the tax credits is valued by entities that are tax-exempt, such as governmental bodies or non-profit organizations, or that otherwise are not yet profitable enough to owe taxes, and increases the number of potential investors.

55 26 USC §45V(d)(2).
56 26 USC § 48V(a)(15)(B).
57 26 USC §48(a)(9); 26 USC §48(a)(10), (11), (13), (14).
58 26 USC §48(a)(10)–(11).
59 26 USC §48(a)(13).
60 26 USC §48(a)(14).
61 26 USC §45(b)(11)(B).
62 26 USC §6418(a); 26 USC §6418(f)(1)(A)(v), (ix).
63 26 USC §6417; see also US Internal Revenue Service, 'Request for Comments on Elective Payment of Applicable Credits and Transfer of Certain Credits' (Notice 2022-50, irs.gov, October 5, 2022) <www.irs.gov/pub/irs-drop/n-22-50.pdf> accessed November 3, 2023.

3.4 INDUSTRY, HYDROGEN HUBS, AND GROWTH

As noted above, presently, production and demand for hydrogen in the United States is small compared to DOE goals for the sector's growth. Hydrogen produced in the United States is used mostly in petroleum refining and ammonia production.[64] However, fuel cells, forklifts, and fleet vehicles are growing sectors (which the DOE has supported with funding under prior laws).[65] There is also a small but burgeoning use in the energy sector. As of October 2021, hydrogen fuel cells accounted for about 260 megawatts (MW) of electric generating capacity, and at least two companies were already planning to blend hydrogen with natural gas to fuel natural-gas-fired electric generators.[66] Industry, and state and local governments in California have been promoting the use of hydrogen vehicles since 1999.[67]

The DOE's $8 billion hydrogen hub program and the IRA tax incentives are critical to reaching the commercial scale and momentum needed to transform this small sector into one that fulfills the US goals for clean hydrogen.[68] In September 2022, the DOE issued a funding opportunity announcement offering $7 billion of the $8 billion authorized to fund between six and ten hubs.[69] The solicitation required a 50 percent non-federal cost share, meaning that the participants would have to place a significant amount of their own money at risk. The period for execution, expected to be 8–12 years, would depend on the complexity of the hubs proposed. Funding would be dispersed in four tranches, based on the work accomplished.[70] The DOE applied the following evaluation criteria: technical merit; financial and market viability; the workplan, including how quickly the hub would build out production and expand end-use markets; the management team and partners; and its community benefits plan, including workforce development, jobs, and support for Justice40 initiatives.[71]

In response to the funding opportunity announcement, the DOE received eighty expressions of interest. It encouraged thirty-three of the eighty to submit applications. In October 2023, the DOE selected seven projects for further negotiation. If all are successfully developed, the anticipated total investment would be nearly $50 billion; and they would produce 3 MMT of hydrogen annually and reduce carbon dioxide emissions by 25 MMT by displacing use of other fuels.[72] The hubs alone will not fulfill the goals set forth in the DOE Roadmap, but they are expected to produce about 30 percent of the 2030 production goal and demonstrate the viability of hydrogen.[73]

64 US Department of Energy, 'Hydrogen Production' (energy.gov) <www.energy.gov/eere/fuelcells/hydrogen-production> accessed November 4, 2023.

65 International Partnership for Hydrogen and Fuel Cells in the Economy, 'United States' (IPHE May 2022) <www.iphe.net/united-states> accessed November 3, 2023.

66 US Energy Information Administration, 'Hydrogen Explained' (eia.gov) <https://eia.gov/energyexplained/hydrogen/use-of-hydrogen.php> accessed November 4, 2022.

67 Hydrogen Fuel Cell Partnership, 'About Us' (h2fcp.org) <https://h2fcp.org/> accessed November 3, 2023.

68 IRA incentives can be used independently of the hydrogen hub program as well.

69 US Department of Energy, 'Funding Notice: Regional Clean Hydrogen Hubs' (energy.gov) <www.energy.gov/oced/funding-notice-regional-clean-hydrogen-hubs> (accessed November 4, 2023).

70 Ibid.

71 US Department of Energy, 'Bipartisan Infrastructure Law: Additional Clean Hydrogen Programs (Section 40314): Regional Clean Hydrogen Hubs Funding Opportunity Announcement, DE-FOA-0002779 FOA Type: Mod 000002' (issued September 22, 2022) 91–95 (hereinafter: FOA).

72 US Department of Energy, 'Biden–Harris Administration Announces $7 Billion for America's First Clean Hydrogen Hubs, Driving Clean Manufacturing and Delivering New Economic Opportunities Nationwide' (energy.gov, October 13, 2023) <www.energy.gov/articles/biden-harris-administration-announces-7-billion-americas-first-clean-hydrogen-hubs-driving#:~:text=WASHINGTON%2C%20D.C.%20%E2%80%94%20As%20part%20of,%2Dcost%2C%20clean%20hydrogen%E2%80%94a> accessed November 4, 2023.

73 Ibid.

TABLE 3.3 *Summary of hub proposals selected for further negotiation, 2023*

Hub	Fuel/technology	Consumers	Additional research goals
ARCH2 (Appalachian region)	Natural gas with carbon capture and storage. Emphasis on hydrogen pipelines.	Fueling stations and other end-uses.	Reduce distribution and storage costs.
ARCHES (California)	Renewable energy and biomass.	Decarbonize transportation and ports and prepare ports for potential export of hydrogen. Generation.	Reduce carbon emissions in hard-to-decarbonize sections of the transportation system. Support tribal power needs.
HyVeloicty H2Hub (Texas)	Natural gas with carbon capture and storage and electrolysis from renewables.	Fuel cell electric trucks, industrial processes, ammonia, refineries and petrochemicals, and marine fuel.	Lower cost of distribution and storage to reach more users. Salt cavern storage.
Heartland Hub (Minnesota, North and South Dakotas)	The region's 'abundant energy resources'.	Co-firing for generation, clean fertilizer.	Decrease regional cost of hydrogen; use open-access storage and pipeline infrastructure.
Mid-Atlantic – MACH2 (Pennsylvania, Delaware, New Jersey)	Electrolysis using renewable and nuclear energy.	Heavy transport, manufacturing and industrial, CHP.	Repurpose oil infrastructure. Develop distribution and fueling infrastructure. Innovative electrolyser technologies.
Midwest (Illinois, Indiana, Michigan)	Mixed resources.	Strategic hydrogen uses including steel and glass production, power generation, refining, heavy-duty transportation, and sustainable aviation fuel.	
PNWH2 (Washington, Oregon, Montana)	Electrolysis using renewables.	Heavy duty transportation, industry generation, fertilizer, seaports.	Coordinated with ARCHES to create a west coast hydrogen transportation corridor.

The participants in each hub vary, but typically consist of a consortium of private companies and state and local governments. The primary features of their proposals, as set forth in the DOE-issued descriptions, are summarized in Table 3.3.[74]

While the response of industry to the hydrogen hub solicitation is encouraging, there are still many points of contention. The industry is not yet mature enough to immediately begin producing hydrogen that accords with the DOE's CHPS (the definition discussed in Section 3.2 above) and apply it in hard-to-decarbonize industries. As discussed above, advocates of additionality and hourly matching want users of renewable energy to build new renewable

[74] Ibid; US Department of Energy, 'Regional Clean Hydrogen Hubs Selections for Award Negotiations' (energy.gov) <www.energy.gov/oced/regional-clean-hydrogen-hubs-selections-award-negotiations> accessed November 5, 2023.

resources for hydrogen production, and match hydrogen production to periods of electricity generation from these resources. An industry group argues that such measures will 'stop the clean hydrogen industry' before it gets started. It points to the delays in permitting and interconnecting new renewable generation as an impediment to accessing enough clean energy fast enough to scale hydrogen at the rate needed to meet climate goals.[75] Other industry advocates have suggested that policies and law should encourage growth in sectors where hydrogen already has a foothold, such as forklifts, and phase in the CHPS and decarbonization of hard-to-decarbonize sectors over time.[76]

In sum, the legislation discussed in Section 3.3 has elicited a positive response from industry and provides the United States with the potential for tremendous sector growth.[77] The varied goals of the hub applicants generally align with the Roadmap goals. However, industry members are concerned that some of the legal standards will be set too high to meet at the outset and will derail growth before it begins. As will be described in the following section, there are other regulatory issues as well.

3.5 REGULATORY CONCERNS

3.5.1 *Regulatory Overview*

The DOE, acting through the Sandia National Laboratory, has evaluated the applications of hydrogen that are subject to, or potentially subject to, federal regulation under existing law.[78] The DOE found that hydrogen is covered by many existing regulations, and as many as fifteen different agencies may have jurisdiction at various points in the supply chain.

Emerging uses for hydrogen, including in the consumer sector, will test whether the regulatory framework is adequately comprehensive and flexible, and harmonized sufficiently to facilitate sector growth. A complete analysis is beyond the scope of this chapter. However, the DOE's Roadmap references particular concerns with permitting, safety, and harmonization. Permitting and regulation for new pipelines, in particular, have been subject to vigorous public debate. Because permitting, pipeline regulation, and safety all raise critical and cross-cutting concerns and have been subject to recent study and discussion, they are addressed below.

3.5.2 *Permitting Reform*

Siting of infrastructure is frequently mentioned as critical to the advancement of the hydrogen economy. Infrastructure includes production facilities, pipelines, fueling stations, and transfer terminals. Siting decisions are also critical to the safety, health, and welfare of the public and to the health of the environment. While acceleration of the process for securing permits is important for meeting the aggressive timelines for build-out of the hydrogen sector and other infrastructure needed to reduce greenhouse gas emissions (such as transmission lines to move

75 Fuel Cell & Hydrogen Energy Association (cleanhydrogentoday.org) <www.cleanhydrogentoday.org/?gclid=CjwKCAjwkY2qBhBDEiwAoQXK5WlKq-4bMJ7icsySp768e1dI38ZKRio8LlILGYIsKItBCOUusxCqfRoCoAIQAvD_BwE> accessed November 3, 2023.

76 Meghan Briggs, Donna M Attanasio, 'Is the Hydrogen Economy Here? A Summary of Experts' Views from Inside the Beltway' (2023) 2–3 (unpublished conference report).

77 42 USC § 16161d.

78 Austin R Baird, Brian D Ehrhart, Austin M Glover, and Chris B LaFleur, 'Federal Oversight of Hydrogen Systems' (Sandia National Laboratories, 2021) <www.osti.gov/servlets/purl/1773235> accessed November 5, 2023.

renewable energy to load centers), faster timelines can also have unintended and adverse impacts on the environment; cultural or historical sites; people, including environmental justice communities; navigation of aircraft or ships; or recreational areas.

With an important exception for certain pipelines, discussed in Section 3.5.3, decisions about where infrastructure may be placed is largely a matter for state and local jurisdictions. However, even where state or local entities are the primary decision-maker, the federal government has a role, since siting requires compliance with federal environmental statutes, where applicable. For example, where federal funds are used, as in the hydrogen hubs, the National Environmental Policy Act could be implicated.[79]

Accelerating the timeline for permitting new infrastructure through federal action has been pressed in Congress for several years, with members both advocating for, and adverse to, streamlining the process. As of May 2023, there were at least six proposed bills in various stages of development in Congress.[80] One issue is whether only infrastructure for clean energy should be accelerated or all infrastructure. The permitting discussion, except as discussed in Section 3.5.3, is not exclusive to the hydrogen sector and it is unclear whether or if reforms will be forthcoming. However, it is one of the factors often cited as a possible obstacle to achieving the full potential of the hydrogen market.

3.5.3 *Jurisdiction over Interstate Pipelines*

Transportation of hydrogen is a critical link in the supply chain that affects how and where the hydrogen production and use markets will evolve, the cost, and the accessibility of hydrogen for projected uses. Pipelines are the most economic form of land-based transport for large quantities of hydrogen.[81] Therefore the process for the development and regulation of a pipeline network is of great concern, and presently unresolved. The potential applicability of as many as three existing regulatory structures have been suggested as discussed in the following subsection, 'Which Regulatory Structure Applies?'[82] The burdens and benefits of regulation would vary depending on which scheme applies, are explained in 'The Importance of the Debate'. The potential pathways forward are discussed in 'Pathway to Resolution?'

Which Regulatory Structure Applies?

The United States has a comprehensive regulatory scheme for the transportation of commodities in interstate commerce by pipeline. The Interstate Commerce Act, as amended by the Hepburn Act in 1906 (ICA) vested authority to regulate *all* interstate pipelines, except those carrying natural gas or water, in a single federal agency, the Interstate Commerce Commission (ICC).[83] In 1938, the Natural Gas Act (NGA) placed regulation of interstate natural gas pipelines under the jurisdiction of the Federal Power Commission. That authority transferred in 1977 when the Federal Power Commission was replaced by the Federal Energy Regulatory Commission (FERC).[84]

[79] FOA 143–145.
[80] Sustainable Energy & Environment Coalition 'What Is Permitting Reform? Here's a Cheat Sheet' (seec.house.gov, May 24, 2023) <https://seec.house.gov/media/in-the-news/what-permitting-reform-heres-cheat-sheet> accessed November 4, 2023.
[81] Congressional Research Service, Pipeline Transportation of Hydrogen: Regulation, Research, and Policy (R46700, 2021) 5 (hereinafter: CRS Report).
[82] William G Bolgiano, 'FERC's Authority to Regulate Hydrogen Pipelines under the Interstate Commerce Act,' 43 Energy L J 1, 19 (2022) (hereinafter: Bolgiano).
[83] Ibid.
[84] See generally 15 USC §§ 717–717z.

In 1977, authority over oil transportation under the ICA was also transferred to FERC, taking advantage of FERC's deep expertise in energy markets.[85] The remainder of the pipeline regulatory authority that had been contained in the ICA was recodified, and in 1995 placed under the Surface Transportation Board (STB); and the ICC was abolished.[86] Because the federal regulatory regime is comprehensive, hydrogen must be covered, even though not explicitly singled out.[87] Where and how is less clear.

The question of which regulatory structure applies to hydrogen stems from its versatility. Natural gas has a specific yet ambiguous meaning under the NGA: '"Natural gas" means either natural gas unmixed, or any mixture of natural and artificial gas.'[88] Because hydrogen in a pure form does not often occur naturally, pure hydrogen is (arguably) not 'natural gas'.[89] Further Congress understood 'artificial' gas as used in the NGA to have a very specific meaning that did not include pure hydrogen.[90] If hydrogen is not a natural gas, and if hydrogen is not blended with natural gas, then transportation of it by pipeline is (arguably) outside of FERC's NGA jurisdiction. It would instead remain subject to regulation by the STB. This approach is consistent with the fact that hydrogen has uses other than as an energy carrier, for example as a feedstock.

But the issue is not that clear-cut. Reading 'natural gas' as excluding gases not primarily composed of methane may be unnecessarily narrow. For example, a 1960 act explicitly excluding helium from FERC's NGA jurisdiction would have been unnecessary if the definition of natural gas had been read so narrowly.[91] Further, one readily available use for hydrogen is blending it with natural gas. In some cases, natural gas pipelines and other equipment are believed to be physically able to tolerate blends of up to 20 percent hydrogen.[92] A blend of hydrogen and natural gas would fit the NGA's definition of natural gas and be regulated by FERC.

A third possibility is that FERC should regulate hydrogen under the same ICA authority under which FERC regulates oil. The ICA authority granted to FERC in 1977 extended to 'pipeline transportation of crude and refined petroleum and petroleum byproducts, derivatives or petrochemicals'.[93] Proponents of this view argue that FERC's authority over oil has previously been read broadly to encompass other energy products;[94] and hydrogen is often derived from petroleum products and fits well with FERC's expertise because hydrogen is presently valued for its energy content.[95] From a policy perspective the ICA requires oil pipelines to be common carriers, ready to serve all comers, which would facilitate the emergence of this new market.[96] However, treating hydrogen as 'oil' under the ICA would lead to the problem of 'bifurcated

[85] Bolgiano 18; 49 USC § 60502.
[86] Bolgiano 29–30.
[87] Ibid 24.
[88] 15 USC §717a(5); Bolgiano 22–28, 30.
[89] Michael I Diamond, 'Jurisdiction over Hydrogen Pipelines and Pathways to an Effective Regulatory Regime', EBA Brief Vol 3, Issue 2, 6 (Energy Bar Association, Fall 2022) (hereinafter: Diamond).
[90] Bolgiano 77; *but see* Diamond 6.
[91] Diamond 3–4.
[92] CRS Report 4.
[93] Bolgiano 28 (quoting S. REP. NO. 95-367, at 69 (1st Sess. 1977) (Conf. Rep.); H.R. REP. No. 95-539, at 69 (1st Sess. 1977) (Conf. Rep.)).
[94] Bolgiano 68.
[95] Ibid 16, 68.
[96] Richard E Powers, Jr., Testimony before S. Comm. On Energy & Nat. Res. 5–12 (July 19, 2022) <https://energy.senate.gov/services/files/542E24C8-F2A2-4483-869F-1201C6E7D9FD> accessed December 1 2022 (hereinafter: Powers).

regulation' because pure hydrogen would be regulated under the ICA, while hydrogen mixed with even a small amount of natural gas would be regulated under the NGA.[97]

Another option is to wholly exempt interstate hydrogen pipelines from the regulatory schemes described above, just as water is exempt. That, however, would require congressional action because the regulatory sweep encompassing *all* interstate pipelines other than those carrying water suggests it must be regulated.

The Importance of the Debate

The importance of this question comes from the distinctions between the NGA and ICA regarding their scope, degree of flexibility, and control over entry and exit, and the expertise of the regulator. Both statutes grant the regulator authority over rates, terms, and conditions of service, but the NGA also provides FERC with authority over determinations of need, siting, and abandonment of interstate pipelines, storage facilities, and import/export facilities for natural gas, including liquified natural gas.[98] Under the ICA, siting and permitting of pipelines is left to the states.

Unlike oil pipelines, an interstate natural gas pipeline must have a certificate of convenience and necessity from FERC to proceed to construction.[99] Although this may seem burdensome, the certification of need takes into consideration the economic demand for pipeline capacity and therefore limits competition to support the economics of those pipelines that are built. That protection could be valuable to a nascent hydrogen pipeline industry. Further, consolidating jurisdiction under FERC would enable it to coordinate the approval for abandonment of a natural gas pipeline with conversion of the pipeline to use for hydrogen transportation (if technically feasible).[100]

Further, once the certificate of need is issued, the pipeline developer is able to exercise a federal right of eminent domain enabling it to take private property (for fair compensation) that is needed for the pipeline right of way.[101] State authorities are unable to deny access to a certificated pipeline that will cross the state, even if the state sees little benefit to its residents or has other parochial concerns. A rapid build-out of an interstate hydrogen pipeline system, if needed, might be facilitated by a similar federal siting authority.

However, the NGA permitting process can also be lengthy and at least one commentator takes the position that he has seen few issues with oil pipeline siting, despite the lack of federal authority.[102] Further, the importance of federal siting authority depends very much on whether new hydrogen pipeline construction will be primarily interstate or for export (that is, potentially within the federal domain under the ICA or NGA) or intrastate (within state control).

97 Ibid 13.

98 *Compare* 49 USC § 60502 and Federal Energy Regulatory Commission, Oil (ferc.gov) <www.ferc.gov/oil> accessed November 4, 2023, to 15 USC §171 et seq. and Federal Energy Regulatory Commission, Natural Gas (ferc.gov) <www.ferc.gov/natural-gas> accessed November 4, 2023.

99 15 USC § 717f.

100 Powers 9.

101 15 USC § 717f(h).

102 Powers 11. Since each pipeline has unique characteristics, the actual time can vary significantly. Two sources suggest the federal approval process takes on average about 1.5 years. US Government Accountability Office, 'Pipeline Permitting' <www.gao.gov/products/gao-13-221> accessed October 21, 2023. INGAA, 'Pipeline Permitting' 2 <https://ingaa.org/wp-content/uploads/2019/01/34233.pdf> accessed October 21, 2023. However, litigation and other factors can extend the time significantly. How the FERC process compares to a state-by-state process is difficult to assess because state processes differ widely and thus timing would be highly dependent on which states would be involved. Ibid.

Uncertainty itself is of concern. Whichever regime applies, the process for permitting and building a pipeline is lengthy and thus a false start under the wrong regime would be costly in terms of time as well as money.

Pathway to Resolution?

Given the ambiguity, the matter will likely require congressional action. In addition to the three options for federal regulation set out above, a fourth option could be a federal exemption from regulation (like water). A variation might explicitly bring hydrogen within the NGA's federal siting regime, coupled with light-handed rate regulation.[103] If hydrogen is exempted from federal regulation (like water), then under the US federalism system, individual states would have discretion over regulation. Should Congress not act, the question could be posed to the agencies and then the courts to decide the ambiguity described.

The timing for resolution of this important issue is unknown.

3.5.4 *Safety*

The DOE Roadmap repeatedly recognizes additional attention to public health and safety is an important 'enabler' for achieving the US goals for hydrogen.[104] It also endorsed a recommendation from the IEA Future of Hydrogen Report, stating that '[a]ddressing safety codes and standards is necessary for a harmonized global supply chain'.[105] But the pathway for gaining this clarity is unclear. The Roadmap does not include a plan for doing so.

The current US laws include safety standards applicable to hydrogen, but they are dispersed across different agencies depending on the point in the supply chain and the activity involved. For example, six different administrations within the US Department of Transportation regulate some aspect of hydrogen transport.[106] Protecting the health and safety of workers in the private sector and some public sector workers is entrusted to the US Occupational Safety and Health Administration (OSHA).[107] The OSHA identifies nine standards that 'may' apply to hydrogen (and cautions that the list is not exhaustive).[108] Proper labeling can also affect safety, including in the workplace. Labeling of alternative fuels, which includes hydrogen, is the responsibility of the Federal Trade Commission.[109] Thus, regulation is already pervasive, but in some instances unclear. Further, it is important that the requirements are appropriate to new uses of hydrogen and facilitate its transport and use across multiple places and jurisdictions. Inconsistencies can create issues of noncompliance or limit market penetration.

Standard setting, often by industry, can play an important role in resolving some of these issues. For example, 'The National Fire Protection Association (NFPA) is a global self-funded nonprofit organization, . . . devoted to eliminating death, injury, property and economic loss due to fire, electrical and related hazards'.[110] The NFPA is not a government agency but its primary

[103] Diamond.

[104] Roadmap 12, 25, 27, 28, 31, 33.

[105] Roadmap 25, 78.

[106] Roadmap 64–67.

[107] US Occupational and Health Administration, 'About OSHA' (osha.gov) <https://osha.gov/aboutosha> accessed December 1, 2022.

[108] US Occupational and Health Administration, 'Green Job Hazards' (osha.gov) <https://osha.gov/green-jobs/hydrogen/standards> accessed December 1, 2022.

[109] 42 USC § 13232(a).

[110] National Fire Protection Association, 'NFPA overview' (nfpa.org) <https://nfpa.org/overview> accessed December 1, 2022.

work is developing and disseminating codes and standards. It has developed several standards applicable to hydrogen. While these standards do not inherently have the force of law, they are sometimes incorporated into local building codes which are binding. Creating standards through industry groups can facilitate uniformity across jurisdictions, where no single law would be applicable.

The Energy Policy Act of 2005 required the DOE to support the development of 'safety codes and standards relating to fuel cell vehicles, hydrogen energy systems, and stationary, portable, and micro fuel cells'.[111] That effort was funded from 2005 to 2020 and during that period the DOE developed the 'H2 Tools' website to help others.[112] However, the resources on the H2 Tool website are now dated and the project is unfunded.

Consistent with the Roadmap, attention to safety and the harmonization of standards is important to market development. Industry can help, but the government needs to act too.

3.6 CONCLUSION

The market for hydrogen in the United States is poised for growth. The infusion of federal funding and favorable tax provisions are intended to bring government and industry together as partners in its development. The strong interest in hydrogen hubs indicates the potential for success. However, industry is concerned that emerging regulations will set standards it cannot yet meet, thus stymying growth before it begins; and there are areas of regulatory uncertainty that must be resolved to facilitate rapid growth. The question of permitting reform and pipeline regulatory-authority are particularly vexing and may require congressional action to resolve. Both government and industry have important roles in updating and harmonizing safety codes and other standards. As long as these regulatory hurdles remain unaddressed, the potential for rapid growth is uncertain.

FURTHER READING

Baird AR, Ehrhart BD, Glover AM, and LaFleur CB, 'Federal Oversight of Hydrogen Systems' (Sandia National Laboratories, 2021) <www.osti.gov/servlets/purl/1773235> accessed 5 November 2023

King B, Larsen J, Bower G, and Pastorek N, 'How Clean Will US Hydrogen Get? Unpacking Treasury's Proposed 45V Tax Credit Guidance' (Rhodium Group, rhg.com 4 January 2024) <https://rhg.com/research/clean-hydrogen-45v-tax-guidance/> accessed 4 January 2024

Talus K, Martin M, 'A Guide to Hydrogen Legislation in the USA: A Renewed Effort', J of World Energy Law & Business (24 September 2022) <https://academic.oup.com/jwelb/article/15/6/449/6713813> accessed 4 November 2023

'US National Clean Hydrogen Strategy and Roadmap' (energy.gov, May 2023) <www.hydrogen.energy.gov/pdfs/us-national-clean-hydrogen-strategy-roadmap.pdf> accessed 4 November 2023

[111] 42 USC § 16158.

[112] US Department of Energy, 'Hydrogen Program: Safety' (energy.gov) <www.hydrogen.energy.gov/program-areas/safety> accessed November 3, 2023.

4

Hydrogen Regulation in Latin America

From Promise to Production

Howard James Foy[*]

4.1 INTRODUCTION

Hydrogen is anticipated to play a central role in the global energy transition towards decarbonized economies.[1] With demand for clean hydrogen[2] projected to surge in the coming decades, particularly in Europe and north-east Asia,[3] Latin America finds itself well positioned to capitalize on this market opportunity.[4] With its vast energy resources, both proven and untapped, the region has the potential to become a production epicentre in the impending hydrogen economy.[5] This ability to produce large quantities of low-cost clean hydrogen and its derivatives can not only catalyse new export sectors for many Latin American countries; it can also contribute to their domestic decarbonization efforts.[6] Indeed, hydrogen's versatility as an energy carrier, storage medium and industrial feedstock makes it a vital component in addressing the challenges of hard-to-abate sectors like heavy industry and heavy-duty transport.[7]

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1 IEA, 'Global Hydrogen Review 2022' (2022) 9, 12, 15 <https://iea.org/reports/global-hydrogen-review-2022> accessed 15 June 2024 (hereinafter: IEA 2022).

2 For the purposes of this chapter, the terms 'clean hydrogen' and 'hydrogen' will be used interchangeably and encompass 'green hydrogen', 'blue hydrogen', 'renewable hydrogen' and 'low-carbon hydrogen'. See Hydrogen Science Coalition, 'Proposed Definition of "Clean" Hydrogen' (2023) <https://h2sciencecoalition.com/wp-content/uploads/2023/04/Clean-Hydrogen-Definition_4-April.pdf> accessed 15 June 2024.

3 The EU aims to import 10 million tonnes of renewable hydrogen by 2030. By 2050, north-east Asian (including China) and European imports of low-carbon hydrogen combined could reach around 103 million tonnes per year. See European Commission, 'Hydrogen' (European Commission) <https://energy.ec.europa.eu/topics/energy-systems-integration/hydrogen_en#:~:text=The%20ambition%20is%20to%20produce,in%20energy-intensive%20industrial%20processes> accessed 15 June 2024, and Wood Mackenzie, 'The Blue Green Planet: How Hydrogen Can Transform the Global Energy Trade' (2021) <www.woodmac.com/horizons/the-blue-green-planet-how-hydrogen-can-transform-the-global-energy-trade/> accessed 15 June 2024.

4 IRENA, 'Hydrogen Economy Hints at New Global Power Dynamics' (2022) <www.irena.org/News/pressreleases/2022/Jan/Hydrogen-Economy-Hints-at-New-Global-Power-Dynamics> accessed 15 June 2024.

5 See generally IEA, 'Hydrogen in Latin America' (2021) <https://iea.org/reports/hydrogen-in-latin-america> accessed 15 June 2024 (hereinafter: Hydrogen in Latin America).

6 Ibid. 9.

7 IEA 2022, 57, 185.

This chapter examines the emerging policy and regulatory frameworks for hydrogen in Latin America by focusing on three regional leaders, Chile, Colombia and Brazil.[8] These countries, endowed with solar, wind, hydro and/or fossil fuel assets, all aim to become major clean hydrogen producers. To achieve this vision, they have each outlined ambitious hydrogen strategies, setting the stage for the industry's growth.[9] In order to keep pace with the increasing interest from policymakers and the private sector, their legal regimes are undergoing a period of significant transformation to scale the hydrogen value chain beyond scattered pilots. While Chile, Colombia and Brazil have made positive strides, as this chapter explores, critical regulatory challenges must be addressed before this promise of a thriving regional hydrogen market can fully materialize.

As a note to the reader, in view of the rapidly evolving nature of the hydrogen legal landscape, the information presented in this chapter is current as of 15 June 2024, unless otherwise noted.

4.2 FROM PROMISE TO POLICY: PARALLEL AMBITIONS, DIVERGENT APPROACHES

Seeking to harness clean hydrogen's power, Chile, Colombia and Brazil have each articulated important policy documents reflective of their ambitions. These documents, while providing insights into their strategic priorities and approaches to hydrogen development, also serve as the foundation for shaping their regulatory environments. In this regard, to properly contextualize the following regulatory discussions, this section will briefly explore some salient aspects of these policy initiatives.

4.2.1 *Kickstarting the Hydrogen Endeavour*

Chile's foray into hydrogen has been a comparatively recent affair, largely motivated by studies that highlighted the country's immense renewable potential.[10] Against this backdrop, swift decision-making coupled with international collaborations, notably with Germany,[11] led

[8] Numerous Latin American nations are actively engaging in hydrogen development, with several having released ambitious hydrogen strategies. However, to allow for a more focused analysis, this chapter concentrates on Chile, Colombia and Brazil, the three leading hydrogen countries in Latin American according to the latest H2LAC Index. See Hinicio & New Energy, 'H2LAC INDEX 2024 Results of the 4th Hydrogen Economy Index, Latin America & The Caribbean' (2024) <https://hinicio.com/wp-content/uploads/2024/06/Hinicio_H2LAC-Index-2024_Official-Results.pdf> accessed 15 June 2024. See also Hinicio, 'Hinicio and New Energy Present the Results of the H2LAC 2024 Index: Chile, Brazil, and Colombia Lead the Market' (Hinicio, 5 June 2024) <https://hinicio.com/hinicio-and-new-energy-present-the-results-of-the-h2lac-2024-index/> accessed 15 June 2024.

[9] Ministerio de Energía (Chile), 'Estrategia Nacional del Hidrógeno Verde: Chile, Fuente Energética para un Planeta Cero Emisiones' (2020) <https://energia.gob.cl/sites/default/files/national_green_hydrogen_strategy_-_chile.pdf> accessed 15 June 2024 (hereinafter: Chile's Strategy); Ministerio de Minas y Energía (Colombia), 'Hoja de Ruta del Hidrógeno en Colombia' (2021) <https://minenergia.gov.co/documents/5862/Colombias_Hydrogen_Roadmap_2810.pdf> accessed 15 June 2024 (hereinafter: Colombia's Roadmap); Ministério de Minas e Energia (Brazil), 'Plano de Trabalho Trienal PNH2' <https://gov.br/mme/pt-br/assuntos/noticias/PlanodeTrabalhoTrienalPNH2.pdf> accessed 15 June 2024 (hereinafter: Brazil's Work Plan).

[10] Ministerio de Energía (Chile), 'Hidrógeno Verde un Proyecto País' (2022) 6–7 <https://energia.gob.cl/sites/default/files/guia_hidrogeno_abril.pdf> accessed 15 June 2024. See, e.g., Christian Santana O et al., 'Energías Renovables en Chile: El Potencial Eólico, Solar e Hidroeléctrico de Arica a Chiloé' [Ministerio de Energía (Chile)/Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ), 2014] <https://4echile.cl/wp-content/uploads/2020/08/Energias-Renovables-en-Chile-El-potencial-eolico-solar-e-hidroele%CC%81ctrico-de-Arica-a-Chiloe.pdf> accessed 15 June 2024; Dominik Schlipf et al., 'CSP – Localization Potential: Analysis and Further Potential for Chile' (GIZ, 2014) <https://4echile.cl/wp-content/uploads/2020/08/CSP-localization-potential-Chile-GIZ-2014.pdf> accessed 15 June 2024.

[11] 4e Chile, 'Quiénes somos – 4e Chile' <https://4echile.cl/quienes-somos/#presentacion-programa> accessed 15 June 2024.

Chile to publish its National Green Hydrogen Strategy in 2020, the first of its kind in Latin America.[12] More recently, Chile released its Green Hydrogen Action Plan 2023–2030,[13] intended to serve as the actionable roadmap for the industry's development for the remainder of the decade.[14]

Colombia, for its part, saw potential in hydrogen as early as 2007, recognizing its capacity to transform the transportation sector.[15] Nonetheless, this interest only matured into a concrete plan with the publication of its Hydrogen Roadmap in 2021, under which the country similarly aims to exploit its natural resources for clean hydrogen production.[16] Unlike Chile's two-pronged approach, Colombia's Roadmap includes the several lines of work on which the different national and regional bodies will work over the current decade.[17]

As for Brazil, its hydrogen endeavour can be traced back to at least the 1990s, with early initiatives focused on exploring hydrogen's energy applications.[18] However, it was only in 2022 that these initiatives fully crystallized with the establishment of its National Hydrogen Programme.[19] As part of this programme, Brazil published its 2023–2025 Three-Year Work Plan, the country's short-term blueprint for its hydrogen ambitions.[20] Like its neighbours, it also plans on capitalizing on its extensive natural assets to become a major hydrogen producer.[21]

This overview reveals a unified vision amongst Chile, Colombia and Brazil to tap their natural resources for clean hydrogen production. Yet, as we will analyse next, their ultimate goals vary in fundamental ways, casting light on the strategic priorities of each country.

4.2.2 *Setting the Goals and Targets*

In the case of Chile, its Strategy outlines particularly ambitious goals. By 2025, the country aims to be the lead recipient of green hydrogen investments in Latin America with $5 billion, have 5 gigawatts (GW) of electrolysis capacity installed or under development, and produce

12 Ministerio de Energía (Chile), 'Gobierno presenta la Estrategia Nacional para que Chile sea líder mundial en hidrógeno verde' (Ministerio de Energía, 3 November 2020) <https://energia.gob.cl/noticias/nacional/gobierno-presenta-la-estrategia-nacional-para-que-chile-sea-lider-mundial-en-hidrogeno-verde> accessed 15 June 2024. See generally Chile's Strategy. See also IEA, 'Latin America's Hydrogen Opportunity: From National Strategies to Regional Cooperation' (2020) <www.iea.org/commentaries/latin-america-s-hydrogen-opportunity-from-national-strategies-to-regional-cooperation> accessed 15 June 2026.

13 Ministerio de Energía (Chile), 'Ministerio de Energía publica el Plan de Acción de Hidrógeno Verde 2023–2030' (Ministerio de Energía, 25 April 2024) <https://energia.gob.cl/noticias/nacional/ministerio-de-energia-publica-el-plan-de-accion-de-hidrogeno-verde-2023-2030> accessed 15 June 2026.

14 Ministerio de Energía (Chile), 'Plan de Acción de Hidrógeno Verde 2023–2030' (2024) <https://energia.gob.cl/sites/default/files/documentos/plan_de_accion_hidrogeno_verde_2023-2030.pdf> accessed 15 June 2024 (hereinafter: Chile's Action Plan).

15 Ministerio de Minas y Energía (Colombia), 'Plan Energético Nacional 2006–2025' (2007) 227 <www.upme.gov.co/Docs/PLAN_ENERGETICO_NACIONAL_2007.pdf> accessed 15 June 2024.

16 See generally Colombia's Roadmap.

17 Ibid. 28–49.

18 Ministerio de Minas y Energía (Colombia), 'Programa Nacional do Hidrogenio: Directrices Propuestas' (2021) 5 <https://gov.br/mme/pt-br/assuntos/noticias/HidrognioRelatriodiretrizes.pdf> accessed 15 June 2024 (Proposed Guidelines).

19 Serviços e Informações do Brasil, 'Brazil Publishes National Hydrogen Program' (gov.br, 29 August 2022) <www.gov.br/en/government-of-brazil/latest-news/2022/brazil-publishes-national-hydrogen-program> accessed 15 June 2024. See also Resolução CNPE No. 6, de 23 de junho de 2022, 23 June 2022, Diário Oficial da União, 4 August 2022 (Brazil) <https://gov.br/mme/pt-br/assuntos/conselhos-e-comites/cnpe/resolucoes-do-cnpe/2022/res_cnpe-6-2022.pdf> accessed 15 June 2024.

20 See generally Brazil's Work Plan.

21 Ibid. 13.

200 kilotons (kt) of green hydrogen a year.[22] By the end of the decade, Chile aspires to become the global leader in exporting green hydrogen and its derivatives ($2.5 billion), produce green hydrogen with the lowest levelized cost worldwide ($1.5/kg) and establish itself as the global leader in green hydrogen production through electrolysis (25 GW).[23] By mid-century, Chile aims to lower its levelized cost of hydrogen (LCOH) to $0.8/kg.[24]

Colombia's Roadmap also lays out ambitious goals, though comparatively smaller in scale. By 2030, Colombia aims to develop 1–3 GW of electrolysis backed by 1.5–4 GW of renewable energies, reach green hydrogen costs of $1.7/kg, and produce at least 50 kt of blue hydrogen via CO_2 capture.[25] Colombia's Roadmap also aims to deploy a fleet of 1,500 to 2,000 light-duty vehicles, 1,000 to 1,500 heavy-duty vehicles, as well as 50 to 100 hydrogen re-fuelling stations.[26] To achieve these goals, the country plans to mobilize $2.5–5.5 billion in investments over the decade, mainly from the private sector.[27]

Brazil's Work Plan contrasts with less defined goals and targets, perhaps owing to its nature as a triennial plan and not a long-term strategy. The main objectives set forth therein are to disseminate low-carbon hydrogen pilots nationally by 2025, become the most competitive global producer of low-carbon hydrogen by 2030 and to establish low-carbon hydrogen hubs by 2035.[28] However, the Plan stops short of specifying detailed figures for these objectives.[29]

When juxtaposed, the hydrogen strategies of these countries exhibit diverse (and even rival) goals and ambitions. Chile sets the bar high, aspiring to global leadership in green hydrogen production and export, as evidenced by its goal to achieve the world's lowest LCOH – a benchmark Brazil also aims to surpass. Colombia, in comparison, while also intent on becoming an important player in the hydrogen market, sets more modest but concrete goals. This includes, like Chile, specific targets for investment, electrolyser capacity and LCOH. Unique to Colombia's strategy, however, is the inclusion of detailed goals for the transport sector and blue hydrogen production. These distinctions not only illustrate the individual ambitions of Chile, Colombia and Brazil, but also hint at the unique policy choices underpinning their hydrogen initiatives, to which we will turn to next.

4.2.3 *Defining the Strategic Approach*

Chile's hydrogen policy distinctively focuses on 'green' hydrogen, bypassing mentions of 'blue' hydrogen or other variants.[30] This is not surprising if one considers that Chile imports nearly 98 per cent of the fossil fuels it uses, while it boasts an estimated renewable energy generation potential that exceeds 2,300 GW – seventy times its currently installed electrical capacity.[31]

In contrast to Chile's green-centric model, Colombia adopts a more inclusive approach which includes both 'blue' and 'green' hydrogen. Explicitly mentioning its abundant reserves of oil, natural gas and coal,[32] its Roadmap emphasizes the potential for harnessing these resources for

22 Chile's Strategy 19.
23 Ibid.
24 Ibid. 11.
25 Colombia's Roadmap 26.
26 Ibid. 26–27.
27 Ibid. 27.
28 Brazil's Work Plan 20.
29 Ibid.
30 See generally Chile's Strategy.
31 Chile's Action Plan 17.
32 Colombia's Roadmap 8.

hydrogen production when coupled with carbon capture, utilization and storage (CCUS) technologies.[33] In this regard, while it recognizes green hydrogen's significance in the longer term, the strategy assigns blue hydrogen a key transitional role.[34]

Brazil's Work Plan, for its part, deviates from a previously heralded and even more eclectic 'rainbow' hydrogen approach, which included 'grey' hydrogen,[35] steering its strategy towards 'low-carbon' hydrogen production.[36] Interestingly, in opting for this terminology, Brazil forwent the traditional 'colour-book' classification, adopted by Chile and Colombia in their initiatives, echoing the preference of the International Energy Agency (IEA) for an emissions intensity-centric framework instead.[37] Under this classification, Brazil's Plan includes hydrogen derived from a wide variety of processes with low lifecycle emissions, including the equivalents of both 'green' and 'blue' hydrogen.[38]

While these documents reflect a unified movement towards integrating clean hydrogen into their national energy mix, Chile, Colombia and Brazil chart distinct strategic pathways reflective of their unique strengths and goals. The success of these ambitious policies hinges on the creation of enabling governance frameworks that keep pace with the momentum set. The following section examines the regulatory regimes of these countries, analysing how each is tackling the legal complexities of turning their hydrogen aspirations into tangible realities.

4.3 FROM POLICY TO REGULATION: STATUS QUO, CHALLENGES AND THE PATH AHEAD

Across the national strategies of Chile, Colombia and Brazil, a common theme threads the discourse: the need for a regulatory infrastructure that can enable the widespread deployment and commercialization of hydrogen technologies.[39] Hydrogen's multidimensional nature, straddling the lines between a fuel source, a storage medium and an industrial feedstock, necessitates a legal framework that can adapt to its unique characteristics and uses. Indeed, adequate regulation has been recognized as the primary enabler for the industry, providing the foresight and stability needed to invest and scale up hydrogen initiatives.[40] To this extent, the particularities of regulation are not merely peripheral considerations; they are central to the entire developmental narrative. As this section will examine, classifications, definitions, regulatory competences, safety protocols and certification procedures are all key facets that require precise legal crafting to adequately support the sector's growth.

33 Ibid. 12–13.
34 Ibid. 12–13, 17.
35 Ministério de Minas e Energía (Brazil), 'Bases para a Consolidação da Estratégia Brasileira do Hidrogênio' (EPE, 2021) 24, 28 <www.epe.gov.br/sites-pt/publicacoes-dados-abertos/publicacoes/PublicacoesArquivos/publicacao-569/Hidroge%CC%82nio_23Fev2021NT%20(2).pdf> accessed 15 June 2024 (hereinafter: EPE Bases).
36 Brazil's Work Plan 7.
37 Ibid. 17. See IEA, 'Towards Hydrogen Definitions Based on Their Emissions Intensity' (2023) <https://iea.org/reports/towards-hydrogen-definitions-based-on-their-emissions-intensity> accessed 15 June 2024.
38 Brazil's Work Plan 19.
39 Chile's Strategy 26; Colombia's Roadmap 25; Brazil's Work Plan 21.
40 DNV, 'Rising to the Challenge of a Hydrogen Economy: The Outlook for Emerging Hydrogen Value Chains, from Production to Consumption' (2021) 11 <https://dnv.com/Publications/rising-to-the-challenge-of-a-hydrogen-economy–203873> accessed 15 June 2024.

4.3.1 *Chile*

In Chile, significant efforts are underway to align its hydrogen regulatory framework with policy aspirations. Central to this task is the reassessment of hydrogen's legal classification.[41] Under Chilean law, molecular hydrogen has historically been (and continues to be) classified as a 'hazardous substance'.[42] As such, a suite of standards apply, including safety protocols for its storage and transportation, and occupational health rules.[43] Nevertheless, as hydrogen expands its applications beyond traditional industrial uses, these existing standards prove inadequate for its broader energy-related roles.[44] This discrepancy between legacy regulations and new applications emphasized the need for a more appropriate framework.

The call for a regulatory realignment to this effect found its legislative response through the enactment of Law 21,305 in 2021.[45] This legislation marked a significant turning point in hydrogen's governance by officially classifying it as a fuel, a measure aligned with Chile's Strategy.[46] In doing so, it conferred oversight of hydrogen to the Ministry of Energy, enabling it to pursue a regulatory agenda in line with hydrogen's new roles.[47] As part of this agenda, the development of safety standards across hydrogen's value chain has been a priority.[48]

This legislative progression has led to a regulatory conundrum: under Chilean law, hydrogen is recognized both as a hazardous substance and as a fuel.[49] While dual classifications are not inherently problematic, the practical implications in this case extend beyond theoretical discord.[50] As exemplified by the Ministry of Health's Supreme Decree 43/2016, they manifest in the potential for regulatory overlap and conflict.[51] In particular, this Decree sets forth safety requirements for hydrogen storage, mandating tank conditions, safety distances and maximum storage capacities.[52] However, it explicitly carves out 'liquid and gaseous fuels' from its scope of application.[53] This exclusion casts uncertainty over the operational parameters within which hydrogen must be managed: tanks storing hydrogen solely for industrial use might be subject to this Decree, whereas those for fuel purposes might not. This becomes more complex when

[41] Zainul Abdin et al., 'Hydrogen as an energy vector' (2020) 120 Renewable and Sustainable Energy Reviews 109620, 1–2 <http://dx.doi.org/10.1016/j.rser.2019.109620> accessed 15 June 2024.

[42] Ministerio de Salud (Chile), Aprueba el Reglamento de Almacenamiento de Sustancias Peligrosas, Decreto No. 43, 27 July 2015, Diario Oficial, 29 March 2016 (Chile) art. 2 <www.leychile.cl/Navegar?idNorma = 1088802> accessed 15 June 2024 (Decree 43/2016) (hereinafter: Decree 43/2016). See also Centro de Energía UC et al., 'Proposición de Estrategia Regulatoria del Hidrógeno para Chile' (GIZ, 2020) 31 <https://energia.gob.cl/sites/default/files/proposicion_de_estrategia_regulatoria_del_hidrogeno_para_chile.pdf> accessed 15 June 2024 (hereinafter: Centro de Energía UC).

[43] Several other regulations address the management of hydrogen as a hazardous substance. For a more detailed analysis, see Centro de Energía UC 32.

[44] Ibid., 33–34.

[45] Sobre Eficiencia Energética, Ley No. 21305, 8 February 2021, Diario Oficial, 13 February 2021 (Chile) <https://bcn.cl/2nnoz> accessed 15 June 2024 (hereinafter: Law No. 21305).

[46] Ibid. art. 7; Chile's Strategy 30.

[47] Law No. 21305 art. 7; Chile's Strategy 29.

[48] Ministerio de Energía (Chile), 'Desarrollo Regulatorio de Hidrógeno' 18 (2021) <https://energia.gob.cl/sites/default/files/3_-_regulacion_de_seguridad_-_ma._de_los_angeles_valenzuela_min_energia.pdf> accessed 15 June 2024; Chile's Action Plan 108–110.

[49] Centro de Energía UC 61.

[50] Danitza Montserrat Eterovic Martí, 'Avances y desafíos en torno a la regulación del hidrógeno verde en Chile' (2022) (10) Revista Derecho Aplicado – LLM UC 33 <http://dx.doi.org/10.7764/rda.10.49971> accessed 15 June 2024 (hereinafter: Martí).

[51] Decree 43/2016.

[52] Ibid. arts. 152–153.

[53] Ibid. art. 3.

hydrogen's end use might span across both energy and non-energy domains. Considering that the risk profiles and mitigation strategies for hydrogen remain invariant throughout its lifecycle, regardless of its final application, this bifurcated governance paradigm risks disrupting regulatory consistency and sowing confusion.[54]

Despite this lack of clear and specific safety regulations for hydrogen installations, interest in pilot projects did not stall. To this extent, Chile introduced a support guide outlining the authorization procedure for hydrogen projects,[55] a requirement all energy facilities must fulfil.[56] This guide plays a crucial role in bridging the regulatory gap, allowing pilot projects to import safety standards dictated by foreign standardization institutes such as the American National Standards Institute (ANSI), the International Organization for Standardization (ISO) and the National Fire Protection Association (NFPA).[57] Since then, there have been attempts to approve an official set of safety regulations for hydrogen installations, which include safety requirements across design, construction, operation, maintenance, decommissioning and other stages.[58] However, despite the decree containing these regulations having been signed by former President Piñera in 2022, they have yet to enter into force.[59]

Another regulatory development in furtherance of Chile's Strategy has been the enactment of Law 21,505, which allowed for the inclusion of green hydrogen technologies into the country's electricity matrix.[60] This law formally recognized 'generation-consumption systems', a classification that includes green hydrogen production facilities.[61] Amongst other provisions, it allows these systems to both draw energy for electrolysis and contribute surplus power back to the grid.[62] This, in turn, allows green hydrogen to play a key role in optimizing the use of excess electricity from intermittent renewable sources, effectively managing power supply during peak demand periods.[63] Also noteworthy, the above classification explicitly extends to water desalination facilities,[64] of relevance as desalinated seawater is expected to be used in the hydrogen production process.[65] As Chile faces acute water scarcity challenges,[66] this inclusion reflects a

54 Centro de Energía UC 60–61.

55 Ministerio de Energía (Chile), 'Guía de Apoyo para Solicitud de Autorización de Proyectos Especiales de Hidrógeno' (2021) <https://energia.gob.cl/sites/default/files/guia_proyectos_especiales_hidrogeno_2021.pdf> accessed 15 June 2024 (hereinafter: Hydrogen Projects Support Guide).

56 Deroga Decreto No. 20, de 1964, y lo Reemplaza por las Disposiciones Que Indica, Decreto con Fuerza de Ley No. 1, 22 September 1978, 14 February 1979 (Chile) art. 2 <www.leychile.cl/Navegar?idNorma=3383> accessed 15 June 2024.

57 Hydrogen Projects Support Guide 2, 16–17.

58 Aprueba Reglamento de Seguridad de Instalaciones de Hidrogeno e Introduce Modificaciones al Reglamento de Instaladores de Gas, Decreto Supremo 13, 22 February 2022 (Chile) <https://energia.gob.cl/consultas-publicas/reglamento-de-seguridad-de-instalaciones-de-hidrogeno> accessed 15 June 2024.

59 Superintendencia de Electricidad y Combustibles (Chile), 'Instalaciones reguladas por el reglamento de seguridad de instalaciones de hidrógeno' <https://sec.custhelp.com/app/answers/detail/a_id/1319/kw/reglamento%20de%20seguridad> accessed 15 June 2024.

60 Promueve el Almacenamiento de Energía Eléctrica y la Electromovilidad, Ley No. 21505 (Law 21505), 8 November 2022, Diario Oficial, 21 November 2022 (Chile) <www.leychile.cl/Navegar?idNorma=1184572> accessed 15 June 2024 (hereinafter: Law 21505). See also Martí 17.

61 Law 21505 art. 7.

62 Ibid.

63 Martí 17.

64 Law 21505 art. 7

65 Martí 18; Friedrich-Ebert-Stiftung, 'Desafíos del Hidrógeno Verde: ¿Nueva Bonanza o Más de lo Mismo?' 40 (2023) <https://library.fes.de/pdf-files/bueros/mexiko/20738.pdf> accessed 15 June 2024.

66 See generally Ariel A Muñoz et al., 'Water Crisis in Petorca Basin, Chile: The Combined Effects of a Mega-Drought and Water Management' (2020) 12(3) Water 648 <http://dx.doi.org/10.3390/w12030648> accessed 15 June 2024.

TABLE 4.1 *Chile's hydrogen regulatory agenda*

Area of focus	Period	Regulatory action
General regulatory enablement	2024–2030	Approve the Hydrogen Installation Safety Regulations Initiate studies for the regulatory proposal of hydrogen quality and hydrogen refuelling stations Present the regulatory strategy for hydrogen derivatives Enact the Law on the Use of Seawater for Desalination
Certification system	2024–2025	Develop a strategic proposal for establishing a sustainability certification system for hydrogen
	2025–2030	Strengthen the National Electric Coordinator's National Registry of Renewable Energies (RENOVA), which will serve as the main platform for hydrogen certification
Permitting system	2023–2025	Strengthen the dependencies that grant critical permits for the proper development of the hydrogen industry
	2023–2024	Update the Guide for the Submission of Hydrogen Projects to the Superintendency of Electricity and Fuels (SEC)
	2023–2026	Implement a comprehensive reform of sectoral permits
	2024–2026	Develop and establish the technical criteria for the environmental assessment of projects related to the value chain of green hydrogen and its derivatives
	2024–2030	Strengthen the Environmental Assessment Service (SEA) and the services involved in the environmental assessment process

Source: Author's own work based on Chile's Action Plan.

potential move towards sustainable water usage in hydrogen production in line with public concerns.[67]

While the above analysis demonstrates concrete progress, it simultaneously highlights the need for further legal refinement and comprehensiveness. For instance, in addition to the aspects previously described, Chile still has not formally defined what constitutes 'green hydrogen', nor has it established a system for certifying the sustainable pedigree of the hydrogen produced.[68] As the country positions itself to be a major exporter, addressing these issues is of paramount importance, particularly for hydrogen destined for the EU.[69]

In response to these and other concerns, and as part of its Action Plan, Chile has recently published the latest version of its hydrogen regulatory agenda, shown in Table 4.1.[70]

Simultaneously, Chilean lawmakers are actively pursuing legislative initiatives to address these gaps. Bill 14756-08 stands out amongst them, aimed at establishing a broad legal framework for promoting the production and use of green hydrogen in Chile.[71] Following the Strategy's green-centric approach, the bill only addresses 'green hydrogen', which it defines as hydrogen produced through renewable energy sources utilizing water electrolysis or other

67 Ministerio de Energía (Chile), 'Hidrógeno Verde: Un Proyecto País' 90–91 (2022) <https://energia.gob.cl/sites/default/files/guia_hidrogeno_abril.pdf> accessed 15 June 2024.

68 Chile's Action Plan 203–204.

69 Janina Franco et al., 'Green Hydrogen for the Decarbonization of Chile: Certification as an Essential Step' (World Bank Blogs, 15 November 2022) <https://blogs.worldbank.org/latinamerica/green-hydrogen-decarbonization-chile-certification-essential-step> accessed 15 June 2024.

70 Chile's Action Plan 107–121.

71 Boletín No. 14756-08 'Impulsa la producción y uso del hidrógeno verde en el país' (Chile) <https://www.camara.cl/verDoc.aspx?prmID=14980&prmTIPO=INICIATIVA> accessed 15 June 2024.

approved technologies.[72] Also of importance, the bill incorporates provisions for establishing a hydrogen certification system, essential for verifying the renewable origins of green hydrogen.[73] As of the time of writing, Bill 14756-08 is, however, still in the early stages of consideration within its originating chamber.[74]

As this analysis shows, Chile finds itself in a transitional phase as regulations play catch-up to policy ambitions, displaying the inherent complexities in this hydrogen transition. Nevertheless, the country's regulatory environment is evolving steadily, as evidenced by the number of hydrogen regulations already enacted, those being developed and those planned for future development. Patient persistence in seeing these efforts through will determine whether Chile seizes the opportunities this new energy paradigm presents.

4.3.2 *Colombia*

Like its neighbour, Colombia is also deeply immersed in a regulatory overhaul. It too recently reclassified hydrogen, defining it as an energy vector suitable for energy storage, fuel or industrial applications.[75] This development, contained in the Ministry of Mines and Energy Decree 1476 of 2022, lays the groundwork for the creation of safety and technical standards better suited to its emerging roles.[76] Despite this reclassification, hydrogen continues to be regulated as a hazardous substance,[77] necessitating compliance with existing safety and technical regulations.[78] These, however, are considered insufficient and technologically outdated for hydrogen's new roles,[79] with Decree 1476 calling for their review and update, in particular those governing hydrogen transport.[80] As of the cut-off date, no updates have been announced. Regarding other elements of the hydrogen value chain, specific safety and technical standards remain undefined.[81]

Shifting focus from classifications to definitions, Colombia's legal delineation of 'green hydrogen' has undergone successive refinements that both expand opportunities and introduce complexity. Initially, Law 2099 of 2021 defined green hydrogen narrowly as produced exclusively from listed non-conventional renewable energy sources, such as wind, solar and biomass.[82] In 2022, this definition was de facto broadened by Decree 1476, which allows green hydrogen projects to also utilize grid-sourced electricity for their production processes, provided

[72] Ibid. art. 1(4).
[73] Ibid. art. 9.
[74] Cámara de Diputadas y Diputados (Chile), Actividad Legislativa Proyecto de Ley: Impulsa la producción y uso del hidrógeno verde en el país, Boletín No. 14756-08 <www.camara.cl/legislacion/ProyectosDeLey/tramitacion.aspx?prmID=15247&prmBOLETIN=14756-08> accessed 15 June 2024.
[75] Decreto 1476 de 2022, 3 August 2022 (Colombia) <https://www.funcionpublica.gov.co/eva/gestornormativo/norma.php?i=191408> accessed 15 June 2024 (hereinafter: Decree 1476).
[76] Colombia's Roadmap 32–33.
[77] Decreto 1496 de 2018, 6 August 2018 (Colombia) arts. 3–4 <www.funcionpublica.gov.co/eva/gestornormativo/norma.php?i=87910> accessed 15 June 2024.
[78] CMS Rodríguez-Azuero, 'Guía del Hidrógeno en Colombia' 11 (2024) <https://cms.law/es/media/local/cms-racla/files/publication/publication/guia-del-hidrogeno-en-colombia-2024?v=1> accessed 15 June 2024. See, e.g., Decreto 1609 de 2002, 31 July 2002 (Colombia) <https://funcionpublica.gov.co/eva/gestornormativo/norma.php?i=6101> accessed 15 June 2024.
[79] Colombia's Roadmap 32–33.
[80] Decree 1476 art. 2.2.7.1.8.
[81] Colombia's Roadmap 32–33.
[82] Ley 2099 del 2021, 10 July 2021 (Colombia) art. 5 <https://www.funcionpublica.gov.co/eva/gestornormativo/norma.php?i=166326> accessed 15 June 2024 (hereinafter: Law 2099).

the electricity is verified through bilateral contracts and renewable certificates.[83] Subsequently, Law 2294 of 2023 formally expanded the definition of Law 2099, introducing another layer to green hydrogen's evolving concept. According to this expanded definition, the green label can also be achieved by balancing a facility's self-generated renewable injections to the grid against any extracts for hydrogen production.[84] As long as injections meet or exceed production draws, the produced hydrogen retains its green designation.

Consequently, as it stands, three different definitions of green hydrogen coexist in Colombia's legal framework. While purely self-generated renewable energy serves as an unambiguous pathway for green hydrogen production, the differing grid-reliant models that have emerged introduce legal uncertainty in determining the compliance and sustainability credentials of green hydrogen projects. Creating further overlap, Decree 1476 also defined 'low-emission hydrogen', tying its designation to a to-be-determined emissions threshold.[85] As of the cut-off date, rules for the verification and operationalization of the two grid-based alternatives remained pending, as did the emissions threshold for 'low-emission hydrogen'.

In contrast to the multi-conceptualization of green hydrogen, the definition of 'blue hydrogen' under Colombian law is more straightforward. In particular, Law 2099 defines it as hydrogen produced from fossil fuels, incorporating a CCUS system within its production process.[86] This formal incorporation of both green and blue hydrogen into Colombia's legal regime represents a foundational step towards fulfilling its hydrogen commitments as outlined in its Roadmap. More recently, building upon this initial taxonomy, Colombia broadened its hydrogen narrative by also legally defining 'white hydrogen',[87] a move in line with its intention to explore for natural hydrogen deposits within the country's geology.[88]

Despite these advancements, important gaps remain in Colombia's regulatory framework, such as the absence of a hydrogen certification system and the lack of comprehensive technical and safety standards for the hydrogen value chain.[89] Addressing these and other challenges, however, is part of Colombia's regulatory agenda, outlined in Table 4.2.[90]

In line with this agenda, Colombian legislators have drafted several legislative proposals, including Bill 275/2022C. Designed as a comprehensive umbrella legislation, the bill's primary objective is to bridge existing regulatory voids while promoting the growth of, interestingly, 'low-emission' hydrogen.[91] In line with this taxonomy, the bill defines it as hydrogen produced from hydrocarbons with CCUS technologies, as well as from renewable energy sources, amongst other methods.[92] In all cases, however, it must meet the greenhouse gas (GHG) emission threshold set by the relevant ministries. This new emissions-based classification, however, does

[83] Decree 1476 art. 2.2.7.1.2.
[84] Ley 2294 de 2023, 19 May 2023 (Colombia) art. 235 <www.funcionpublica.gov.co/eva/gestornormativo/norma.php?i=209510> accessed 15 June 2024 (hereinafter: Law 2294).
[85] Decree 1476 art. 2.2.7.1.4.
[86] Law 2099 art. 5.
[87] Law 2294 art. 235.
[88] Lina Quiroga Rubio, 'ANH destinará $ 170.000 millones para buscar hidrógeno blanco en Colombia' (El Tiempo, 21 April 2023) <www.eltiempo.com/economia/sectores/anh-destinara-170-000-millones-para-buscar-hidrogeno-blanco-761498> accessed 15 June 2024.
[89] Colombia's Roadmap 31–33. See also Hinicio, 'Entregable 3 "Reporte Final de Recomendaciones"' (2022) <https://minenergia.gov.co/documents/8596/Recomendaciones_Certificacion_de_origen_hidrogeno.pdf> accessed 15 June 2024.
[90] Colombia's Roadmap 29–36.
[91] Proyecto de Ley 275 de 2022 Cámara, Gaceta del Congreso Año XXXIII, No. 298, 20 March 2024 (Colombia) <http://svrpubindc.imprenta.gov.co/senado/index2.xhtml?ent=Cámara&fec=20-3-2024&num=298> accessed 15 June 2024.
[92] Ibid. art. 2.

TABLE 4.2 *Colombia's hydrogen regulatory agenda*

Phase	Goal	Regulatory action
Phase 1	**Promote institutional articulation and assign responsibilities on hydrogen issues**	Establish working groups to identify and allocate institutional competencies amongst different ministries Articulate the Hydrogen Roadmap with the implementation instruments of the national climate change policy
	Establish the concepts of green and blue hydrogen in line with the national legal framework	Consolidate the definitions and taxonomy of green and blue hydrogen considering associated CO_2 emissions
	Design a system of guarantees of origin and certifications for hydrogen	Involve Colombia in international working groups Design a system of guarantees of origin through working groups with industry and other stakeholders Develop a monitoring tool for the system of guarantees of origin and certifications
	Develop and update technical and safety regulations for hydrogen	Review current national regulations through working groups and identify uses where new technical regulations need to be incorporated Adopt international standards in the technical regulation of hydrogen in Colombia
Phase 2	**Adapt regulation for new applications such as 'blending'**	Revise and update the Single Transport Regulation to allow for 'blending'
	Simplify and adapt administrative procedures	Review permits and procedures for the implementation of hydrogen projects including environmental aspects and land use Reduce the administrative red tape for low-emission hydrogen projects
	Adapt the regulation of the electricity system to better match hydrogen production	Analyse the participation of electrolysers in grid flexibility services Analyse electricity cost reduction in hydrogen production

Source: Author's own work based on Colombia's Roadmap.

not replace the current 'blue' and 'green' definitions, but rather explicitly covers them, potentially creating further definitional overlap.[93] Also of importance, the bill directs the relevant government bodies to establish the emissions threshold for low-emissions hydrogen, and to formulate regulations spanning technical specifications, safety protocols, certification systems and integration into the country's energy matrix, alongside other aspects.[94] Status-wise, Bill 275/2022C had been approved by the Chamber of Representatives in early 2024 and was awaiting treatment in the Senate.[95] However, the bill has since been shelved, requiring a complete restart of the legislative process.[96]

93 Ibid.
94 Ibid. arts. 4–5.
95 Ibid. See also CMS Rodríguez-Azuero, 'Boletín Energético No. 21' 10–11 (2024) <https://cms.law/en/media/local/cms-racla/files/publication/publication/boletin-energetico-21?v=1> accessed 15 June 2024.
96 Daniela Morales Soler, 'Proyecto de ley de hidrógeno tendrá nueva estrategia tras ser archivado en el Senado' (Portafolio.co, 13 June 2024) <www.portafolio.co/energia/proyecto-de-ley-de-hidrogeno-tendra-nueva-estrategia-tras-ser-archivado-en-senado-606707> accessed 15 June 2024.

As evidenced by the preceding analysis, Colombia's hydrogen governance is undergoing a period of important evolution, in many respects reflecting the process also underway in Chile. Colombia's path through this regulatory transformation thus far shows its commitment to seeing its policy ambitions through, as well as the challenges along the route towards maturation. While recent developments serve as crucial legal implementations of the country's Roadmap, the regulatory environment remains underdeveloped, with key areas still awaiting further definition and operationalization. Like Chile, continued efforts in addressing these gaps will be essential in establishing a robust hydrogen ecosystem in Colombia.

4.3.3 *Brazil*

Brazil's hydrogen regulatory framework, in a more nascent stage compared to Chile and Colombia, is marked by a dynamic parliamentary scene teeming with activity. As acknowledged by the Brazilian Energy Research Company (EPE), the country lacks adequate institutional and regulatory governance to support the deployment of hydrogen's diverse applications and usage scenarios.[97] This situation presents challenges in addressing concerns such as hydrogen's oversight, definitions and classifications, safety and technical standards, and certification processes.[98]

In this regard, under Brazilian law, hydrogen retains its traditional classification as a hazardous good, which encompasses both flammable gases and liquids.[99] This subjects hydrogen's handling to, inter alia, the Brazilian Norm NBR 14725:2023 and the resolutions issued by the National Land Transport Agency (ANTT).[100] Specifically, NBR 14725:2023 outlines hydrogen's labelling requirements in line with the Globally Harmonized System of Classification and Labelling of Chemicals (GHS),[101] while ANTT Resolution 5998/2022 sets forth requirements for the identification, packaging, marking and documentation for the transport of hydrogen.[102] While these regulations provide a safety baseline consistent with its current uses, they fail to address the specialized needs of hydrogen's new applications across its value chain, mirroring the challenges that Chile and Colombia also face.

In view of these shortcomings, Brazil has outlined a broad regulatory agenda within its Three-Year Plan.[103] This agenda, as shown in Table 4.3, spans a wide spectrum of measures, ranging

97 EPE Bases 22. See also Sabrina Macedo and Drielli Peyerl, 'Hydrogen: A Brazilian Outlook', Energy Transition in Brazil (Springer Nature Switzerland, 2023) 166 <http://dx.doi.org/10.1007/978-3-031-21033-4_10> accessed 15 June 2024.

98 Ibid.

99 Associação Brasileira de Normas Técnicas, NBR 14725:2023 'Produtos químicos – Informações sobre segurança, saúde e meio ambiente – Aspectos gerais do Sistema Globalmente Harmonizado (GHS), classificação, FDS e rotulagem de produtos químicos' (Brazil) (hereinafter NBR 14725:2023). See also Resolução No. 5.998, de 3 de novembro de 2022, 3 November 2022 <https://anttlegis.antt.gov.br/action/ActionDatalegis.php?acao = detalharAto&tipo = RES&numeroAto = 00005998&seqAto = 000&valorAno = 2022&orgao = DG/ANTT/MI&codTipo = &desItem = &desItemFim = &cod_menu = 5408&cod_modulo = 161&pesquisa = true> accessed 15 June 2024 (hereinafter: Resolution 5.998).

100 NBR 14725:2023; Lei No. 10.233 de 05/06/2001, Lei No. 10233, 5 June 2001, Diário Oficial da União, 6 June 2001 (Brazil) <https://legis.senado.leg.br/norma/552109> accessed 15 June 2024.

101 NBR 14725:2023. See also UL Solutions, 'Brazil Implements Revision 7 of GHS' (UL Solutions, 6 July 2023) <www.ul.com/news/brazil-implements-revision-7-ghs> accessed 16 June 2024.

102 See generally Resolution 5.998. See also Resolução No. 6.016, de 11 de maio de 2023, 3 May 2022 <https://anttlegis.antt.gov.br/action/ActionDatalegis.php?acao = detalharAto&tipo = RES&numeroAto = 00006016&seqAto = 000&valorAno = 2023&orgao = DG/ANTT/MT&codTipo = &desItem = &desItemFim = &cod_menu = 5408&cod_modulo = 161&pesquisa = true> accessed 15 June 2024.

103 Brazil's Work Plan 64–68.

TABLE 4.3 *Brazil's hydrogen regulatory agenda*

Goal	Regulatory action
Improve the institutional, legal and infra-legal frameworks	Draft regulation establishing the definition of low-carbon hydrogen Propose text amending Law 9.478/1997 in order to provide for activities related to low-carbon hydrogen and confer relevant competences on the National Agency of Petroleum, Natural Gas and Biofuels of Brazil (ANP) Draft report mapping the regulations that establish existing competences and gaps
Develop the codes, norms, standards and certifications in line with the timetable and development of international rules	Propose certification governance model Propose product coverage and scope Analyse and interact with international organizations for certification systems
Create carbon-intensity certification mechanisms for hydrogen and ethanol chains derivatives	Propose a certification standard for the carbon-intensity bands of the hydrogen and derivatives produced in Brazil
Foster interrelationships between sectors, and bolster harmonization and cooperation between government agencies	List governance instruments for interrelations between sectors, harmonization and cooperation to be improved or drawn up Propose new governance instruments and/or revise existing governance instruments between government agencies Study the possibility of blending hydrogen into the existing natural gas network
Enact additional safety standards	List additional safety standards or revisions to standards Propose new additional safety standards or revisions to standards
Develop regulations, codes, norms and standards for new hydrogen uses and technologies	Draft National Electricity Agency (ANEEL) normative resolution(s) for the insertion of storage systems in the grid, including via hydrogen Develop ANP technical note on international specifications for hydrogen as a transport fuel List regulations, codes, norms, standards for new uses and technologies Propose regulation, codes, norms, standards for new uses and technologies

Source: Author's own work based on Brazil's Work Plan.

from defining low-carbon hydrogen and assigning oversight to establishing adequate safety and technical norms for its novel applications.

In line with this plan, several concrete actions are already underway, such as studies on low-carbon hydrogen certification schemes.[104] In parallel, as mentioned, Brazilian lawmakers are currently drafting and deliberating upon various hydrogen bills aimed at legally enabling its policy ambitions. Amongst these, three proposals have garnered particular attention.

[104] Ibid. 30.

Bill 2308/2023, originating from Brazil's Chamber of Deputies, sets out to establish the legal framework for hydrogen in the country.[105] In line with Brazil's Work Plan, it focuses primarily on 'low-carbon hydrogen'.[106] Unlike the Plan, however, it defines it using a fixed emissions intensity threshold – four kilograms of carbon dioxide equivalent (CO_2e) per kilogram of hydrogen produced.[107] This numerical approach, while improving legal certainty in the short term, raises concerns about its adaptability to evolving market dynamics and technological advancements.[108] In fact, in line with the latest EU-delegated acts, the emissions threshold for hydrogen to be considered low-carbon is 3.38 kilograms of CO_2e per kilogram of hydrogen.[109] To this extent, Brazil's potential adoption of a higher threshold could impact its alignment with international standards, particularly as the EU moves towards more stringent GHG emission benchmarks.[110] The bill also refers to 'renewable hydrogen', a terminology not present in Brazil's Plan, defining it as hydrogen produced from listed renewable sources.[111] Also deviating from the Plan, the bill's latest amendment added the definition of 'green hydrogen', which covers hydrogen produced by electrolysis of water, from wind and solar energy sources.[112] Beyond definitions, the bill also includes risk management guidelines and seeks to establish a hydrogen certification system, amongst other aspects.[113] Regarding competences, it grants the ANP the authority to oversee hydrogen production activities.[114]

Bill 5816/2023, which comes from Brazil's Senate, likewise aims to lay certain regulatory foundations for hydrogen's development in the country.[115] To this extent, it also includes several important definitions, in particular those for 'low-carbon hydrogen' and, intriguingly, 'green hydrogen'.[116] In line with its counterpart from the Chamber of Deputies, it defines 'low-carbon hydrogen' using the same fixed carbon emission threshold, with the ensuing issues mentioned above.[117] 'Green hydrogen', on the other hand, is defined as hydrogen produced exclusively from listed renewable energy sources, and serves as this bill's equivalent to 'renewable

105 Câmara dos Deputados, Projeto de Lei No. 2308, de 2023 (Brazil) <https://legis.senado.leg.br/sdleg-getter/documento?dm=9518494&ts=1718339679320&disposition=inline> accessed 15 June 2024 (hereinafter: PL 2308/2023).

106 Ibid. art. 1.

107 Ibid. art. 4.XII. See Brazil's Work Plan 19.

108 EPBR, 'O que dizem os Projetos de Lei sobre Hidrogênio de Baixo Carbono?' (Agência epbr, 24 November 2023) <https://epbr.com.br/o-que-dizem-os-projetos-de-lei-sobre-hidrogenio-de-baixo-carbono/> accessed 15 June 2024.

109 Gregor Erbach and Sara Svensson, 'EU rules for Renewable Hydrogen: Delegated Regulations on a Methodology for Renewable Fuels of Non-biological Origin' 6 (European Parliamentary Research Service, April 2023) <www.europarl.europa.eu/RegData/etudes/BRIE/2023/747085/EPRS_BRI(2023)747085_EN.pdf> accessed 15 June 2024. See also Thomas Boigontier et al., 'Low-Carbon Hydrogen Production in the EU: Are 2030 Targets Achievable?' 3 (2023) <https://hal.science/hal-04158824> accessed 15 June 2024.

110 Rosa Oyarzabal et al., 'New Definitions for Blue and Green Hydrogen: The European Commission's Package on Hydrogen and Decarbonized Gas Markets' (Inside Energy & Environment, 7 January 2022) <www.?insideenergyandenvironment?.com/2022/01/new-definitions-for-blue-and-green-hydrogen-the-european-commissions-package-on-hydrogen-and-decarbonized-gas-markets> accessed 15 June 2024.

111 PL 2308/2023 art. 4.XIII.

112 Senado Federal (Brazil), Parecer (SF) No. 1, de 2024, 12 June 2024, amendment 17 modifying art. 4.XIV <https://legis.senado.leg.br/sdleg-getter/documento?dm=9634429&ts=1718339679869&rendition_principal=S&disposition=inline> accessed 15 June 2024.

113 PL 2308/2023 arts. 10, 15.

114 Ibid. art. 11 § 1º.

115 Senado Federal (Brazil), Atividade Legislativa PL 5816/2023 <www25.senado.leg.br/web/atividade/materias/-/materia/161378#tramitacao_10637832> accessed 15 June 2024.

116 Senado Federal (Brazil), Projeto de Lei No. 5816, de 2023 art. 4 <https://legis.senado.leg.br/sdleg-getter/documento?dm=9537460&ts=1704277318573&disposition=inline> accessed 15 June 2024 (hereinafter: PL 5816/2023).

117 Ibid. art. 4.I.

hydrogen'.[118] By adopting this colour taxonomy, however, this bill deviates from the Work Plan's recommendations regarding hydrogen classifications as well.[119] Besides these definitional aspects, and similar to the previous proposal, Bill 5816/2023 also contains risk management guidelines and enables the creation of a hydrogen certification system, along with other measures.[120] As it relates to oversight, it bifurcates competences, assigning regulatory authority over hydrogen production to either the National Electricity Agency (ANEEL) or the ANP depending on the technological pathways.[121]

The third bill, the legislative initiative of the Brazilian Federal Government, also seeks to lay the groundwork for its hydrogen plans.[122] This bill exclusively addresses 'low-carbon emission hydrogen', with its definition adopting practically the same language as Brazil's Work Plan.[123] Namely, it defines it as hydrogen produced via technologies and energy sources with low lifecycle GHG emissions or utilizing carbon removal technologies – thus encompassing 'renewable', 'green' and 'blue' hydrogen.[124] While this approach circumvents the potential limitations of a fixed emission threshold, the bill does not otherwise define what constitutes 'low lifecycle emissions', requiring eventual clarification. Definitions aside, the bill also seeks to establish a hydrogen certification framework, with much of its text dedicated to this purpose.[125] Unlike the previous bills, however, it does not contain safety or risk management guidelines, nor does it assign regulatory competences over hydrogen production activities, except as it relates to naturally occurring hydrogen.[126]

In terms of legislative progression, Bill 2308/2023 represents the most advanced of the three. At the time of writing, the bill cleared the Chamber of Deputies, and is being analysed in the Senate.[127] Bill 5816/2023 has also made headway, securing approval from the relevant Senate commission and being consequently sent to the Chamber of Deputies for deliberation.[128] Trailing these proposals, the Federal Government's bill was presented to the Sustainable Economic and Social Council for further consideration.[129] As of the time of writing, it has yet to be formally submitted to the Brazilian Congress.

118 Ibid. art. 4.II.
119 Brazil's Work Plan 17.
120 PL 5816/2023 arts 6–8.
121 In particular, it authorizes the National Petroleum Agency (ANP) to govern the production of low-carbon hydrogen, and the National Electric Energy Agency (ANEEL) for electrolysis-based hydrogen production, PL 5816/2023 art. 9.
122 Comitê Gestor do Programa Nacional do Hidrogênio (Brazil), Projeto de Lei do Hidrogênio art. 1 <https://gov.br/mme/pt-br/assuntos/noticias/mme-apresenta-proposta-de-projeto-de-lei-do-hidrogenio-ao-2018conselhao2019/20231030.Minuta_PLHidrognio_MMECogesPNH2.pdf> accessed 15 June 2024.
123 Ibid. art. 5.X.
124 Ibid.
125 Ibid. arts 6–17.
126 Ibid. art. 19.
127 Senado Federal (Brazil), Atividade Legislativa Projeto de Lei no. 2308, de 2023 <www25.senado.leg.br/web/atividade/materias/-/materia/161391> accessed 15 June 2024. See also Agência Senado, 'Marco legal para a produção do hidrogênio verde vai a Plenário' (Agência Senado, 12 June 2024) <www12.senado.leg.br/noticias/materias/2024/06/12/marco-legal-para-a-producao-do-hidrogenio-verde-vai-a-plenario> accessed 15 June 2024; 'Câmara aprova marco legal para produção de hidrogênio verde, o combustível do futuro' (Portal da Câmara dos Deputados, 29 November 2023) <www.camara.leg.br/radio/programas/1021143-camara-aprova-marco-legal-para-producao-de-hidrogenio-verde-o-combustivel-do-futuro/> accessed 15 June 2024.
128 Câmara dos Deputados (Brazil), Atividade Legislativa PL 5816/2023 <www.camara.leg.br/proposicoesWeb/fichadetramitacao?idProposicao=2416789> accessed 15 June 2024. See also Agência Senado, 'Comissão do Hidrogênio Verde aprova marco legal; texto segue para a Câmara' (Agência Senado, 14 December 2023) <www12.senado.leg.br/noticias/materias/2023/12/14/comissao-do-hidrogenio-verde-aprova-marco-legal-texto-segue-para-a-camara> accessed 15 June 2024.
129 Agência Gov, 'MME apresenta proposta de Projeto de Lei do Hidrogênio ao "Conselhão"' (Agência Gov, 7 November 2023) <https://agenciagov.ebc.com.br/noticias/202311/mme-apresenta-proposta-de-projeto-de-lei-do-hidrogenio-ao-2018conselhao2019> accessed 15 June 2024.

As we can see, while Brazil lacks hydrogen regulations formally in force, it exhibits a flurry of legislative activity across chambers and ministries seeking to enable the industry's ascent. Still, it simultaneously reveals a universe of conflicting definitions, competences and paths towards certification systems, evidencing the complexity and diversity of views in the country. These varied proposals, each with its unique focus and regulatory approach, emphasize the dynamic and fragmented nature of Brazil's pursuit of a hydrogen economy. Until the fog of competing visions clears, the precise contours of Brazil's soon-to-be hydrogen legal framework will remain uncertain.

Overall, the regulatory environment for hydrogen in Chile, Colombia and Brazil reveals an evolving terrain. Each country, dealing with its unique complexities, has set out on a path to establish frameworks conducive to clean hydrogen development. While appreciable progress has been made, significant work remains ahead to truly match policy ambitions. Even so, as the following section will discuss, these regulatory imperfections have not stopped the number of clean hydrogen projects in Chile, Colombia and Brazil from growing considerably.

4.4 FROM REGULATION TO PRODUCTION: ON-THE-GROUND DEPLOYMENT UNDER EXISTING GOVERNANCE

Despite this evolving character of the hydrogen regulatory frameworks in Chile, Colombia and Brazil, the pace of on-the-ground project development is continuing. Developers are forging ahead, undeterred by the gaps and inadequacies in existing governance.[130] This section briefly explores these tangible developments, highlighting how, even amid a backdrop of regulatory uncertainty, the industry is making strides in turning policy visions into concrete projects.

This apparent paradox between incomplete regulation and robust project activity stems, at least in part, from these countries' constitutional provisions enshrining a principle of freedom of enterprise. Namely, in Chile, Colombia and Brazil, business activity can proceed freely absent explicit prohibition, thus requiring no prior authorizations or permits except as provided by law.[131] In this context, hydrogen-related activities across the value chain are, by default, free to be pursued and developed, provided they adhere to any applicable rules. This backdrop of flexibility has provided latitude for the hydrogen industry to advance even under transitional governance.

In this scenario, absent specific legal provisions, hydrogen ventures remain subject to the same permitting obligations and licensing protocols imposed universally across infrastructure projects. Thus, hydrogen undertakings, akin to hazardous chemical production plants in many respects,[132] require an array of permits to break ground and eventually become operational. This process typically entails adherence to a diverse range of mandates, including but not limited to

130 Julián González Martínez and Fernando Cubillos, 'Green Hydrogen Is Picking Up Speed in Latin America and the Caribbean' (IDB Invest, 22 November 2022) <www.idbinvest.org/en/blog/energy/green-hydrogen-picking-speed-latin-america-and-caribbean> accessed 15 June 2024.

131 Fija el Texto Refundido, Coordinado y Sistematizado de la constitucion politica de la Republica de Chile, Decreto No. 100, 17 September 2005, Diario Oficial, 22 September 2005 (Chile) art. 19.21 <www.leychile.cl/Navegar?idNorma=242302> accessed 15 June 2024; Constitución Política de Colombia 1991, 6 July 1991 (Colombia) art. 333 <https://dapre.presidencia.gov.co/normativa/normativa/Constitucion-Politica-Colombia-1991.pdf> accessed 15 June 2024; Constituição de 1988, Constituição, 5 October 1988 (Brazil) art. 170 <www.lexml.gov.br/urn/urn:lex:br:federal:constituicao:1988-10-05;1988> accessed 15 June 2024.

132 GIZ et al., 'Identificación de aspectos ambientales, sectoriales y territoriales para el desarrollo de proyectos de hidrógeno verde en toda su cadena de valor' 36 (2020) <https://4echile.cl/wp-content/uploads/2021/09/Aspectos-ambientales-H2.pdf> accessed 15 June 2024.

site planning, construction compliance, environmental impact assessments, water resource management, waste disposal protocols and observance of health and safety guidelines.[133]

Pragmatically leveraging the existing frameworks, over 100 hydrogen projects across different phases have been logged across these countries as of late 2023, spanning from initial feasibility studies to fully operational plants.[134] More than half of these are in Chile, with at least three projects under construction and six already operational.[135] Amongst these, the Cerro Pabellón microgrid pilot project, operational since 2019, has been utilizing solar energy to generate 10 tonnes of green hydrogen per year.[136] Of larger scale, the Haru Oni demonstration plant is capable of producing 130,000 litres of e-fuels per year, making it the first operating e-fuels facility in the world.[137]

Colombia's hydrogen sector includes twenty-seven projects across various stages, with three in construction and four operational.[138] Notably, in early 2022, the Ecopetrol Group launched a three-month pilot project with the aim of producing 20 kg daily of high-purity green hydrogen for refinery usage. While small-scale, the pilot's objective was to assess the technical and environmental feasibility and performance of green hydrogen generation at the Cartagena Refinery.[139] Capitalizing on this experience, Ecopetrol is set to start the construction of two green hydrogen 'megaprojects' in 2024, expected to be amongst the largest in Latin America.[140]

Following closely behind, Brazil accounts for the remaining twenty-four projects, with two operational and a third under construction. In particular, White Martins has launched a green hydrogen production project with a yearly output of 156 tonnes destined for the local market.[141] Importantly, this project has been certified by TÜV Rheinland, making it the first plant in Latin America certified to produce green hydrogen.[142] The second operational undertaking is EDP Brazil's pilot project, part of a larger R&D initiative, which can produce 250 normal cubic metres of hydrogen gas per hour – operational hours determining annualized output.[143]

133 Ibid.

134 Although the number of projects varies by source and criteria, this chapter relies on the IEA's Hydrogen Production and Infrastructure Projects Database, last updated October 2023, available at IEA, 'Hydrogen Production and Infrastructure Projects Database' (2023) <www.iea.org/data-and-statistics/data-product/hydrogen-production-and-infrastructure-projects-database> accessed 15 June 2024 (hereinafter: IEA Project Database).

135 Ibid.

136 Hydrogen in Latin America 29.

137 HIF, 'HIF Haru Oni Demonstration Plant' (HIF Global) <https://hifglobal.com/haru-oni> accessed 15 June 2024.

138 IEA Project Database.

139 Ecopetrol, 'El Grupo Ecopetrol inició la producción de hidrógeno verde en Colombia' (Ecopetrol, 18 March 2022) <www.ecopetrol.com.co/wps/portal/Home/es/noticias/detalle/Noticias+2021/el-grupo-ecopetrol-inicip-la-produccion-de-hidrogeno-verde-en-colombia> accessed 15 June 2024.

140 Lina Quiroga Rubio, 'En 2024, Ecopetrol comenzará construcción de 2 megaproyectos de hidrógeno verde' (El Tiempo, 21 April 2023) <www.eltiempo.com/economia/empresas/ecopetrol-comenzara-construccion-de-2-megaproyectos-de-hidrogeno-verde-761523> accessed 15 June 2024.

141 White Martins, 'White Martins produz o primeiro hidrogênio verde certificado do Brasil' (White Martins, 8 December 2022) <www.whitemartins.com.br/news/2022/white-martins-produz-o-primeiro-hidrogênio-verde-certificado-do-brasil> accessed 15 June 2024.

142 FuelCellsWorks, 'TÜV Rheinland Issues First Green Hydrogen Certificate in Brazil for White Martins, Linde's Subsidiary' (FuelCellsWorks, 21 December 2022) <https://fuelcellsworks.com/news/tuv-rheinland-issues-first-green-hydrogen-certificate-in-brazil-for-white-martins-lindes-subsidiary> accessed 15 June 2024; White Martins, 'Brasil produz primeiro hidrogênio verde da América do Sul com certificação internacional' (Valor Econômico, 21 December 2022) <https://valor.globo.com/conteudo-de-marca/white-martins/noticia/2022/12/21/brasil-produz-primeiro-hidrogenio-verde-da-america-do-sul-com-certificacao-internacional.ghtml> accessed 15 June 2024.

143 Robson Rodrigues, 'EDP inaugura primeiro projeto-piloto de hidrogênio verde do Brasil, no CE' (Um só Planeta, 22 January 2023) <https://umsoplaneta.globo.com/energia/noticia/2023/01/22/edp-inaugura-primeiro-projeto-piloto-de-hidrogenio-verde-do-brasil-no-ce.ghtml> accessed 15 June 2024.

This overview reveals a significant trend: although the regulatory structures may still be in a state of flux, they have not impeded the practical progression of hydrogen pilot projects. Still, reliance on (permitting) frameworks not specifically designed with the particularities of hydrogen projects in mind poses risks and increases stakeholder uncertainty. The varied nature of hydrogen undertakings, shaped by diverse technologies and processes, stresses the need for a tailored regulatory approach. This requires not only the adoption of hydrogen-specific regulations, as previously discussed, but also a thorough review and amendment of existing permitting structures in line with the characteristics of hydrogen projects. Recognizing this imperative, the strategies of Chile, Colombia and Brazil all include actions towards adapting their permitting procedures.[144] As the industry shifts from scattered pilots to widespread commercialization, these countries' continued regulatory efforts remain integral to realizing hydrogen's potential across the region.

4.5 CONCLUSION

The hydrogen landscape in Latin America, as exemplified by the endeavours of Chile, Colombia and Brazil, is marked by promise and challenge. Driven both by growing global demand and the motivation to decarbonize their economies, their initiatives represent a regional shift towards embracing clean hydrogen. These resource-rich countries have quickly progressed from articulating ambitious strategies to dealing with the complexities of designing enabling regulatory frameworks. While distinct in approach and execution, their policies converge on a common goal: to position themselves as major players in the impending hydrogen economy.

However, as their experiences reveal, the path from promise to production is fraught with challenges. Indeed, creating a regulatory environment that accommodates hydrogen's multidimensional nature is proving to be a demanding task, with governance structures struggling to match the pace of technological developments and market demands. Yet, despite these regulatory uncertainties, interest in clean hydrogen projects continues to grow, with pilot ventures forging ahead undeterred.

As Latin America looks to the future, the hydrogen promise appears compelling, even if exacting. The experiences and lessons emerging from Chile, Colombia and Brazil offer valuable insights for other countries, highlighting the critical role of coherent policy and regulatory frameworks in the transition towards a hydrogen future. While the full realization of Latin America's hydrogen potential remains to be seen, the current momentum offers reasons for optimism.

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144 Chile's Action Plan 112–121; Colombia's Roadmap 35, 43, 48; Brazil's Work Plan 27.

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5

Hydrogen Regulation in Oceania

Enabling Renewable Hydrogen Licensing on Complex Land Uses

Madeline Taylor

5.1 INTRODUCTION

Hydrogen and its derivates are widely touted as an essential component in the quest for global decarbonisation. Hydrogen is a versatile and dynamic energy carrier that can be harnessed as an alternative feedstock in industrial processes, transportation, and storage, and may be blended with natural gas as an alternative to fossil fuels, amongst other potential applications.[1] More than forty countries have released hydrogen strategies, and the International Energy Agency (IEA) has predicted the low-emissions hydrogen sector value may increase from $1.4 billion in 2023 to $12 billion by 2030.[2] To reach these projections, it is widely recognised that 'the emergence of a clean hydrogen economy depends on regulation'.[3] Planning and licensing hydrogen with concurrent land uses is a piece of the hydrogen regulatory rubric. Licensing and permitting procedures to assess and manage hydrogen land uses must be efficient, transparent, and coordinated to minimise planning assessment lead times and ensure sustainable siting of hydrogen coexisting with other land uses.[4]

The Oceania region is increasingly targeting the production and export of renewable hydrogen, also referred to as 'green hydrogen', which is typically produced by separating hydrogen from oxygen via electrolysis of water to harness renewable energy.[5] Other than water

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[1] IRENA, 'International Trade and Green Hydrogen: Supporting the Global Transition to a Low-Carbon Economy' (2023) <https://irena.org/Publications/2023/Dec/International-trade-and-green-hydrogen-Supporting-the-global-transition-to-a-low-carbon-economy> accessed 10 December 2023.

[2] International Energy Agency, 'Global Hydrogen Review 2023' (2023) <https://iea.blob.core.windows.net/assets/ecdfc3bb-d212-4a4c-9ff7-6ce5b1e19cef/GlobalHydrogenReview2023.pdf> accessed 10 October 2023.

[3] Sonja van Renssen, 'The hydrogen solution?' (2020) 10 Nature Climate Change 799. See also Gerry Nagtzaam and Steve Kourabas, 'Hydrogen Regulation' in Gerry Nagtzaam, Katie O'Bryan, and Mark Beaufoy (eds), *Legal Pathways to Deep Decarbonisation in Australia* (Lexis Nexis 2023) 227–253.

[4] International Energy Agency, 'Global Hydrogen Review 2023' (2023) <https://iea.blob.core.windows.net/assets/ecdfc3bb-d212–4a4c-9ff7–6ce5b1e19cef/GlobalHydrogenReview2023.pdf> accessed 10 October 2023.

[5] Other emerging methods to create renewable hydrogen include concentrated solar, direct solar desalination, or photocatalytic methods. However, this chapter will focus on electrolysis as the most mature technology in renewable (or green) hydrogen production. Electrolysis requires water which is split into hydrogen (H_2) and oxygen (O_2) within an electrolyser. See Ruven Fleming, 'The Hydrogen Revolution and Natural Gas: A New Dawn in the European

requirements for electrolysis, considerable amounts of land are also critical for large-scale renewable hydrogen production. Land access and use are required to host the suite of renewable hydrogen infrastructure supporting its generation and further infrastructure to enable export. For example, the co-location of wind and solar farms to efficiently produce renewable hydrogen requires an estimated land area of about 168,000 square kilometres (km^2). This positions countries with large amounts of cleared land situated in proximity to existing energy infrastructure and ports, like Australia, at an advantage. Up to 11 per cent of Australia (872,000 km^2) has been estimated as highly suitable for renewable hydrogen production.[6]

Countries with existing high penetration of renewable energy into their electricity generation mix, coupled with ample water reservoirs without the necessity for desalination,[7] may also enjoy advantages in establishing a renewable hydrogen sector. In New Zealand, renewables provide 82 per cent of electricity generation, primarily comprising its significant hydropower capacity representing 55.6 per cent,[8] coupled with accessible fresh water basins, and between 600 and 10,000 mm of rainfall per annum across the country.[9]

Renewable hydrogen development consequently requires strategic planning due to the land use footprints of projects, requiring renewable energy generation, electrolyser siting, and export and transportation infrastructure. Without a clear regulatory approach for renewable hydrogen siting, licensing, and development assessment, communities may contest renewable hydrogen projects based on conflicting land uses and the preservation of existing land rights.

This chapter examines renewable hydrogen policies and regulatory trends in Oceania. Specifically, it analyses the regulatory approach taken by two of the most proactive Australian states with renewable hydrogen ambitions, Western Australia and South Australia, and their recent regulatory reforms for renewable hydrogen licensing on pastoral land. In so doing, it surveys the emerging challenges and opportunities for renewable hydrogen siting by exposing crucial legal processes to avoid land use conflict for the renewable hydrogen sector.

The chapter is structured as follows. Firstly, it first explores the different national hydrogen strategies in Australia and New Zealand (Section 5.2). Secondly, it analyses and compares the new regulatory amendments and new hydrogen licensing regulation on pastoral land uses in Western Australia and South Australia (Section 5.3). Finally, it concludes by charting the

Union?' in Damilola Olawuyi and Eduardo Pereira (eds) *The Palgrave Handbook of Natural Gas and Global Energy Transitions* (Palgrave Macmillan 2022); Ruven Fleming 'Clean or renewable – Hydrogen and power-to-gas in EU energy law' (2021) 39(1) Journal of Energy and Natural Resources Law 43; Ruven Fleming and Gijs Kreeft, 'Power-to-Gas and Hydrogen for Energy Storage under EU Energy Law' in Martha Roggenkamp and Catherine Banet (eds) *European Energy Law Report XIII* (Intersentia Cambridge 2020) 101–125.

6 COAG Energy Council, 'Australia's National Hydrogen Strategy' (2019) <https://dcceew.gov.au/sites/default/files/documents/australias-national-hydrogen-strategy.pdf> accessed 20 October 2022. See also Paul J. Burke, Fiona J. Beck, Emma Aisbett, Kenneth G. H. Baldwin, Matthew Stocks, John Pye, Mahesh Venkataraman, Janet Hunt, and Xuemei Bai. 'Contributing to regional decarbonization: Australia's potential to supply zero-carbon commodities to the Asia-Pacific' (2022) 278 Energy 123563 (hereinafter: COAG Energy Council, 'Australia's National Hydrogen Strategy').

7 For example, Australia's 2019 National Hydrogen Strategy highlights the need for water desalination to support renewable hydrogen as Australia is one of the driest continents in the world. Australian Government, 'Australia's National Hydrogen Strategy' (2019) <www.dcceew.gov.au/sites/default/files/documents/australias-national-hydrogen-strategy.pdf> accessed 10 September 2023. See also Tina Soliman Hunter, Kerryn Brent, Alex Wawryk, Jordie Pettit, and Nate Camatta, 'Hydrogen production in Australia from renewable energy: No doubt green and clean, but is it mean?' (2023) 41 Journal of Energy and Natural Resources Law 1.

8 Castalia, 'New Zealand Hydrogen Scenarios Report' (2022) <https://mbie.govt.nz/dmsdocument/20118-new-zealand-hydrogen-scenarios-pdf> accessed 10 October 2023 (hereinafter: Castalia, 'New Zealand Hydrogen Scenarios Report').

9 World Bank, 'New Zealand Climatology' (2023) <https://?climateknowledgeportal?.worldbank.org/country/new-zealand/climate-data-historical> accessed 10 December 2023.

challenges for the development of renewable hydrogen regulation to realise hydrogen licensing coexistence with pastoral land uses in both Australia and New Zealand (Section 5.4).

5.2 THE OCEANIA REGION AS A POTENTIAL HYDROGEN POWERHOUSE

New Zealand and Australia aim to become the leading hydrogen production powerhouses of the Oceania region. Existing renewable hydrogen strategies in both New Zealand and Australia rest on their innate advantages – increasing renewable energy[10] penetration and proximity to Asian energy markets.[11] Both countries hold federal Commonwealth systems of government regulating overarching hydrogen strategies with subnational states, territories, or provinces regulating planning and land use.[12] Hence, consideration of existing federal strategies for the production and potential export of hydrogen is examined in Sections 5.2.1 and 5.2.2 below before an analysis of hydrogen licensing and land use systems at the state level.

5.2.1 *New Zealand's Hydrogen Roadmap*

Renewable hydrogen will play a crucial role in shaping New Zealand's energy landscape as the nation works towards achieving its legislated target of net zero greenhouse gas (GHG) emissions (excluding biogenic methane)[13] by 2050.[14] More than twenty hydrogen projects stretching from Marsden Point in the North Island to Invercargill in the South Island are in development or being considered in New Zealand's early-stage hydrogen ecosystem.[15] However, New Zealand does not hold a finalised national hydrogen strategy, with its first Hydrogen Roadmap due for release in late 2024.

The lag in creating a national hydrogen policy in New Zealand is due to several factors, including the low projections of hydrogen reaching just 8 per cent of total energy demand domestically.[16] Such low projections are in stark contrast to Australian demand projections for hydrogen, which may represent 20 per cent of total energy demand in 2050.[17] The low demand estimate and delayed delivery of a national hydrogen in New Zealand has created a regulatory

[10] Alberto Boretti, 'Green hydrogen to address seasonal variability of wind and solar energy production in Australia' (2023) 53 International Journal of Hydrogen Energy <https://sciencedirect.com/science/article/pii/S0360319923046918> accessed 10 December 2023; Alberto Boretti, 'The progress toward net-zero passes through hydrogen also in New Zealand' (2023) 53 International Journal of Hydrogen Energy <https://sciencedirect.com/science/article/pii/S036031992303820X?casa_token=_Qb10BYiEuUAAAAA:KsEFctQOosi_QbGKTAzC86lB9C6DM2TJG4pf6DjmU8F5G9rI4m4hB3iHg0wxTn4N-wfHf7C-bgs> accessed 12 December 2023.

[11] Kim Beasy, 'Hydrogen economies and energy futures: A new Australian dream?' (2022) 91 Energy Research and Social Science 102751; Kim Beasy, Oluwadunsin Ajulo, Sherridan Emery, Stefan Lodewyckx, Charmaine Lloyd, and Amirul Islam, 'Advancing a hydrogen economy in Australia: Public perceptions and aspirations' (2023) 53 International Journal of Hydrogen Energy <https://sciencedirect.com/science/article/pii/S0360319923059104> accessed 30 November 2023.

[12] Constitution Act 1986 (NZ); Commonwealth of Australia Constitution Act (The Constitution) 1977 (Aus).

[13] New Zealand's domestic emissions reduction target for biogenic methane is to 24–47 per cent below 2017 levels by 2050, including to 10 per cent below 2017 levels by 2030. Ministry for the Environment (NZ), 'Greenhouse Gas Emissions Targets and Reporting (2023) <https://environment.govt.nz/what-government-is-doing/areas-of-work/climate-change/emissions-reduction-targets/greenhouse-gas-emissions-targets-and-reporting/> accessed 3 December 2023.

[14] Climate Change Response (Zero Carbon) Amendment Act 2019 (NZ).

[15] New Zealand Government, 'Hydrogen in New Zealand' (2023) <https://mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-strategies-for-new-zealand/hydrogen-in-new-zealand/> accessed 12 November 2023.

[16] Ibid.

[17] Castalia, 'New Zealand Hydrogen Scenarios Report' 21.

and policy environment 'at least three years behind Australia',[18] particularly in terms of secured capital investment and hydrogen standards adoptions. To date, New Zealand's developing hydrogen policy position has focused on hydrogen applications to decarbonise industrial processes, evident in an over NZ$ 30 million budgetary commitment to accelerate the adoption of renewable hydrogen to decarbonise energy in hard-to-abate sectors, particularly ammonia manufacturing.[19]

The first national response to hydrogen in New Zealand was the 2019 Vision for Hydrogen in New Zealand ('2019 Hydrogen Vision').[20] The 2019 Hydrogen Vision targeted New Zealand's 84 per cent renewable electricity penetration,[21] representing the fourth highest in the Organisation for Economic Development and Co-operation (OECD), with a goal to transition to 90 per cent renewable energy by 2025 and 100 per cent by 2030.[22] However, as a consultation Green Paper rather than a finalised national policy, the 2019 Hydrogen Vision produced feedback to inform the creation of a national hydrogen strategy.

Following the 2019 Hydrogen Vision, the Interim Hydrogen Roadmap was released in 2023 to provide another stocktake of policy options and invite another round of consultation to support renewable hydrogen development in New Zealand.[23] Similarly to the 2019 Hydrogen Vision, the Interim Hydrogen Roadmap is seeking feedback on the overarching potential policy focus to optimise hydrogen to contribute to New Zealand's domestic emissions reduction goals, stimulate economic development, and, interestingly, bolster its energy security and resilience. New Zealand's decision to prohibit new petroleum permits outside Taranaki onshore[24] and become more reliant on petroleum imports has seen energy security become a new potential policy pillar for hydrogen. A focus on hydrogen to create energy security exists in contrast to Australia, where energy security is not evident in hydrogen policymaking to date. In emphasising the importance of domestic use of hydrogen at the household and industrial levels, the Interim Hydrogen Roadmap rules out the case for government incentivisation and support to scale-up a hydrogen export industry.[25] A domestically focused hydrogen roadmap in New Zealand represents another point of comparison to Australia's export-orientated hydrogen policy focus.[26]

Consistent with the previous 2019 Hydrogen Vision, a similar emphasis in the Interim Hydrogen Roadmap is placed on the potential for renewable hydrogen to decarbonise industrial production of fertiliser-based chemicals, particularly as New Zealand is largely dependent on the

[18] Standards New Zealand, 'Hydrogen Standards Review' (2023) 33 <https://standards.govt.nz/assets/documents/news/hydrogen-report-v2.pdf> accessed 10 November 2023.

[19] New Zealand Government, 'Budget 2023, Support for Today Building for Tomorrow' (2023) <www.beehive.govt.nz/feature/budget-2023-support-today-building-tomorrow#:~:text=Budget%202023%20strikes%20a%20careful,a%20more%20sustainable%20fiscal%20position> accessed 10 December 2023 (hereinafter: Standards New Zealand, 'Hydrogen Standards Review').

[20] New Zealand Government, 'A Vision for Hydrogen in New Zealand: Green Paper' (2019) <https://mbie.govt.nz/dmsdocument/6798-a-vision-for-hydrogen-in-new-zealand-green-paper> accessed 10 September 2023 (hereinafter: New Zealand Government, 'A Vision for Hydrogen in New Zealand: Green Paper').

[21] In 2021, the percentage of total renewable energy supply in New Zealand is comprised of 55.6 per cent hydroelectricity; 17.7 per cent geothermal; 7.6 per cent wind; 0.5 per cent solar. Castalia, 'New Zealand Hydrogen Scenarios Report'.

[22] New Zealand Government, 'A Vision for Hydrogen in New Zealand: Green Paper'.

[23] New Zealand Government, 'Hydrogen Interim Roadmap' (2023) <https://mbie.govt.nz/dmsdocument/26911-interim-hydrogen-roadmap-pdf> accessed 20 October 2023 (hereinafter: New Zealand Government, 'Hydrogen Interim Roadmap').

[24] As enacted in the Crown Minerals (Petroleum) Amendment Bill (2018).

[25] Ibid 5.

[26] As discussed below in Section 5.2.2.

importation of urea.[27] For example, the Balance Agri-Nutrients Plant in Kapuni is New Zealand's only ammonia-urea manufacturing facility, producing 730 tonnes of urea per day with an annual natural gas consumption of 7 petajoule (PJ).[28] The Balance Agri-Nutrients Plant is cited as a key project to develop a green hydrogen production facility to enable the production of lower-carbon urea and offset up to 12,000 tonnes of domestic emissions.[29] Agriculture represents 48 per cent of the gross GHG emissions for New Zealand and a legislated price on emission from agricultural activities to meet its Emissions Trading Scheme will likely commence on 1 January 2026.[30] In preparation for an agriculture-sector-specific emissions price and reporting scheme, the opportunity to decarbonise ammonia processing to create 'green ammonia urea'[31] specifically targets hydrogen as an important potential alternative feedstock to natural gas.[32] This policy position fundamentally differs from Australia's approach prioritising hydrogen exports as an initial policy platform with industrial feedstock usage for hydrogen as a secondary policy priority.

To support the development of a national energy strategy, Standards New Zealand completed its review of the current gaps in existing natural gas standards for hydrogen in 2023. The Standards New Zealand review identifies the overlapping regulatory regimes spanning gas safety, electrical safety, land transport, and other hazards and the six existing standards relevant to hydrogen for possible revision.[33] In particular, NZS 5442:2008 – Specification for reticulated natural gas – has not been holistically updated since 2008, with the most recent interim revision to permit blending of biomethane. However, the blending of hydrogen with natural gas is currently not permitted under NZS 5442:2008.[34] The resulting review advocates for a safety-focused guidance handbook and support for coordinated cross-agency action to implement standards amendments as a preliminary step to support a domestic hydrogen sector.[35]

The 2023 New Zealand Hydrogen Regulatory Pathway review similarly analysed forty-four Acts and ninety-three regulations and rules that may be relevant to hydrogen based on safety, use, markets, measurements, infrastructure, and resources to support a hydrogen sector. The Hydrogen Regulatory Pathway review critiques prescriptive rule-based regulatory requirements for gas usage resulting in regulatory gaps or uncertainty over hydrogen transportation. For example, the Hazardous Substances and New Organisms Act (1996) (NZ) prohibits the production of refrigerated liquefied hydrogen and exposes policy opaqueness as to whether hydrogen blends would fall under the Commerce Act (1986) (NZ), which currently does not define or

27 As recognised by Castalia, New Zealand imports 654,000 tonnes of fertiliser per annum primarily from Malaysia and Saudi Arabia. Castalia, 'New Zealand Hydrogen Scenarios Report' 46.

28 Environmental Protection Authority, 'Kapuni Green Hydrogen Project' (2023) <https://epa.govt.nz/fast-track-consenting/referred-projects/kapuni/#:~:text=Electricity%20will%20be%20generated%20by,an%20electrolysis%20plant> accessed 9 December 2023.

29 New Zealand Government, 'Hydrogen Interim Roadmap'.

30 New Zealand Ministry of Environment, 'Deferral of NZ ETS reporting obligations for animals–farmer activities' (2023) <https://environment.govt.nz/assets/publications/climate-change/Deferral-of-NZ-ETS-reporting-obligations-for-animals-farmer-activities-Discussion-document.pdf> 20 August 2023. The NZ ETS backstop will consist of two parts processor-level pricing farm-level pricing for animals – farmer activities.

31 Haris Ishaq, Muhammad Faisal Shehzad, and Curran Crawford, 'Transient modelling of a green ammonia production system to support sustainable development' (2023) 48 International Journal of Hydrogen Energy 39254.

32 Castalia, 'New Zealand Hydrogen Scenarios Report' 19.

33 NZS 5263:2003 Gas detection and odorization; NZS 5266:2014 Safety of gas appliances; NZS 5255:2014 + A1 Safety verification of existing gas installations; NZS 5259: 2015 Gas measurement; NZS 5266:2014 Safety of gas appliances; and NZS 5442:2008 Specification for reticulated natural gas. Twenty shared standards with Australia were also reviewed.

34 Standards New Zealand, 'Hydrogen Standards Review' 30.

35 Ibid.

incorporate the regulation of blended gases. The Hydrogen Regulatory Pathway review recommends similar policy developments completed in the EU, particularly in Germany and the Netherlands, including 'the development of dedicated small–medium scale renewable generation for direct connection to electrolysers to be used as hydrogen "hubs"'.[36]

An additional differing policy juncture between New Zealand and Australia is New Zealand's emphasis on supporting just transition goals for communities hosting hydrogen. Supporting landholders and communities in proximity or hosting hydrogen projects has been emphasised since the 2019 Vision. A focus on creating just outcomes for communities associated with hydrogen production is reiterated in the Interim Hydrogen Roadmap through the establishment of the $100 million ten-year Regional Hydrogen Transition Initiative.[37] The Regional Hydrogen Transition will provide governmental rebates to support first-mover hydrogen projects through long-term contracts between government and commercial hydrogen consumers.

In awarding long-term contracts, the Regional Hydrogen Transition Initiative targets creating a 'Just Transition' for key regions, including Southland, traditionally an oil and gas region, and Taranaki to support the transition of workers within the New Zealand Aluminium Smelter at Tiwai Point. To access the Regional Hydrogen Transition Initiative rebate, proponents must demonstrate how their proposal meets the four elements of the Regional Hydrogen Transition benefit sharing model: (1) selecting a just transitions region; (2) Iwi (meaning cultural, environmental, social, and economic opportunities must be reflected in contractual applications) and the community; (3) renewable energy generation; (4) contribution to the development of the hydrogen economy. Community benefit funds, regional skills and training commitments, and contracting with new renewable energy generation may be conditions to satisfy the four outlined criteria.[38]

Overall, New Zealand's comparatively domestic and justice-focused hydrogen strategy represents an interesting approach to support key hydrogen projects that aim to help build and test early-stage projects while engaging directly with communities. Australia's National Hydrogen Strategy takes a more responsive, interventionist, and export-focused policy and regulatory approach to establishing its hydrogen ambitions, as explored below.

5.2.2 *Australia's National Hydrogen Strategy*

Australia's hydrogen export objectives are evident in its pioneering of the first liquified international trade of hydrogen to Japan in 2022. The Suiso Frontier shipped 75 tonnes of liquified hydrogen to Japan as part of the Hydrogen Energy Supply Chain (HESC) project. The HESC project positions Australia as a key exporter of hydrogen to Japan to 225 kilotonnes (kt) per year in the 2030s.[39] Although the potential for hydrogen exports first became a policy focus for Australia in 2019, developing a hydrogen economy was first highlighted in Australia in 2002 when the Renewable Energy Technology Roadmap labelled renewable hydrogen as having 'huge future potential'.[40] Nearly two decades later, Australia's first National Hydrogen

36 PWC, 'New Zealand Hydrogen Regulatory Pathway' (2022) 66 <https://mbie.govt.nz/dmsdocument/25671-new-zealand-hydrogen-regulatory-pathway> accessed 10 November 2023.

37 Government of New Zealand, 'Regional Hydrogen Transition Draft Technical Design Paper' (2023) <https://static1.squarespace.com/static/5c350d6bcc8fedc9b21ec4c5/t/64e2836b29e7580ddd4dbd3b/1692566380938/regional-hydrogen-transition-draft-technical-design-paper.pdf> accessed 10 October 2023.

38 Ibid.

39 HESC, 'HESC Project' (2023) <https://?hydrogenenergysupplychain?.com/> accessed 11 November 2023.

40 Parliament of Australia, 'Development of Australia's Hydrogen Industry 2000 to 2021: A Chronology' (2022) <https://aph.gov.au/About_Parliament/Parliamentary_departments/Parliamentary_Library/pubs/rp/rp2223/Chronologies/

Strategy was released in 2019 underpinned by three key policy goals to facilitate fifty-seven joint actions around seven themes[41] targeting the renewable hydrogen pricing stretch goal of reaching AU$2 per kg ($H_2$ (hydrogen) under $2) originally set in the Low Emissions Technology Statement.[42] This cost target is ambitious, with stand-alone wind and solar projects (financed over twenty years) utilising renewable electrolysis to produce renewable hydrogen currently projected to cost AU$4–12/kg.[43]

To create the rapid reduction of hydrogen production costs, in 2023 the federal public renewable energy funding body, the Australian Renewable Energy Agency, announced the establishment of the AU$2 billion Hydrogen Headstart Fund with a further $2 billion announced in the 2024–2025 Australian Federal Budget.[44] The Hydrogen Headstart Fund will award production credits to support large-scale renewable hydrogen projects to cover the commercial gap between the cost of hydrogen produced and the sale price of the hydrogen, or its derivatives.[45] The Hydrogen Headstart Fund projects will be funded from 2026/27 for a maximum funding period of ten years.[46] While this funding is dwarfed compared to other hydrogen funding schemes in the European Union and United States,[47] it is likely to support the first large-scale renewable hydrogen export projects in Australia.

To become a 'hydrogen production powerhouse'[48] by 'shipping sunshine' in the form of liquefied hydrogen to the world, Australia has adopted a responsive regulatory stance to ensure regulatory reform facilitating investment.[49] The responsive regulatory approach is built upon the proportional regulatory intervention required to meet regulatory objectives according to the responsive regulation pyramid, originally conceptualised and championed by Braithwaite.[50]

The responsive regulation pyramid aims to promote voluntary compliance at the 'base' of the pyramid, through guidelines that are typically industry-led, with increasing severity of stations at the 'apex' of the pyramid. This responsive regulatory approach was also adopted within Australia's East Coast Domestic Gas Market. For example, Australia created its leading global liquified natural gas export sector without any legislation mandating gas reservation for Australia's largest gas market. In line with a responsive approach, Australia has adopted an industry-led agreement and code of conduct to prevent gas supply shortfalls and secure

Hydrogen#:~:text=ARENA%20releases%20a%20summary%20report,be%20completed%20by%20early%202022> accessed 18 November 2022.

41 The seven themes underpinning Australia's current hydrogen strategy are: National coordination; Developing production capacity, supported by local demand; Responsive regulation; International engagement; Innovation and R&D; Skills and workforce; and Community confidence. See Australian Hydrogen Council, 'Government Policies' (2022) <https://h2council.com.au/government-hydrogen-policies/> accessed 20 November 2022.

42 Australian Government, 'Technology Investment Roadmap: First Low Emissions Technology Statement – 2020' (2020) <https://consult.dcceew.gov.au/low-emissions-technology-statement-2022> accessed 23 October 2023.

43 Muhammad Haider Ali Khan, Rahman Daiyan, Zhaojun Han, Martin Hablutzel, Nawshad Haque, Rose Amal, and Iain MacGil, 'Designing optimal integrated electricity supply configurations for renewable hydrogen generation in Australia' (2021) 24(6) iScience 102539.

44 Australian Government, 'Hydrogen Headstart Program' (2024) <www.dcceew.gov.au/energy/hydrogen/hydrogen-headstart-program> accessed 15 June 2024.

45 ARENA, 'Hydrogen Headstart Guidelines' (2023) <https://arena.gov.au/assets/2023/10/Hydrogen-Headstart-Guidelines.pdf> accessed 1 December 2023 (hereinafter: ARENA, 'Hydrogen Headstart Guidelines').

46 Ibid.

47 João Moura and Isabel Soares, 'Financing low-carbon hydrogen: The role of public policies and strategies in the EU, UK and USA' (2023) 5 (2) Green Finance 165.

48 COAG Energy Council, 'Australia's National Hydrogen Strategy' v.

49 Ibid.

50 John Braithwaite, 'Restorative Justice and Responsive Regulation: The Question of Evidence' (2016) 51 RegNet Research Papers, Canberra: Regulatory Institutions Network 28.

competitively priced gas for the domestic gas market with the LNG export sector.[51] Similarly, five industry codes of practice are being developed with the hydrogen industry, as discussed below.

Australia has built its strategy around enabling 'clean hydrogen', rather than a narrower approach targeting renewable hydrogen only, as is the case in New Zealand. Clean hydrogen pathways are not restricted to renewable hydrogen but rather include gasification through thermochemical reactions with coal as a feedstock and steam methane reforming using natural gas coupled with carbon capture and storage. The responsive pathway to realise Australia's position as a hydrogen exporter is divided into two phases. The first phase between 2019 and 2025 seeks to provide 'foundations and demonstrations'[52] of hydrogen by undertaking priority pilot, trials, and demonstration projects; assess supply chain infrastructure needs; build demonstration hydrogen hubs; and develop supply chains for prospective hydrogen hubs to scale-up supported by bilateral agreements, including with Germany, Japan, and The Netherlands.[53]

From 2025 to 2030 the second hydrogen strategy phase seeks to create 'large-scale activisation'[54] of hydrogen to scale up industry capacity for hydrogen supply chain to support export industry infrastructure and create a domestic market with explicit public benefits.[55] Overall, four key progress measures for the success of Australia's hydrogen industry are mapped, ranging from Australia developing an internationally accepted certification regime to hydrogen providing jobs and economic benefits.[56] Yet no baseline data, data sharing, or demand and production targets have been set to assess progress towards these measures.

Since the development of the National Hydrogen Strategy, the interim 2022 State of Hydrogen report provides an update on the advancement and progress towards realising Australia's overall goal of becoming a top three hydrogen exporter. The State of Hydrogen Report confirms 'Australia has around 40 percent of all announced global hydrogen projects, with the Australian pipeline valued from $230 billion to $300 billion'.[57] To support the development of a hydrogen projects pipeline to support export, the federal Australian government is also developing a proposed Guarantee of Origin Scheme.[58] The Guarantee of Origin Scheme seeks to track and verify emissions associated with hydrogen production and its derivatives. The proposed Guarantee of Origin Scheme will also create a mechanism for renewable energy certification in direct response to the revised EU Renewable Energy Directive and supporting delegated acts defining renewable fuels of non-biological origin (RFNBOs).[59]

[51] The East Coast Gas Market. Western Australia, by comparison, does hold a domestic gas reservation policy. Australian Domestic Gas Security Mechanism (ADGSM) is negotiated with east coast LNG exporters via a Heads of Agreement rather than gas reservation legislation. See Australian Government, 'Heads of Agreement: The East Coast Domestic Gas Supply Commitment' (2022) <https://industry.gov.au/sites/default/files/2022-09/heads_of_agreement_the_australian_east_coast_domestic_gas_supply_commitment.pdf> accessed 10 November 2023.

[52] COAG Energy Council, 'Australia's National Hydrogen Strategy' x.

[53] Australian Government, 'Australia's International Clean Energy Partnerships' (2023) <https://dcceew.gov.au/climate-change/international-climate-action/international-partnerships> accessed 2 December 2023.

[54] COAG Energy Council, 'Australia's National Hydrogen Strategy' xi.

[55] Kim Beasy, Sherridan Emery, Kerrin Pryor, and Tuong Anh Vo, 'Skilling the green hydrogen economy: A case study from Australia' (2023) 48 International Journal of Hydrogen Energy 19811.

[56] COAG Energy Council, 'Australia's National Hydrogen Strategy' xiii.

[57] Australian Government, 'State of Hydrogen Report' (2022) <https://dcceew.gov.au/sites/default/files/documents/state-of-hydrogen-2022.pdf> accessed 10 October 2023, ix (hereinafter: Australian Government, 'State of Hydrogen Report').

[58] Australian Government, 'Australia's Guarantee of Origin Scheme: Consultation Papers' (2023) <https://consult.dcceew.gov.au/aus-guarantee-of-origin-scheme-consultation> accessed 20 May 2023.

[59] European Commission, 'Renewable Hydrogen Production: New Rules Formally Adopted' (2023) <https://energy.ec.europa.eu/news/renewable-hydrogen-production-new-rules-formally-adopted-2023-06-20_en> accessed 10 September 2023.

In a similar vein to the EU-based CertifHY scheme,[60] an industry-led Zero Carbon Certification Scheme has been launched by peak industry body the Smart Energy Council to promote the creation of an Australian hydrogen export sector.[61] The first renewable hydrogen project to receive pre-certification is Yara's green ammonia plant currently being built in the Pilbara, Western Australia. While certification schemes are crucial, particularly to support hydrogen exports, to implement hydrogen initiatives and schemes, one of the key inhibitors to rapidly building up the Australian hydrogen supply chain is the need for consistency in 'implementing standards, regulations, and certification'[62] for hydrogen at the national and state levels in Australia. This has led the federal Australian government to conduct its current holistic review of the National Hydrogen Strategy with a revised strategy anticipated in 2024.

Since 2022, the Australian government has been undertaking a national Review of Hydrogen Regulation to ensure hydrogen safety[63] and development.[64] At the federal level, several regulatory amendments are being planned to support the development of the Australian hydrogen sector ranging from safety laws to hydrogen transportation. In a responsive approach, new standards will be co-designed with the industry under five codes of practice, on hydrogen production; ammonia production; hydrogen refuelling; hydrogen appliances; and ammonia appliances, and are likely to be finalised in 2024.

As an interim measure before the finalisation of the five codes of practice and to support immediate applications of hydrogen blending into the domestic East Coast Gas Market, the federal National Gas Law (NGL) and National Energy Retail Law (NERL)[65] have been amended to incorporate hydrogen. As the Australian Constitution makes no express reference to energy, responsibility for energy market regulation falls within the plenary legislative power of the states and territories. Exercising cooperative federalism, participating jurisdictions have adopted a 'unitary regulatory system'[66] whereby each state adopts national laws mirroring the South Australian energy legislation. The NGL and NERL previously regulated third-party access to pipeline services and other services of 'natural gas processable gas' only.[67] Hydrogen did not fall under the definition of a naturally occurring gas and consequently the NGL and NERL are being amended pursuant to the recent passage of the Statutes Amendment (National Energy Laws) (Other Gases) Act 2023. Under the amendment, hydrogen is explicitly defined as a 'relevant covered gas' to enable low-level blends of hydrogen with gases within the domestic East Coast Gas network.[68]

As the discussion above illustrates, enthusiasm and strategies are not lacking to develop hydrogen sectors in Australia and New Zealand. However, robust national regulatory frameworks

60 For an analysis of hydrogen classifications in the EU see Ruven Fleming, 'Clean or renewable – Hydrogen and power-to-gas in EU energy law' (2019) 39 Journal of Energy and Natural Resources Law 43.

61 Smart Energy Council, 'Zero Carbon Certification Scheme' (2023) <https://smartenergy.org.au/zero-carbon-certification-scheme/> accessed 12 November 2023.

62 Australian Government, 'State of Hydrogen Report' 59.

63 See Fatemeh Salehi, Rouzbeh Abbassi, Mohsen Asadnia, Billy Chan, and Longfei Chen, 'Overview of safety practices in sustainable hydrogen economy – An Australian perspective' (2022) 478 International Journal of Hydrogen Energy 34689.

64 Australian Government, 'Review of Hydrogen Regulation: Hydrogen Industry Consultation' (2022) <https://consult.dcceew.gov.au/review-of-hydrogen-regulation> accessed 10 September 2023.

65 The NGL and NERL are encapsulated within the National Gas (South Australia) Act 2008 (SA) and the National Energy Retail Law (South Australia) Act 2011 (SA) along with supplementary rules and regulation.

66 Lee Godden and Anne Kallies, 'Governance of the Energy Market in Australia' in Michael Faure (ed) *Elgar Encyclopedia of Environmental Law* (Edward Elgar 2021) 208.

67 Statutes Amendment (National Energy Laws) (Other Gases) Act 2023 s 5.

68 Ibid s 148AA.

providing the foundation for hydrogen production, processing, and potential export are evidently at differing states of maturity. Australia has enacted the first federal changes to permit the regulation of gas pipelines blended with hydrogen in amending the NGL and NERL. Developing domestic hydrogen capacity and infrastructure early is crucial to reaching export and decarbonisation goals for industrial processes such as ammonia in New Zealand. From an export perspective, the entire hydrogen production lifecycle must be effectively regulated to provide commercial investment certainty and conformity with international hydrogen certification and greenhouse gas calculation methodologies.[69] From a domestic perspective and to activate a hydrogen export sector, the planning, assessment, and licensing regime to rapidly scale up renewable hydrogen production is crucial, as explored below in Section 5.3.

5.3 HARMONISING HYDROGEN LAND USE: COMPARING AUSTRALIAN STATE APPROACHES TO RENEWABLE HYDROGEN LICENSING ON PASTORAL LAND

Developing renewable hydrogen economies in Australia and New Zealand will require the planning and allocation of licences and the management of competing land uses. This regulatory need arises from the fact that renewable hydrogen infrastructure will require the industrial use of land which may conflict with existing non-industrial uses. One of the key land use competitions with hydrogen production, particularly in Australia and potentially in New Zealand, is on pastoral lease Crown land traditionally reserved for pastoral land uses. The cost of constructing transmission infrastructure and accessing large areas of cleared land in proximity to major energy load centres will likely increase the economic viability of renewable hydrogen. These elements are often evident in pastoral leasehold land, which covers 44 per cent of Australia[70] and 37 per cent of New Zealand,[71] rendering it ideal to use for hydrogen production. However, this may lead to regulatory complexities over how hydrogen licences should be assessed and awarded by regulators in pastoral land use zones previously prohibited to utility-scale energy development.

This section will be confined to an analysis and comparison of the recent regulatory reforms to support hydrogen production facilities on pastoral lands in two Australian states, Western Australia and South Australia.[72] Although New Zealand also holds a pastoral leasehold system, New Zealand has recently overhauled its previous environment and planning law, the Resource Management Act 1991 (NZ), and enacted two new pieces of legislation: the Natural and Built Environment Act 2023 (NZ) (NBA) and the Spatial Planning Act 2023 (SPA) (NZ), to be phased in over a ten-year period.[73] Neither statute currently contains any express reference to hydrogen. Consequently, this chapter will focus on the Australian state experience, representing a more mature regulatory environment with express reforms relating to hydrogen.

[69] Particularly in conformity with the EU Delegated regulations defining renewable hydrogen under the Renewable Energy Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources (recast).

[70] Australian Government Productivity Commission, 'Pastoral Leases and Non-Pastoral Land Use' (2002) <https://pc.gov.au/research/completed/pastoral-leases#:~:text=Pastoral%20leases%20exist%20on%20around,areas%20and%20the%20tropical%20savannas> accessed 30 October 2023.

[71] Ministry for the environment, 'Land' (2023) <www.linz.govt.nz/guidance/crown-property/crown-pastoral-land-management/leases-and-licences-crown-pastoral-land> accessed 1 December 2023.

[72] Section 51(xxxvii) of the Australian Constitution expressly enables the states and territories to refer powers to the Commonwealth Parliament to make laws on the matter which is referred.

[73] The Crown Pastoral *Land Reform Act 2022* (NZ) also does not refer to hydrogen.

5.3.1 *Defining Pastoral Leases*

Following colonisation by Britain, and to prevent unauthorised settlement, the majority of Australia's rural arid and semi-arid lands were granted as a Crown statutory estate called pastoral leases. Pastoral leases as a tenure system became formalised by the landmark 1847 Order in Council and 'established 14-year leases in the unsettled districts and gave lessees renewal and compensation rights'[74] as a form of progressive land settlement requiring that land is held for 'pastoral purposes' only – traditionally sheep and cattle grazing. Pastoral leases are vast in Australia, currently constituting nearly half of Australia's mainland (equating to 338 million hectares).[75]

Unlike traditional common law or equitable leases, pastoral leases are purely a creature of statute to permit Crown-owned land to be leased for commercial grazing, agricultural, horticultural, or other supplementary pastoral use. Pastoral lease terms vary greatly within Australian states and territories. For example, in NSW pastoral leases are perpetually equated to a right to possess the land for an indefinite period.[76] In Queensland, the Northern Territory, and Western Australia pastoral leases are generally fixed-term agreements that expressly do not afford leaseholders a right to exclusive possession.[77] Eighty-seven per cent of Western Australia consists of rangelands and 38 per cent of the rangelands are held under pastoral leases.[78] Forty per cent of South Australia consists of land held under pastoral leases.

The high renewable energy potential, existing oil and gas infrastructure, and the need to access land to produce large-scale renewable hydrogen projects have led to Western Australia and South Australia either amending their pastoral lease regulation or creating new hydrogen licensing regulations to access pastoral land. Western Australia was the first Australian state to amend its pastoral leasehold regulation to accommodate renewable hydrogen siting, which will be discussed in more detail in Section 5.3.2.

5.3.2 *Diversification Leases: The Western Australian Approach*

Western Australia is the largest Australian state, covering 2.5 million km². One-third of the Western Australian state landmass is held under pastoral leases.[79] Pastoralism became the central socio-economic land use in Western Australia from the late 1890s, attracting settlers in the rangelands to farm. From the 1920s onwards, pastoral leases became increasingly popular, with cattle and sheep stations becoming a key sector of the Western Australian economy. In particular, pastoral leases have become common in the Pilbara region, one of nine regions located in Western Australia, the geographical size of Spain, with large rangelands

74 J. H. Holmes and L. D. P. Knight, 'Pastoral lease tenure in Australia: Historical relic or useful contemporary tool?' (1994) 16(1) Rangelands Journal 106.

75 Austrade, 'Pastoral Leases' (2022) <https://austrade.gov.au/land-tenure/land-tenure/pastoral-leases#:~:text=Pastoral%20leases%20are%20primarily%20situated,is%20subject%20to%20pastoral%20leasing> accessed 3 November 2022.

76 Crown Land Management Act 2016 (NSW).

77 *Wik Peoples v Queensland* (1996) 187 CLR 1; *Western Australia v Ward* (2002) 213 CLR 1.

78 Pastoral leases represent 857,833 km² of Western Australia. Government of Western Australia, 'Rangelands of Western Australia' (2022) <https://agric.wa.gov.au/rangelands/rangelands-western-australia> accessed 10 October 2023.

79 Western Australian Auditor General, 'Management of Pastoral Lands in Western Australia' (2017) <https://audit.wa.gov.au/reports-and-publications/reports/management-pastoral-lands-western-australia/auditor-generals-overview/> accessed 10 September 2023.

and considerable endowments of iron ore, lithium, gold, copper, nickel, and offshore petroleum.[80]

The Pilbara will become one of the most important hydrogen-producing regions in Australia. Its strategic geographical location close to Asian markets on Australia's west coast coupled with existing mining and petroleum value chains and petroleum export infrastructure have created the ideal conditions for prospective hydrogen hubs. The five hydrogen production hubs planned in the Pilbara region to be connected by hydrogen pipelines are touted as strategic zoning areas 'to provide common user infrastructure to support renewable hydrogen supply chain activity',[81] with the potential to produce from 3 to over 10 million tonnes of hydrogen per annum by 2050.[82]

For example, the H2Kwinana Hydrogen Hub will host a 100 megawatt (MW) electrolyser to produce over 14,000 tonnes of green hydrogen per annum for industrial use, heavy transport, and export.[83] The development of hydrogen hubs in the Pilbara sparked the need to consider reform to permit hydrogen production facilities on pastoral land. As pastoral leases are Crown-owned and restricted to pastoral activities,[84] alternative land uses and planning approvals for hydrogen infrastructure were previously not permitted pursuant to the Land Administration Act 1997 (WA).[85] To unlock the potential for hydrogen in Western Australia, pastoral leases need to host multi-purpose industrial land uses.[86]

The default statutory prohibition of any development activities other than pastoral for pastoral leases led to the first regulatory shift in Australia relating to hydrogen land use. While pastoralist landholders could previously apply for a diversification permit to undertake activities for non-pastoral purposes, such permits were only granted in limited circumstances and would not allow for the development of hydrogen and other renewable projects. The Crown could also acquire[87] and terminate pastoral leasehold interests for 'public works' land uses,[88] which holds a limited definition, including public infrastructure such as public schools and hospitals, and did not expressly include energy development. Consequently, a new non-exclusive land tenure type, the Diversification Lease, was proposed and enacted in the Land and Public Works Legislation Amendment Act 2023 (WA) (LPWLA Act).[89]

[80] OECD, 'Pilbara, Australia' (2023) <https://oecd.org/regional/Pilbara-mining-region-PH.pdf> accessed 13 September 2023.

[81] Government of Western Australia, 'Western Australia: An Outstanding Place for Renewable Hydrogen Investment' (2022) <https://wa.gov.au/system/files/2022-07/220629_Hydrogen%20Prospectus-Web.pdf> accessed 20 November 2022.

[82] Ibid.

[83] The Hon Madeleine King MP, '$70 million investment in Kwinana Hydrogen Hub enables major step forward for WA hydrogen industry' (2023) <https://minister.industry.gov.au/ministers/king/media-releases/70-million-investment-kwinana-hydrogen-hub-enables-major-step-forward-wa-hydrogen-industry#:~:text=Site%20works%20for%20H2Kwinana%20are,in%20Australias%20heavy%20vehicle%20fleet> accessed 20 November 2023.

[84] Land Administration Act 1997 (WA) Civ 3.

[85] However, pursuant to s 5 of the Land Administration Act 1997 (WA), the rights over Crown land in respect of minerals, petroleum, geothermal energy or geothermal energy resources are not impacted by the pastoral leasehold regime.

[86] Eddie J. B. van Etten, 'Changes to land tenure and pastoral lease ownership in Western Australia's central rangelands: Implications for co-operative, landscape-scale management' (2013) 35 The Rangeland Journal 37.

[87] Land Administration Act 1997 (WA) Div 2.

[88] Public Works Act 1902 (WA) s 2.

[89] Land and Public Works Legislation Amendment Act 2023 (WA) amends a suite of legislation including: Conservation and Land Management Act 1984 (WA); Duties Act 2008 (WA); Land Administration Act 1997 (WA); Mining Act 1978 (WA); Planning and Development Act 2005 (WA); Public Works Act 1902 (WA). For the purpose of this chapter, amendments to the Land Administration Act 1997 (WA) concern the introduction of the Diversification Lease.

The LPWLA Act amends the Land Administration Act 1997 (WA) (LAA Act) and the Public Works Act 1902 (WA) to permit the grant of a new Diversification Lease 'for any purpose or purposes'[90] on unallocated Crown land or to enable existing and new pastoral leases to be transferred to diversification leases.[91] In adapting existing pastoral land regulation to enable non-pastoralist activities supporting a hydrogen sector, Western Australia has adopted an 'adaptive' approach by amending its existing pastoral lands regulation.[92] Adaptive management is often deployed in the context of natural resources regulation and aims to adapt legal frameworks to accommodate new technologies and monitor outcomes potentially requiring adaptive amendments to existing legislation.[93]

The adaptive approach permits Diversification Leases to be applied for in a streamlined approach prospectively and retrospectively on unallocated Crown land, new pastoral leases, and existing pastoral leases to permit hydrogen production and other activities, including carbon farming and renewable energy. A Diversification Lease will be awarded by the Minister for Lands and will be an optional tenure type available to both pastoral lessees and energy proponents without the conferral of exclusive possession.[94] However, unlike pastoral leases, diversification leases are designed for diverse non-exclusive and concurrent land uses including, but not exclusive to, grazing livestock, horticulture, renewable hydrogen, and carbon farming.[95]

Diversification lessees must maintain the condition of the pastoral land and prevent land degradation.[96] It remains unclear whether the diversification lessee must act in accordance with standards and guidelines that will be set under powers afforded to the statutory Pastoral Lands Board pursuant to Division 2A of the LPWLA Act.[97] Such standards are applicable for pastoral leaseholders, setting out benchmarks and objectives about the condition of land held under pastoral leases.[98] As leasehold rental payments will not be afforded to landholders but rather will be received by the Crown, an assessment regimen requiring environmental impact assessments to preserve pastoral activities following Pastoral Lands Board guidelines is crucial.

Diversification lessees must satisfy the relevant Minister, rather than the Pastoral Lease Board as the statutory authority for pastoral leases, that land under the lease will be treated 'using methods of best environmental management practice appropriate to the area where the land is situated'.[99] Environmental management practices are currently undefined. Guidance for diversification lessees should be issued, particularly in consideration for water licensing, given water requirements for electrolysis and enduring water scarcity in the Pilbara region.[100]

Diversifying pastoral leasehold land uses and conditions in Western Australia to permit renewable hydrogen development is crucial to support the development of hydrogen hubs.

[90] Land and Public Works Legislation Amendment Act 2023 (WA) Pt 6A, s 92B.
[91] Ibid s 92C(3).
[92] Madeline Taylor and Tina Soliman Hunter, *Agricultural Land Use and Natural Gas Extraction Conflicts: A Global Socio-Legal Perspective* (Routledge 2019).
[93] Nicola Swayne, 'Regulating coal seam gas in Queensland: Lessons in an adaptive environmental management approach?' (2012) 29 Environmental and Planning Law Journal 163.
[94] Land and Public Works Legislation Amendment Act 2023 (WA), Pt 6A, s 92D.
[95] Ibid Pt 6A.
[96] Ibid Pt 6A, s 92F.
[97] The Pastoral Lands Board is the statutory authority with joint responsibility with the Minister for Lands for administering Western Australian pastoral leases in accordance with Pt 7 of the Land Administration Act 1997 (WA).
[98] Land and Public Works Amendment Act 2023 (WA), s 100A.
[99] Ibid s 92F.
[100] Government of Western Australia, Department of Planning, Lands and Heritage, 'Guiding the Use of Diversification Leases on Crown Land under the Land Administration Act 1997' (2023) <https://wa.gov.au/system/files/2023-08/policy-framework-diversification-leases.pdf> accessed 29 November 2023.

Pastoralists, rather than energy proponents alone, are permitted to apply for diversification leases to acquire additional income through new land use activities, such as carbon sequestration.[101] Carbon management and sequestration activities often operate on at least a twenty-five-year project lifecycle, hence the amendment to permit pastoral leases and accompanying diversification leases to a maximum of fifty years via re-grant or extension is another important development.[102] However, pastoralists must be adequately consulted and informed when considering the option to surrender pastoral leasehold lands in favour of a diversification lease. Arguably, the direct co-location of pastoralist activities alongside renewable energy production supporting renewable hydrogen, for example by way of agrivoltaics,[103] appears a missed opportunity as a mixed agricultural and renewable energy activity and land use does not appear to be expressly included within the LPWLA Act.

An alternative regulatory approach to extending the permissibility of renewable hydrogen within existing pastoral regulatory frameworks is to create bespoke and specific renewable hydrogen development principles, assessments, and licensing procedures. South Australia has taken this approach in its recently enacted Hydrogen and Renewable Energy Act 2023 (SA) (HRE Act).

5.3.3 *Hydrogen Generation Licences: The South Australian Approach*

South Australia is the vanguard of renewable energy success in Australia. It has transitioned its energy system from 1 per cent to 68 per cent renewable energy in a fifteen-year period and is forecast to reach 90 per cent renewable energy by 2025.[104] In 2022, South Australia became the first Australian state with 85.4 per cent of electricity demand being contributed by solar and wind.[105] With such high variable-renewable energy penetration, South Australia has set its policy sights on becoming a 'world-class renewable hydrogen supplier'.[106] An initial hydrogen export feasibility study has projected South Australian renewable and blue hydrogen[107] could satisfy 10 per cent of Rotterdam's hydrogen demand in 2050, forecast to reach 18 million tonnes per annum by 2050.[108] This policy aim seeks to be realised through South Australia's Hydrogen Action Plan setting out twenty key actions across five areas to integrate hydrogen into its domestic energy system and scale up renewable hydrogen production for export.

101 Western Australian Government, 'Land and Public Works Legislation Amendment Act 2023 Frequently Asked Questions' (2023) <https://wa.gov.au/government/document-collections/land-and-public-works-legislation-amendment-act-2023> accessed 13 December 2023.

102 Land and Public Works Legislation Amendment Act 2023 (WA), s 105.

103 Madeline Taylor, 'Planning the energy transition: A comparative examination of large-scale solar energy siting on agricultural land in Australia' (2022) 18(2) Utrecht Law Review 70; Madeline Taylor, Jordie Pettit, Takashi Sekiyama, and Maciej Sokolowski, 'Justice-driven agrivoltaics: Facilitating agrivoltaics embedded in energy justice' (2023) 188 Renewable and Sustainable Energy Reviews 1.

104 Government of South Australia, 'South Australia's Hydrogen Action Plan' (2019) <https://energymining.sa.gov.au/industry/modern-energy/hydrogen-in-south-australia/hydrogen-files/south-australias-hydrogen-action-plan-online.pdf> accessed 10 December 2023 (hereinafter: Government of South Australia, 'South Australia's Hydrogen Action Plan').

105 Renew Economy, 'South Australia Hits Stunning New High in Race to Renewables-Only Grid' (2023) <https://reneweconomy.com.au/south-australia-hits-stunning-new-high-in-race-to-renewables-only-grid/> accessed 20 May 2023.

106 Government of South Australia, 'South Australia's Hydrogen Action Plan' 19.

107 As defined and discussed in Chapter 2 by Leigh Hancher and Simina Suciu in this book.

108 Government of South Australia, 'South Australia–Port of Rotterdam Hydrogen Supply Chain Pre-feasibility Study' (2021) <https://energymining.sa.gov.au/__data/assets/pdf_file/0007/733237/RELEASE_FINAL_SA_-_Rotterdam_H2_Supplychain_pre-FS_report_-_exec_summary_presentation.pdf> accessed 24 November 2023.

Building on its success in regulating tight and shale gas as Australia's leading onshore gas producer,[109] action two of the South Australian Hydrogen Action Plan is to establish a 'world class regulatory framework'[110] to build community and investor confidence as a key action. Similar to Western Australia, South Australia has also sought to amend its pastoral leasehold conditions to encourage renewable hydrogen development and 'unlock land access to pastoral land'.[111]

For example, the Planning and Design Code (SA), a statutory instrument representing the policies, rules, and classifications for land use planning, previously restricted renewable energy facility land uses, in Rural Land Zones where land is used wholly or mainly for primary production, such as pastoral leases.[112] Renewable energy facilities were defined to include solar, tidal, hydropower, biomass, and/or geothermal. However, hydrogen facilities were not recognised or defined under the Planning and Design Code (SA). This regulatory gap led the South Australian Productivity Commission in 2022 to recommend the Pastoral Land Management and Conservation Act 1989 (SA) (PLMC Act) be amended to enable renewable energy development and corresponding renewable hydrogen development on pastoral leases.[113]

Wind farm developments were previously the only utility-scale renewable energy developments permissible on pastoral land under s 49J of the PLMC Act with ministerial approval in South Australia. The PLMC Act governs land use and permissible development on pastoral land. As a pastoral lessee holds limited property rights to undertake pastoral activities only, applications seeking to access or use pastoral lease land for non-pastoral purposes are to be assessed by the Pastoral Unit and Pastoral Board and require ministerial approval. Applications are assessed according to their potential impact on the ongoing viability of pastoral activities, and their alignment with the objects of the PLMC Act to 'make provision for the management and conservation of pastoral land'.[114] Under the PLMC Act, all land uses apart from pastoralism and ancillary activities, mining, and wind farms are treated as 'non-pastoral' purposes or alternative land uses.

Despite advances in permitting wind farm development on pastoral land, other renewable energy activities were incompatible with pastoral activities under the PLMC Act. Thus, any application to develop pastoral land for renewable hydrogen production by co-locating would involve 'excising the required land, changing the tenure and issuing of Crown licence(s) to facilitate land access and use'.[115] This clear regulatory gap for renewable hydrogen development creating investment uncertainty and the need to access pastoral land has led to the enactment of the first bespoke hydrogen regulatory framework in Australia – the HRE Act.

The HRE Act provides a streamlined land use approvals and licensing scheme for hydrogen and renewable energy projects on pastoral leasehold land, other Crown land tenures defined as

109 See Barry Goldstein, Michael Malavazos, and Belinda Hayter, 'Leading Practice Regulation for Unconventional Reservoir Development in South Australia' in Michal C. Moore, Ian G. Cronshaw, and R. Quentin Grafton (eds), *Risks, Rewards and Regulation of Unconventional Gas: A Global Perspective* (Cambridge University Press 2016).

110 Government of South Australia, 'South Australia's Hydrogen Action Plan' 23.

111 Government of South Australia, 'Hydrogen and Renewable Energy Act: Explanatory Guide to the Bill' (2023) <https://energymining.sa.gov.au/__data/assets/pdf_file/0019/905311/Explanatory_Guide_to_the_HRE_Bill.pdf> accessed 1 December 2023 (hereinafter: Government of South Australia, 'Hydrogen and Renewable Energy Act: Explanatory Guide to the Bill').

112 See Planning and Design Code (SA) Pt 2.

113 South Australian Productivity Commission, 'Final Report Inquiry into South Australia's Renewable Energy Competitiveness' (2022) 11 <https://sapc.sa.gov.au/__data/assets/pdf_file/0007/847348/Renewable-Energy-Competitiveness-Final-Report-Website-Version.pdf> accessed 10 November 2023.

114 Pastoral Land Management and Conservation Act 1989 (SA) s 1.

115 Ibid.

'designated land',[116] And some freehold land as 'non-designated land'. The corresponding amendment of the PLMC Act upon the enactment of the HRE Act permits 'renewable energy infrastructure and the undertaking of associated infrastructure activities'.[117] The HRE Act is underpinned by the proposed legislative objective to 'establish an effective, efficient and flexible regulatory framework for the constructing, operating, maintaining and decommissioning of renewable energy infrastructure and facilities for generating hydrogen for commercial purposes'.[118] This objective represents a pivot away from a rules-based and adaptive approach to enact new regulation in the existing PLMC Act to a principle-based or goal-setting approach specifically for renewable hydrogen licensing to enable coexistence with other land uses in South Australia.[119]

Principle-based regulation is outcome orientated and describes the method of achieving a regulatory outcome by setting a general objective, standard, or duty without specifying the means of achieving that outcome in absolute terms.[120] Conversely, rule-based regulation places the proponent as an adversary, constantly testing and finding methods to check and reinterpret regulatory inconsistencies, requiring continuous amendments and updates to accommodate new legal issues. Principle-based regulation seeks to produce a regulatory system that is more effective and sustainable in the face of changing circumstances and complex technological developments in emerging sectors such as renewable hydrogen development.[121] By taking a principle-based approach in South Australia, the HRE Act will permit regulators to actively participate in managing renewable hydrogen to encourage co-location with other land uses and activities, such as pastoral lessees, by regulating and enforcing the conditions of production and hydrogen development. This approach functions to ensure the activities of renewable hydrogen titleholders are aligned with broad regulatory principles. Similarly, France has also taken a goal-setting approach to the regulation of hydrogen transport.[122]

The HRE Act provides the legal framework for Crown-owned land and waters, including pastoral leases to be identified and declared as suitable for the operation of renewable energy infrastructure and establish a competitive merit-based hydrogen generation licensing regime.[123] Where the release area comprises pastoral land, 'occurrence of the Minister responsible for the administration of the Pastoral Land Management and Conservation Act 1989 (SA) is also required'.[124] Following the release of an HRE Act area, a competitive process for determining access to and use of pastoral land by the award of a hydrogen generation licence which authorises the construction, installation, operation, maintenance, and decommissioning of a hydrogen generation facility which must not exceed 5 km^2.[125]

116 Government of South Australia, 'Hydrogen and Renewable Energy Act: Explanatory Guide to the Bill'; Hydrogen and Renewable Energy Act 2023 (SA) s 4.
117 Pastoral Land Management and Conservation Act 1989 (SA) s 4.
118 Hydrogen and Renewable Energy Act 2023 (SA) s 3(b).
119 Ibid s 3(j).
120 Neil Gunningham and Darren Sinclair, 'Integrative regulation: A principle-based approach to environmental policy' (2018) 24(4) Law and Social Inquiry 853.
121 Julia Black, 'Forms and Paradoxes of Principles-based Regulation' (2008) LSE Legal Studies Working Paper No. 13/2008, 3(4).
122 See Chapter 16 by Kleopatra-Eirini Zerde in this book.
123 Hydrogen and Renewable Energy Act 2023 (SA) s 10.
124 Ibid s 10(4)(a).
125 Ibid s 14 and s 37. However, a licensee will likely be able to apply for multiple licences concurrently held and overlapping, approved by the relevant minister, meaning a proposed hydrogen generation facility exceeding 5 km^2 may require multiple licences.

In contrast to Western Australia's diversification lease, the environmental assessment and requirements for hydrogen production licences are clear. An Environmental Impact Report and Statement of Environmental Objectives[126] to assess and manage any adverse effects, the 'risk of any significant long-term damage'[127] on the environment 'as far as reasonably practicable',[128] and ensuring rehabilitation of pastoral land will be required pursuant to the HRE Act. Finally, an operational management plan must be accepted and approved prior to the commencement of authorised operations.[129]

In comparison to the Western Australian approach, the HRE Act expressly requires an access agreement to be entered into with a pastoral lessee before undertaking authorised operations under a hydrogen generation licence. Mandating an access agreement under the HRE Act explicitly recognises and protects the incumbent and persevering property rights of pastoralists. The access agreement must include an agreement as to any compensation that may be payable for the resumption of pastoral land for the purpose of a hydrogen generation facility or by associated infrastructure[130] and access conditions to the licence area or in the vicinity of the licence area.[131] A process to mediate the negotiation of an access agreement is also stipulated within s 41 of the HRE Act including powers for the Minister to facilitate and assist in obtaining a land access agreement or determination by the South Australian Environment, Resources and Development Court. The South Australian government is currently finalising the HRE Regulations,[132] which will include consultation requirements and criteria for the release area and licensing stages and the role of pastoralists and their interests during the negotiation of the land access agreement and throughout the hydrogen generation licence term.[133]

As illustrated in the above discussion, the HRE Act not only creates the first hydrogen-specific planning and licensing regulation in Australia but also elevates the rights of pastoral leaseholders by expressly requiring access agreements and potential compensation to be negotiated prior to the award of a hydrogen generation licence. This position fundamentally differs from Western Australia's diversification lease which expressly recognises pastoral leases retaining non-exclusive possessory rights over pastoral land and is silent as to whether pastoral lessees may receive compensation or require an access agreement. It is also notable that South Australia has chosen to implement hydrogen licensing interests in comparison with Western Australia's approach to diversification leasehold interests. Consequently, hydrogen licences in South Australia may lead to challenges regarding the transferability of hydrogen licences between entities. In establishing a competitive tender process, the HRE Act seeks to uphold 'environmentally sustainable and safe'[134] development of land use for hydrogen production by requiring an Environmental Impact Assessment including decommissioning and rehabilitation requirements.

Overall, the HRE Act, combined with its supplementary regulations currently in draft form, introduces a principle-based regulatory approach to the Australian hydrogen regulatory environment. It remains to be seen whether the HRE Act will enable an 'effective, efficient and flexible

[126] Ibid Div 4.
[127] Ibid s 58 (b).
[128] Hydrogen and Renewable Energy Act 2023 (SA) s 58 (a).
[129] Ibid s 66.
[130] Pastoral Land Management and Conservation Act 1989 (SA) s 39.
[131] Hydrogen and Renewable Energy Act 2023 (SA) s 41.
[132] Hydrogen and Renewable Energy Regulations 2024 (SA).
[133] Government of South Australia, 'Hydrogen and Renewable Energy Regulations Information Sheet' (2023) <https://energymining.sa.gov.au/__data/assets/pdf_file/0007/967543/HRE-Act-Regulations-consolidated-information-sheet.pdf> accessed 6 December 2023.
[134] Ibid 10.

regulatory framework'.[135] However, its principle-based requirements coupled with mandating access agreements provide enhanced regulatory certainty for hydrogen proponents and pastoral lessees alike.

5.4 CONCLUSION

Australia and New Zealand in the Oceania region have clear ambitions to become regional and global leaders in renewable hydrogen production. The federal Australian regulatory framework is actively being amended using a responsive regulatory approach commencing with the amendment to its National Gas Law and National Energy Retail Law and the current review of its National Hydrogen Strategy. However, many crucial aspects of the future renewable hydrogen supply chain and licensing systems will be regulated by states and territories. In practical terms, this requires measurable national strategies aligned with state and territory planning systems to design regulatory frameworks covering various aspects of the renewable hydrogen supply chain and, importantly, the siting of renewable hydrogen projects.

New Zealand is at the initial stages of mapping regulatory reform priorities to create its first federal hydrogen roadmap. Regulatory amendments will likely commence with amending natural gas pipeline standards and a rebate scheme to enable a just transition for hydrogen-hosting communities. The Regional Hydrogen Transition Initiative framework will likely stir a similar debate and suite of regulatory reform to permit the development of renewable hydrogen through a competitive licensing scheme on complex and overlapping land uses.

The differing approaches in Western Australia and South Australia to hydrogen regulation are apparent in regulatory amendments made to existing pastoral land legislation or the introduction of new hydrogen licensing regulations for renewable hydrogen facilities on pastoral land. As the renewable hydrogen regulatory landscape undergoes rapid changes in Australia, the effectiveness of South Australia's principles-based approach encapsulated in the HRE Act and Western Australia's adaptive strategy in establishing diversification leases is uncertain. The question remains as to which regulatory path will be more effective in encouraging renewable hydrogen development while maintaining and upholding pastoral land uses. Lessons from both states will be instrumental in shaping New Zealand's approach to hydrogen planning and licensing within its recently enacted Natural and Built Environment Act 2023 (NZ) and Spatial Planning Act 2023 (NZ) and its Regional Hydrogen Transition Initiative.

Principles for renewable hydrogen development are crucial to guide and develop consistent and coherent licensing and planning regulatory regimes. Objectives and supporting standards to encourage the award of hydrogen production licences while preserving multiple land uses are becoming important in the hydrogen regulatory ecosystem. Realising Australia and New Zealand's hydrogen aspirations undoubtedly raise evolving and persistent legal questions concerning the allocation of licences on complex and multiple land uses, particularly pastoral land.

Regardless of the differing approaches in Western Australia and South Australia's hydrogen licensing regime, and the emerging hydrogen roadmap in New Zealand under development, it is crucial for both Australia and New Zealand to establish supportive legal frameworks for hydrogen development. Such frameworks must be crafted with careful consideration to maintain the balance between pastoral land uses and potential future complexities in land utilisation for renewable hydrogen.

135 Hydrogen and Renewable Energy Act 2023 (SA) s 3(b).

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6

Hydrogen Regulation in the Middle East and North Africa Region

Trends, Limitations, and Ways Forward

Damilola S. Olawuyi and Mehrnoosh Aryanpour

6.1 INTRODUCTION

This chapter examines law and governance innovations required to integrate the production, distribution, and commercialization of hydrogen into the energy mix in the Middle East and North Africa (MENA) region. It examines current regulatory uncertainties and gaps in the design and implementation of hydrogen projects across the MENA region, and the legal pathways for addressing those challenges.

The development of low-carbon blue and green hydrogen has been identified as a national priority in several MENA countries.[1] For example, Qatar's national oil and gas company, Qatar Energy – which already oversees one of the world's most significant gas field and liquefaction facilities[2] – has signed an agreement with Shell to develop large-scale blue and green hydrogen projects.[3] In particular, 'Qatar plans to build a $1 billion plant to make blue ammonia, a fuel that can be converted into hydrogen'.[4] Similarly, Morocco is pursuing green hydrogen studies and exploring policies to promote investment in the country's green hydrogen economy.[5] A Belgian engineering firm recently entered into a joint venture agreement with Morocco to create an electrolyser manufacturing plant, which can offer integrated green hydrogen solutions.[6] Likewise, Saudi Arabia has already commenced work on the NEOM Green Ammonia project, a US$5 billion green hydrogen plant, and prospectively one of the world's largest

[1] Giampaolo Cantini, 'Hydrogen in the MENA Region: Priorities and Steps Forward' (*Atlantic Council*, 14 February 2023) <www.atlanticcouncil.org/blogs/energysource/hydrogen-in-the-mena-region-priorities-and-steps-forward/> accessed 31 October 2023.

[2] United States Energy Information Administration, 'Country Analysis Brief: Qatar' (28 March 2023) 2 <www.eia.gov/international/content/analysis/countries_long/Qatar/qatar.pdf> accessed 31 October 2023.

[3] MEED, 'Qatar Energy and Shell to Explore Hydrogen Projects' (*Offshore Technology*, 22 October 2021) <www.offshore-technology.com/analyst-comment/qatarenergy-shell-hydrogen-projects/> accessed 31 October 2023.

[4] Bloomberg, 'Qatar to Tap Global Hydrogen Market with $1 Billion Plant' (*Gulf News*, 31 August 2022) <https://gulfnews.com/business/energy/qatar-to-tap-global-hydrogen-market-with-1-billion-plant-1.90238648> accessed 31 October 2023.

[5] Theresa Smith, 'Electrolyser Manufacturing for Morocco Green Hydrogen Value Chain' (*ESI Africa*, 9 January 2023) <www.esi-africa.com/business-and-markets/electrolyser-manufacturing-for-morocco-green-hydrogen-value-chain/> accessed 31 October 2023.

[6] Ibid.

hydrogen facilities.[7] Similarly, the United Arab Emirates has announced seven green and blue hydrogen projects.[8] Efforts are also ongoing in Egypt to produce 20 million tons of green hydrogen annually by 2035, while Oman also signed a $3.5 billion deal for a green hydrogen plant.[9]

The MENA region is thus projected to become one of the world's largest exporters of hydrogen by the year 2050, boasting significant proven reserves of natural gas – a key fuel for blue hydrogen projects – and a demonstrated track record of experience in managing complex logistics and infrastructure for the energy industry.[10] However, while the proposed projects underscore increasing commitments across the region to diversify the energy mix and advance a low-carbon economy through the production of green hydrogen, the corresponding legal, governance, and institutional frameworks would need to be bolstered to keep pace with such hydrogen infrastructure investments.[11] A shift to a hydrogen economy in a region traditionally heavily reliant on fossil fuels will require the development of robust legal and governance frameworks that will provide a foundation for coherent implementation. The injection of significant amounts of hydrogen into the national energy networks comes with a wide range of logistical, infrastructure, and grid-balancing questions across the entire hydrogen production and supply chain. At the same time, health, safety, and environmental standards (HSE) for hydrogen infrastructure will need to be developed. Hydrogen is both complex to produce and store and capital intensive to distribute.[12]

After this introduction, Section 6.2 examines the drivers of the hydrogen revolution in the MENA region. Section 6.3 analyzes current regulatory uncertainties and gaps in the design and

7 Joelle Thomas, 'The Energy–Water Nexus in the Middle East: Will Water Scarcity Compromise the Middle East's Green Hydrogen Future?' (*Energy Transition*, 8 September 2021) <https://energytransition.org/2021/09/the-energy-water-nexus-in-the-middle-east-will-water-scarcity-compromise-the-middle-easts-green-hydrogen-future/> accessed 31 October 2023.

8 United Arab Emirates Ministry of Energy & Infrastructure, 'UAE Hydrogen Leadership Roadmap' (4 November 2021) <https://u.ae/-/media/Documents-2022/UAE-Hydrogen-Roadmap–Eng.ashx> accessed 31 October 2023 (hereinafter: United Arab Emirates Ministry of Energy & Infrastructure).

9 Arab Finance, 'Egypt Could Produce 20m Tons of Green Hydrogen by 2035: EIB' (*Zawya*, 28 December 2022) <www.zawya.com/en/economy/north-africa/egypt-could-produce-20m-tons-of-green-hydrogen-by-2035-eib-fuhypv67> accessed 31 October 2023; and Adal Mirza, 'Oman Signs Land Deal for New Green Hydrogen Plant' (*Argus Media*, 24 August 2021) <www.argusmedia.com/en/news/2247165-oman-signs-land-deal-for-new-green-hydrogen-plant> accessed 31 October 2023.

10 'The MENA region holds the world's largest proven oil reserves (approximately 59%), approximately 45% of the world's proven natural gas reserves, and 30% of global mineral reserves.' Damilola S Olawuyi, 'Can MENA Extractive Industries Support the Global Energy Transition? Current Opportunities and Future Directions' (2021) 8(2) Extractive Industries and Society 100685, 1 <www.sciencedirect.com/science/article/abs/pii/S2214790X19303399> accessed 31 October 2023 (hereinafter: Olawuyi 2021).

11 A hydrogen economy is one in which hydrogen is used as the major energy source. See Yi Dou and others, 'Opportunities and Future Challenges in Hydrogen Economy for Sustainable Development' in Antonio Scipioni, Alessandro Manzardo and Jingzheng Ren (eds.), *Hydrogen Economy: Supply Chain, Life Cycle Analysis and Energy Transition for Sustainability* (Academic Press 2017) 277, 279.

12 'The hydrogen value chain is both complex and capital intensive.' Arnout de Pee and others, 'The Clean Hydrogen Opportunity for Hydrocarbon-Rich Countries' (*McKinsey & Company*, 23 November 2021) <www.mckinsey.com/industries/oil-and-gas/our-insights/the-clean-hydrogen-opportunity-for-hydrocarbon-rich-countries> accessed 1 November 2023; and 'Hydrogen's low energy density, high volume and need for cryogenic storage are some of the biggest barriers to its growth'. Andrea Willige, '4 Ways of Storing Hydrogen from Renewable Energy' (*Spectra*, 30 November 2022) <https://spectra.mhi.com/4-ways-of-storing-hydrogen-from-renewable-energy> accessed 1 November 2023; see also Bernard Chukwudi Tashie-Lewis and Somtochukwu Godfrey Nnabuife, 'Hydrogen Production, Distribution, Storage and Power Conversion in a Hydrogen Economy – A Technology Review' (2021) 8 Chemical Engineering Journal Advances 100172 <www.sciencedirect.com/science/article/pii/S2666821121000880> accessed 1 November 2023.

implementation of hydrogen projects across the MENA region. Section 6.4 proffers legal pathways for addressing those challenges. Section 6.5 concludes.

6.2 DRIVERS OF THE HYDROGEN REVOLUTION IN THE MENA REGION

The growing emphasis on the transition to a hydrogen economy across the MENA region is due to four key drivers. First, there is an unprecedented rise in domestic energy demand in the region which will necessitate the diversification and expansion of supplemental energy supplies.[13] 'Intertwined with oil driven economic expansion is a geometric rise in population and energy consumption across the Gulf at a median rate of 5–10 per cent per year.'[14] 'Peak energy demand in the Middle East … is currently close to, and in some countries, slightly above installed capacity', 'especially during daytime in summer months when air conditioning use is highest'.[15] For example, as of 2013, electricity demand in Qatar had steadily risen by more than 30 percent over the previous four years.[16] 'In Saudi Arabia, it is projected that peak-time electricity demand will almost triple to 120,000 megawatts by 2032, from around 46,000 megawatts in 2010.'[17] Given these realities, investments in energy infrastructure for cleaner and potentially more efficient alternative supplies, including hydrogen grids, to meet the increasing peak demand for energy, and promote energy diversification, remains paramount across the region.[18]

A second driver of the increased interest in hydrogen investments in the region is the need for economic and energy diversification in preparation for the post oil and gas era. 'Oil and gas resources across the region are not infinite and could be depleted within the next few decades',[19] at least to the point that marginal rises in costs render conventional hydrocarbons less competitive in the face of secular improvements in the economics of renewable/clean technology investments. The International Energy Agency (IEA) and BP both predicted a decline in global oil demand, 'with demand falling by ten per cent this decade and by as much as 50 per cent over the next twenty years',[20] as those cleaner sources expand their share of the energy consumption basket. Studies show that the Middle East could run out of oil by 2057, while natural gas supplies could be depleted by 2064.[21] Given these statistics, MENA countries have embraced

[13] Damilola S Olawuyi, 'Advancing Innovations in Renewable Energy Technologies as Alternatives to Fossil Fuel Use in the Middle East' in Donald Zillman and others (eds.), *Innovation in Energy Law and Technology: Dynamic Solutions for Energy Transitions* (OUP 2018) 357 (hereinafter: Olawuyi 2018).

[14] Ibid.

[15] Ibid.

[16] Ibid.

[17] Ibid.

[18] Ibid.

[19] Victoria R Nalule, 'How to Respond to Energy Transitions in Africa: Introducing the Energy Progression Dialogue' in Victoria R Nalule (ed.), *Energy Transitions and the Future of the African Energy Sector* (Palgrave MacMillan 2021) 8. See also Mohammad Al Asoomi, 'Time for Change in Gulf's Energy Policy' (Gulf News, 29 October 2018) <https://gulfnews.com/business/energy/time-for-change-in-gulfs-energy-policy-1.1553842> accessed 1 November 2023; Jamie Ingram, 'Kuwait Burns Record Crude to Meet Power Surge' (2020) 63(39) Mees <www.mees.com/2020/9/25/power-water/kuwait-burns-record-crude-to-meet-power-surge/82458f70-ff47-11ea-9e8d-7b6c0659de24> accessed 1 November 2023; 'Kuwait Ponders Long-Term Power Fuel Supply Options: MEES Analysis' (2013) 56(24) Mees <http://archives.mees.com/issues/1481/articles/50278> accessed 1 November 2023.

[20] Cameron Kelly, 'Leveraging Renewable Energy Technologies for Climate Change Mitigation and Adaptation in the Middle East' in Damilola S Olawuyi (ed.), *Climate Change Law and Policy in the Middle East and North Africa Region* (Routledge 2022) 232 (hereinafter: Olawuyi 2022).

[21] Olawuyi 2018 358. See also Steve Sorrell and others, *Global Oil Depletion: An Assessment of the Evidence for a Near-Term Peak in Global Oil Production* (UK Energy Research Centre 2009); R Aguilera and others, 'Depletion and the Future Availability of Petroleum Resources' (2009) 30(1) Energy Journal 141.

energy diversification through increased investments in hydrogen and renewable energy projects 'as ways of mitigating the oil and gas depletion, while also preparing for life after oil and gas'.[22] For example, the Pan-Arab Strategy for the Development of Renewable Energy (2010–2030) specifically sets a target of increasing installed renewable energy power generation capacity across the region from 12 gigawatts (GW) in 2013 to 75 GW in 2030.[23] Similarly, 'Qatar expressly indicates in its [Qatar National Vision] 2030 the intention to invest in world-class infrastructure necessary to achieve "a diversified economy that gradually reduces dependence on hydrocarbon industries" by the year 2030.'[24] In recognition of the key roles that hydrogen will play in meeting the energy and economic diversification targets, MENA countries are coming together to expand joint initiatives and projects aimed at integrating hydrogen production into the energy mix.[25]

Third and related is the increased emphasis on decarbonization and net-zero emissions across the world in response to the climate change emergency.[26] Efforts to mitigate climate change across the world sparked a gradual 'shift away from carbon intensive fossil fuels, the bedrock of several MENA economies'.[27] Similarly, as signatories to the Paris Agreement and the United Nations Framework Convention on Climate Change, several MENA countries have already committed, via their intended nationally determined contributions (INDCs), to advance climate mitigation and adaptation efforts.[28] This includes 'investing in climate-smart energy systems, *ie* structures and systems that lower greenhouse gas (GHG) emissions, and improve [national capacity] to adapt to, and cope with, the risks posed by climate change'.[29] Through investments in green hydrogen projects that leverage on, and repurpose existing natural gas infrastructure, MENA countries now aim to be at the forefront of the low-carbon hydrogen revolution.[30] Increased production and use of green hydrogen as a sustainable and low-carbon fuel can reduce the volume of GHG emissions in the region, while also advancing the availability, accessibility, and reliability of energy for the region's growing population.[31] This will go a long way in advancing the realization of the United Nations Sustainable Development Goals (SDGs) across the region, particularly SDG 13 on climate change and 'SDG 7 on clean stable, and affordable energy for all by the year 2030'.[32]

A fourth key driver of the hydrogen revolution in the MENA region is the effort by gas-rich MENA countries to leverage their comparative advantages as hubs for blue and green hydrogen

[22] Olawuyi 2018 359.

[23] Mohammad El-Khayat and others, *Pan-Arab Renewable Energy Strategy 2030: Roadmap of Actions for Implementation* (International Renewable Energy Agency 2014) 17 <www.irena.org/-/media/Files/IRENA/Agency/Publication/2014/IRENA_Pan-Arab_Strategy_June-2014.pdf> accessed 2 November 2023.

[24] Olawuyi 2018 359.

[25] See the MENA Hydrogen Alliance, which was launched in 2020 to 'bring . . . together private and public sector actors as well as science and academia to kick-start green hydrogen economies' in the MENA region. 'About MENA Hydrogen Alliance' (*Dii Desertenergy*) <https://dii-desertenergy.org/mena-hydrogen-alliance/> accessed 2 November 2023 (hereinafter: 'About MENA Hydrogen Alliance'). See also Olawuyi 2022.

[26] Olawuyi 2022 1–10.

[27] Olawuyi 2021 1.

[28] Ibid 2.

[29] Ibid.

[30] Faran Razi and Ibrahim Dincer, 'Renewable Energy Development and Hydrogen Economy in MENA Region: A Review' (2022) 168 Renewable and Sustainable Energy Reviews 112763, 4–8 <www.sciencedirect.com/science/article/abs/pii/S1364032122006487> accessed 2 November 2023.

[31] Ibid 4, 8.

[32] Damilola S Olawuyi, 'The Search for Climate and Energy Justice in the Global South: Shifting from Global Aspirations to Local Realization' (2023) 14 George Washington Journal of Energy and Environmental Law 98, 98; see also UNGA Res 70/1 (21 October 2015) UN Doc A/RES/70/1.

projects. The global momentum to transition to a hydrogen economy is projected to increase demand for natural gas, a transition fuel needed to drive the hydrogen revolution.[33] With significant deposits of natural gas, great sunshine intensity for solar-powered green hydrogen projects, and significant experience in infrastructure repurposing, MENA countries have elaborated plans to become the new hydrogen superpowers.[34] Oman and United Arab Emirates (UAE) have released National Hydrogen roadmaps and strategies, while such strategies are already under development in Morocco and Saudi Arabia, amongst other MENA countries.[35] For example, the UAE's Hydrogen Leadership Roadmap specifically aims to capture 25 percent of the global hydrogen market by leveraging the country's solar potential to attract investments in green hydrogen, while also pursuing investment plans in blue hydrogen projects.[36]

Given these main drivers, the appetite for hydrogen investments across the MENA region is currently very high and could remain so for the next decade. However, to ensure that hydrogen investments proceed in a safe, orderly, and sustainable manner, there is a need for a comprehensive legal framework on hydrogen that elaborates upon health, safety, and design standards for hydrogen infrastructure. Section 6.3 develops a profile of key legal issues and gaps in the design and implementation of hydrogen projects across the MENA region that must be addressed to support the safe, orderly, and sustainable transition to a hydrogen economy in the region.

6.3 ADVANCING A HYDROGEN ECONOMY IN THE MENA REGION: SURVEY OF LEGAL BARRIERS AND LIMITATIONS

As can be seen in jurisdictions such as France, Sweden, Finland, Denmark, and Germany, where significant progress has been recorded in the transition to a hydrogen economy, investments in hydrogen infrastructure and technologies must be backed by a clear and transparent legislative framework, including licensing and permitting processes and standards for hydrogen production, storage, commercialization, and export. Governments should design financial incentives to encourage the development of hydrogen projects and to offset the higher capital expenditures and operating costs associated with both investing in and utilizing hydrogen technologies, particularly as compared to conventional means.

There is an urgent need for MENA countries to put in place robust and coherent law and governance frameworks to support the ambitious hydrogen economy goals. This section discusses legal barriers that must be promptly addressed if current national and regional goals to develop hydrogen production across the MENA region are to come to pass.

[33] Although natural gas is a fossil fuel, studies have shown that it remains the cleanest, least polluting, and most hydrogen rich of all hydrocarbon energy sources. See Michael Levi, 'Climate Consequences of Natural Gas as a Bridge Fuel' (2013) 118 Climate Change 609; Xiaochun Zhang and others, 'Climate Benefits of Natural Gas as a Bridge Fuel and Potential Delay of Near-Zero Energy Systems' (2016) 167 Applied Energy 317; Fang-Yu Liang and others, 'The Role of Natural Gas as a Primary Fuel in the Near Future, Including Comparisons of Acquisition, Transmission and Waste Handling Costs of as with Competitive Alternatives' (2012) 6 (supp 1) Chemistry Central Journal S4; Damilola S Olawuyi, 'The Role of Natural Gas in a Just and Equitable Energy Transition' in Damilola S Olawuyi and Eduardo G Pereira (eds.), *The Palgrave Handbook of Natural Gas and Global Energy Transitions* (Palgrave Macmillan 2022).

[34] Studies already project Morocco and Saudi Arabia as two of the countries that 'are best placed to emerge as major clean hydrogen producers by 2050'. Thijs Van de Graaf and others, *Geopolitics of the Energy Transformation: The Hydrogen Factor* (International Renewable Energy Agency 2022) 48 (hereinafter: Van de Graaf et al.).

[35] Ibid. See also 'Oman Announces Investment Opportunities in Green Hydrogen' (*Foreign Ministry of Oman*, 23 October 2022) <https://fm.gov.om/oman-announces-investment-opportunities-in-green-hydrogen/> accessed 2 November 2023 (stating the country's aim to become one of world's leading green hydrogen hubs).

[36] United Arab Emirates Ministry of Energy & Infrastructure.

6.3.1 *Unclear Legal Framework*

One of the most important barriers to achieving the hydrogen economy visions of MENA countries is the absence of a clear and coherent legal framework on hydrogen. While there are several natural resource laws that may, directly or indirectly, apply to hydrogen projects in these jurisdictions, specific legislation or guidelines on the development, production, and commercialization of hydrogen has yet to come to fruition. For example, in the UAE, hydrogen investment may implicate the nation's oldest laws (numbers 4 and 7 from 1971 and 1976, respectively)[37] which formed the Abu Dhabi National Oil Company and granted it certain exclusive control of the energy sector. While such existing laws provide a general legal framework that can guide investments in hydrogen technology, they do not adequately address specific requirements and questions on the functioning of a hydrogen market, as well as export of hydrogen for cross-border trade. Under a strict reading of the UAE law, it is unclear how it would support or regulate the development, licensing, and implementation of new energy technologies such as green and blue hydrogen (with both conventional and renewable power source utilization).[38]

In addition to providing clarifications on what exactly is defined as green, gray, or blue hydrogen under the relevant laws of countries in the MENA region, a clear legal framework is required to clarify the standards to be complied with for the safe and reliable development and operation of hydrogen infrastructure and networks.[39] There are three relevant observations to be made. First, a clear regulatory framework should establish a licensing framework that will ensure the safe, orderly, and sustainable development of hydrogen. Second, given the need to attract foreign investment and technologies required to drive hydrogen expansion across the region, there is a necessity to integrate performance standards and financial incentives to increase the demand for hydrogen across the region, as well as the investments to meet such demand. Third, the integration of a significant amount of hydrogen into power grids requires substantial transformations of existing electricity laws to ensure coherence and remove barriers to achieving grid integration, balancing, storage, interconnection, and regional grid connection.[40] EU countries are also introducing sustainability and certification standards to ensure that the entire value chain of the production and distribution of hydrogen, including procurement practices, comply with all applicable laws, including ethical sourcing and respect for human rights.[41] With increased emphasis across the world on business and human rights, as well as environment, social, and governance (ESG) risks in the energy sector, investors in hydrogen projects will seek clear legislative guidance to properly anticipate and mitigate legal, financial, and reputational risks associated with hydrogen projects.[42] A selected review of some among those considerations

[37] '(Abu Dhabi) Law No. 4 of 1976 – Gas Ownership Law' (*International Energy Agency*, 15 February 2022) <www.iea.org/policies/12298-abu-dhabi-law-no-4-of-1976-gas-ownership-law> accessed 2 November 2023; and 'Hydrogen Law and Regulation in the Middle East' (*CMS Expert Guides*, 24 November 2021) <https://cms.law/en/int/expert-guides/cms-expert-guide-to-hydrogen/middle-east> accessed 2 November 2023.

[38] Ibid.

[39] For example, Germany's recently amended Energy Industry Act (*Energiewirtschaftsgesetz* – EnWG) clarifies the standards to be complied with in the development and operation of hydrogen infrastructure and networks.

[40] Olawuyi 2021.

[41] Proposal for a Directive of the European Parliament and of the Council on common rules for the internal markets in renewable and natural gases and in hydrogen [2021] COM (2021) 803 final, 15 December 2021.

[42] Damilola S Olawuyi, 'Corporate Accountability for the Natural Environment and Climate Change' in Ilias Bantekas and Michael Ashley Stein (eds.), *Cambridge Companion to Business and Human Rights* (Cambridge University Press 2021) 257.

are also treated within Chapter 10, 'Sustainability Criteria for Renewable Hydrogen'. The adoption of clear and specific hydrogen laws and regulations could provide robust and tailor-made requirements to guide the industry going forward.

6.3.2 *Barriers to Private Sector Participation*

A key objective of the emerging hydrogen strategies across the MENA region is to promote participation of the private sector in hydrogen investments and projects.[43] The partnership approach adopted by several of the mentioned hydrogen development plans show the increased realization that government alone may not be able to meet the financial and technical requirements needed to finance, develop, and maintain capital-intensive energy infrastructure.[44] Despite this recognition, however, many MENA countries have yet to enact public–private partnership (P3) laws that set out 'the requirements and process[es] for developing, financing and implementing P3 projects'.[45] Hydrogen presents an excellent opportunity to do so. Currently only Egypt, Jordan, Abu Dhabi, Oman, Qatar, Kingdom of Saudi Arabia, Kuwait, and Dubai have implemented P3 legislation and many of these are recent developments, which means their overall impact in terms of enhancing private investments in infrastructure projects is yet to be fully tested. As a matter of comparison: in the United States of America more than thirty P3 laws have been enacted at the state and federal levels,[46] whereas Dubai's first P3 law was only enacted in 2015.[47] Even in those Middle East jurisdictions that have enacted P3 laws, 'poorly functioning legal structures (including contract enforceability and governance), poor regulatory frameworks, [and] lack of standardized contracts' are some of the impediments to effective deployment of P3s, according to recent research.[48]

Additional barriers for the deployment of P3 include blurry apportionments between the interests of private parties and the government, which are common problems with investments in the Middle East and other jurisdictions. Direct or indirect state ownership and control of many of the private sector's most influential actors is common. Contracts in the Middle East, therefore, often lack a precise risk allocation between a [P3's] public and private sector parties, while also saddling operators with the burden of incompetency of the national institutions that promote P3.[49] The economics behind P3 is that the private sector participants stand to achieve material benefits in the event of project success, but are often left to face unclear permitting and approvals processes, resulting in delays while awaiting regulatory clarity, and, when things go wrong, an uncertain limbo until backstops from state coffers can be actionable. This was the case, for example, with the landmark default, restructuring, and recapitalization of Dubai Ports

[43] United Arab Emirates Ministry of Energy & Infrastructure 9.

[44] See Olawuyi 2018 364–65; see also Organisation for Economic Co-operation and Development, *Public–Private Partnerships in the Middle East and North Africa: A Handbook for Policy Makers* <https://oecd.org/mena/competitiveness/PPP%20Handbook_EN_with_covers.pdf> accessed 26 October 2023.

[45] Damilola S Olawuyi, 'Financing Low-Emission and Climate-Resilient Infrastructure in the Arab Region: Potentials and Limitations of Public-Private Partnership Contracts' in Walter Leal Filho (ed.), *Climate Change Research at Universities: Addressing the Mitigation and Adaptation Challenges* (Springer 2017) 539 (hereinafter: Olawuyi 2017).

[46] Dan McNichol, *The United States: The World's Largest Emerging P3 Market* (AIG 2013) <https://riskandinsurance.com/wp-content/uploads/2016/10/the-us-the-worlds-largest-emerging-p3-market.pdf>.

[47] 'Dubai Law No. 22 of 2015 on Public–Private Partnerships (in Arabic): Public–Private Partnership' (*Public–Private Partnership Legal Resource Center*) <https://ppp.worldbank.org/public-private-partnership/library/dubai-law-no-22-2015-public-private-partnerships-arabic> accessed 2 November 2023.

[48] Olawuyi 2022 234; Olawuyi 2018.

[49] Olawuyi 2022 234.

World that began in 2009 and was not functionally complete until 2020.[50] As this procedure, which saw a publicly traded company at the center of a major logistic initiative with tacit government backing file for bankruptcy, demonstrated: '[i]n the absence of a clear institutional and legal framework for the promotion of P3 investments', wide-scale development of hydrogen projects may face longer-term structural challenges.[51]

6.3.3 *Unclear Pricing and Financing Framework*

Another key implementation gap is the lack of clarity on the pricing and financing framework for hydrogen in the MENA region. Unlike other hydrocarbons markets where prices are, to a large extent, set by global and local supply and demand, with broad presumptive fungibility between similar energy carriers, hydrogen is a unique commodity. Without the infrastructure to support its distribution and combustion, regardless of its production costs, hydrogen is – due to the limited outlets for consumption via fuel cell vehicles (FCVs) or in specialized power-generative and as yet comparatively narrow swath of industrial applications – a zero-value commodity, except for where it can be utilized. The vagaries of hydrogen pricing are also evident in the wide range of prices throughout the globe: Japan: ~$10 per kilogram;[52] Europe: ~$20 per kilogram;[53] and North America: ~$7 per kilogram.[54]

Yet it is not fair to compare geographic pricing in a vacuum without a commensurate assessment of demand stability and supply growth, particularly with the advent of hydrogen 'clusters'[55] such as in Japan,[56] which boasts an expansive hydrogen mobility infrastructure worldwide.[57] Not only did Japan introduce a comprehensive Strategic Roadmap for Hydrogen and Fuel Cells in 2011, it also released a national Basic Hydrogen Strategy in 2017, a 'Green Growth Strategy through Achieving Carbon Neutrality in 2050', which was announced in 2020, and the 6th Strategic Energy Plan released in 2021.[58] These documents clarify the framework for the development and pricing of hydrogen in the country. Japan has taken, in a sense, a dual-track approach to pricing hydrogen at a level that can induce marginal supply with compelling producer economics while also stoking demand by getting consumers accustomed to using the fuel in everyday life at an affordable price. At present, this approach requires a number of

[50] 'DP World Returns to Full State Ownership, Takes on $8.1 Billion Debt' (*Reuters*, 17 February 2020) <www.reuters.com/article/us-dp-wrld-delisting-idUSKBN20B0F8> accessed 2 November 2023.

[51] Domilola S Olawuyi, 'From Energy Consumers to Energy Citizens: Legal Dimensions of Energy Citizenship' in Ruven Fleming and others (eds.), *Sustainable Energy Democracy and Law* (Brill 2021) 115.

[52] 'Japan – Eneos and Chiyoda to Slash Green Hydrogen Costs by Two Thirds' (*Hydrogen Central*, 21 June 2021) <https://hydrogen-central.com/japan-eneos-chiyoda-green-hydrogen-costs/> accessed 2 November 2023 (hereinafter: 'Japan – Eneos and Chiyoda to Slash Green Hydrogen Costs by Two Thirds').

[53] 'Hydrogen Price Trend and Forecast' (*ChemAnalyst*) <www.chemanalyst.com/Pricing-data/hydrogen-1165> accessed 2 November 2023.

[54] Ibid.

[55] Lucy Roue, 'What Is a Hydrogen Cluster and How Can It Boost the Regional Economy by £1.6bn' (*Manchester Evening News*, 1 November 2017) <https://www.manchestereveningnews.co.uk/business/business-news/hydrogen-cluster-peel-report-vehicle-13837281> accessed 2 November 2023.

[56] Jane Nakano, 'Japan's Hydrogen Industrial Strategy' (*Center for Strategic and International Studies*, 12 January 2023) <www.csis.org/analysis/japans-hydrogen-industrial-strategy> accessed 2 November 2023.

[57] Ibid. See also Noriko Behling, Mark C Williams and Shunsuke Managi, 'Fuel Cells and the Hydrogen Revolution: Analysis of a Strategic Plan in Japan' (2015) 48 Economic Analysis and Policy 204.

[58] Organisation for Economic Co-operation and Development, 'The Hydrogen Regulatory Landscape' (*OECD iLibrary*) <www.oecd-ilibrary.org/sites/6130062f-en/index.html?itemId=/content/component/6130062f-en> accessed 6 November 2023. See also Clifford Chance, 'Focus on Hydrogen: Japan's Energy Strategy for Hydrogen and Ammonia' <www.cliffordchance.com/content/dam/cliffordchance/briefings/2022/08/focus-on-hydrogen-in-japan.pdf> accessed 23 October 2023.

subsidies.[59] As a consequence, raw hydrogen prices cannot, strictly speaking, be compared in an apples-to-apples fashion and must be taken in the context of other associated economics, including FCV rebates, hydrogen producer incentives, carbon credit frameworks, and other energy costs associated with the creation and distribution of the fuel.

The multifaceted nature of hydrogen economics has meant that the general ambition of sovereign state sponsors of hydrogen tends toward stable but gradually declining hydrogen pricing over time. By construction, such a scheme serves as an impetus for immediate investment in the sector given the implied higher future rates of return necessary to compensate for the incremental risks of allocating capital to a new energy carrier in the grids.

To provide a comparison, the US Department of Energy launched the Hydrogen Shot program in June 2021 with a goal of reducing green hydrogen costs by roughly 80 percent, to $1 per kilogram, within a decade.[60] 'The Hydrogen Shot establishes a framework … for clean hydrogen deployment', including the outfit of several dedicated offices and a total of approximately $400 million in financial year 2022.[61] Astonishingly, commitments to back hydrogen infrastructure within the recently enacted Inflation Reduction Act are nearly 100 times this amount,[62] attesting to the degree of priority attached to this energy source. Similarly, Japan has stated its ambition to reduce hydrogen pricing from the current level of 1,100 yen (~$100 per kilogram) to as little as 330 yen by 2030,[63] with billions in incremental funding to support cost reductions and further roll-out of the country's orthodox cluster-based system.[64]

Theoretically, notwithstanding the preemptive first-mover advantages enjoyed by the United States and Japan, MENA countries should be among 'the cheapest producers of hydrogen in the world, second only to Australia in markets assessed by Platts',[65] which makes a compelling case for a future MENA hydrogen hub. When it comes to the MENA region, moreover, hydrogen is likely to be a truly carbon-neutral proposition given that current expected cost prices for green hydrogen may underpin commercial competitiveness with the expected primacy of gray or blue fuel.[66] Bargain-priced renewable power has, in a sense, rendered the cost of both electrolysis and desalinization sufficiently marginal that the alternative of stripping hydrogen from fossil fuels

59 Soon Chen Kang, 'Japan Keeps Auto Industry's Hydrogen Dreams Alive' (*S&P Global Market Intelligence*, 10 February 2021) <www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/japan-keeps-auto-industry-s-hydrogen-dreams-alive-62160857> accessed 2 November 2023.

60 'Hydrogen Shot' (*Office of Energy Efficiency & Renewable Energy*) <www.energy.gov/eere/fuelcells/hydrogen-shot> accessed 9 November 2023.

61 Ibid.

62 Alan Krupnick and Aaron Bergman, 'Incentives for Clean Hydrogen Production in the Inflation Reduction Act' (*Resources for the Future*, 9 November 2022) <www.rff.org/publications/reports/incentives-for-clean-hydrogen-production-in-the-inflation-reduction-act/> accessed 2 November 2023.

63 'Japan – Eneos and Chiyoda to Slash Green Hydrogen Costs by Two Thirds'.

64 Petra Schwager and others, *Green Hydrogen Industrial Clusters Guidelines* (United Nations Industrial Development Organization 2023) <www.unido.org/sites/default/files/files/2023-08/GH2_ClusterGuidelines_0.pdf> accessed 2 November 2023; Daisuke Akimoto, 'A Look at Japan's Latest Hydrogen Strategy' (*The Diplomat*, 7 July 2023) <https://thediplomat.com/2023/07/a-look-at-japans-latest-hydrogen-strategy/> accessed 2 November 2023.

65 James Burgess, 'Platts Launches Middle East Hydrogen Prices as Mega-Projects Underline Region's Ambitions' (*S&P Global Commodity Insights*, 22 November 2021) <www.spglobal.com/commodityinsights/en/market-insights/latest-news/electric-power/112221-platts-launches-middle-east-hydrogen-prices-as-mega-projects-underline-regions-ambitions> accessed 2 November 2023.

66 Carol Nakhle, 'The Hydrogen Craze Hits the Middle East' (*Geopolitical Intelligence Services*, 16 May 2022) <www.gisreportsonline.com/r/middle-east-hydrogen> accessed 2 November 2023.

and offsetting (or capturing) the embedded carbon emissions is not necessarily demonstrably advantageous on a carbon-equivalent basis.[67]

Hence, the MENA region starts with better enabling conditions than other regions (such as Europe) for hydrogen, but it will still need to establish appropriate pricing frameworks that can mitigate risks associated with the high and uncertain costs of entering fixed-price supply contracts essential for attracting long-term competitive financing. Such mitigation will entail government support in the form of subsidies, grants, or preferential financing, as well as duly structured power-purchase agreements and access to clean water, even with low input costs to production, courtesy of some of the world's most competitive renewables and large reserves of surplus hydrocarbons.[68] If a private sector appetite to provide financing via green bonds or other more innovative mechanisms such as securitization of future carbon credits[69] materializes, the need for state support may be reduced commensurately. One can imagine any number of enhanced mobility schemes in which fresh hydrogen demand is spurred via well-constructed P3 to mimic programs from the United States or Japan. The MENA region, especially the Gulf Cooperation Council, has shown that it can leapfrog rapidly in terms of technological progress and the rapid adoption of innovations (including but not limited to mobile device coverage, flying cars, or high-speed intranational transport[70]) to create a cycle of hydrogen investment, production, and consumption for decades to come. To achieve this ambitious goal, clear and comprehensive legal frameworks that elaborate the pricing and financing framework for hydrogen, ranging from deliberate P3 programs to coherent incentive schemes and accommodative application of competition law, amongst other factors, would be essential to unlock a hydrogen economy in the region.

6.3.4 *Institutional Gaps*

'The absence of [a] legally recognized national authority for [hydrogen regulation], coupled with the lack of coordination amongst existing government institutions and ministries, remains one of the serious institutional challenges [undermining] the successful implementation of [hydrogen] projects in the [MENA] region.'[71] Despite the ambitious aims to transition to hydrogen economies, several MENA countries currently lack the dedicated institutional mechanisms to track the production, consumption, and sale of hydrogen.[72]

Oman is one of the few countries in the region to have, in 2022, established a focal agency on hydrogen, the Hydrogen Oman (HYDROM), specifically to lead the country's green hydrogen strategy.[73] HYDROM's mandate includes the supervision of land allocation and licensing and

[67] Jim Magill, 'Blue vs. Green Hydrogen: Which Will the Market Choose?' (*Forbes*, 9 November 2022) <www.forbes.com/sites/jimmagill/2021/02/22/blue-vs-green-hydrogen-which-will-the-market-choose/?sh = 32cfdb643878> accessed 2 November 2023.

[68] Gajendra Yadav, 'Financing Green Hydrogen Projects in the Middle East' (*Synergy Consulting*, 23 November 2022) <www.synergyconsultingfa.com/industry-knowledge/financing-green-hydrogen-projects-in-the-middle-east/> accessed 2 November 2023.

[69] Garrett Monaghan and Alan Heuston, 'Green IFSC: Securitisation of Carbon Offsets and Creation of a New Crossover Credit – Structured Finance' (*Mondaq*, 1 March 2011) <www.mondaq.com/ireland/structured-finance/124580/green-ifsc-securitisation-of-carbon-offsets-and-creation-of-a-new-crossover-credit> accessed 2 November 2023.

[70] 'Chinese "Flying Car" Makes First Public Flight in Dubai' (*Reuters*, 13 October 2023) <www.reuters.com/technology/chinese-flying-car-makes-first-public-flight-dubai-2022-10-11/> accessed 2 November 2023.

[71] Olawuyi 2017 541.

[72] Van de Graaf et al. 31.

[73] 'Home' (*Hydrom*) <https://hydrom.om> accessed 2 November 2023.

structuring of associated large-scale, world-class green hydrogen projects in Oman.[74] While Oman's example is expected to guide other MENA countries to put in place similar tailored institutional and governance structures to guide the coherent development of hydrogen projects, institutional development in this regard remains scarce. In addition to facilitating the coherent development and implementation of a country's hydrogen strategy, a focal agency in countries of the MENA region will also play key roles in 'serving as a one-stop shop' that streamlines and simplifies the licensing processes for projects, including ensuring land access and promoting data collection to ensure that hydrogen production is accounted for in official statistics on energy production and consumption in a country.[75] Similarly, a focal agency can help to promote coordination and create synergies 'between all government institutions, both new and old, to fast track and simplify the implementation of' hydrogen infrastructure projects.[76]

The progress made in hydrogen infrastructure development in France, Germany, and Denmark, amongst others, is due largely to the existence of regulatory bodies and industry institutions, both old and new, to guide and monitor the development of hydrogen projects. For example, German energy regulator the Bundesnetzagentur is now in charge of hydrogen infrastructure, while France in 2021 established a National Hydrogen Council (Conseil National de l'hydrogène) to monitor hydrogen development projects and policies. The French association for hydrogen and fuel cells (France Hydrogène, previously Afhypac) also plays a key role in promoting the sharing of knowledge and best practices amongst private sector operators and investors on hydrogen development. Similarly, in 2020 Germany also established the National Hydrogen Council (Nationaler Wasserstoffrat), a multidisciplinary body made up of experts in science, business, and law to facilitate the coherent implementation of the country's National Hydrogen Strategy.[77] In addition to promoting public awareness about hydrogen projects, such focal expert bodies, agencies, or councils can play key roles in providing clarifications and guidelines to investors when proposing and developing hydrogen infrastructure projects in order to ensure that such projects 'are in line with the country's national vision[s]'.[78] This 'can result in real, measurable and long-term [environmental and socio-economic] benefits'.[79] The lack of clear and coordinated governance structures in several MENA countries is a key barrier that must be addressed if hydrogen development and commercialization is to proceed in a safe, orderly, and coherent manner.

The gaps and barriers in ongoing efforts to transition to hydrogen economies in the MENA region must be addressed through holistic law and governance systems. Section 6.4 now discusses legal pathways for addressing those challenges.

6.4 IMPROVING LAW AND GOVERNANCE FRAMEWORKS ON HYDROGEN IN THE MENA REGION

While setting national strategies and targets for hydrogen development reflects the political commitment towards a progressive transition to a hydrogen economy, the next step would be for

74 Conrad Prabhu, 'Hydrogen-Powered Green Future Awaits Oman' (*Oman Observer*, 28 February 2023) <www.omanobserver.com/article/1133416/business/energy/hydrogen-powered-green-future-awaits-oman> accessed 2 November 2023.

75 Olawuyi 2018 369.

76 Ibid 366.

77 'The German National Hydrogen Council' (*Nationaler Wasserstoffrat*) <www.wasserstoffrat.de/en/national-hydrogen-council> accessed 2 November 2023.

78 Olawuyi 2018 367.

79 Ibid.

national authorities across the MENA region to develop a 'comprehensive and holistic legal framework'.[80] That framework should support and govern ongoing hydrogen projects while also attracting new ones. In the following, four recommendations to that effect will be made.

First, for hydrogen to play a substantial role in the future blend of energy consumption in the region – for mobility, consumer living, or industry – it must be viable for both investors and consumers. The cost dynamics of today's hydrogen markets mean that everything from fuel distribution stations to hydrogen fuel cells in cars to public sector implementation of systems capable of integrating hydrogen use are not, at a baseline, financially viable. Thus, a starting point is for MENA countries to put in place clear, tailored, and comprehensive laws to streamline and incentivize large-scale investments in hydrogen projects.

Current natural resource laws should also be expanded to establish clear guidelines that specifically mention and cover hydrogen. Such laws should also clarify questions relating to permitting, licensing, and pricing and include mandatory performance standards, especially amongst state-owned entities to integrate hydrogen into their energy mix. Such a requirement will increase demand for hydrogen, which will then further boost investor confidence and stimulate a competitive and attractive investment climate for hydrogen projects.

Second, building that competitive environment will require a wide range of legislative reforms aimed at streamlining market access requirements, while promoting private sector participation in hydrogen projects. To streamline market access, MENA countries will need to expand the use of tax-free or special economic zones to allow for streamlined registration and formation of dedicated operational entities to import and deploy the energy carrier, related equipment, hardware, and capital necessary to build the desired hydrogen infrastructure. Exempting hydrogen projects from stipulations on the involvement of minimum percentages of local partners and/or domestic content requirements can also enhance market upscaling. Moreover, it is necessary to enact P3-specific laws[81] or, if already enacted, to ensure that the local compliance regulations are structured to maintain the interest of international investors in pursuing projects in the MENA region. For example, P3 laws should include transparency measures to help with due diligence and equitable risk allocation so that the private sector does not have to carry all the risks associated with projects and to ensure that the finite delineation of responsibility between investor and state sponsor is clear.

Third, to promote the coherent development of hydrogen 'projects, it is important to establish a focal institution or administrative unit that will coordinate the design, approval, and implementation of such projects', including setting clear roles for different administrative entities.[82] Depending on the specific situation of each MENA country, such an institutional framework can be in the form of expanding the mandates and budgets of existing energy agencies to enable them to regulate and monitor hydrogen investments and development or of establishing new and dedicated agencies on hydrogen. 'Apart from serving as a one-stop shop that will streamline the approval processes for projects, such an institution would also provide capacity development opportunities for administrators to acquire technical knowledge about the methods, requirements, and challenges of' the hydrogen value chain.[83] 'By empowering and establishing a focal institution on' hydrogen projects, a country can develop a systemic understanding, including

[80] Damilola S Olawuyi, 'Local Content Requirements in Oil and Gas Contracts: Regional Trends in the Middle East and North Africa' (2017) 37 *Journal of Energy & Natural Resources Law* 93, 113.

[81] Damilola S Olawuyi, 'Energy Poverty in the Middle East and North African (MENA) Region' in Iñigo del Guayo and others (eds.), *Energy Justice and Energy Law* (Oxford University Press 2020).

[82] Olawuyi 2018 369.

[83] Ibid.

statistical data analysis and gathering of the contributions of hydrogen to the energy mix and ways to further enhance hydrogen development and commercialization.[84]

Fourth, regional collaboration and knowledge sharing between countries with experience and expertise on hydrogen can help to promote the adoption of hydrogen development and its efficiency across the Middle East. While countries such as Oman, the UAE, Saudi Arabia, and Morocco have some experience with hydrogen projects, 'several other countries within the [MENA region] have little to no experience at all'.[85]

> It is therefore important to promote cooperation and knowledge sharing between regional networks and institutions, within and outside of the [region], on [hydrogen], low-carbon transition, and on how P3 models can help facilitate [hydrogen] development and integration. Regional centres and platforms can also enhance the exchange of ideas, best practices, and knowledge on existing [hydrogen] project opportunities, model contracts, and practical steps for planning and implementing [hydrogen] projects.[86]

In Europe, the European Clean Hydrogen Alliance, founded in 2020, is part of EU efforts to accelerate the decarbonization and 'support[s] the large-scale deployment of clean hydrogen technologies ... by bringing together renewable and low-carbon hydrogen production, demand in industry, mobility and other sectors, and hydrogen transmission and distribution'.[87] The MENA Hydrogen Alliance is already filling a gap in this respect, although current membership is not very widespread across the region.[88] There is a need for more active engagement of the Arab League, national authorities, regulators, and research institutions across the region in this and other regional bodies that can strengthen knowledge sharing on hydrogen development. Finally, more active participation and engagement by policymakers in knowledge-sharing platforms can accelerate region-wide deployment of clean hydrogen technologies.

6.5 CONCLUSION

Endowed with conventional and renewable energy sources needed to drive the large-scale production and commercialization of green and blue hydrogen, MENA countries have increasingly announced strategic investments and plans to become hydrogen superpowers over the next decade. The wide-scale deployment of hydrogen can provide viable opportunities for countries in the region to diversify their economies, become less oil dependent, lower their carbon emissions, and generate a greater share of domestic energy from clean sources.

However, lack of regulatory clarity on the standards, certifications, and incentives to drive hydrogen production, especially to stimulate required hydrogen grid integration, distribution, and storage infrastructure in the region, is exacerbated by the absence of robust institutional frameworks to streamline and supervise hydrogen projects. Legal barriers that stifle the development of a coherent hydrogen market must be addressed to advance the comprehensive implementation of hydrogen visions and targets across the region.

[84] Ibid.
[85] Ibid.
[86] Ibid.
[87] 'The European Clean Hydrogen Alliance brings together industry, public authorities, civil society, and other stakeholders. Alliance members meet twice a year in the Hydrogen Forum to discuss the large-scale deployment of clean hydrogen technologies and what this requires.' 'European Clean Hydrogen Alliance' (*European Commission*) <https://single-market-economy.ec.europa.eu/industry/strategy/industrial-alliances/european-clean-hydrogen-alliance_en> accessed 2 November 2023.
[88] 'About MENA Hydrogen Alliance'.

To do so, there is a need for a robust regulatory framework that not only introduces transparency and certainty to the hydrogen market but also promotes and supports sustained P3 investments. Regulatory coherence and clarity can boost investor confidence on the economics of hydrogen, in terms of both profitability and long-term sustainability value. Promoting such clarity requires equilibrating risk-adjusted returns for hydrogen through focused incentives, guaranteed pricing frameworks, and, critically, a feed-in-tariff system, to offset the higher costs associated with producing energy from hydrogen or tax credits. The regional sharing of expertise, knowledge, and best practices could also provide an effective platform for MENA countries to identify unique challenges for hydrogen development in the region.

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7

Hydrogen Regulation in Southeast Asia

Steam Reforming from Biofuels as an Alternative to Electrolysis?

Piti Eiamchamroonlarp

7.1 INTRODUCTION

The ASEAN Center for Energy (ACE) highlights the potential for hydrogen to serve as an energy storage medium for intermittent renewable generation, especially from solar and wind energy.[1] It acknowledges the potential role of hydrogen, especially the contribution of hydrogen produced from biofuels from food crops, as an alternative to fossil fuel imports.[2] This chapter explains that, in spite of an absence of special legislation and regulations on hydrogen production, Association of Southeast Asian Nations (ASEAN) countries can rely on existing regulatory frameworks, especially manufacturing or industrial works and environmental protection regulatory regimes, for the regulation of the establishment and operation of hydrogen production plants. It uses Thailand as a case study to make a bigger point about regulatory techniques on hydrogen production in ASEAN countries, arguing that the current regulatory frameworks on energy production, for example, the one based on the Energy Industry Act BE 2550 (2007) (the Energy Industry Act), are too general in nature and incapable of sufficiently regulating production of green hydrogen.

This chapter starts by addressing the extent to which international climate policies have an impact on ASEAN countries' regulatory frameworks on energy production as well as manufacturing activities and environmental protection, followed by an overview of hydrogen utilisation plans in ASEAN countries. Section 7.3 analyses how the current Thai government is incorporating hydrogen production activities into the general energy production framework, due to a lack of comprehensive or special hydrogen legislation. Section 7.4 looks at how electricity procurement procedures under the Energy Industry Act can allow unintentional subsidisation of grey electricity that was formerly only thought to be available for the generation of green and blue hydrogen. The chapter concludes with some observations on the potential of hydrogen in ASEAN countries considering the current lack of regulation and an outlook on future activities.

[1] ASEAN Centre for Energy (ACE), 'Hydrogen in ASEAN: Economic Prospects, Development & Applications' (ASEAN Centre for Energy, 30 September 2021), 2 <https://aseanenergy.org/hydrogen-in-asean-economic-prospects-development-and-applications/> accessed 13 May 2022.

[2] Ibid.

7.2 THE TECHNICALITIES OF STEAM REFORMING FROM BIOFUELS AND ASEAN'S LAWS AND POLICIES ON HYDROGEN

Typically, green hydrogen is produced by water electrolysis,[3] but few people are aware that it is also possible to use chemical processes such as steam methane reforming (SMR) for the production of green hydrogen. This is a process involving the endothermic conversion of methane and water vapour into hydrogen and carbon monoxide.[4] SMR is a process by which natural gas or methane reacts with steam in the presence of a catalyst to produce hydrogen and carbon dioxide.[5] Technically speaking, a catalyser such as nickel is used to facilitate the thermochemical reaction of feedstocks such as natural gas and liquid petroleum gas to heat water to a temperature of around 850 °C and a pressure of 2.5 megapascal.[6] The methane found in natural gas reacts with steam to produce a syngas consisting of hydrogen and carbon monoxide.[7]

Depending on the fuels or energy carriers used for its generation, hydrogen produced via steam reforming itself can be categorised by colour. If it involves high greenhouse gas emissions, hydrogen produced by steam reforming of methane/natural gas is categorised as grey hydrogen.[8] Blue hydrogen is a more environmentally friendly choice – it is produced through steam methane reforming of natural gas or coal gasification, but with carbon dioxide capture and storage.[9] In any case, green and blue hydrogen are considered low-carbon hydrogen in Asia.[10] Alternatively, hydrogen may also be produced from biogas via steam reforming, and this chapter will now discuss if this can be considered green hydrogen.[11]

The exciting twist that ASEAN countries can bring to the table is to use biofuels to produce low-carbon hydrogen. Biofuels are defined by the Food and Agriculture Organization of the United Nations (FAO) as fuel produced directly or indirectly from biomass.[12] First-generation biofuels can be derived from agricultural crops grown for food and animal feed, including grains, starches, oil crops, sugarcane, sweet sorghum and non-food plants such as jatropha and pongamia pinnata.[13] Second-generation biofuels can also be produced from agricultural residue or from dedicated 'energy crops' such as grasses and fast-growing trees.[14] Organic waste, animal

[3] Martin Robinius et al., 'Economics of Hydrogen' in Manfred Hafner and Giacomo Luciani (eds.), *The Palgrave Handbook of International Energy Economic* (Palgrave Macmillan 2022) 83.

[4] Mahin Basha Syed, 'Technologies for Renewable Hydrogen Production' in Abul Azad and Mohammad Khan (eds.), *Bioenergy Resources and Technologies* (Academic Press 2021) 158.

[5] Sonal Singh et al., 'Hydrogen: A sustainable fuel for future of the transport sector' (2015) 51 Renewable and Sustainable Energy Reviews 623, 625.

[6] A. Velazquez Abad and P. E. Dodds, Production of Hydrogen in Martin Abraham (ed.), *Encyclopedia of Sustainable Technologies* (Elsevier 2017) 293–295.

[7] Ibid 295.

[8] Robert W. Howarth and Mark Z. Jacobson, 'How green is blue hydrogen?' (2021) 9 Energy Science & Engineering 1676, 1677.

[9] Ibid.

[10] Meng Yuan et al., 'Accelerating the Net-Zero Transition in Asia and the Pacific: Low-Carbon Hydrogen for Industrial Decarbonization' in Dina Azhgaliyeva, K. E. Seetha Ram and Haoran Zhang (eds.), *Decarbonization Strategies in Asia and the Pacific* (Asian Development Bank Institute 2023) 3.

[11] Hon Chung Lau, 'Decarbonization roadmaps for ASEAN and their implications' (2022) 8 Energy Reports 6000, 6019.

[12] Food and Agriculture Organization of the United Nations (FAO), 'Unified Bioenergy Terminology' (FAO, December 2004), 30 <https://fao.org/3/j4504e/j4504e00.pdf> accessed 26 January 2024.

[13] United States Agency for International Development (USAID), 'Biofuels in Asia: An Analysis of Sustainability Options' (USAID, March 2009), 9 <https://cbd.int/doc/biofuel/USAID-biofuels-asia-2009-03.pdf> accessed 26 January 2024.

[14] Ibid 12.

manure and sewage sludge can be used in anaerobic digestion to produce what is considered in ASEAN countries to be gaseous biofuels.[15] Third-generation biofuels are produced from feedstock with better sustainability properties than second-generation biofuels, especially biodiesel produced from microalgae.[16]

Given the current and potential availability of biofuels, hydrogen produced from biofuels can serve as reliable inputs for the ASEAN countries' need for low-carbon hydrogen. ACE and the International Renewable Energy Agency (IRENA) emphasised the potential roles of low-carbon hydrogen in industry sectors such as iron and steel, aluminium, chemicals and international bunkering for shipping.[17] Later, ACE published the ASEAN Biofuel Research and Development Roadmap, highlighting that ASEAN countries boast immense agricultural goods that offer promising feedstock sources for biofuel production, such as sugar cane, crude palm oil and cassava.[18]

Biomass is defined by the FAO as material of biological origin excluding material embedded in geological formations and transformed into fossil form, for example, herbaceous biomass, fruit biomass and woody biomass.[19] Biomass can be converted into biofuels, as discussed earlier. Classification of biofuels is based on their state (at room temperature) and includes the following: (a) gaseous biofuels, like biogas from different sources and syngas (coal gas); (b) liquid biofuels, including biodiesel, bioethanol, vegetable oil and bio-oil; and (c) solid biofuels such as wood, biomass briquettes, sawdust and charcoal.[20]

Examples of different applications of hydrogen production are present in ASEAN countries. These countries recognised biomass as a renewable source of energy and its potential use as feedstock for hydrogen production in the ASEAN Strategy on Sustainable Biomass Energy for Agriculture Communities and Rural Development in 2020–2030.[21] With the exception of Singapore, most ASEAN countries are strong agricultural countries.[22] Agricultural products such as rubber, acacia and eucalyptus as well as waste products from production such as palm oil mill effluent (POME), cassava pulp, sugarcane molasses, cassava roots and starch are highlighted as potential feedstocks and as biomass energy resources in Indonesia, Thailand, Vietnam, Malaysia and Myanmar.[23] With the widespread presence of available biomass resources, ASEAN countries can rely in particular on the gasification process to produce hydrogen.

By extracting oil from oil palms, biodiesel and glycerol can be produced.[24] The produced glycerol can undergo a steam reforming process to produce hydrogen.[25] Biomass residue from

[15] ASEAN Centre for Energy and International Renewable Energy Agency, 'Renewable Energy Outlook for ASEAN: Towards a Regional Energy Transition' (2nd ed.) (International Renewable, Energy Agency, Abu Dhabi; and ASEAN Centre for Energy Jakarta, 2022), 6.

[16] Ibid 14.

[17] ASEAN Centre for Energy and International Renewable Energy Agency (n15) 21.

[18] ASEAN Centre for Energy, 'ASEAN Biofuel Research and Development Roadmap' (ACE, September 2023), 2 <https://aseanenergy.org/publications/asean-biofuel-research-and-development-roadmap/> accessed 6 February 2024.

[19] Food and Agriculture Organization of the United Nations (FAO) (n12), 31.

[20] Silvia Daniela Romano and Patricio An Anibal Sorichetti, *Dielectric Spectroscopy in Biodiesel Production and Characterization* (Springer London 2011) 2.

[21] ASEAN, 'ASEAN Strategy on Sustainable Biomass Energy for Agriculture Communities and Rural Development in 2020–2030' (ASEAN, August 2020), 2 <https://asean.org/wp-content/uploads/2021/12/FAFD-53.-Biomass-Energy-Strategy-ASEAN-2020-2030-Final-Draft-210820.pdf> accessed 26 January 2024.

[22] Ibid 3.

[23] IRENA, *Scaling Up Biomass for the Energy Transition: Untapped Opportunities in Southeast Asia* (International Renewable Energy Agency 2022) 14.

[24] Ibid.

[25] Ibid.

rice paddies and the rice itself can undergo a gasification process to be converted into a combustible gas that consists of carbon monoxide, carbon dioxide, hydrogen and methane.[26] Biomass can also be used in the metabolic processes of microorganisms to produce green hydrogen, which is of particular relevance in Malaysia, for instance, as will be discussed further below.[27]

Given the technical nature of hydrogen production processes, this gives rise to a legal question: how effective is a given regulatory framework in regulating the establishment and operation of such hydrogen production activities? This will now be answered by describing the main colours of hydrogen and the respective regulations thereof in selected ASEAN countries.

7.2.1 *Grey Hydrogen: Abundant Fossil Fuels*

ASEAN countries are blessed with fossil fuel resources and, at the current production rate, can continue producing coal for another half a century.[28] To give an example: coal is defined as an 'industrial mineral' by the Myanmar Mines Law (1994).[29] A person desiring to commercially produce coal must obtain a permit from the Ministry of Mines.[30] A coal production permit holder is obligated to, inter alia, comply with conditions specified in the permit, pay the royalty[31] and other fees to the Myanmar government,[32] and make provisions for safety and the prevention of accidents in the mine.[33]

However, the Myanmar legal system lacks legislation to regulate the production of hydrogen from the extracted coal. The absence of hydrogen-specific regulations, however, does not mean that a hydrogen producer can freely produce hydrogen. A person desiring to use electricity generated from coal to produce grey hydrogen in Myanmar via a manufacturing process is subject to the Factories Act 1951. A manufacturing process in Myanmar is broadly defined as the creation of an article or substance with a view to its use, sale, transport, delivery or disposal.[34] In addition, this process also includes 'generating power'.[35] The term 'power' refers to 'electrical energy or any other form of energy which is mechanically generated and transmitted and is not generated by human or animal agency'.[36] Grey hydrogen produced from steam reforming of methane in natural gas is not considered a type of power under the Factories Act 1951 as it is not energy created by machines but thermochemical reaction of natural gas. However, the production of hydrogen from such a process can still be deemed to create an 'article or substance with a view to its use or sale'. Consequently, a person wishing to use any premises to produce hydrogen through natural gas via SMR in Myanmar is required by the Factories Act 1951 to obtain a factory licence by submitting a written notice to the Chief Inspector.[37] Therefore, hydrogen production is indirectly regulated via the Factories Act 1951. Requirements include, for

[26] Jitti Mungkalasiri and Woranee Paengjuntuek, 'Energy analysis of hydrogen production from biomass in Thailand' (2016) 21 Thammasat International Journal of Science and Technology 26, 27.
[27] Rafal Lukijtis et al., 'Hydrogen production from biomass using dark fermentation' (2018) 91 Renewable and Sustainable Energy Reviews 665, 666.
[28] ASEAN Centre for Energy (ACE) (n1) 3.
[29] Myanmar Mines Law (1994), Section 2(e).
[30] Ibid Section 4(c).
[31] Ibid Section 12(b).
[32] Ibid Section 12(f).
[33] Ibid Section 13(c).
[34] Myanmar Factories Act 1951, Section 2(k)(i).
[35] Ibid Section 2(k)(iii).
[36] Ibid Section 2(g).
[37] Ibid Section 6(1).

example, that a hydrogen production factory must be kept clean,[38] have adequate ventilation and be maintained at a steady temperature.[39]

In Singapore, grey hydrogen is produced from the gasification of coal. There is also currently an absence of special hydrogen production regulation in Singapore, but this does not mean that hydrogen production is unregulated in Singapore. According to the Factories Act 1987, a factory means any premises in which, close to or within the precincts of, persons are employed in manual labour in any process for or incidental to the making of any article or part of any article.[40] Since the air separation plant, gas processing units and sulphur recovery plants can be used to produce hydrogen, these plants shall be deemed to be factories. Consequently, operators of these plants are required by the Factories Act 1987 to register them as factories.[41] Regulatory requirements concerning cleanliness, overcrowding, ventilation, lighting, drainage of floors and sanitary conveniences apply.[42]

7.2.2 *Blue Hydrogen: Deployment of Carbon Capture Storage Technologies*

In other parts of Southeast Asia, slightly different priorities are set with regard to hydrogen production. The example of Vietnam will be examined more closely here. According to the National Green Growth Strategy for 2021–2030, the Ministry of Industry and Trade of Vietnam, for example, shall formulate mechanisms to encourage the development of hydrogen as a fuel, in particular blue hydrogen.[43]

Some words on the general regulatory climate in Vietnam are required before the next paragraph turns to blue hydrogen in Vietnam specifically. Similar to Myanmar, a regulatory framework on hydrogen production is absent in Vietnam. However, hydrogen production activities are governed by general regulatory rules concerning factory construction and fire prevention. A person wishing to construct a hydrogen production plant must obtain a construction permit from a competent state agency.[44] If the plant will be in an urban area, a construction permit can only be granted if an applicant can demonstrate that construction safety and environmental protection are ensured.[45] At the operational stage, a hydrogen facility, which can be deemed as a plant for producing flammable liquid or a gas station with total gas storage of at least 150 kg, is classified as an Appendix III facility and, therefore, is subject to fire safety requirements.[46] Consequently, a producer is required to use electrical equipment, spark-generating equipment, heat-generating equipment and fire sources and heat sources that comply with regulations and standards on fire prevention and fighting or regulations of the Ministry of Public Security.[47] However, it must be noted that to produce blue hydrogen, a producer must capture the emissions and permanently store them. Therefore, when it comes to blue hydrogen, a question on the permitting of carbon capture storage arises.

38 Ibid Section 13(1).
39 Ibid Section 15(1).
40 Factories Act 1987 (Singapore), Section 6(1)(a).
41 Ibid Section 8(1).
42 Ibid Part IV.
43 The Prime Minister's Decision to Ratify the National Green Growth Strategy for the 2021–2030 Period, Vision towards 2050 (No. 1658/QD-TTg), Article 1 para. IV.
44 Construction Law (No. 50/2014/QH13), Article 89.
45 Ibid Article 91 para. 3.
46 Ibid Appendix III.
47 Ibid Article 5 (d).

In other words, does carbon capture and storage (CCS) for blue hydrogen purposes require a separate permit and is it subject to any specific regulations? Comparable to Myanmar's legal system, mineral exploration and mining activities in Vietnam require a permit that is handed out by a competent state agency.[48] Exploration and mining activities focus on exploration for and production of minerals from reservoirs,[49] and therefore no injection of captured carbon into pore space. The same finding can be applied to petroleum activities. A holder of a petroleum contract granted by competent agencies can lawfully explore for and produce petroleum from reservoirs.[50] It does not regulate activities relating to the injection of a captured carbon stream into empty petroleum reservoirs. Many environmental laws and regulations were enacted before carbon emissions became a concern.[51] There are no regulations for land use and monitoring of long-term projects such as CCS.[52] In a nutshell, the result is that the injection does not require a permit and can be used for blue hydrogen purposes (in principle) in Vietnam.

7.2.3 *Green Hydrogen: Potential Roles of Biomass and Biogas*

Among ASEAN countries, Thailand, Indonesia, Malaysia and the Philippines have the highest bioenergy potential.[53] The two major biofuels produced in ASEAN countries are biodiesel and bioethanol.[54] Indonesia's biofuel industry mostly produces biodiesel made from palm oil.[55] In Malaysia, biodiesel products are also mainly produced from palm oil.[56] Biodiesel products in the Philippines are mostly produced from coconut oil and bioethanol from sugarcane.[57] In Malaysia, a hydrogen producer desiring to produce green hydrogen through metabolic processes of microorganisms or biogas reforming techniques is deemed to be a manufacturer under the Industrial Co-ordination Act 1975. Under this law, a manufacturer is a person who engages in making, altering, blending, ornamenting, finishing or treating any article or substance with a view to its use, sale, transport or delivery.[58] Since metabolic processes of microorganisms or biogas reforming techniques can be applied to produce hydrogen which will be used, commercially sold or transported, production of hydrogen from biomass or biogas shall be deemed to be manufacturing activities. Consequently, to lawfully produce hydrogen from biomass or biogas in Malaysia, a manufacturing licence must be obtained.[59] With a view to the occupational safety and health of workers in hydrogen production plants, a producer, as an employer, owes a duty under the Occupational Safety and Health Act 1994 to ensure the safety of a hydrogen production plant and operate it without risks to health.[60]

A hydrogen producer in Indonesia is subject to the Law on Energy (Law of the Republic of Indonesia No. 30/2007 dated 10 August 2007) and the Industrial Affairs Law (Law of the

48 Mineral Law (Resolution No. 51/2001/QH10), Article 4 para. 2.
49 Ibid Article 2 paras. 5–7.
50 Law on Petroleum 1993, Article 15.
51 Minh Ha-Duong and Hoang Anh Nguyen Trinh, 'Two scenarios for carbon capture and storage in Vietnam' (2017) 110 Energy Policy 559, 564.
52 Ibid.
53 Hon Chung Lau et al., 'A review of the status of fossil and renewable energies in Southeast Asia and its implications on the decarbonization of ASEAN' (2022) 15 Energies 2152, 2159.
54 Ibid.
55 Ibid.
56 Ibid.
57 Ibid.
58 Industrial Co-ordination Act 1975, Section 2.
59 Ibid Section 3(1).
60 Occupational Safety and Health Act 1994, Section 15(2)

Republic of Indonesia No. 5/1984). The Law on Energy allows business entities to exploit energy resources.[61] Energy resources are defined as natural resources that can be utilised, both as energy sources and as energy directly.[62] Energy resources can be used to produce energy, both directly and indirectly, through conversion or transformation processes.[63] A process converting or transforming biomass or biogas into hydrogen through a conveyor of energy shall be deemed energy resource exploitation. Therefore, the state can regulate hydrogen production, which is a kind of exploitation of energy resources, through the Law on Energy. For example, a hydrogen producer will become an energy business operator and is obliged to preserve and maintain the environmental sustainability function.[64]

In addition, the conversion or transformation processes of biomass or biogas into hydrogen can be deemed industrial affairs under the Industrial Affairs Law. Industrial affairs refers to settings and all activities relating to industrial activities.[65] The term 'industry' is defined as an economic activity that involves the processing of raw materials, basic materials, semi-finished goods and/or finished goods into goods of higher value, and includes design activity and industrial engineering.[66] Biomass and biogas can serve as inputs for the SMR to produce hydrogen, which is a new product of higher value. Both biogas and hydrogen are gaseous substances and can be directly utilised as fuels for electricity generation and vehicles.[67] A question therefore arises as to why producing hydrogen from biogas can be deemed converting raw materials into goods of higher value.

Firstly, it has to be determined whether hydrogen is another kind of gaseous substance which is a byproduct of industrial processes. Like natural gas, biogas primarily consists of methane along with small amounts of carbon dioxide, hydrogen and hydrogen disulfide.[68] Biomass gasification and biogas reforming can serve as methods to produce syngas.[69] By manipulating the reforming process, the ratio of hydrogen and carbon monoxide in syngas can be optimised, and high-purity hydrogen gas can be produced.[70] Hydrogen produced from biogas is a cleaner fuel for vehicles[71] and the gas turbine and fuel cell system for power generation.[72] It can be said that the steam reforming process is a means of converting one gaseous substance into another more environmentally friendly gaseous substance.[73]

Secondly, hydrogen will be the outcome of economic activity and can be deemed to be an industrial affair if hydrogen is a gaseous substance that has a higher value compared with biogas

[61] Law of the Republic of Indonesia No. 30/2007, Article 23(1).
[62] Ibid Article 1 para. 3.
[63] Ibid Article 1 para. 2.
[64] Ibid Article 24(1) b.
[65] Law of the Republic of Indonesia No. 5/1984, Article 1 para. 1.
[66] Ibid Article 1 para. 2.
[67] Joonsik Hwang, Krisha Maharjan and HeeJin Cho, 'A review of hydrogen utilization in power generation and transportation sectors: Achievements and future challenges' (2023) 48 International Journal of Hydrogen Energy 28629, 28636.
[68] Jai M. Mehta and Kenneth Brezinsky, 'Natural Gas for Combustion Systems' in Kenneth Brezinsky (ed.), *Combustion Chemistry and the Carbon Neutral Future: What Will the Next 25 Years of Research Require?* (Elsevier 2023) 65.
[69] L. Yang and X. Ge, 'Biogas and Syngas Upgrading in Advances in Bioenergy' in *Advances in Bioenergy* (Vol. 1) (Elsevier 2016) 161
[70] Ibid.
[71] Ibid.
[72] Md Abdus Salam, Md Aftab Ali Shaikh and Kawsar Ahmed, 'Green hydrogen based power generation prospect for sustainable development of Bangladesh using PEMFC and hydrogen gas turbine' (2023) 9 Energy Reports 3406, 3406.
[73] Fernando Vidal-Barrero et al., Hydrogen production from landfill biogas: Profitability analysis of a real case study' (2022) 324 Fuel 124438.

and biomass. Hydrogen has a higher value because of its usability and environmentally friendly qualities. Burning biogas, which primarily consists of methane, for electricity generation and combusting biogas for use in vehicles can produce carbon dioxide, thus contributing to climate change. However, biogas can be utilised to produce high-value products.[74] It can be upgraded through purification processes by removing some components such as carbon dioxide to increase its heating value or to standardise its quality to meet the requirements of gas appliances, for example, engines, boilers, fuel cells and vehicles.[75] Low-carbon hydrogen, which results from processing biogas and biomass, can be used to produce electricity that causes less environmental impact than the electricity from directly burning biogas. Given its enhanced usability and more environmentally friendly nature, hydrogen shall be deemed to have a higher value when compared with biomass and biogas that are used as inputs for hydrogen production.

When hydrogen production can be deemed an industrial affair under the Industrial Affairs Law, the state can regulate this economic activity through a licensing system. Under the Industrial Affairs Law, a person producing hydrogen from biomass or biogas must obtain an industrial business licence.[76] A hydrogen producer, being an industrial company, owes a statutory duty to prevent damage and pollution to the living environment resulting from the production processes.[77]

7.2.4 *Summary of Manufacturing and Environmental Permit Requirements in ASEAN Countries*

To sum up, environmental protection plays an important role with regard to whether permission is given for the operation of a hydrogen production facility. However, the environmentally friendly nature of green hydrogen does not mean that its production is free from safety and environmental risks. Hydrogen is still a hazardous chemical and flammable substance.[78] This means that safety requirements are necessary for grey (and blue) hydrogen production, which can also apply for green hydrogen production. If the regulatory regime only regulates hydrogen production through gas separation operations, it will be unable to mitigate safety risks inherently associated with other hydrogen production procedures.

Thermal processes for hydrogen production typically involve steam – for example, steam reforming. If the fuel used for steam reforming is of hydrocarbon origin, such as natural gas or diesel, the hydrogen production facility will emit carbon dioxide, having a negative impact on the environment. In addition to the discussed manufacturing licence, the state can require a person who wishes to conduct activities potentially causing adverse impacts on the environment to conduct an environmental impact assessment (EIA) and submit a report thereon in ASEAN countries.[79] The requirements of the EIA report are subject to the discretion of the relevant competent national authority.[80] Environmental legislation or regulations can require a person seeking to produce hydrogen to conduct an EIA.

74 Tomy Hos and Moti Herskowitz, 'Techno-economic analysis of biogas conversion to liquid hydrocarbon fuels through production of lean-hydrogen syngas' (2022) 2 ACS Engineering Au 450, 451.
75 R. Borja and B. Rincón, 'Biogas Production' in Murray Moo-Young (ed.), *Comprehensive Biotechnology* (2nd ed.) (Elsevier 2011) 785.
76 Law of the Republic of Indonesia No. 30/2007, Article 13(1).
77 Ibid Article 21(1).
78 Itsuki Uehara, 'Handline and Safety of Hydrogen' in Tokio Ohta (ed.), *Energy Carriers and Conversion Systems* (Vol. 1) (Encyclopedia of Life Support Systems 2009) 253.
79 Rio Declaration on Environment and Development, Principle 17.
80 Ibid.

The particular requirements of the individual EIAs depend on the individual country. In Malaysia, a person intending to carry out any of the prescribed activities under the Environmental Quality Act 1974 shall, before any approval for the carrying out of such activity is granted by the relevant approving authority, submit a report to the Director General of Environmental Quality.[81] The EIA regime in Malaysia makes no specific reference to hydrogen production; however, it categorises a 'chemical' factory with a total production capacity of each product or of a combined product that is equal to or greater than 100 tons per day as an activity that requires the submission of an EIA Report.[82]

Taking these findings into account, it seems necessary to look more closely into a specific case from one of the ASEAN countries to understand the interplay of norms. The following section therefore provides a case study on how Thailand and its existing, relatively advanced, natural resources regulatory regime tackle hydrogen production.

7.3 THAILAND AS A CASE STUDY

In Thailand, hydrogen is recognised as an alternative transport fuel.[83] In addition, the state mentions in the Power Development Plan (PDP) 2018–2037 that it will promote the establishment of biomass and biogas power plants having a combined capacity of 3,180 megawatts (MW) by 2037.[84] These goals trigger a question concerning how and to what extent Thai regulatory regimes can regulate the production of hydrogen. Regulatory requirements for hydrogen production cover at least operational safety, occupational safety and environmental safety. However, activities relating to hydrogen production in Thailand are not considered energy production under the Energy Industry Act or the Petroleum Act BE 2514 (1971) (the Petroleum Act). In the absence of specific hydrogen legislation, a hydrogen producer relying on machinery to produce hydrogen, including gasification and fermentation of biomass and the reformation of biogas, is subject to the factory licensing regime under the Factory Act BE 2535 (1992) (the Factory Act).

7.3.1 *Hydrogen Production under Thai Energy Law*

Unlike the Indonesian energy regulatory regime as discussed in Section 7.2.3 above, the Thai energy licensing regime does not recognise hydrogen as energy or an energy resource. The Energy Industry Act of Thailand only regulates the production of electricity.[85] Production of electricity as well as establishment of an electricity production facility are subject to a licensing requirement under the Energy Industry Act.[86] The law only limitedly applies to the production of electricity and not to the production of energy from other resources, including the conversion of biomass or biogas into green hydrogen.

Apart from producing green hydrogen from biomass and biogas, the production of grey hydrogen from natural gas via the steam reforming process is also conducted in Thailand.[87]

[81] Environmental Quality Act 1974 (Malaysia), Section 34A(2).
[82] Environmental Quality (Prescribed Activities) (Environmental Impact Assessment) Order, 1987 (Malaysia), para. 8 (a).
[83] Alternative Energy Development Plan (AEDP 2015), 14.
[84] Power Development Plan 2018–2037, 23.
[85] Energy Industry Act BE 2550 (2007) (Thailand), Section 5.
[86] Ibid Sections 47 and 48.
[87] For example, a hydrogen production project located in an industrial estate in Rayong Province relying on steam reformer to convert natural gas into hydrogen. Please see Air Liquide(Thailand), 'EIA Report: Hydrogen Production,

Comparable to the situation in Myanmar, Thai energy law does not regulate the production of hydrogen from fossil fuels either. Production of natural gas is not governed by the Energy Industry Act but by the Petroleum Act. Any person seeking to explore for and produce natural gas is required to obtain a concession, production-sharing contract or service contract from the Ministry of Energy.[88] However, the law defines natural gas as 'all kinds of gaseous hydrocarbons whether wet or dry, produced from oil or gas wells, and shall include the residue gas remaining after the extraction of liquid hydrocarbons or by-products from wet gas'.[89] Since hydrogen is not extracted from oil or natural gas wells and nor is it a by-product remaining after the extraction of liquid hydrocarbons, a hydrogen producer is not required to obtain a concession, production-sharing contract or service contract under the Petroleum Act.

7.3.2 *Hydrogen Production under the Current Thai Industrial Works Regulatory Regimes*

In line with Myanmar, Singapore, Vietnam, Malaysia and Indonesia, a person desiring to legally establish and operate a hydrogen production facility in Thailand, whether to produce grey, blue or green hydrogen, has the statutory duty to comply with general laws governing the establishment and operation of a factory, as well as environmental protection regulations.

Establishment of Hydrogen Production Factory

In the Factory Act, a 'factory' means buildings, premises or vehicles using machines with a total power output of 50 horsepower (hp) or more, or the equivalent, or which employ fifty workers or more with or without machinery to engage in the operation of a factory in accordance with the type or kind of factory as prescribed in the Ministerial Regulations.[90] These Ministerial Regulations do not specifically refer to hydrogen production but 'gas production'.[91] A plant with the capability of converting natural gas into gaseous hydrogen through the steam reforming process relying on a reactor with 50 or more hp, or the equivalent, is, therefore, deemed to be a factory. If these machines together with others that are used in a plant have 50 or more hp, or the equivalent, this plant will be deemed a factory under the Factory Act. Likewise, if machines with 50 or more hp, or the equivalent, are used in a plant for biogas reforming, whether dry reforming (DR), steam reforming (SR), catalytic partial oxidation (CPOX) or auto-thermal reforming (ATR), this plant will become a factory under the Factory Act.

The Minister of Industry has powers to categorise hydrogen production plants as a 'group 3 factory', which are factories of the type, kind and size that require a permit to be granted prior to creation and operation.[92] The Minister of Industry is vested with regulatory power to enact a Ministerial Decree requiring a hydrogen producer to use particular types of machines and equipment for hydrogen production.[93] To ensure that a hydrogen producer, who holds a factory licence, will produce hydrogen from these second-generation biofuels, the Minister of Industry can exercise power under Section 8 para. 1(4) of the Factory Act to promulgate a Ministerial Decree requiring that hydrogen must be produced from agricultural residues.

Carbon Monoxide, and Infrastructure Project' (Office of Natural Resources and Environmental Policy and Planning, January 2012), 1–2 <https://eia.onep.go.th/eia/detail?id = 10892> accessed 28 January 2023.

[88] Petroleum Act BE 2514 (1971) (Thailand), Section 23.

[89] Ibid Section 4.

[90] Ministerial Regulation Prescribing Types, Kinds, and Size of Factories BE 2563 (2020) (Thailand).

[91] Ibid Annex (No. 89).

[92] Factory Act BE 2535 (1992), Section 7 para. 1(3).

[93] Ibid Section 8 para. 1(2).

Once regulated under the Factory Act, a hydrogen producer must adhere to the ministerial rules on production processes and provisions concerning other equipment or tools to prevent or stop or mitigate dangers that may be caused to the persons or property in the factory or its vicinity.[94] Hence, biomass gasification and biofuel reforming plants can be listed as factories that are subject to by-laws prescribing criteria relating to production processes[95] as well as standards and methods of controlling the discharge of waste, pollutants or anything affecting the environment as a result of the factory operation.[96]

Occupational Safety and Health Management

A hydrogen production plant can be deemed as a working place under the Occupational Safety, Health, and Environment Act BE 2554 (2011) (the OSHE Act). The law primarily places statutory duties upon the employer to ensure the safety and hygiene of a working place for its employees.[97] In line with Malaysia, the OSHE can serve as a legal basis for the Minister of Labour to promulgate ministerial decrees imposing duties on hydrogen producers, as the employers, to manage and operate their hydrogen production plants in accordance with the prescribed occupational safety, health and environmental standards.[98]

Environmental Impact Assessment

Under the Enhancement of National Environmental Quality Act BE 2535 (1992) (the Enhancement of National Environmental Quality Act), the Minister of Natural Resources and Environment is vested with the power to promulgate a ministerial notification prescribing which projects, business operations or activities require an EIA report.[99] If the establishment and operation of a hydrogen production factory is prescribed as a project, business operation or activity that requires an EIA report, the Permanent Secretary of the Ministry of Energy or a delegated official cannot grant a factory licence to the applicant unless the EIA report for the hydrogen factory is approved by the Environmental Expert Committee.[100]

The Ministerial Notification concerning Projects, Operation or Activities that require an EIA Report and Criteria, Methods and Conditions on the EIA Report Preparation BE 2566 (2023) (the EIA Notification) does not specifically make any reference to hydrogen production. However, it imposes the EIA report requirement on industrial activities involving natural gas separation. Regardless of the size of the factory, a factory established for natural gas separation by conversion of natural gas from gaseous status into liquid status and natural gas separation by conversion of natural gas from liquid status by using seawater or water from natural water resources for heating the separation are subject to the EIA report requirement.[101] It appears that the current environmental protection regime in Thailand places its focus on inputs used for manufacturing processes. Therefore, a person seeking to use natural gas as an input to produce hydrogen through the natural gas separation process will be required to prepare an EIA report.

94 Ibid Section 8 para. 1(4).
95 Ibid Section 8 para. 1(4).
96 Ibid Section 8 para. 1(5).
97 Occupational Safety, Health, and Environment Act BE 2554 (2011), Section 6 para. 1.
98 Ibid Section 8.
99 Enhancement of National Environmental Quality Act BE 2535 (1992), Section 48 para. 1.
100 Ibid Section 50.
101 Ministerial Notification concerning Projects, Operation, or Activities that require an Environmental Impact Assessment Report and Criteria, Methods, and Conditions on the Environmental Impact Assessment Report Preparation BE 2566 (2023), Annex 4 (No. 7).

The term 'natural gas' is not specially defined by the Enhancement of National Environmental Quality Act or its by-laws. However, natural gas is defined by the Petroleum Act as all kinds of gaseous hydrocarbons, whether wet or dry, produced from oil or gas wells; and also includes the residue gas remaining after the extraction of liquid hydrocarbons or by-products from wet gas.[102] Moreover, the Ministry of Energy Notification concerning Criteria and Safety Standard of a Place where Natural Gas Is Used and Regulated by Department of Energy Business BE 2550 (2007) defines natural gas as gaseous hydrocarbon mainly consisting of methane.[103] Therefore, a person using biogas, which is a kind of natural gas, as an input to produce hydrogen will be required to prepare an EIA report. In practice, hydrogen production from natural gas is deemed a project that is subject to the EIA requirements. The Environmental Expert Committee, in its meeting No. 3/2561 of 16 July 2018, opined that the utilisation of natural gas to produce hydrogen is considered a kind of natural gas separation and transformation project.[104]

However, the EIA Notification does not govern the utilisation of renewable sources as inputs for manufacturing or production. Production of green hydrogen does not use natural gas as an input for production, but electrolysis from renewable sources. In relation to energy projects, it only applies to a thermal power plant with an installed capacity of 10 MW and more.[105] Therefore, if a person is seeking to use natural gas to produce hydrogen, this is not a type of renewable source, so they are not required to submit an EIA Report.

7.4 (RE-)CONVERSION OF ELECTRICITY: UNINTENDED SUBSIDISATION OF ELECTRICITY GENERATED FROM GREY OR BLUE HYDROGEN

To support the energy transition, the state may create market demand for green hydrogen. In Thailand, demand for green hydrogen, such as hydrogen produced from biomass and biofuel, can be stimulated by the state through subsidisation of renewable electricity generated from green hydrogen. Hydrogen end users, such as renewable electricity producers, can be encouraged to purchase hydrogen from hydrogen producers or suppliers if the government is also allowing them to participate in subsidised electricity selling prices.[106] However, the Energy Industry Act of Thailand gives the Energy Regulatory Commission broad powers to procure renewable electricity generated from 'hydrogen' without specific reference to its colour.

7.4.1 *Electricity Procurement under the Energy Industry Act BE 2550 (2007)*

Thailand does not have a competitive wholesale electricity market, as the government gave a mandate to state-owned electricity enterprises to purchase electricity from producers based on the allocated quotas.[107] The Energy Policy Committee has the power to determine the amount

[102] The Petroleum Act BE 2514 (1971), Section 4.
[103] Ministry of Energy Notification concerning Criteria and Safety Standard of a Place Where Natural Gas Is Used and Regulated by Department of Energy Business BE 2550 (2007), Clause 4.
[104] Division of Environmental Impact Assessment Development, 'Hydrogen Production, Carbon Monoxide, and Infrastructure Factories' (Office of Natural Resources and Environmental Policy and Planning, June 2022) <https://eia.onep.go.th/eia/detail?id = 10892> accessed 26 January 2024.
[105] Ministerial Notification BE 2566 (n101) Annex 4 (No. 18).
[106] Ministry of Energy, 'Power Development Plan 2018 Revision 1' (Energy Policy and Planning Office, October 2021), 11 <https://eppo.go.th/images/Infromation_service/public_relations/PDP2018/PDP2018Rev1.pdf> accessed 26 January 2024.
[107] Cabinet Resolution dated 9 December 2003.

of electricity that can be procured from the private sector as well as the purchase price, including the guaranteed price of electricity generated from hydrogen.

In practice, the Energy Policy Committee will instruct the Energy Regulatory Commission to take necessary steps for electricity procurement in accordance with its requests. This instruction will refer to the type of electricity to be procured, for example, electricity from renewable resources such as electricity from biomass and biogas.[108] This procurement announcement can invite electricity producers to sell electricity generated from renewable resources, including hydrogen, at a fixed subsidised price, thus stimulating demand for hydrogen consumption.

7.4.2 *Current Practice on Procurement of Hydrogen-Based Electricity*

Hydrogen that is used to fuel electricity generation can be grey, blue or green or have other colours. The current practice on electricity procurement is that the criteria that have been announced by the Energy Regulatory Commission feature hydrogen as a renewable resource that qualifies for subsidised electricity purchasing prices.[109] For example, in 2018 the Energy Regulatory Commission invited power producers with a generation capacity of not exceeding 10 MW to sell electricity generated from 'renewable resources' to the state-owned electricity enterprises.[110] This regulation explicitly included hydrogen as a renewable resource.[111] After the competitive bidding process, a selected power producer will sign a long-term power purchase agreement that recognises subsidised electricity prices, based on the type of renewable resource. The state-owned buying enterprises will be responsible for paying the seller a fixed and subsidised wholesale price as announced by the Energy Regulatory Commission. This subsidy scheme is called the Feed-in Tariff (FiT) scheme.[112]

Notwithstanding, electricity producers are not prohibited from using grey or blue hydrogen for the generation of electricity and can nonetheless apply for subsidies from the scheme. This loophole exists because the Energy Regulatory Commission does not recognise any differences between types of hydrogen. Its regulations in the past simply featured hydrogen as automatically qualifying for the bidding process.[113] Renewable electricity procurement announcements typically refer to 'hydrogen' as a kind of renewable resource which is qualified to gain benefits from the price guarantee scheme without making specific reference to green hydrogen, so all kinds of hydrogen can benefit equally.

This is an undesirable and possibly unintended outcome because hydrogen produced from natural gas – grey hydrogen – relies on the fossil fuel natural gas. Its production process involves the conversion of fossil fuels into another form of energy. Therefore, hydrogen produced from fossil fuels should not be deemed a renewable energy resource and the loophole needs to be closed.

7.5 CONCLUSION

In Southeast Asia no common approach towards hydrogen regulation has evolved so far. ASEAN countries are mainly at the initial stages of hydrogen production and there is currently little

[108] For example, Regulations of the Energy Regulatory Commission on Procurement of Renewable Electricity in the Form of Feed-in-Tariff (FiT) in 2022–2030 for the Non-Fuel Group 2022.

[109] For example, the Energy Regulatory Commission's Regulation re: Procurement of Electricity from Renewable Electricity Projects of Very-Small Power Producers BE 2561 (2018).

[110] Ibid Clause 5.

[111] Ibid Clause 3.

[112] Piti Pita et al., 'Assessment of Feed-in Tariff Policy in Thailand: Impacts on National Electricity Prices' (2015) 79 Energy Procedia 584, 585.

[113] For example, Energy Regulatory Commission's Regulation BE 2561 (n109) Clause 3.

utilisation of hydrogen. However, in the absence of such legislation in Myanmar, Singapore, Vietnam, Malaysia and Indonesia, a hydrogen producer does not necessarily have full freedom to produce hydrogen without being subject to regulations. These ASEAN countries can rely on factory or industrial affairs legislation to impose a duty upon a hydrogen producer to obtain a factory or manufacturing activity licence before operating a hydrogen production plant. These regulations mainly focus on ensuring the safety of the factory establishment and operation and do not always specify how hydrogen is produced.

The existing environmental impact assessment requirements in Malaysia and Thailand can serve as regulatory bases to require certain types of hydrogen production plants, including biomass gasification and biogas steam reforming plants, to be activities that need to conduct an EIA prior to their operation. Like most other ASEAN countries, except Indonesia, activities relating to hydrogen production in Thailand are not deemed to be energy production under the Energy Industry Act or under the Petroleum Act.

However, a hydrogen producer relying on machines to produce hydrogen, including the gasification and fermentation of biomass and the reformation of biogas, can be considered an industrial operator who is required to obtain a factory licence. Production of blue and grey hydrogen from natural gas including biogas through the SMR process is considered natural gas separation activity and needs an EIA report. Once a hydrogen producer becomes a factory licensee, the Minister of Industry can regulate how hydrogen is produced through ministerial rules concerning machines, equipment or other things used for engagement in a factory business. On the grounds of avoidance of conflict between food security and energy security, the Factory Act can be utilised by the Minister of Industry to require a hydrogen producer, who is a holder of a factory licence, to produce hydrogen from these second-generation biofuels.

The Thai government could stimulate demand for electricity produced from biogas. The stimulated demand for biogas as inputs for electricity to be purchased by the state at a subsidised price could contribute to the formulation and development of hydrogen markets in Thailand. The problem arises of possible diversion of subsidies that are intended to promote green hydrogen and electricity produced from green sources. In spite of the ability to regulate safety and mitigate environmental impacts, the Thai legal system faces challenges arising from unintentionally subsidising grey or blue hydrogen through electricity procurement legislation. This is an issue because the Energy Industry Act of Thailand gives the Energy Regulatory Commission broad powers to procure renewable electricity generated from 'hydrogen' without specific reference to its colour. This loophole demonstrates a general issue with the current stage of hydrogen regulation in ASEAN countries: the existing regulations have not been created with hydrogen in mind and if they are amended there can be a lack of technical understanding that could lead to unintended side effects. It therefore remains a challenge for ASEAN countries in the coming years to improve their regulatory approaches towards hydrogen and to better incorporate it into their existing regulatory landscape.

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PART II

Regulating Hydrogen Markets

8

Economics of Regulating Hydrogen Markets

Machiel Mulder

8.1 INTRODUCTION

Because of the need to reduce carbon emissions, the usage of hydrogen is expected to grow strongly in the coming decades. The International Energy Agency expects a growth from the about 90 million metric tonnes in 2020 to 500–700 million metric tons in 2050.[1] Such a strong growth will only be possible when marketplaces are developed where the parties can meet to exchange hydrogen. Such marketplaces have to be developed on top of the presence of physical infrastructure for transport and storage, just as is currently the case for the natural gas market. For the development of the role of hydrogen in future energy systems, it is crucial that the hydrogen market functions well because efficient price formation is essential for producers, traders, and consumers to come up with optimal decisions.

In this chapter, the focus is on how to obtain a well-functioning hydrogen market, departing from the assumption that there will be a demand for hydrogen and that several options to supply hydrogen to the market are available. This implies that we do not dive into the regulatory question of how to realize a transition from fossil energy towards renewable and clean hydrogen and, hence, we do not discuss regulatory measures like support schemes for hydrogen, carbon taxes, or hydrogen obligation (quota) schemes for energy users. Nonetheless, the chapter discusses how to deal with the various types of hydrogen having different environmental consequences (emissions). The key question addressed by this chapter, however, is to what extent governments need to intervene in the development of a hydrogen market to improve its functioning. This question is answered by departing from microeconomic theoretical concepts related to conditions for the functioning of markets (Section 8.2). Based on these concepts, the hydrogen market is systematically analysed by looking at potential shortcomings in the various layers of the hydrogen supply chain (Section 8.3). Section 8.4 then wraps up the chapter by formulating some conclusions.

[1] IEA, *The Future of Hydrogen: Seizing Today's Opportunities*. Report prepared by the IEA for the G20, Japan, 2019.

8.2 ECONOMIC FRAMEWORK FOR REGULATING MARKETS

8.2.1 *Theoretical Benchmark and Market Failures*

In economics, a market can be defined as a facility that allows buyers and sellers to exchange any type of goods, services, and information.[2] These facilities used to exist mainly as physical marketplaces where the parties met each other in person. Increasingly, however, they exist in the form of virtual places where the parties submit their bids on digital platforms and the market operator sets the clearing prices and quantities. Irrespective of the way markets are organized in practice, they are meant to help the parties to realize the best deal for themselves. When these markets function well, one can say that the goods are produced and allocated to users in the most efficient way. This means that the goods are supplied by producers having the lowest costs, which refers to the productive efficiency in a market, and that these goods are consumed by the consumers that have the highest willingness to pay for these goods, which is referred to as the allocative efficiency of a market. The amount of goods produced is determined by the point where the marginal costs[3] of the producers equal the marginal willingness to pay of consumers. After all, if a good is consumed by a consumer with a lower willingness to pay than the marginal costs needed to produce that good, then this exchange between producer and consumer would result in a loss of welfare. This loss of welfare is seen as an allocative inefficiency, as the allocation results in lower welfare than what would be possible. One can also say that in well-functioning markets, the exchange of goods results in the maximum possible welfare.[4]

It is important to realize that this theoretical notion of a well-functioning market is not meant to describe real markets, but it can be used as a benchmark for the assessment of actual markets. This also holds for microeconomic theories in general, which are meant to provide analytical frameworks that can be used to analyse actual behaviour of economic agents, such as consumers, producers, and traders. In practice, however, many markets suffer from fundamental shortcomings which prevent the market resulting in an efficient allocation of goods. These fundamental shortcomings are called market failures. The concepts of well-functioning markets and market failures can be used by regulators to determine to what extent and what type of regulatory intervention is needed. Below we will discuss a number of these market failures and how they can be addressed by regulators.

For a perfectly functioning market, a number of conditions have to be fulfilled. One of these conditions is that no market player is able to strategically influence the market outcomes, which means that the market prices are fully exogenous to the suppliers and consumers. If this is not the case, then market prices may get distorted by some suppliers with the result that (other) individual producers and consumers are not correctly informed about the marginal conditions of the other players. For instance, if the market price exceeds the marginal costs of the marginal supplier, then a consumer may decide not to consume a good even though that consumer's willingness to pay may be higher than these marginal costs. As a result, an allocative inefficiency exists, which is a loss of welfare, referred to as 'deadweight loss'. This also implies that in a

[2] For a more extensive discussion of the economics of regulating energy markets, see Mulder, M., *Regulation of Energy Markets: Economic Mechanisms and Policy Evaluation*. Springer, 2nd ed., 2023.

[3] The marginal costs are defined as the extra costs to supply one extra amount of a good. As an example: the marginal costs of a gas-fired power plant to supply one unit of electricity consist of the costs of the usage of gas (and carbon allowances) to produce that unit.

[4] For a more detailed discussion of the microeconomic concepts, see e.g. Varian, H. R., *Intermediate Microeconomics: A Modern Approach*. W. W. Norton, 8th ed., 2009.

perfectly functional market the only option firms have to make higher profits is to either reduce their costs or to improve the quality of their products and to sell the products to consumers with a higher willingness to pay for such products. In other words, in such markets all suppliers can be seen as price takers, as they can only respond to the market price but not influence it. Generally, one can say that the higher the number of producers in a market, the less firms are able to act strategically. The relation between market structure (degree of concentration) and intensity of competition is, however, not that straightforward as even in industries with only a few firms operating on the particular market, fierce competition may exist, while in industries with a large group of firms, these firms may be able to make joint agreements on, for instance, the magnitude of their supply to the market. Regulators address the risk of abuse of market power by general competition oversight, which consists of two main components: merger control (to prevent the establishment of dominant firms) and antitrust (to monitor and punish the abuse of market power by dominant firms or firms jointly participating in a cartel).

Another condition for a well-functioning market is that no firm has a strategic advantage over others because it is better able to access the market, for instance by using specific infrastructure which cannot be used by others. In other words, all firms should operate on a level playing field. When strategic advantage may result from the usage of essential infrastructure, regulators can implement rules regarding the usage of the infrastructure by other market players. A structural competitive advantage may also result from the presence of economies of scale or scope. This can occur in the case of activities with large fixed costs, such as investments in electricity and gas networks, which have the effect that one firm can conduct these activities more efficiently than a number of (smaller) firms. Such cost advantages result in natural monopolies, which means that the technological characteristics of a given industry results in the fact that it is most efficient to have one firm being responsible for the total supply. As is the case with other (normal) monopolies of firms having market power, unregulated naturally monopolistic firms (such as operators of natural gas and electricity grids) may abuse their position by charging so-called monopoly tariffs, which are tariffs intended to maximize the profits of the firm instead of being related to the marginal costs of production. Hence, such firms with a natural monopoly are not price takers but can be seen as price setters. These firms may also increase their profits by saving on costs for quality improvements or maintenance of their assets, which implies that the resulting higher profits come at the expense of lower quality for customers. To address this type of market failure, regulators may implement rules that restrict the freedom of naturally monopolistic firms regarding the tariffs they charge (so-called tariff regulation) and rules regarding the minimum required quality levels of service provision to customers (so-called quality regulation). In addition, it is crucial for all potential network users to get access to the network, which is called third-party access (TPA).

What is also necessary to obtain well-functioning markets is the presence of full transparency. Producers and consumers need to know what the relevant product characteristics are and under what conditions market transactions can be concluded. In practice, however, markets may fail to realize an efficient allocation in the presence of information asymmetry, which means that the parties (suppliers and buyers) cannot have the same type of information on the characteristics of the commodities. This market failure may result in so-called adverse selection, for instance when high-quality products cannot compete with products of lower quality, where the higher-quality product is more costly but consumers are uncertain about the quality of the product. Consumers are generally not prepared to pay their maximum price for a high-quality product if they are uncertain about the true characteristics (quality) of a product. This may occur if consumers cannot fully assess the quality of a commodity and, as a result, they may not be inclined to pay the full price. If this market failure occurs, coordination or regulation is required, for instance by organizing a trustworthy certification scheme.

Another type of market failure consists of externalities, which occur when economic agents do not take into account all costs or benefits of their activities. Negative externalities result in too high a level of activities from a social point of view. An example of such an externality is carbon emissions resulting from the use of fossil fuel energy. Positive externalities result in too low a level of activities of firms as they cannot capture all the benefits of their activities. This may, for instance, occur if the benefits of innovation cannot be protected by innovative firms. In that case, firms will not innovate enough, or at least they innovate less than they would do if the benefits could be fully captured. Another type of externality is called network externalities, which may result in a limited number of suppliers capturing the full market and, as a result, other firms being unable to enter the market. If network externalities exist in the market, the parties should coordinate how they want to organize the market, or a regulator should impose regulations on market design.

A final type of market failure is the presence of so-called hold-up, which is that the parties are hesitant to take actions which would be beneficial from a social welfare point of view. This may occur in the case of long-term investments without long-term contracts with customers or without the existence of liquid markets. For instance, in the case of a natural gas grid, the owner may be uncertain to what extent the users of that grid will keep using the grid and to what extent they are willing to pay the required tariffs. Because of that uncertainty, the owner of that grid may be hesitant to invest in grid extension unless users have made explicit long-term commitments about their future usage or regulators have indicated that future losses due to a lower utilization will be reimbursed. Consequently, the presence of this market failure may result in too little investment because firms are uncertain about the ex post revenues once they have made an investment. When this market failure exists, coordination or regulation is needed to give investors more certainty about the future revenues.

8.2.2 *Regulatory Measures to Develop Energy Markets*

If there are no fundamental shortcomings, markets just develop when individual suppliers and consumers see opportunities to start exchanging goods. In several cases, however, some factors lead to situations where markets cannot develop themselves and therefore they need regulatory help. This is true in particular for energy markets, where, because of some peculiarities, these markets cannot fully develop automatically without any help. Energy markets are based on physical networks, conveying natural gas, electricity, heat, and hydrogen and require government intervention to develop. In many countries in the recent past, the previously centrally coordinated systems for the delivery of gas and electricity have been replaced by markets through policy interventions. These interventions included various measures, which can be distinguished as liberalization by fostering competition and creating liquid marketplaces, restructuring of the industry, regulating natural monopolies and externalities, and removing bottlenecks for international trade.

With the liberalization of markets, a main goal is to develop effective competition and create liquid markets. A market is called liquid when the price of a good traded is not noticeably affected by actions taken by an individual. The liquidity depends on the transaction costs parties must put up with and the confidence they have in the market system. The latter depends on transparency of the operation of the market. When these conditions are met, the market will attract more parties, increase its volume, and further improve its liquidity. However, at times not every aspect of a market is well suited for competitive behaviour. One factor making parts of the market unsuitable for competition is the presence of natural monopolies. In electricity and gas markets, and possibly also in hydrogen markets, the networks are characterized by economies of scale, which make it unfeasible to create parallel networks. This situation requires the implementation of tariff regulation, quality regulation, and regulation of TPA.

Energy markets also require regulatory measures to address externalities, in particular environmental emissions. By imposing emissions standards or introducing emissions trading schemes or fossil-fuel energy taxes, the parties are incentivized to take the (negative) external effects into account when they are making decisions on production, investment, or consumption.

Although energy markets typically include some monopolistic elements that cannot be eliminated by increasing competition, there are other elements that are well suited for competition. To foster the entry of players in those segments of the market, authorities can choose to restructure the market in such a way that the monopolistic and competitive activities are not done by the same firm. This is called vertical unbundling of activities and is a well-known way to prevent conflict of interest. Another restructuring measure is the horizontal splitting of large incumbent firms into competitive segments. Without this, incumbent firms may have excessive market power, which will enable them to behave strategically – raise the market price to the monopoly level. A final form of restructuring is the privatization of ownership of incumbent firms. Privatizing the commercial elements of a sector gives those firms stronger incentives to be efficient as they face more pressure from the providers of equity or the capital market.

Vertical unbundling of monopolistic segments and the introduction of TPA does not automatically result in a competitive market. Effective market competition can only be achieved when the number of firms active in the market is sufficiently high while consumers are able to make a choice of their preferred supplier and the type and number of products they prefer. The benefits of such effective competition are that the market price is more related to the marginal costs. A regulatory measure that may further enhance competition is international market integration. When regional markets become more integrated with each other, domestic firms are able to operate in other markets as well. This (potentially) increases the number of players in all the regional markets which will foster competition and, therefore, the final price will be a better reflection of costs. Next to improving competition, market integration may also result in higher productive efficiency since firms with lower costs will replace those with higher costs. Second, and especially important in energy markets, there will be more flexibility to deal with demand or supply shocks. A larger integrated market has more options to deal with shocks to demand or supply than a market in a smaller region.

8.2.3 *Regulatory Failures*

When a market suffers from a fundamental shortcoming, like the ones described above, regulatory measures may help to improve the development or functioning of the market. However, finding and implementing the best type of regulation is often challenging. In this respect, it is important to realize that governments may also fail to implement the most appropriate regulatory measures. Such regulatory failures may be the result of various factors.

The first factor to mention is the information asymmetry between government (including the regulator) and market parties. Governments are generally less well informed than the parties about the precise characteristics of technologies (such as their costs and revenues), the actual outcomes of markets (such as profits realized by the various parties) or the (in)ability of the parties to enter into a market. Because of such information asymmetries, regulatory measures may be too generous at the expense of the public budget, or they may be too strict, with the result that the measures are less effective. Information asymmetry may also refer to a lack of information on the actual behaviour of market parties. This regulatory failure results in so-called moral hazard behaviour by regulated parties, which is, for instance, that they make less effort to realize their own objectives because of the impact on regulatory decisions. As an example, subsidies to compensate for all costs of a renewable energy project take away the incentives for firms to reduce these costs. Another example of moral hazard resulting from regulation is the so-called cost-plus tariff regulation of grid operators, which entails that these operators are allowed to raise their tariffs in response to an increase in their own costs. These operators don't have any incentive to become more efficient, while they would have such incentives if their regulated tariffs were not related to their own costs.

Regulatory failures may also be due to rent-seeking behaviour by some parties. This can be related to information asymmetry, as an information advantage by market parties may be used to plead for regulations which are beneficial to them, but are not in the general interest, while the regulator is unable to check this. The likelihood of such behaviour is the greater, the more regulators depend on information provided by the regulated parties. Rent-seeking behaviour is also more likely to occur when parties are able to jointly act as a coherent group submitting internally consistent messages to politicians.[5] In such circumstances, it is more difficult for politicians to withstand such pressure from interest groups.

Regulatory measures may also not be in the public interest when politicians pursue their own (political) interests instead of the general welfare. This may occur when politicians implement measures which foster the interests of those they expect to support them. To give an example: politicians with the majority of their voter base amongst homeowners instead of renters may promote financial measures supporting the installation of rooftop solar photovoltaics systems while this measure, from an overall welfare perspective, may not be efficient.

8.3 REGULATING THE HYDROGEN MARKET

8.3.1 *Market Failures in Hydrogen Supply Chains*

To determine whether the development of a market for hydrogen needs specific regulation, we first analyse the presence of market failures in the hydrogen supply chain.[6] This supply chain basically consists of the production, transport, storage, distribution, and consumption layers (see Figure 8.1). While the supply chain refers to how the hydrogen flows from production to consumption, the term hydrogen markets is understood in this chapter as how the commercial relations between agents in this supply chain are organized. Just as with natural gas and electricity markets, the functioning of hydrogen markets is related to the functioning of the physical infrastructure. Below we analyse for the various components of the supply chain and the markets to what extent there is potential for market failures, like economics of scale, externalities, structural lack of competition, information asymmetry, or hold-up. If such failures are found, we explore potential regulatory solutions to address them.

[5] Viscusi, W. K., J. E. Harrington and J. M. Vermont, *Economics of Regulation and Antitrust*, MIT Press, 2005.

[6] This section is based on Mulder, M., P. Perey and J. L. Moraga, Outlook for a Dutch Hydrogen Market; Economic Conditions and Scenarios, CEER Policy Papers No. 5, March 2019.

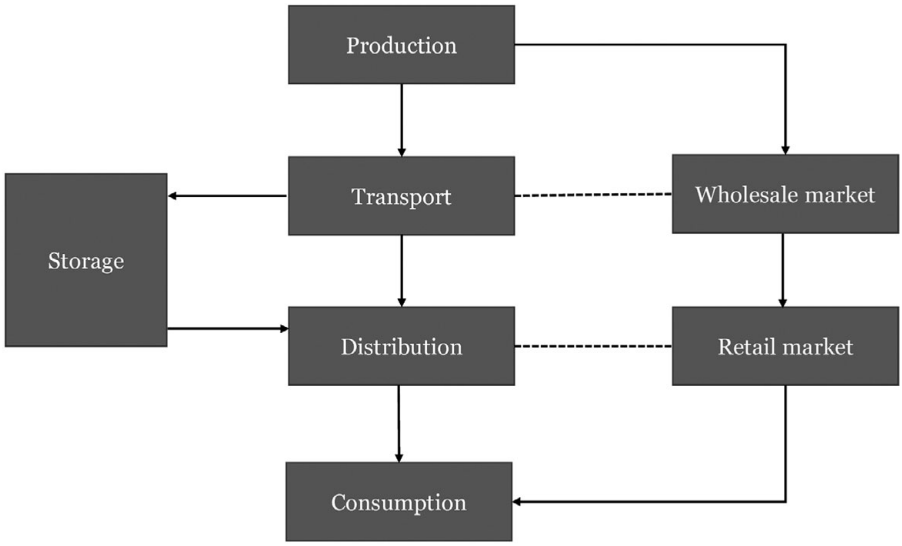

FIGURE 8.1 Supply chain of hydrogen
Source: Author.

8.3.2 *Production of Hydrogen*

Hydrogen is an energy carrier, not an energy source, which implies that it has to be produced from other energy carriers.[7] This production can be done in various ways which can be distinguished into two groups: production based on fossil energy, in particular natural gas, and production based on electricity. In the first method, the methane molecules (NH_4) of natural gas molecules are split into H_2 and CO_2. This is still the common method of hydrogen production. When the CO_2 is captured and stored (so-called carbon capture and storage – CCS), for instance in depleted gas fields, the resulting hydrogen can be almost 90 per cent carbon free (not 100 per cent as full capture is technically not possible). One of the technical methods in this type of hydrogen production is called steam methane reforming. In the second method, water molecules (H_2O) are split into H_2 and O_2 using electricity. This is called electrolysis, which can be differentiated into different types – such as alkaline electrolysis, which is the oldest technique, and proton exchange membrane (PEM) electrolysis.[8] Depending on how the electricity is generated, the resulting hydrogen can be called fossil-based (when the electricity is generated by fossil-fuel power plants) or fossil free (when the electricity is generated based on renewable sources or nuclear power). As electricity is a secondary energy carrier, this type of hydrogen can be seen as a tertiary energy carrier. This is relevant for the economics of hydrogen production as the costs of the primary energy carriers used and the efficiency of the conversion processes determine the costs of hydrogen supply.

To determine to what extent the production of hydrogen is characterized by economies of scale, one can look at the required investments per megawatt (MW) of capacity in relation to the magnitude of demand in the market. In this respect, it appears that production of hydrogen can be compared to the production of electricity. The installations required to convert an energy

[7] Mulder, *Regulation of Energy Markets*.
[8] IEA, *The Future of Hydrogen*.

carrier into hydrogen or electricity require similar amounts of investments. An advanced combustion turbine gas plant requires about 0.5 million euros/MW, which is a bit less than the investment size of a steam-methane reforming plant, while the investment in an electrolysis plant is equal to about 1 million euro/MW. Coal-fired and, in particular, nuclear power plants are, however, much more capital intensive.

In addition, it appears that neither type of hydrogen production requires specific locational circumstances. Steam-methane reforming plants need access to the gas network, as they need gas as input, and electrolysis plants need access to the electricity grid and water network, as they need electricity and water as inputs, but access to these networks is in principle everywhere available in most countries, due to the existing TPA regulation of gas and electricity grids. In the case of steam methane reforming in combination with CCS, proximity to a transport and storage system for CO_2 is also required, and here we may find some locational constraints.

The above implies that, from a competition point of view, the supply side of hydrogen production needs no particular economic regulation as the relatively small scale of the production facilities and the absence of strong locational advantages prevent the occurrence of a natural monopoly. Hence, the existing regulation of TPA to electricity and gas networks will be sufficient along with the general competition policy oversight to realize competition in the production of hydrogen.

For the negative environmental externalities occurring through the production process, however, regulation is required. As in the case of steam methane reforming, even when combined with CCS, there are always remaining carbon emissions because of technical constraints regarding the conversion process of making hydrogen based on natural gas as well as the transportation of carbon. Hence, these emissions should be subject to environmental regulation, such as a cap-and-trade emissions scheme, in order to give the hydrogen producers incentives to take these emissions into account when they decide upon investment and production levels. In the case of electrolysis, the production of hydrogen does not generate any carbon emissions, but indirectly these emissions do occur when the electricity is generated based on fossil fuels. This negative environmental externality is (partly) addressed through environmental regulation of the electricity industry, such as through emissions trading schemes, support schemes for renewable electricity (which reduces the share of fossil-based electricity in the mix) and taxation on the use of fossil fuel energy in electricity generation. In addition, when hydrogen from various sources is transported through one network, potential users of that hydrogen are not able to determine the environmental burden during the production process of the hydrogen they want to use. Hence, regulation is needed to enable producers of hydrogen to inform their customers about the carbon content of their production process. This regulation will be discussed below in Section 8.3.7 on retail markets.

There is potentially another externality related to the supply of hydrogen in the market, which is the security of supply externality. When significant amounts of hydrogen are coming from a small number of countries, this may result in geopolitical dependence, as we have seen in the natural gas market.[9] In order to address this risk, governments could foster diversification of the sources of hydrogen imports by enabling parties not only to import from nearby sources at lowest costs, but also to import from sources at a greater distance.[10]

[9] Perey, P. and M. Mulder, 'International competitiveness of low-carbon hydrogen supply to the Northwest European market' 48/4 (2023) International Journal of Hydrogen Energy 1241–1254.

[10] Nunez-Jimenez, A., and N. De Blasio, 'Competitive and secure renewable hydrogen markets: three strategic scenarios for the European Union' 47 (2022) International Journal of Hydrogen Energy 35553–35570.

8.3.3 *Transport of Hydrogen*

Just as hydrogen can be produced in various ways, it can also be transported through various modes: via pipelines, trucks, and ships. The different forms of transportation require different amounts of investment, which affects the economies of scale and potential sources of market power. In the first mentioned way, hydrogen is transported in gaseous form, and in the latter two in liquid form. Before hydrogen can be transported in gaseous form through a pipeline system, its volume is reduced (the energy content per unit of volume is raised) through compressing, just as is the case with the transport of natural gas through pipelines, which means that additional investments have to be made. In the case of transport via trucks or ships, the temperature of hydrogen needs to be lowered in order to raise the energy content per unit of volume, which is required to reduce the transportation costs.[11]

These transportation options have strikingly different economic characteristics. The transport of hydrogen by pipeline is characterized by scale economies as the investment costs per unit of energy transported decrease more the larger the capacity of the transport infrastructure. Although the capital costs of pipelines are high, the large quantities that can be transported (up to 9,000 kg/h) and the relatively low operation costs reduce the costs per kilogram (kg) of hydrogen. Hence, with large quantities of hydrogen, transport via pipelines is the most suitable and cost-efficient option. In addition, the greater the quantity transported, the lower the unit costs. For smaller quantities, however, the construction costs of a pipeline per unit of hydrogen are simply too high, which means that in such a situation transport by truck is more efficient. Therefore, transport through pipelines has to be regarded as a natural monopoly when the amount of hydrogen to be transported exceeds a minimum threshold. This in particular holds for the situation in which existing natural gas pipelines can be repurposed for hydrogen. In that case, the average costs per unit of transport are much lower than in alternative transportation modes, which gives the operator of such a pipeline system a competitive advantage.

A consequence of the cost advantages of pipeline transport compared to transport by truck is that when the hydrogen market evolves, transport will be done through pipelines. Because of the natural monopoly characteristic of pipelines, it is not efficient to have more than a single network for the transport of hydrogen, which means that competition cannot evolve in the transport business. The transport of hydrogen, therefore, needs to be subject to economic regulation, just like the transport of natural gas and electricity. This regulation should entail tariff regulation, protecting network users from tariffs that are too high, giving network operators incentives to operate as efficiently as possible, and enabling other market participants (producers and users of hydrogen) to make use of the transport infrastructure.

As hydrogen transportation infrastructure has to be developed, investors in this infrastructure need to have some certainty about future utilization and revenues. Without this certainty, they may delay their investment. Governments can play a role in providing regulatory certainty about how the future revenues will be determined and how extensive the future utilization of the infrastructure may become.[12]

[11] Boudellal, M., *Power-to-Gas: Renewable Hydrogen Economy*. De Gruyter, 2018.

[12] Nunez-Jimenez, A. and N. De Blasio, 'Competitive and secure renewable hydrogen markets: three strategic scenarios for the European Union' 47 (2022) International Journal of Hydrogen Energy 35553–35570.

8.3.4 *Storage of Hydrogen*

Hydrogen can be stored in several ways. The simplest option is to store hydrogen in tanks, for which it needs to be compressed, but even with high pressures the required volumes remain large, which makes it an unrealistic option for large-scale storage. To store the same amount of energy by hydrogen compared to natural gas, the required volume is about four times greater.[13] The volume of the storage can be reduced through liquefaction, but this requires significant amounts of energy, which also makes it less attractive from an economic point of view. An option to store large quantities of hydrogen in an efficient way is to make use of salt caverns or depleted natural gas fields.[14] Salt caverns in particular do have great potential in many countries because of their widespread presence (although this is not possible everywhere), and their ability to provide large-scale storage which can be used with a high level of flexibility in terms of injection and withdrawal.[15]

Storing hydrogen can be relevant when the timing of production and consumption are not similar. When hydrogen is mainly used for industrial processes or heavy transport, consumption will be fairly flat, which implies that the producers of hydrogen do not need to (greatly) adapt their production profile. This situation differs, of course, when hydrogen consumption is more volatile. This will occur when hydrogen is used for producing heat in households and offices, as then the demand will depend on the outside temperature. If the temperature drops, the supply side should be able to increase its supply to the market to meet demand. For competition to be effective under such circumstances, it is crucial to know what type of and how many facilities would be required to realize this increase in supply. The more facilities required to provide the flexibility in supply, the less individual suppliers are in a strategic position to influence market outcomes. To obtain a better impression of the competitive situation in case of a cold two-week winter period (as an example), one can estimate the number of facilities required for various types of techniques.

If storage were available in the form of salt caverns, then about fifty of them would be needed to meet the Dutch demand for hydrogen for heating purposes during a cold winter period as defined above. However, if depleted gas fields could be used, then only three fields would be needed. In the latter case, a monopoly may easily occur if these fields were all operated by a single firm. In such case, regulation would be required to assure that the flexibility to supply extra hydrogen during cold winter days is available to the market at reasonable prices. This regulation would be comparable to the current regulation of storage in the natural gas market because of the importance of having flexibility in the form of storage available at reasonable prices if hydrogen is used for heating homes.

The same conclusion holds when instead of depleted gas fields or salt caverns another large-scale storage option were to become available. As many technologies to store hydrogen as liquid, compressed gas, or chemical storage are under development, this may result in a storage solution which outcompetes other technologies in terms of efficiency and costs.[16] In that case, the storage side of the hydrogen market may be characterized by a few players, which would require

[13] Boudellal, *Power-to-Gas*.

[14] Ibid.

[15] Michalski, J., et al., 'Hydrogen generation by electrolysis and storage in salt caverns: potentials, economics and systems aspects with regard to the German energy transition' 42(2017) International Journal of Hydrogen Energy 13427–13443.

[16] Andersson, J. and S. Grönkvist, 'Large-scale storage of hydrogen' 44 (2019) International Journal of Hydrogen Energy 11901–11919.

regulation as mentioned above. However, if hydrogen is not (so much) used for heating homes but more in industry then there is less need to implement strict access regulation storage as industries generally have more options to deal with supply disruptions, while their demand for hydrogen would be less dependent on external weather conditions than the demand from households.

8.3.5 *Consumption of Hydrogen*

In its pure form, hydrogen is currently mainly used in industry (in particular refining, ammonia, chemicals, metals, electronics), while in a blended form (mixed with other gases), it is mainly used for creating methanol and heat.[17] In oil refining, hydrogen is used to convert crude oil into various end-user products such as transport fuels and feedstock for the chemical industry. This use of hydrogen is currently responsible for a major share in the carbon emissions of the industry, as the hydrogen that is used here is produced as a by-product of fossil energy or created through steam methane reforming. In the future, emissions stemming from the production and consumption of hydrogen have to be reduced sharply, which can be done by either using renewable hydrogen or capturing and storing the carbon emissions in the production process (see Section 8.3.2). This transition requires environmental regulation, in particular by imposing a carbon price on remaining carbon emissions or a constraint through, for instance, a cap-and-trade emissions trading scheme.

In the future, low-emission hydrogen demand will not only come from the abovementioned industries, but also from the transport sector, in particular from heavy freight transport, where hydrogen can be used in fuel cells as well as in internal combustion engines.[18] To realize this potential, more specific regulation is needed regarding the development of appropriate charging infrastructures.[19] In addition, hydrogen may also play a role in providing seasonal flexibility to electricity markets which are characterized by high shares of renewable generation. The potential of this usage depends on the competitive position of hydrogen storage combined with hydrogen power plants in comparison to other options to provide flexibility to electricity markets (such as hydropower and demand response).[20] As long as electricity prices reflect the changing scarcity conditions in these markets, no specific regulation is needed to foster particular sources of flexibility, such as hydrogen. Note that this statement refers to the wholesale market, as in the retail market the end-user prices are generally less directly related to changing market circumstances. For hydrogen producers, however, the wholesale market is relevant as that is where they buy their electricity.

8.3.6 *Wholesale Markets*

Just as for the natural gas market, a hydrogen wholesale market could function based on a transport and storage infrastructure that is accessible by all those who want to trade in hydrogen. After all, the wholesale market will include a physical exchange of the commodities, although financial markets will also emerge, once the physical trade options exist. The latter markets are

[17] IEA, *The Future of Hydrogen*.

[18] Grand View Research (2022). Green Hydrogen Market Size, Share & Trends Analysis Report, 2022–2030 <https://grandviewresearch.com/industry-analysis/green-hydrogen-market> accessed 23 January 2024.

[19] IEA, *The Future of Hydrogen*.

[20] See e.g. Li, X. and M. Mulder, 'Value of power-to-gas as a flexibility option in integrated electricity and hydrogen markets' 304 Applied Energy, 15 December 2021.

more related to the desire of parties to hedge their risks through long-term financial forward contracts or options. The physical market can exist as an over-the-counter (OTC) market with bilateral exchange through a broker or an exchange with standardized products and clearance by the exchange operator, who also takes over the financial risks. The last option facilitates the liquidity of the wholesale market as it results in standardization of the products which reduces the transaction costs, while transparency on prices and market conditions is fostered, which results in a higher volume of trades.

The hydrogen market may learn from how the market for natural gas developed over the past decade. Because of the differences in quality of various gases depending on their source, the trade in natural gas is done in uniform thermal (energy) units (in MWh), which strongly facilitates trade. To sell the commodity as a homogenous product, each type of gas is valued in terms of the energy content it carries. This means that it is not the volume (such as cubic metres – m^3) of the gas that is sold, but the amount of energy it carries, since heating is the main purpose of natural gas. In addition, to reduce the transaction costs and increase the transparency of trade, market hubs have been created in many countries: for example, the Title Transfer Facility (TTF) in the Netherlands, Net Balancing Point (NBP) in the United Kingdom, NetConnect Germany and GasPool in Germany (which recently have merged into Trading Hub Europe (THE)) and Virtual Gas Trading Point PSV in Italy. These marketplaces are virtual hubs based on an entry–exit system in which parties can transfer gas already injected into the national grid to other parties. As long as the gas is within the system, it can change owner. It is common that gas ownership changes numerous times between entry and exit. This is the so-called churn rate.[21] In particular, the churn factor of the TTF has increased strongly over recent years, thereby indicating that this market has become highly liquid. One factor behind the liquidity of the TTF are the high quantities supplied relative to the quantities demanded. The total supply to the Dutch natural gas market has been about twice as high as total Dutch gas consumption, while in most other countries this ratio is much lower.

8.3.7 *End-User Market*

Consumers may have different preferences for the type of hydrogen they want to use, just as they have different preferences for various types of electricity and gas. The economics of the transport of hydrogen, however, shows that it is not efficient to have alternative transport infrastructures. In the situation of a well-developed large-scale hydrogen market, all hydrogen coming from different sources (be it on the basis of steam methane reforming with or without CCS or on the basis of electrolysis based on grey or green electricity) will have a standardized physical quality as it will be transported through the same infrastructure. Users who prefer a specific physical quality (for example, pureness) of hydrogen, may need to convert the hydrogen to a different quality level upon its arrival at their location. This will likely hold for various industries, such as chemicals, glass-making, and steel. If hydrogen is used for heating, for instance in industry, users only have to adapt their appliances to the hydrogen quality transported through the network.

A more important distinction in quality is related to the way in which the hydrogen is produced, as consumers may have a preference for low-carbon hydrogen. This quality is not related to the physical characteristics of hydrogen, but to how 'sustainably' it is produced. To facilitate these consumer preferences, a certification system is required, just as currently

[21] The churn rate measures how often a commodity changes from ownership before it is actually used. See Mulder, *Regulation of Energy Markets*.

exists for electricity and gas based on the European system of Guarantees-of-Origin. This certification scheme, which is included in the European Renewable Energy Directive II, provides an internationally consistent approach to monitor carbon emissions throughout the supply chain, taking into account that hydrogen can be used in various types of end-user products, such as ammonia or fuels.[22] As countries and regions are currently developing their own certification schemes, it will be crucial for international trade to harmonize these into a global scheme.

8.4 CONCLUSIONS

The future outlook for the hydrogen market can be explored by comparing this market with the characteristics of natural gas and electricity markets. Regarding the production side of hydrogen markets, it will be fairly similar to the electricity market. Like electricity, the production of hydrogen is not bound to a particular place, since hydrogen can be produced wherever a gas or electricity network, or even a cluster of windmills, solar panels, and direct connections exists. In addition, it can be stated that the capital intensity of hydrogen production is very close to that of electricity generation. Hence, the supply side of hydrogen does not require special regulation from a competition point of view. Looking at environmental externalities, of course, regulation is required.

Regarding the transport side of the hydrogen market, it seems to be fairly similar to the natural gas market. Similar types of techniques are used, and various options for transport also exist, while that is not the case in electricity systems. The transport of large volumes of hydrogen is most efficiently done through pipelines, which means there exists a natural monopoly that requires appropriate regulation (in terms of tariff setting, quality requirements, and third-party access). For the consumption of energy, it will be necessary to develop global systems for certificates to enable users to make informed choices about the way the hydrogen that they are using is being produced.

FURTHER READING

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[22] IRENA, Creating a Global Hydrogen Market; Certification to Enable Trade, January 2023 <www.irena.org/Publications/2023/Jan/Creating-a-global-hydrogen-market-Certification-to-enable-trade> accessed 29 June 2024.

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9

The Role of Regional and Local Authorities in Developing a Regional Hydrogen Economy

Ceciel Nieuwenhout

9.1 INTRODUCTION

Academic and professional discussions on the development of a hydrogen economy often focus on the role of the industry and a national hydrogen pipeline infrastructure. What is frequently overlooked in these discussions, however, are important local and regional developments, which support the creation and development of a regional hydrogen economy. Some regions even declared themselves 'hydrogen valleys'.[1] This chapter deepens the understanding of the role of regions in the development of hydrogen markets. In practical terms, this is done by bringing parties together and positioning the specific region as a (green) hydrogen hotspot, but also by creating local demand. This chapter investigates the role of regional and local authorities in creating and developing a hydrogen market and the limits thereof. First, the ways in which regional and local authorities can influence the development of a local or regional hydrogen market is analysed (Section 9.2). Then, the policy and legal instruments for doing so are investigated in Section 9.3. This section is based on a functional comparative approach between two 'hydrogen regions', Groningen and Puglia. These regions are chosen as they are frontrunners in the development of hydrogen, but with a different approach.[2] The chapter closes with a conclusion and recommendations on the role of regions and regional authorities in the development of a hydrogen market.

9.2 THE ROLE OF REGIONS IN THE DEVELOPMENT OF HYDROGEN MARKETS AND INFRASTRUCTURE

Although the development of hydrogen infrastructure and hydrogen markets is mainly considered to be a national issue, there is a role for regional and local governments, especially in situations where no or only a limited national infrastructure or policy exists. Each country has a different

[1] For examples in Europe and around the world, see U. Weichenhain and others, 'Going Global – An Update on Hydrogen Valleys and Their Role in the New Hydrogen Economy', commissioned by Joint Undertaking Clean Hydrogen (EU), September 2022, p. 15 and further <https://clean-hydrogen.europa.eu/system/files/2022-09/Hydrogen_Valleys_online_2022.pdf> accessed on 8 February 2024 (Roland Berger report).

[2] It must be noted that there are many other regions that could be compared, but it lies beyond the scope of this chapter to provide a full overview of all hydrogen activities by all regions. The chapter focuses on the two selected regions as examples of how regions could develop hydrogen policy and regulations.

general division of competences between the national, regional and local governments, but even when certain issues are seen as a national competence, there may still be specific regional policies stimulating the development of hydrogen in that region in at least three respects.

Regional authorities may aspire to position themselves specifically as a 'hydrogen region' or 'hydrogen valley'.[3] They can bring together knowledge institutions and innovative companies, as well as specific industrial demand or supply of hydrogen. Moreover, as regional authorities are often in charge of the regional economic and industrial policy, they can focus on filling in specific gaps in the development of hydrogen chains. A further role that regional and local authorities may assume is related to the first role concerns help in creating local demand for hydrogen. Regional and local authorities can do so directly via the tender processes for public transportation[4] and/or maintenance vehicles,[5] and indirectly by stimulating industry in the region to transition to hydrogen usage rather than fossil fuels for industrial processes. With regard to the latter, local and regional authorities entrusted with environmental control over the local industry may also have to give specific environmental or spatial planning permits for such transitions. Finally, regional authorities in some countries, such as the Netherlands local authorities (*gemeentes*), are responsible for designing policy regarding the heat transition[6] and may use this role to stimulate system integration between heat, electricity and various gases in the transition to a fossil-free energy sector, for example by creating district heating networks for residential heating.[7] For this, they have to draft a heat transition plan in which they determine the source of heating in the future for each neighbourhood. This could be a (collective) heat network, individual heat pumps or a system based on a form of renewable gas.[8] If local governments decide that part of their neighbourhoods should be heated via district heating, this heat network should also be run on some form of renewable energy.[9] Next to geothermal, solar thermal and aquathermal energy (energy from surface water or sewage water),[10] waste heat can be an important source of heat for a low-carbon district heating network.[11]

[3] Cf Roland Berger report.

[4] Hydrogen trains (Coradia iLint) are used by Landesnahverkehrsgesellschaft Niedersachsen: J. Buckley, 'world's first hydrogen-powered passenger trains are here', CNN, 24 August 2022 <https://edition.cnn.com/travel/article/coradia-ilint-hydrogen-trains/index.html> accessed on 8 February 2024. There are currently 5,648 fuel cell buses in operation worldwide (2020 figures): R. Can Samsun, L. Antoni, M. Rex, D. Stolten, 'Deployment Status of Fuel Cells in Road Transport: 2021 Update', International Energy Agency (IEA) Advanced Fuel Cells Technology Collaboration Programme (AFC TCP). Forschungszentrum Jülich. The majority of these buses are located in China.

[5] With the HECTOR (Hydrogen Waste Collection Vehicles in Northwest Europe) project, waste collection vehicles on hydrogen are produced and tested in practice in seven cities around Europe: 'Project Summary' Interreg North-West Europe Hector <https://nweurope.eu/projects/project-search/hector-hydrogen-waste-collection-vehicles-in-north-west-europe/> accessed on 8 February 2024.

[6] Right now, this responsibility is not based on law but on the Climate Agreement, a form of soft law, signed by representatives from municipal and provincial governments as well as interest groups from different fields, such as the electricity sector, heavy industry, transportation sector and NGOs.

[7] Dutch Ministry of Economic Affairs and Climate, Kamerbrief DGKE-DE/22494404 on *Wet collectieve warmtevoorziening, besluit infrastructuur in publieke handen*, 21 October 2022.

[8] Such as biogas, syngas or hydrogen.

[9] Currently, however, only 8 per cent of heat in district heating is from renewable sources. IEA, Report: 'District Heating', IEA 2022, Paris <https://iea.org/reports/district-heating> accessed on 8 February 2024, Licence: CC BY 4.0.

[10] T. Pauschinger, 'Solar thermal energy for district heating' in R. Wiltshire (ed.) *Advanced District Heating and Cooling (DHC) Systems* (Woodhead Publishing 2016); for an analysis of the potential of aquathermia in the Netherlands: K. Kruit (CE Delft), B. Schepers (CE Delft), R. Roosjen (Deltares), P. Boderie (Deltares), 'Nationaal potentieel van aquathermie Analyse en review van de mogelijkheden', Delft, CE Delft, September 2018.

[11] The extent to which different sources of heat are used in a residential heat network depends on the local availability of these sources. Losses of heat during transportation over long distances is an important factor in this. However, the availability of waste heat can be steered by the (industrial) policy of the local authorities. This is especially relevant in cases where the (future) demand for heat exceeds the (existing or future) supply of heat.

In this context, a local government may also wish to incentivise hydrogen production facilities in the proximity of the district heat network. In this way, the waste heat from hydrogen production can serve a useful purpose[12] when a (residential) heat network is available nearby. As the process of electrolysis as well as the storage of hydrogen may not be allowed in the vicinity of residential buildings,[13] local governments do need to take into account the space necessary for such facilities in their spatial planning processes.

9.3 HYDROGEN POLICY AND LAW IN GRONINGEN AND PUGLIA

Different regions are developing their hydrogen law and policy in different ways. A comparison between regions is useful to gain insights into the different choices to be made and the consequences of those choices. This section compares the way policy and law are used to further the regional ambitions regarding a green hydrogen economy. The comparison focuses on the interplay between hydrogen policy and law, as well as on the interplay between regional and national governments.

Several regions are now developing hydrogen policy and law. For this comparison, the choice of regions was based on two elements: they need to be sufficiently advanced in the development of hydrogen law and/or policy, which ensures there is sufficient comparison material, and they must have a sufficiently distinct approach from each other, so the approaches can be compared. Finally, the actual availability of legal and policy documents also played a role. On the basis of these criteria, Puglia in Italy and Groningen in the Netherlands have been chosen for comparison. The lessons learned in these regions may serve other regions aspiring to develop hydrogen policy and law.

The comparison is made by first analysing the general objectives of the regions (why does this region aspire to be a hydrogen region?); then, the policy adopted to support this ambition, and finally the legal framework (as far as existent) applicable to the development of a regional hydrogen economy. After analysing these topics for both Puglia and Groningen (respectively Sections 9.3.2 and 9.3.3), the differences and similarities between the two regions are analysed in Section 9.3.4.

9.3.1 *Puglia*

The Italian region of Puglia, with its capital Bari, is very active in promoting hydrogen, via both policy and law. In 2019 Puglia adopted a regional Act on the promotion of the use of hydrogen,[14] and various interesting projects are being developed in the Puglia region. The reason why this region is specifically interested in hydrogen is due to the high potential of energy production from renewable sources,[15] with relatively low demand for electricity in the region.

12 F. Jonsson, A. Miljanovic, 'Utilization of Waste Heat from Hydrogen Production – A Case Study on the Botnia Link H2 Project in Luleå, Sweden', MSc Thesis, Mälardalen University, August 2022; F. S. Le Coultre, 'Utilisation of Heat Released during the Production of Green Hydrogen Using Alkaline Electrolysis', MSc Thesis, Technical University Delft, June 2022.

13 What the minimum distances to the nearest residential buildings should be depends on the size of the electrolyser and the method and capacity of storage. As an example, the forthcoming Decision on Activities in the Environment (Besluit Activiteiten Leefomgeving), Staatsblad 2018, 293, art. 4.1008(2), gives a distance of 15 metres for more than 1,000 litres of inflammable gases stored in gas cylinders. For underground gas storage, different rules apply.

14 Regional Act No. 34-2019 (Legge Regionale Puglia del 23 luglio 2019, no. 34) <https://dait.interno.gov.it/territorio-e-autonomie-locali/legittimita-costituzionale/legge-regionale-puglia-del-23-luglio-2019> accessed on 8 February 2024.

15 The region, located in the south of Italy, has high potential for solar energy. Moreover, the region also has wind resources. Terna, 'Provisional Data on Operation of the Italian Electricity System', 2020, p. 16 <https://download.terna.it/terna/2020_Provisional_data_operation_8d921d62b13a935.pdf> accessed on 29 June 2024. See also M.

Hence, hydrogen production infrastructure can facilitate the grid integration of fluctuating renewable energy sources.[16]

Policy

As a region, Puglia is devoted to developing a hydrogen economy. The regional authorities created a hydrogen policy, which has been codified in the abovementioned regional Hydrogen Act. With this Act, the region confirms that it aims to promote hydrogen and incentivize its usage and production, explicitly recognizing its roles in energy storage, as alternative fuel and especially as a means of integrating renewable energy into the electricity grid.[17] The Act is broader than only hydrogen, as it also includes provisions on the renewal of existing electricity production facilities as well as the general goal to contribute to greenhouse gas emissions reduction and tackling the dependency on fossil fuels.[18] The Act provides a comprehensive overview of the hydrogen policy for Puglia, based on four pillars.

First, the region stimulates projects on the production of hydrogen; hydrogen-based co-generation plants for the production of electricity and heat; a regional distribution network for hydrogen; increased demand for hydrogen as fuel for vehicles; aggregation and storage; and the development of R&D facilities with a view to expand knowledge and skills on hydrogen.[19] The instruments used for this purpose are agreements, conventions and memoranda of understanding with various partners, such as public bodies, research bodies, companies, trade associations and business consortia.[20]

Second, the Regional Council develops a regional hydrogen plan.[21] This plan, to be updated every three years, analyses the current state and development prospects of research and technical knowledge related to hydrogen; defines objectives for the upcoming three-year period; identifies regional measures for promotion and support of hydrogen production from renewable sources; lists the financial means for implementing the regional hydrogen plan; and provides tools for monitoring the implementation of the plan.[22]

A third aspect is the adoption of supporting measures to implement the hydrogen ambitions. For example, the region makes funding available for both the production and consumption of hydrogen.[23] It is specified that funding is also available for experimental projects and for specific groups, such as the operators of highways (for refuelling stations) and producers of biomethane

Pierro, D. Moser, R. Perez, C. Cornaro, 'The Value of PV Power Forecast and the Paradox of the "Single Pricing" Scheme: The Italian Case Study' Energies 13, 15 (2020), 3945, for the market impact of renewables on the Italian system (in this case solar resources). Finally, as a coastal area, Puglia may also be used as a landing point for offshore wind farms: A. Memija, 'New Joint Venture to Develop 525 MW Floating Offshore Wind Project in Italy', *Offshorewind.biz*, 29 September 2022.

16 This objective is formulated explicitly in LR Puglia 2019–34, art. 1(2). Whether grid integration of renewables improves due to the presence of hydrogen production infrastructure depends on other parameters as well, such as the way the electricity market is organised (are hydrogen producers rewarded for providing flexibility?), the availability of subsidies that take grid integration into account (are electricity producers rewarded for contracting hydrogen production facilities?), the capacity of hydrogen production (is the capacity sufficient to shave the peaks of electricity surplus?) and finally the price of hydrogen compared to the price of electricity.

17 Ibid., art. 1(2).

18 Ibid., art. 1(1) and 1(3).

19 Ibid., art. 2(2).

20 Ibid., art. 2(3).

21 Ibid., art. 3(1). The Regional Council does so in coherence with European and national plans on energy and transport. Moreover, coherence with the regional renewable energy plan is assured through art. 3(4) of the Act.

22 Ibid., art. 3(2).

23 Ibid., art. 5(1).

from green hydrogen.[24] In addition, the Regional Act targets public transportation as a source of hydrogen consumption: it promotes the renewal of the vehicle fleet with hydrogen fuel cell systems.[25] Moreover, the region uses tax measures to encourage investment in hydrogen fuel cell vehicles by companies and individuals: such vehicles are exempted from the regional car tax for a certain period.[26]

A fourth pillar in the hydrogen policy is the creation of a 'Regional Hydrogen Observatory' that collects and analyses data on the regional hydrogen economy and forecasts hydrogen trends. It also promotes meetings, studies and debates on hydrogen and assists the Regional Council in its decision-making on hydrogen-related topics.[27] The Regional Hydrogen Observatory consists of experts from various walks of life, such as representatives from the renewable energy sector, hydrogen production, academia and NGOs focusing on the energy and mobility sector.[28]

With these four pillars, Puglia covers the first two identified roles that regional authorities can take to stimulate a regional hydrogen economy, namely bringing different actors together and creating or stimulating local demand. The third, a role in the heat transition, is less relevant in a Mediterranean region like Puglia.

Law

As Italy is a republic, the regions have significant autonomy to develop their own policy and law in a wide variety of sectors.[29] This is the case for hydrogen. As both 'scientific and technological research and innovation support for productive sectors' and 'transport and distribution of energy' are listed as fields of concurring legislation, both the national government and the regions have legislative competences; lacking express coverage by state legislation, the hydrogen sector can be covered by regional legislation.[30] The regional government has made use of its competences by adopting the Regional Hydrogen Act that was elaborated in the preceding section. However, important aspects of the hydrogen economy, including safety of installations and transportation, are regulated at national level. Therefore, the national legal framework for hydrogen is also briefly described here.

There is no overarching hydrogen Act in Italy. Instead, hydrogen regulation is fragmented – based on the specific use and sector. An important aspect regulated at national level is permits and authorisations for hydrogen installations. At first, hydrogen was, from a legal point of view, considered to be a chemical. It was regulated like other (explosive) chemicals. Interestingly, already from 2006 onwards, a technical rule on hydrogen facilities for automotive vehicles was adopted.[31] This was renewed in 2018,[32] when omissions in the previous rule were

[24] Ibid., art. 5(2)b and c.
[25] Ibid., art. 5(3).
[26] Ibid., art. 5(5). Moreover, after the exemption period, the regional car tax remains reduced to 25 per cent for hydrogen fuel cell vehicles.
[27] Ibid., art. 4.
[28] Ibid., art. 4(4).
[29] Constituzione della Repubblica Italiana, art. 117.
[30] The Italian constitution states that in sectors of concurring legislation (between the republic and its regions), 'legislative powers are vested in the Regions, except for the determination of the fundamental principles, which are laid down in State legislation. The Regions have legislative powers in all subject matters that are not expressly covered by State legislation'. Senato della Repubblica, Constitution of the Italian Republic (Official English translation of the Constituzione della Repubblica Italiana).
[31] Technical Rule on Fire Prevention in Distribution of Hydrogen at Refuelling Stations 2006 (*Regola tecnica di prevenzione incendi per la progettazione, costruzione ed esercizio degli impianti di distribuzione di idrogeno per autotrazione*) DM 31 agosto 2006 (GU n. 213 del 13 settembre 2006).
[32] Technical Rule on Fire Prevention in Distribution of Hydrogen at Refuelling Stations 2018 (*Regola tecnica di prevenzione incendi per la progettazione, costruzione ed esercizio degli impianti di distribuzione di idrogeno per autotrazione*), DM 23 ottobre 2018, DM 23 ottobre 2018.

addressed.[33] The translated title of the instrument is: Ministerial Decree on Technical Rules of Fire Prevention for Design, Construction and Operation of Hydrogen Distribution Facilities for Automotive Vehicles. As the title suggests, the rule is narrow in scope as it concerns facilities for automotive vehicles, but it does in fact cover the entire chain including the production of hydrogen at locations relevant for automotive vehicles.

Other activities (not related to automotive uses) do not have such a specific regulation. For example, electrolysers are mainly treated as a form of industrial activity and not as a specific element of the energy chain. They do not have a specific status and they are regulated like other industrial activities of the same size and hazard category. The grid connection of electrolysers is based on general rules concerning grid connection of industrial installations.[34] This can be considered a missed opportunity, as this way of regulating does not take into account the specific added benefits that hydrogen production could have for the grid integration of renewable energy sources.[35] Especially in the context of the Puglian hydrogen economy, which is explicitly aiming at increased grid integration of renewable energy, a regulatory framework that rewards the benefits of hydrogen production would be an important addition.

Transportation of hydrogen by road, rail and inland waterways is regulated like every other form of transportation of dangerous or inflammable products, namely on the basis of the Legislative Decree on the Transport of Dangerous Goods,[36] a direct implementation of the European legal framework on the transportation of dangerous goods.[37] It includes standards for the transportation of dangerous goods (including hydrogen), classification of dangerous goods for road transport, shipping procedures, as well as provisions on the construction, testing and approval of packaging and tanks, use and requirements for means of transport and cases of exemption. However, this legal framework is not applicable to transportation by pipeline. As transportation by pipeline is expected to bring together hydrogen production and consumption within a region or between regions, it is important that the legal framework for transportation of hydrogen via pipeline is being developed. It is important that this issue is not only approached in the context of safety and permits, but also with regard to the issues of which actors should develop transmission infrastructure; whether or not a transmission system operator should be appointed and whether or not there should be third-party access to hydrogen pipeline infrastructure.

In conclusion, the legal framework for hydrogen in Italy is fragmented and there is no overarching national Act on hydrogen. This creates legal uncertainty regarding various hydrogen-related activities, especially when they are organised differently per region. Nevertheless, the Regional Act on Hydrogen, adopted by the Puglian Regional Council, does give legal certainty to project developers, companies and knowledge institutions on the direction

[33] An example of an omission is that the 2006 rule only considered hydrogen from fossil sources, whereas the 2018 rule also includes electrolysis. DM 23 ottobre 2018, art. 2.2.

[34] These rules are laid down in the 'TICA': ARERA (Italian regulatory authority), *Testo integrato delle condizioni tecniche ed economiche per la connessione alle reti elettriche con obbligo di connessione di terzi degli impianti di produzione di energia elettrica (Testo integrato delle connessioni attive – TICA).*

[35] M. Ciminelli, P. Cavasola, 'Hydrogen Law, Regulations & Strategy in Italy', CMS Law <https://cms.law/en/int/expert-guides/cms-expert-guide-to-hydrogen/italy> accessed on 8 February 2024.

[36] Decreto legislativo – 27/01/2010 – n. 35 – Trasporto interno di merci pericolose. This Act has been amended several times Ministero Delle Infrastrutture e dei Trasporti, Decreto 12 maggio 2017. Recepimento della direttiva 2016/2309 della Commissione del 16 dicembre 2016 che adegua per la quarta volta al progresso scientifico e tecnico gli allegati della direttiva 2008/68/CE del Parlamento europeo e del Consiglio relativa al trasporto interno di merci pericolose.

[37] Directive 2008/68/EC of the European Parliament and of the Council of 24 September 2008 on the inland transport of dangerous goods, OJ L 260, 30.9.2008, and following Acts, specifically Commission Directive (EU) 2016/2309 of 16 December 2016 adapting for the fourth time the Annexes to Directive 2008/68/EC.

of hydrogen policy in Puglia in the coming years. Moreover, the Regional Act also provides sufficient instruments for the regional hydrogen policy. Finally, a danger to the implementation of the regional Hydrogen Act is dependency on the underdeveloped national legal framework for important matters such as permits, integration in the energy sector and transportation by pipeline: development of national overarching laws on this topic may be too slow for the regional ambitions, leaving project developers with legislative uncertainty. Moreover, in the absence of a national framework for the governance of hydrogen pipelines, the regions may all develop their own approaches, creating a patchwork of different systems. As long as all hydrogen developments take place within one region, this is not problematic, but as soon as pipelines cross regional borders, it may become so.

9.3.2 *Groningen*

The north of the Netherlands, with a key role for Groningen,[38] refers to itself as the first 'hydrogen valley' of Europe.[39] That is, inter alia, because over recent years many hydrogen-related projects have been or are currently being developed in this region.[40] There are three main reasons why Groningen as a region has an interest in the development of a hydrogen economy: first, Groningen is home to one of the largest natural gas fields in Europe.[41] The region traditionally focused on gas production, but due to earthquakes, and the resulting damage,[42] it was decided that the gas production should end.[43] However, Groningen is still home to significant amounts of knowledge and skilled workers in the gas industry, which could be used for the setting up of a more sustainable gas industry.[44] Thus, hydrogen can play a role in the transition from a natural gas industry region to a clean energy region. It must be noted in this context that the gas industry has played a large role in lobbying for hydrogen activities in the region.[45] A second reason for Groningen's interest in hydrogen is that it is currently one of the regions with the highest penetration of renewable energy in the Netherlands, and it has high ambitions with regard to the development of renewable energy (solar power plants and wind energy) in the years ahead. Hydrogen production could help facilitate grid integration of renewables.[46] A third reason is that hydrogen can be used as a feedstock for the industrial clusters of the region.[47]

[38] It is important to note that the name 'Groningen' refers to a province of the Netherlands as well as the capital thereof. In this chapter, it is indicated whether the city or the province of Groningen is meant in a specific context.

[39] Provincie Groningen, 'Waterstof' <https://provinciegroningen.nl/actueel/dossiers/energietransitie/waterstof/#:~:text=De%20provincie%20Groningen%20zet%20zich,Den%20Haag%20en%20in%20Europa> accessed on 8 February 2024.

[40] Provincie Groningen, 'The Northern Netherlands Hydrogen Investment Plan 2020 – Expanding the Northern Netherlands Hydrogen Valley', October 2020 <https://groningen.stateninformatie.nl/document/9479729/1/Investment_Plan_Hydrogen_Northern_Netherlands_2020> accessed on 8 February 2024, p. 38.

[41] Parliamentary Committee of Inquiry into Natural Gas Extraction in Groningen, 'Groningers before Gas', 24 February 2023, pp. 14 and 71.

[42] Ibid., pp. 16–17.

[43] Dutch Ministry of Economic Affairs and Climate, Kamerbrief 'Wetsvoorstel "Wat na nul" – wetswijzigingen in verband met de definitieve sluiting van het Groningenveld', DGKE-PDG/20243498, 24 November 2020.

[44] Provincie Groningen, 'The Northern Netherlands Hydrogen Investment Plan 2020', p. 16.

[45] B. Schohaus, B. van Beek, J. Mast, M. de Buck, A. Beunder, 'Shell beloofde Groningen ooit een 'goene' toekomst', *Follow the Money*, 17 June 2024 <www.ftm.nl/artikelen/shell-beloofde-groningen-groene-toekomst?share=JEtlrWdSM2%2F8bjT84tzIhKtQYOuaaG9MVxBKIuy4R%2FIGqkahQ6VG7CyA1u5bISw%3D> accessed on 21 June 2024.

[46] Provincie Groningen, 'The Northern Netherlands Hydrogen Investment Plan 2020', p. 16.

[47] Delfzijl, Eemshaven and, just outside Groningen province, Emmen. The HEAVENN project shows various ways in which the industry uses the produced hydrogen. HEAVENN, 'Projects' <https://heavenn.org/heaven-projects/> accessed on 8 February 2024.

Policy

The Province of Groningen has an active role in developing a hydrogen network. This policy has resulted from considerations related to strengthening the local economy and retaining sufficient employment possibilities while the fossil fuel production region was declining.[48] The policy was partially designed in close connection to the companies involved in the production of natural gas in the region.[49]

The role of the province in the development of a hydrogen region is twofold: on the one hand, the province creates a network of companies working together in the hydrogen chain, and on the other hand, together with its partners, it develops a pipeline of projects which it coordinates in terms of timing and funding.[50] This translates into an active lobby for hydrogen on the national and EU scale, and in a stimulus for companies to apply for funding for projects.[51] Moreover, the province developed an Investment Plan with concrete actions for the coming years. The Investment Plan can be compared to the Regional Hydrogen Plan that is to be developed in Puglia; it contains various projects, measures and a roadmap for future hydrogen expansion. With this Investment Plan, the Groningen Regional Council demonstrates the political will to invest in hydrogen, which will help to create investment certainty for project developers.

A recent update of the Investment Plan has shown a vast increase in hydrogen-related projects (from fifty to more than eighty), but at the same time it has become clear that no investment decisions have been made on large(r)-scale green hydrogen projects.[52] Compared to the 2020 ambitions, there is a serious delay, which also involves the hydrogen infrastructure projects that serve as a backbone for the other activities. This is due to the reluctance of parties to conclude long-term contracts, making the business case (too) uncertain to proceed to a final investment decision.[53] Higher energy costs and economic uncertainty, for example in the chemical industry, have also played a role in the delay of these projects.[54] Without these large projects, it is difficult to keep the 'hydrogen frontrunner' position that Groningen aims for.[55]

The efforts are coordinated via HyNorth, the Transformation and Coordination Office founded by the provincial hydrogen roadmap. This organisation is also responsible for monitoring the results and for bringing together partners that depend on each other in the 'hydrogen chain'.

Next to the provincial efforts, there are also other local entities active in the promotion of hydrogen. One of the ways in which the city of Groningen influences the demand for hydrogen is by experimenting with hydrogen as a fuel for public transportation,[56] and (heavy duty) vehicles owned by the municipality itself.[57] By doing so, a city or region can speed up the innovation process for fuelling heavy vehicles with hydrogen. Not only large cities are developing hydrogen projects: In Wagenborgen, a village in the rural area of East Groningen, thirty houses owned by

[48] Schohaus et al., 'Shell beloofde Groningen ooit een "goene" toekomst' (2024).
[49] Ibid.
[50] Provincie Groningen, 'The Northern Netherlands Hydrogen Investment Plan 2020', p. 41.
[51] See Provincie Groningen, 'Waterstof'.
[52] HyNorth, 'Samen aan de slag, Investeringsplan Waterstof Noord-Nederland 2024', Groningen, June 2024, 6.
[53] Ibid., 6.
[54] Ibid., 7.
[55] Ibid., 7.
[56] As part of OV-bureau Groningen-Drenthe, 'De Toekomst Is Groen' <https://ovbureau.nl/themas/de-toekomst-is-groen/#:~:text=van%20Nederlandse%20windparken.-,Waterstofbussen,te%20maken%2C%20de%20Hydrogen%20Valley> accessed on 8 February 2024.
[57] As of February 2023: three waste collection trucks as part of the H2Revive project (Horizon2020); two passenger cars, two vans, two waste collection vehicles and a hydrogen maintenance boat as part of the HyTrEc2 project (Interreg North Sea); one waste collection vehicle as part of the Hector project (Interreg North Sea); four waste collection trucks, eight hydrogen vans and a building heating system as part of HEAVENN (Horizon2020).

a social housing corporation are connected to a small hydrogen grid.[58] This allows the project partners to experiment with different components (such as residential hydrogen heating installations), new roles (the distribution system operator of the region, Enexis, which normally operates the electricity and gas network, will also develop the hydrogen network) and citizen engagement.[59]

However, it must be noted that, despite claims that these cases help to increase local demand for hydrogen and thereby boost the development of clean hydrogen production, critics claim that one should not use the (scarce) amounts of clean hydrogen for purposes in which other technologies or fuels are available (and sometimes better suited).[60] In fact, both views can be applicable at the same time, namely in a situation where hydrogen consumption and production are still at a low level. The weighing of different interests and alternatives for specific purposes may differ by region and vary over time. It helps if regions have a clear vision on what the purpose of a pilot is and how the resulting knowledge and infrastructure will be used in the future.

Of the three roles identified in Section 9.2, the province of Groningen is most active in the first role (bringing together various parties and completing the hydrogen chain), whereas various municipalities (together with the province of Groningen) are investing in the second role (increasing the demand for hydrogen via public transport and municipal vehicles and hydrogen usage in residential areas). Interestingly, even though there is significant heat demand in the Netherlands, and Groningen has a heat network based on waste heat, this has not yet been coupled to the hydrogen economy.

Law

The different hydrogen production and use activities in the northern Netherlands must fit within the existing legal framework. In the Netherlands, the regulation of hydrogen lies with the national authorities. As such, Groningen cannot adopt specific legislation on hydrogen, even though it wishes to be a frontrunner in the development of hydrogen. It should therefore seek support from other regions with similarly high hydrogen ambitions: the port areas of Rotterdam and Amsterdam,[61] as well as the chemical cluster of Zeeland, with the first Dutch hydrogen pipeline between Dow and Yara.[62] The various Dutch regions with hydrogen ambitions are at the same time competing and cooperating with each other: there is competition, for example, in

[58] Groninger Huis, 'WaterstofWijk Wagenborgen' <https://groningerhuis.nl/projecten/waterstofwijk-wagenborgen/> accessed on 8 February 2024.

[59] Citizen engagement in hydrogen heating trials is important, as is shown by events in Whitby, United Kingdom: A. Lawson, '"We've got no choice": Locals fear life as lab rats in UK hydrogen heating pilot', *The Guardian*, 21 November 2022; R. Parkes, 'Hundreds of residents vent anger over "entirely pointless" hydrogen heating trial during hostile public meeting', *Hydrogen Insight*, 2 March 2023.

[60] For example, in transportation, personal vehicles do not necessarily need to be fuelled by hydrogen: regular electric cars are an energy- (and cost-)efficient alternative. For heavy-duty vehicles, there may not be sufficient alternative options. F. Ueckerdt, C. Bauer, A. Dirnaichner, J. Everall, R. Sacchi, G. Luderer, 'Potential and risks of hydrogen-based e-fuels in climate change mitigation' *Nature Climate Change* 11 (2021) 384–393. For residential heating, electrical heat pumps and heat networks based on sustainable heat are also clean technologies, which may also have lower system costs than hydrogen-based residential heating. J. Rosenow, 'Is heating homes with hydrogen all but a pipe dream? An evidence review' *Joule* 6, 10, 19 October 2022, 2225–2228.

[61] Rotterdam Sea Port, 'Factsheet Waterstofeconomie in Rotterdam', April 2021; Port of Amsterdam, 'Hydrogen Hub Amsterdam North Sea Canal Area', October 2021.

[62] The pipeline has been operational since 2018. Hynetwork, 'Waterstofleiding Dow-Yara' <https://hynetwork.nl/over-hynetwork-services/waterstofleiding-dow-yara> accessed on 8 February 2024.

the application for national or EU-based funding for their projects, and cooperation takes place in joint efforts for the development of national policies and legislation on hydrogen.

Despite all the ambitious hydrogen regions in the Netherlands, the current legal framework for hydrogen is still under construction: the new Energy Act which is currently still in the parliamentary process, is the first Act to include hydrogen regulation. It proposes to include hydrogen in the rules on unbundling, making it in principle impossible for the same legal entity to be involved in both commercial activities (production, trade, sale) and transportation of hydrogen.[63] Infrastructure companies are allowed to develop hydrogen transmission infrastructure as well as to organise hydrogen trading platforms.[64] They are also allowed to develop hydrogen storage facilities, as well as terminals and interconnectors for export of hydrogen.[65] A major point of consideration is the re-use of the existing natural gas infrastructure for the creation of a hydrogen pipeline infrastructure 'backbone'. Moreover, an important highlight of this proposed Energy Act is that it puts an end to the long discussion on whether or not the hydrogen pipeline system should be owned by a party that is unbundled from the production, supply and storage of hydrogen.[66] An additional question is whether the entity responsible for natural gas (owning the gas pipeline structure that will partially be re-used), Gasunie Transport Services (GTS), should become the transmission system operator (TSO) of the hydrogen system.[67]

Next to the debate on the direction of the legal framework concerning the ownership of pipeline infrastructure, other relevant topics are the permitting and licensing regimes and the rules that are applicable to hydrogen transportation via road, rail and inland waterways. Permitting and licensing regimes, for example for hydrogen production and refuelling stations, are based on the legal framework for industrial activities, which is also undergoing a major legislative overhaul.[68] Regarding transportation of hydrogen via road, rail and waterways, the legal framework is based on the implementation of European legislation.[69] The regional experiments with hydrogen as a fuel for residential heating (Wagenborgen) are based on exemptions to the existing legislation, rather than on a solid legal framework. The Minister of Economic Affairs requested the Dutch State Supervision of Mines (Staatstoezicht op de Mijnen), which is also the authority for the safety of gas extraction activities, to supervise the safety of experiments with hydrogen in residential areas.[70]

9.3.3 *Comparison*

In this section, the 'hydrogen regions' of Groningen and Puglia are compared on both the policy and law related to hydrogen. Main points that stand out are a focus on the energy chain; the

[63] Energy Act (version as decided by the Second Chamber on 4 June), art. 3.10.
[64] Ibid., 3.19.
[65] Ibid., 3.19(4)
[66] The Dutch regulatory authority ACM has published a report on this topic, focused on the activities allowed under the current legal framework. ACM, 'Leidraad Netwerkbedrijven en Alternatieve Energiedragers', 14 September 2021, ACM/19/036168/Documentnr. ACM/UIT/555471.
[67] For details see Chapter 17 by Maaike Broersma, Philipp Jäger and Marijn Holwerda in this book.
[68] The '*Omgevingswet*' (Environmental Planning Act) will replace nineteen legal instruments on environmental permits and procedures. The envisaged end result is a simplified and more coherent legal framework for environmental permits and procedures.
[69] In the Netherlands, this is implemented in the Act on the Transportation of Dangerous Goods (*Wet Vervoer Gevaarlijke Stoffen*, WVGS). Instituut Fysieke Veiligheid, 'Kennisbundel transport van waterstof(dragers)', 2 March 2022.
[70] Dutch Ministry of Economic Affairs and Climate, Letter: 'Toezicht op waterstofpilots en demonstratieprojecten', 6 October 2022, Document No. DGKE-DE/22510896.

underlying policy goals of the ambition to develop a hydrogen region; the role of municipalities; the regional legal framework; and the relation to the national legal framework. These topics are treated in more detail below.

First, regarding the hydrogen chain, both Puglia and Groningen have applied for projects related to a combination of electrolysis, hydrogen storage and various forms of hydrogen use, in order to reach a 'hydrogen chain' rather than separate projects.[71] This could be explained as follows. For entities to benefit from the regional focus (contrary to a national focus), it is important that the region includes various parts of the chain, such as production, storage, transportation and use, within a geographically limited area. With isolated projects, there is less benefit from a regional approach compared to a national approach, as geographical proximity between projects is not exploited. As mentioned in the updated hydrogen investment plan for Groningen, this focus on a chain of projects has the downside that delays in one project influences the projects surrounding it and can affect the activities in the entire region.

A second point relates to the underlying goals of the hydrogen ambitions. There is a clear difference between Puglia and Groningen, at least in the communication about the goals. Puglia focuses mainly on the combination of renewable energy and green hydrogen production, driven by the need for better grid integration of the large potential for renewable energy in Puglia. This is also mentioned in the Groningen case, but in policy documents it becomes clear that Groningen focuses more on industrial policy and economic considerations, and specifically on the link between green hydrogen production, infrastructure and integration in industrial processes. A secondary goal is to use hydrogen as a replacement for the natural gas sector that is seeing its activities decline in Groningen.[72]

Whereas the goals and background of the ambition differ, the means to reach it are similar: both regions adopted specific policy instruments to this end, which focus not only on the energy installations as such, but also on other aspects such as expanding knowledge and skills in the hydrogen industry and collecting data and trends on the development of the regional hydrogen economy. In both cases, a coordinating and monitoring body is present.

The involvement of municipalities is different in Groningen and Puglia. Whereas they are essential to the policy framework in Groningen, this is less so (or at least less visible from the outside) in Puglia. In Groningen, some municipalities are actively promoting the use of hydrogen in municipal vehicles or in a 'hydrogen neighbourhood' in which hydrogen is used as a means of heating. A recommendation in this regard is to couple the development of a hydrogen economy to other municipal tasks, such as heating transition (in the Netherlands) or transportation policy (local public transport for example). This may deliver mutual benefits to the policy goals, such as the use of waste heat from hydrogen production that can be used in a municipal heat network.

The next point of comparison is the development of a regional legal framework. Puglia and Groningen differ significantly in their approaches. This difference stems from the constitutional and political differences between the regions: Italy is a republic, and regions in Italy are more accustomed to adopting their own legislation on a wide variety of topics. Thus, Puglia laid down

[71] In northern Netherlands, an example is the EU-funded HEAVENN project: HEAVENN is a large-scale programme of demo projects bringing together core elements: production, distribution, storage and local end use of hydrogen (H_2) into a fully integrated and functioning 'H_2 valley' (H_2V) that can serve as a blueprint for replication across Europe and beyond. The Puglia green hydrogen valley project combines three hydrogen electrolysis plants (220 MW) with 400 MW of solar energy plants. This hydrogen will then be used in local industries as well as for injection in the local gas network and for transportation purposes.

[72] Provincie Groningen, 'The Northern Netherlands Hydrogen Investment Plan 2020', p. 7.

its policy in a Regional Act, whereas Groningen only has policy documents. Although the difference between the two regions can be explained, the outcome is that Puglia creates more legal certainty. The Regional Act explains the ambitions, instruments and scope of the hydrogen plans unambiguously and for the longer term. Groningen does not have a similar Act but did adopt a regional investment plan on hydrogen that lays down ambitions and projects as well as a development plan for the longer term. However, this document has less legal value than an Act.

Both regions rely on national legislation on hydrogen infrastructure and safety of installations. In the Netherlands, the legal framework is under development, after a long period of discussions on which entity should own and operate hydrogen infrastructure. In Italy, the lack of legislation on hydrogen transportation via pipeline is a legislative gap: pipelines are a logical mode of transportation to match production and consumption of hydrogen within a region. Both countries have legislation regarding transportation of hydrogen via road, rail and waterways, which is based on European law regarding dangerous goods.

Finally, a missed opportunity is that neither of the countries has specific legislation on the integration of hydrogen in the energy sector, whereas in both countries, a main reason for the development of a hydrogen economy is to relieve the stress put on the electricity system regarding the increased load and penetration of intermittent renewable energy sources.

9.4 CONCLUSION AND RECOMMENDATIONS

Hydrogen infrastructure is expected to develop as national infrastructure, but the role of regional and local authorities in the creation and development of the hydrogen market should not be underestimated. Regional and local authorities can have several roles in this respect. First, they can bring parties (companies, industrial associations, knowledge institutions) together and position the specific region as a hydrogen hotspot. Regions are often already in charge of industrial policy and employment policy, and the development of a hydrogen region fits with this competence. Secondly, regions can create local demand through the procurement of public transport services and/or maintenance for vehicles, also in areas where there is no industrial demand for hydrogen (yet). In doing so, they can also complete the 'hydrogen chain', when there is potential for hydrogen production. Third, local and regional authorities can play a role in system integration between electricity, hydrogen and heat by using the waste heat from hydrogen production in district heating. When creating a local demand for hydrogen, municipalities may want to steer towards *local* production of hydrogen, as the waste heat of this process can then be used in local district heating networks. Even though there is an identified potential for use of waste heat from hydrogen production, this chapter shows that possibility is currently not taken up by local or regional authorities in the investigated regions (Groningen and Puglia).

The comparison between these regions showed that there are differences in regional hydrogen policy and law either on the general purpose or on the approach and the translation into legal instruments. First, the purposes for the development of a regional hydrogen economy differ significantly. Whereas Puglia's main reason for the development of a hydrogen economy is the facilitation of the grid integration of renewables, Groningen developed its hydrogen policy in its search for a replacement for natural gas production and transportation in its regional economy, both the physical infrastructure and the socio-economic infrastructure, including knowledge and skills. The approach to hydrogen policy is also different: whereas Puglia has an overarching instrument, the Groningen approach is based more on projects. Nevertheless, both regions focus on the entire chain, from production to transportation and various types of consumption. In terms of the translation into legal instruments, Puglia adopted a specific legal instrument on hydrogen. This is not the case in Groningen. Codifying the policy into legal instruments has an advantage in that it formalises the regional commitment to hydrogen, thereby providing a stable investment climate for project developers as well as R&D facilities. Both regions, however, struggle with a lack of coherent national legislation for hydrogen.

Based on this chapter, recommendations for regions wishing to create a regional hydrogen policy and legal framework are, first, to consider the purpose for which the hydrogen economy will be developed and to design the policy and legal framework in a way that fits with this purpose; second, to consider whether or not the policy should be based only on soft law instruments or whether a local legal instrument can be used; third, to involve local authorities, such as municipalities, which can also take up their own role in the development of a regional hydrogen economy; and fourth, in regions with district heating, whether or not system integration between hydrogen production and heat networks can be accomplished, as the potential value of waste heat from the hydrogen production process can only materialise if the facilities are located sufficiently close to the district heating network and if the use of waste heat is taken into account in the design of the production facilities. This requires a far-sighted policy that also considers future demand for low-carbon heat. Next to recommendations for local and regional authorities, a recommendation for national authorities is to develop a coherent legal framework on hydrogen that recognises the role(s) of regions in the development of a hydrogen economy.

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J. Rosenow, 'Is heating homes with hydrogen all but a pipe dream? An evidence review' Joule 6, no. 10, 19 October 2022, 2225–2228]

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U. Weichenhain and others (Roland Berger), 'Going Global – An Update on Hydrogen Valleys and Their Role in the New Hydrogen Economy', commissioned by Joint Undertaking Clean Hydrogen (EU), September 2022, available at <https://clean-hydrogen.europa.eu/system/files/2022-09/Hydrogen_Valleys_online_2022.pdf> accessed on 8 February 2024

10

Sustainability Criteria for Renewable Hydrogen

Romain Mauger, Paola Villavicencio-Calzadilla and Ruven Fleming

10.1 INTRODUCTION

Hydrogen can come in all shapes and forms. According to the so-called colour-book of hydrogen, several different types of hydrogen exist and are clustered depending on their production method and input (electricity, gas, and so on). However, things are even more complicated given that different terminology exists in different regions of the world. This chapter focuses on Europe. The use of hydrogen terminology by European institutions has been explained before in this book by Leigh Hancher and Simina Suciu[1] and will not be repeated here. The focal point of this chapter is, in line with these EU definitions, renewable hydrogen. Renewable hydrogen means hydrogen produced with the help of renewable energy carriers, such as electricity from solar panels and wind turbines. Whether renewable hydrogen produced from biomass is part of that definition or instead is defined as biogas is still debated between European institutions at the time of writing.[2]

The Hydrogen and Decarbonized Gas package is finally well on its way to implementation and it contains a revised Gas Directive (hereinafter rGD).[3] This rGD indirectly features sustainability criteria for hydrogen. Indeed, article 8 (1) rGD requires renewable gases to be

[1] For details see Chapter 2 in this book: Leigh Hancher and Simina Suciu, 'Hydrogen Regulation in Europe: The EU's "Hydrogen and Decarbonized Gas" Package'.

[2] The proposition of the Council can be found at Recital 9 of Council of the European Union Interinstitutional file 2021/0425(COD) Proposal for a Directive of the European Parliament and of the Council on common rules for the internal markets in renewable and natural gases and in hydrogen (recast) – Analysis of the final compromise text with a view to agreement at <https://data.consilium.europa.eu/doc/document/ST-16516-2023-INIT/en/pdf> accessed 2 January 2024. The opposite position (no separate treatment) by the Commission can be found at Recital 9 of European Commission Proposal for a Directive of the European Parliament and of the Council on common rules for the internal markets in renewable and natural gases and in hydrogen COM/2021/803 final <https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A52021PC0803> accessed 2 January 2024.

[3] At the time of writing there is a political compromise between the three EU institutions and agreement on the shape and guise of a common Gas Directive, see: Council of the European Union Interinstitutional file 2021/0425(COD) Proposal for a Directive of the European Parliament and of the Council on common rules for the internal markets in renewable and natural gases and in hydrogen (recast) – Analysis of the final compromise text with a view to agreement, available at <https://data.consilium.europa.eu/doc/document/ST-16516-2023-INIT/en/pdf> accessed 2 January 2024. Moreover, European Commission Proposal for a Directive of the European Parliament and of the Council on common rules for the internal markets in renewable and natural gases and in hydrogen COM/2021/803 final <https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A52021PC0803> accessed 2 January 2024.

certified in accordance with articles 29, 29a and 30 of the 2023 Renewable Energy Directive (RED III).[4] Renewable gases encompass biogas and renewable fuels of non-biological origins (RFNBOs).[5] RFNBOs are themselves defined as liquid and gaseous fuels, the energy content of which is derived from renewable sources other than biomass.[6] This is where renewable hydrogen lies. All this means that RED III's bioenergy sustainability criteria should also apply to renewable hydrogen.

To guarantee that RFNBOs are indeed of renewable origin, they have to comply with a 2023 Delegated Act from the Commission.[7] This Delegated Act was adopted as required by RED III.[8] For hydrogen to be considered as renewable, the electrolyser must consume electricity either through a direct connection to a generation plant using renewable sources, or through a connection to the grid with the condition that it runs overwhelmingly on renewable sources, or otherwise through power purchase agreements with generation from renewable sources and additionality, temporal correlation and geographical correlation rules. These rules all apply to hydrogen whether produced inside the EU or imported,[9] and they come on top of the sustainability criteria.

For a genuine transformation and decarbonization of our energy systems, a lot of hydrogen needs to be produced globally. However, when looking into renewable hydrogen specifically, it becomes immediately clear that production conditions differ widely across the globe, as the sun does not shine equally bright and the wind does not blow equally strong everywhere. As a result, some areas and regions will be far more suitable for the production of renewable hydrogen than others. The crux is that, despite great differences in possibilities for production, renewable hydrogen will be required all around the world. Thus, trade in hydrogen becomes crucial. Some countries might be able to export surplus production of hydrogen, while others will have great demand in terms of import.

The International Energy Agency (IEA) did extensive research into these geographical disparities around the globe and compiled the results in its Global Hydrogen Review 2022.[10] According to this, an estimated 12 million metric tons (Mt) of hydrogen could be exported annually by 2030 around the globe, with 2.6 Mt/year planned to come online by 2026.[11] Of the 12 Mt H2/year of planned exports by 2030, the region with the largest amount is Latin America (3.0 Mt H2/year). This is followed by Australia (2.7 Mt H2/year), Europe (1.79 Mt H2/year), Africa (1.7 Mt H2/year), North America (1.1 Mt H2/year), Middle East (1.0 Mt H2/year) and Asia (0.7 Mt H2/year).[12] Abundant solar, wind and hydropower resources to supply clean electricity for electrolysis is a key driver of these projects.[13]

[4] Directive (EU) 2023/2413 of the European Parliament and of the Council of 18 October 2023 amending Directive (EU) 2018/2001, Regulation (EU) 2018/1999 and Directive 98/70/EC as regards the promotion of energy from renewable sources, and repealing Council Directive (EU) 2015/652.

[5] rGD, art 2 (2).

[6] RED III, art 2 (36).

[7] Commission Delegated Regulation (EU) 2023/1184 of 10 February 2023 supplementing Directive (EU) 2018/2001 of the European Parliament and of the Council by establishing a Union methodology setting out detailed rules for the production of renewable liquid and gaseous transport fuels of non-biological origin (hereinafter: Delegated Act).

[8] As the Delegated Act was adopted before RED III, it still refers to art 27 (3) RED II, but in RED III this provision is now numbered 27 (6).

[9] Delegated Act, art 1.

[10] International Energy Agency (IEA), 'Global Hydrogen Review 2022' (2022) <https://iea.blob.core.windows.net/assets/c5bc75b1-9e4d-460d-9056-6e8e626a11c4/GlobalHydrogenReview2022.pdf> accessed 13 September 2023.

[11] Ibid 6 and 162.

[12] Ibid 163–164.

[13] Ibid.

As opposed to this export capacity, import capacity around the globe is lagging. Of the 12 Mt H2/year of proposed exports by 2030, only projects accounting for 2 Mt H2/year have made off-take agreements or have a potential off-taker in a project consortium.[14] Projects representing a further 2.6 Mt H2/year cite intend export to a specific region but do not have off-take agreements.[15] The remaining 7.5 Mt H2/year of projects have not announced proposed delivery destinations.[16]

However, of interest is the regional breakdown of the expected imports: the biggest importer by 2030, according to IEA projections, is Europe with 1.9 Mt H2/year.[17] The EU itself estimates that it will produce 10 million tonnes of renewable hydrogen by 2030 and sees the need to import a further 10 million tonnes by 2030.[18] Given that Europe is projected to have the biggest demand for hydrogen imports, it is worthwhile asking in particular if there are and/or should be requirements and conditions for all that hydrogen that is expected to come to Europe. In particular, the 2020 European Hydrogen Strategy is putting strong emphasis on the import of renewable hydrogen, as opposed to other types of hydrogen.[19]

The question that this raises is: do all stakeholders agree on similar criteria for what exactly is renewable hydrogen and when it can be considered sustainable? Indeed, to meet the EU's import ambitions in terms of renewable hydrogen, a clear system of criteria must exist to avoid 'green washing' of hydrogen that has been produced by 'non-green' methods. Given the above-described recent changes in legislation concerning, for example, RFNBOs, now might be a good moment to clarify the sustainability dimension of the future legislation and make some suggestions. It might make sense to take a step back and assess whether or not the sustainability criteria that currently exist in EU law for bioenergy make sense, what the critique is and whether or not these (or other) criteria on sustainability should be applied to the production and import of hydrogen into the EU.

A common starting point to find out if something can be labelled as 'green' or not are criteria that relate to the sustainability of the product, here hydrogen. Sustainability criteria for fuels and energy carriers are well-known in EU law, particularly in the context of the import of bioenergy into the EU. After this introduction, the chapter discusses below in Section 10.2 what sustainability criteria are, how they have been used in EU law on bioenergy and what type of critique has arisen. Section 10.3 then provides an analysis on sustainability criteria and how they can be used (or not) for hydrogen purposes, before concluding with some reflections and recommendations on the directions that the transposition of EU legislation into Member State (MS) law should take and, possibly, further amendments.

10.2 SUSTAINABILITY CRITERIA FOR BIOENERGY IN EU LAW

10.2.1 *What Are Sustainability Criteria?*

To address the notion of sustainability criteria one must first refer to the concept of sustainable development. In the early 1970s, sustainable development emerged as an alternative to the

[14] Ibid 166.
[15] Ibid 166–167.
[16] Ibid.
[17] Ibid.
[18] European Commission, 'Hydrogen' <https://energy.ec.europa.eu/topics/energy-systems-integration/hydrogen_en> accessed 20 January 2024.
[19] European Commission, 'A hydrogen strategy for a climate-neutral Europe', COM(2020) 301 final, at 19–21 <https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:52020DC0301> accessed 2 January 2024.

unlimited economic growth model and in response to the previous decades' concerns about risks and damage of technological advances, development failures and evident growth limits in an already overexploited planet.[20] Recognizing the tension between economic growth and environmental protection, the 1987 Brundtland Commission report *Our Common Future* defined sustainable development as 'development which meets the needs of current generations without compromising the ability of future generations to meet their own needs'.[21] The report emphasized the needs and interests of human beings and stressed the necessity to apply an integrated decision-making process taking into account both economic development and environmental protection to further human welfare.[22] Since then, and especially since the 1992 Earth Summit in Rio de Janeiro, sustainable development has gained popularity and prominence in varied spaces and discourses, has been placed at the centre of international development policy and has been incorporated into numerous national and supranational legal instruments.[23]

While the Brundtland definition of sustainable development is the most widely used, a plethora of other definitions, meanings, approaches and interpretations exists.[24] Some argue that because of its complex and disparate historical origins, sustainable development 'remains both context specific and ontologically open'.[25] Yet it is widely admitted that sustainable development rests on three distinct but interdependent, equally important and mutually reinforcing pillars, namely environmental, social and economic. The environmental pillar (environmental sustainability) requires the preservation and maintenance of the natural environment to support development and human quality of life. The social pillar (social sustainability) encompasses many issues such as human rights, equality, cultural identity and public participation, all of which promote peace and social stability. Lastly, the economic pillar (economic sustainability) implies the maintenance of the natural, social and human capital required for incomes and living standards.[26] Sustainable development can only be achieved through multilevel efforts to integrate these three pillars in a balanced way, so prioritizing is not an option; they 'cannot be pursued in insolation for S[ustainable] D[evelopment] to flourish'.[27]

Although sustainable development has achieved notorious prominence in various spaces, it remains a highly contested concept. For instance, it has been criticized for being a rather vague, ambiguous and inherently anthropocentric and political concept, based on Western thinking and serving neoliberal interests by not questioning the economic growth ideology or the

[20] Jacobus A Du Pisani, 'Sustainable development – historical roots of the concept' (2006) 3(2) Environ Sci 83 (hereinafter: Du Pisani); Robert B Gibson and others, *Sustainability Assessment: Criteria and Processes* (Earthscan, 2005) 47 (hereinafter: Gibson et al).

[21] World Commission on Environment and Development, *Our Common Future* (Oxford University Press, 1987) 43.

[22] Ibid 37–41.

[23] With the adoption of the Sustainable Development Goals in 2015, the international commitment to action on sustainable development in all sectors of the development agenda was reaffirmed. See, for instance, Du Pisani; Justice Mensah, 'Sustainable development: Meaning, history, principles, pillars, and implications for human action: Literature review' (2019) 5(1) Cogent Soc Sci 1 (hereinafter: Mensah); Tomislav Klarin, 'The concept of sustainable development: From its beginning to the contemporary issues' (2018) 21(1) ZIREB 67 (hereinafter: Klarin).

[24] Colin C Williams and Andrew C Millington, 'The diverse and contested meanings of sustainable development' (2004) 170(2) Geogr J 99 (hereinafter: Williams and Millington); Klarin.

[25] Ben Purvis, Yong Mao and Darren Robinson, 'Three pillars of sustainability: In search of conceptual origins' (2018) 14 Sustain Sci 681, 692 (hereinafter: Purvis, Mao and Robinson).

[26] Klarin; Mensah 10; On the complex dynamic interrelations between economic, environmental and social aspects see, for instance, Rodrigo Lozano, 'Envisioning sustainability three-dimensionally' (2008) 16(17) J Clean Prod 1838 (hereinafter: Lozano).

[27] Mensah 15.

consumerist culture.[28] Others consider sustainable development as an oxymoron because economic development or growth is inconsistent with environmental protection or sustainability.[29] Despite criticisms, it is argued that sustainable development has become the internationally accepted decision-making framework for achieving, maintaining and improving human well-being for both the present and future generations and that the challenge is to use and improve this framework taking into account and seeking to achieve environmental protection, social justice and economic development.[30]

Tying sustainable development to sustainability, both concepts are frequently used interchangeably, while they are intrinsically different: sustainable development is the journey to achieve sustainability.[31] Yet some argue that sustainability 'has been co-opted into the sustainable development discourse where development is first and foremost about human survival and meeting human needs, but does not necessarily have much to do with genuine sustainability, which is reliant upon the continuation of the earth'.[32] For others, the 'transformation and operationalization at the practical level' is the main obstacle regarding both concepts.[33]

Sustainable development and sustainability form the basis for understanding sustainability criteria and their content. Sustainability criteria have been explored from various scientific perspectives and interpreted in different ways.[34] Defining product sustainability criteria, Pavlovskaia states that these 'are requirements to the sustainable quality of a product and its sustainable production, which have to be fulfilled in order to acquire a sustainability status or certification'.[35] In this sense, it is argued that product sustainability criteria can be applied to identify unsustainable trends and effects and to assess opportunities and risks deriving from economic, environmental and social sustainability dimensions, also helping to assure long-term sustainability and secure investment.[36]

Sustainability criteria can be binding when included in a legal framework – for instance, the EU's binding sustainability criteria for bioenergy as detailed in Section 10.2.2, but can also be established in voluntary schemes, such as those existing in the coffee sector.[37] These criteria can be of a qualitative or quantitative nature; are usually developed for certain purposes and according to specific conditions; are not static, so continuous assessment, reconsideration and improvement can be required; and different actors at different levels can be responsible for setting and supporting their implementation.[38]

The three pillars of sustainable development, it has been argued, 'are attractive as organizing categories for sustainability criteria'.[39] In fact, it could be said that, to avoid negative

[28] See, for instance, Williams and Millington; Du Pisani; Purvis, Mao and Robinson; Sophia Imran, Khorshed Alam and Narelle Beaumont, 'Reinterpreting the definition of sustainable development for a more ecocentric reorientation' (2014) 22(2) Sust Dev 134; John C Dernbach and Federico Cheever, 'Sustainable development and its discontents' (2015) 4(2) TEL 247 (hereinafter: Dernbach and Cheever).

[29] Michael Redclift, 'Sustainable development (1987–2005): An oxymoron comes of age' (2005) 13(4) Sust Dev 212.

[30] Dernbach and Cheever.

[31] Lozano.

[32] Heather M Farley and Zachary A Smith, *Sustainability: If It's Everything, Is It Nothing?* (Routledge, 2013, 1st ed) 150.

[33] Evgenia Pavlovskaia, 'Sustainability criteria: Their indicators, control, and monitoring (with examples from the biofuel sector)' (2014) 26(17) Environ Sci Eur 1, 2 (hereinafter: Pavlovskaia).

[34] Ibid.

[35] Ibid 2.

[36] Ibid.

[37] Sustainability criteria in legal frameworks and voluntary sustainability standards usually coexist and may overlap, see Pavlovskaia.

[38] These actors include international institutions, states, independent bodies established by states, NGOs, producers and users. Pavlovskaia.

[39] Gibson et al 94.

sustainability impacts – for instance of a product – sustainability criteria should comprehensively address the most urgent sustainability concerns focusing on environmental, social and economic aspects, as they all are important to assure sustainability compliance, although particular contexts and specific conditions should be considered when identifying and developing the criteria.[40]

Moreover, for sustainability criteria to work as intended, they should be understandable and it should be possible to implement and monitor them, as well as to control compliance through the establishment of an organizational structure.[41] To verify compliance with defined sustainability criteria, certification processes have been created in some cases – for instance, to certify that a product was sustainably produced.[42] Thus, alongside the creation of different types of sustainability criteria, different certification systems have also been established.[43] In any case, it is argued that the establishment and implementation of sustainability criteria should be done in a transparent and consistent manner and that the control systems linked to their fulfilment should be reliable, trustworthy and transparent.[44]

10.2.2 *Sustainability Criteria for Bioenergy in EU Law*

Sustainability criteria for the production and import of bioenergy into the EU were included in the law for the first time in the 2009 Renewable Energy Directive (hereinafter RED I).[45] The scope of this Directive was limited to biofuels and bioliquids. According to the Directive, both are produced from biomass, but biofuels are liquid or gaseous fuels for transport, while bioliquids are liquid fuels for energy purposes other than for transport, including electricity, heating and cooling.[46]

The mandatory sustainability criteria of the EU have two components. First, biofuels and bioliquids must achieve a certain threshold of greenhouse gas (GHG) emissions savings in comparison to the use of fossil fuels.[47] Second, the raw materials cultivated for the production of biofuels or bioliquids must not come from land with high biodiversity value, land with high carbon stock or from peatlands.[48] If these criteria are not met, the biofuels or bioliquids can still enter and be sold in the EU market, but they cannot receive financial support or count towards the renewable energy targets of EU MSs.[49]

Compliance with the sustainability criteria must be proven by the producers of biofuels or bioliquids through independent audits;[50] in other words, through private voluntary certification schemes. Alternatively, third countries may conclude bilateral or multilateral agreements

[40] Thuy Mai-Moulin and others, 'Effective sustainability criteria for bioenergy: Towards the implementation of the European renewable directive II' (2021) 138 RSER 1 (hereinafter: Mai-Moulin et al); Gibson et al 115.

[41] Pavlovskaia.

[42] This is the case of the sustainability verification and certification defined in the RED for bioenergy. See Section 10.2.2.

[43] Mai-Moulin et al.

[44] Ibid; Pavlovskaia 9.

[45] Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC, arts 17 and 18. The same criteria were also included in parallel in a revision to the Directive 98/70/EC of 13 October 1998 relating to the quality of petrol and diesel fuels.

[46] Ibid art 2 (h) and (i).

[47] Ibid art 17 (2).

[48] Ibid art 17 (3)–(5).

[49] Ibid art 17 (1).

[50] Ibid art 18 (3).

providing for sustainability criteria equivalent to those in the Directive,[51] exempting the producers from independent audit.[52] However, the vast majority of producers of biofuels and bioliquids made use of the private schemes instead of these options.[53]

In addition to the sustainability criteria, the European Commission must report every two years to the European Parliament and the Council on the impact of the increased demand for biofuels on the availability of food and on social sustainability in and outside of the EU.[54] It must also report on the respect for land use rights and indicate whether the supplying countries have ratified and implemented a number of Conventions of the International Labour Organization (ILO).[55] Auditors of private schemes also have reporting obligations on topics not limited to the sustainability criteria. They must inter alia provide information about soil, water and air protection, about the restoration of degraded land and about the avoidance of excessive water consumption in areas where water is scarce.[56]

In the midst of mounting controversy on the effect of the increase in biofuels consumption in the EU on food prices and about their real GHG emissions savings,[57] RED I was amended in 2015.[58] This amendment mainly served to include provisions to limit indirect land use change (ILUC). ILUC happens where pasture or agricultural land previously destined for food and feed markets is diverted to biofuel production, displacing the non-fuel demand to new, non-agricultural land.[59] When this involves the conversion of land with high carbon stock, it can lead to significant GHG emissions.[60] To tackle this issue, the amended directive caps the total share of energy from biofuels produced from food crops to 7 per cent of the final consumption of energy in transport in the EU by 2020.[61]

Only three years later, RED I was overhauled and gave place to RED II.[62] This new version of the Directive separates sustainability from GHG emissions saving criteria[63] while they were mashed in RED I. Yet the criteria follow the same logic: they are mandatory but limited to GHG emissions savings on the one hand and the risk of land use change on the other.[64] They do not

51 Ibid art 18 (4).
52 Ibid art 18 (7).
53 Juan Ignacio Staricco and Monica Buraschi, 'Putting transnational "hybrid" governance to work: An examination of EU-RED's implementation in the Argentinean biodiesel sector' (2022) 131 Geoforum 185, 186 (hereinafter: Staricco and Buraschi).
54 RED I, art 17 (7).
55 Ibid.
56 Ibid art 18 (3).
57 Karl Mathiesen, 'Are biofuels worse than fossil fuels?' *The Guardian* (29 November 2013) <www.theguardian.com/environment/2013/nov/29/biofuels-worse-fossil-fuels-food-crops-greenhouse-gases> accessed 11 December 2023; James Crisp, 'Biodiesel worse for the environment than fossil fuels, warn green campaigners' Euractiv (26 April 2016) <www.euractiv.com/section/climate-environment/news/biodiesel-worse-for-the-environment-than-fossil-fuels-warn-green-campaigners> accessed 11 December 2023; Harish K Jeswani, Andrew Chilvers and Adisa Azapagic, 'Environmental sustainability of biofuels: A review' (2020) 476(2243) Proc R Soc A 1, 11 (hereinafter: Jeswani, Chilvers and Azapagic).
58 Directive (EU) 2015/1513 of 9 September 2015 amending Directive 98/70/EC relating to the quality of petrol and diesel fuels and amending Directive 2009/28/EC on the promotion of the use of energy from renewable sources.
59 Ibid recital 4.
60 Ibid.
61 Ibid art 2 (2) (b) (iv).
62 Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources.
63 Ibid; see the title of art 29.
64 Ibid art 29 (3)–(5).

restrict market access but are a condition to access financial support and count towards MSs' renewable energy targets,[65] and compliance is controlled by private certification schemes.[66]

Three novelties with relevance to this chapter were introduced. First, the directive's scope on biofuels and bioliquids was extended to biomass fuels too, defined as gaseous and solid fuels produced from biomass.[67] Second, the requirements on GHG emissions savings have been made more stringent and are increasing in line with the opening date of a facility. Third, it has to be noted that sustainability criteria only apply to biomass fuels used for producing electricity, heating and cooling or fuels from a certain installation size onwards, namely a total energy generation capacity of a rated thermal input of 20 megawatts (MW) for production from solid biomass and of 2 MW from gaseous biomass fuels.[68] This last point is of interest, given that current electrolysers for the production of green hydrogen are operating mostly at a similar scale (between a few MW to around 20 MW), which makes an analogy easy.

In October 2023, once again, a revised version of the RED was adopted. RED III amends and reshuffles the provisions detailing the GHG and sustainability criteria applicable to bioenergy and RFNBOs, strengthened some GHG reduction targets[69] and doubled the previous target for the share of renewable energy within the final consumption of energy in the transport sector to 29 per cent by 2030.[70] Yet no major change impacted the sustainability criteria, the sectors to which they apply, and so on.

In a nutshell, sustainability criteria in EU law tackle GHG emissions and (direct or indirect) land use change that impacts upon environmentally valuable types of land. These GHG emission reductions are a condition for bioenergy to qualify for financial support and to count towards renewable energy targets. They apply to both domestic production and imports and compliance is (mostly) checked by private certification bodies. However, issues such as soil, air and water quality and their usage or social aspects are not part of the criteria. These are merely subject to a reporting requirement.

10.2.3 *The Critique of Sustainability Criteria for Bioenergy in EU Law*

The critique of sustainability criteria for bioenergy in EU law mainly focuses on two dimensions: the environmental and the social spheres. Although several points of critique about the environmental impact of bioenergy on GHG emissions and on the local environment have been addressed with the legislative process leading to RED II and III, some persist. Three issues in particular remain, which will now be explained in more depth: first, the issue of green protectionism; second, the problem of non-carbon-related local environmental impacts; and third, problems with the certification process.

As far as the first point is concerned, it has been argued that the EU created the sustainability criteria to protect 'its own inefficient domestic biofuels production'.[71] These accusations amount to alleged green imperialism in the sense that EU institutions decide what is to be considered sustainable bioenergy and how the specific local ecological and social needs are to be balanced

[65] Ibid art 29 (1).
[66] Ibid art 30 (3).
[67] Ibid art 2 (27).
[68] Ibid art 29 (1).
[69] RED III, art 29 (a) (iii).
[70] Ibid art 25 (1) (a) (i).
[71] Stavros Afionis and Lindsay C Stringer, 'European Union leadership in biofuels regulation: Europe as a normative power?' (2012) 32 J Clean Prod 114, 114 (hereinafter: Afionis and Stringer).

with economic and social development interests in producing countries.[72] Using other terms, this is labelled as a transnational legal process, being the 'impact of unilateral legal developments in one jurisdiction that affect behaviour in others'.[73]

Second, many critics point out that sustainability criteria prioritize carbon concerns over non-carbon ones,[74] adopting 'a limited definition of sustainable development'.[75] Academics would like to see sustainability criteria extended to soil, water and air protection, to the restoration of degraded land and to the avoidance of excessive water consumption in areas where water is scarce.[76] As things stand, these are only subject to a reporting obligation to the Commission by private certification schemes.[77] Yet several studies show that reductions in GHG emissions from biofuels are achieved at the expense of other impacts, such as acidification, eutrophication, water footprint and biodiversity loss.[78] A 2013 study on the topic of air, soil and water protection acknowledged that introducing mandatory quantitative criteria is not feasible, given the wide variety of crops and the prevailing bio-physical, environmental and climatic conditions for producing bioenergy, and proposed instead to place greater emphasis on targeted management practices.[79] Such practices would require compliance with relevant legislation on soil, water and air, the creation of management plans at farm level for soil and water management and the creation of river basin management plans to identify regions at risk of water scarcity.[80] In the 2016 impact assessment for the preparation of RED II, the European Commission clearly indicated that, while the inclusion of these issues in the sustainability criteria was requested by stakeholders during the public consultation, it decided not to reopen the topic due to the industry complaining about the administrative burden that these additional criteria would bring about.[81] In addition, the Commission argued that many private certification schemes that it recognizes already require good agricultural practices, including for soil, water and air.[82]

Third, the private certification schemes that control compliance with the sustainability criteria have been widely criticized, as they allegedly amount to an externalization of the control of legal compliance to private parties. The literature describes this system as a hybrid approach,[83] which allows a formally voluntary certification system to become de facto mandatory through formal enshrinement in law.[84] The advantage is that some schemes are targeted to a particular feedstock and/or regional conditions and therefore have the specific expertise needed to define

72 Emily Webster, 'Transnational legal processes, the EU and RED II: Strengthening the global governance of bioenergy' (2020) 29 RECIEL 86, 93–94.

73 Ibid 87. See also Christian Gamborg, Helle Tegner Anker and Peter Sandøe, 'Ethical and legal challenges in bioenergy governance: Coping with value disagreement and regulatory complexity' (2014) 69 Energy Policy 326, 328 (hereinafter: Gamborg, Tegner Anker and Sandøe).

74 See for instance, Gamborg, Tegner Anker and Sandøe 326.

75 Laura Kemper and Lena Partzsch, 'A water sustainability framework for assessing biofuel certification schemes: Does European hybrid governance ensure sustainability of palm oil from Indonesia?' (2018) 192 J Clean Prod 835, 836 (hereinafter: Kemper and Partzsch).

76 Ibid; Mai-Moulin et al 6.

77 RED III, art 30 (4) and (5).

78 Jeswani, Chilvers and Azapagic 1–2.

79 ECOFYS, 'Report on mandatory requirements in relation to air, soil, or water protection: analysis of need and feasibility' (21 February 2013) 2 (hereinafter: ECOFYS).

80 Ibid.

81 European Commission, 'Commission Staff Working Document – Impact Assessment Accompanying the document Proposal for a Directive of the European Parliament and of the Council on the promotion of the use of energy from renewable sources' SWD(2016) 418 final, 36.

82 Ibid Annex 10 (only available in the html version of the Impact Assessment).

83 Gamborg, Tegner Anker and Sandøe 328; Kemper and Partzsch 837; Staricco and Buraschi 186.

84 Staricco and Buraschi 193.

management requirements targeted at the local conditions.[85] It also allows bioenergy producers to choose a more ambitious certification scheme, with higher requirements than those in RED III.[86] Moreover, when non-governmental organizations (NGOs) are participating in certification schemes, research shows a strengthening of the criteria.[87] However, the literature also pointed to the risk of a 'race to the bottom' or 'forum shopping', where producers overwhelmingly choose the less demanding certification scheme, even when the final product is sold with an upper quality certificate.[88] The consequence is that to really improve the sustainability of bioenergy production, raising the 'meta-standard' is the safest option: sustainability criteria could integrate what is already being proposed by various certification schemes and make these elements mandatory.[89]

Besides this criticism on the environmental side of sustainability criteria, there is also long-standing dissatisfaction about the exclusion of social issues, which will be discussed now. The absence of the social dimension means that the negative effects of bioenergy production on social and human rights, such as 'appropriate wages and working conditions or land rights of smallholders and indigenous peoples', is often disregarded.[90]

Despite the absence of mandatory social requirements in EU law, many private certification schemes do integrate such prerequisites.[91] The situation is very similar to the one described above on the inclusion of non-carbon environmental aspects in private certification schemes. Indeed, some standards are quite comprehensive on the issue while others are very light,[92] and schemes with NGOs forming part of the board are more stringent in their criteria than industry-only ones.[93] Yet overall social criteria are usually less present than environmental ones in the certification schemes,[94] and they also suffer from a race to the bottom.[95] For these reasons, scholars are prone to request the inclusion of mandatory social sustainability criteria in EU law, for instance based on what many private schemes already propose,[96] to 'set the "bottom line" higher'.[97]

85 ECOFYS 3.
86 For instance, on the issue of water, research found that many schemes actually integrated monitoring and control criteria and indicators such as availability of water, accessibility, quality, identification and protection of existing formal and customary water rights. See Nidia Elizabeth Ramirez-Contreras and André PC Faaij, 'A review of key international biomass and bioenergy sustainability frameworks and certification systems and their application and implications in Colombia' (2018) 96 RSER 460, 467 (hereinafter: Ramirez-Contreras and Faaij); see also Mai-Moulin et al 10.
87 Kemper and Partzsch 836.
88 A study of Argentinean biodiesel production and export to the EU shows that while all exported biodiesel is certified (and the vast majority of it under a certification scheme that is more demanding than the bottom line), the actual standard used for the cultivation of the feedstock is the basic one, but then accounted as higher quality through 'a simple administrative procedure'. See Staricco and Buraschi 187–191. See also Sarah L Stattman and others, 'Toward sustainable biofuels in the European Union? Lessons from a decade of hybrid biofuel governance' (2018) 10(11) Sustainability 1, 3 (hereinafter: Stattman et al).
89 Kemper and Partzsch 842.
90 Afionis and Stringer 117.
91 Ramirez-Contreras and Faaij 473; Mai-Moulin et al 5.
92 Staricco and Buraschi 192; Laura German and George Schoneveld, 'A review of social sustainability considerations among EU-approved voluntary schemes for biofuels, with implications for rural livelihoods' (2012) 51 Energy Policy 765, 765 (hereinafter: German and Schoneveld).
93 Hans Morten Haugen, 'Coherence or forum shopping in biofuels sustainability schemes?' (2015) 33(1) Nord J Hum Rights 52, 52; Kemper and Partzsch 836.
94 Ramirez-Contreras and Faaij 472.
95 Stattman et al 8; Staricco and Buraschi 185.
96 Kemper and Partzsch 842; Stattman et al 13; Mai-Moulin et al 10; Jamie Konopacky, 'Refueling biofuel legislation: Incorporating social sustainability principles to protect land rights' (2012) 30(2) Wis Int Law J 401, 421 (hereinafter: Konopacky).
97 German and Schoneveld 776.

However, there is a large stumbling block on the way to this integration. When writing RED I, the European Parliament's Industry Committee proposed to include social aspects in the sustainability criteria.[98] Due to deep concerns about the compatibility with World Trade Organization (WTO) rules, raised by the Commission especially, this idea was abandoned.[99] Imposing mandatory social sustainability criteria was seen as overstepping 'some countries' "red lines" and thus would almost certainly trigger an action in the WTO'.[100] Most of the academic debate about the legal feasibility of social sustainability criteria with regard to WTO law took place during and shortly after the establishment of RED I and many scholars considered this option to be difficult.[101] However, there is some discrepancy and a few authors believe that it would be possible to include such criteria, especially based on the requirements that are already widely used in private certification schemes.[102]

Based on this section, one may consider that the EU sustainability criteria on bioenergy should more accurately be renamed 'environmental criteria' (without downplaying all the criticisms of the scope and control of the environmental aspects). Indeed, in contrast with what was mentioned in Section 10.2.1, while the use of the term sustainability criteria suggests an inclusion of the three pillars of sustainable development – economic, social and environmental – only the environmental one is part of the binding EU requirements applying to the production and import of sustainable bioenergy products.

10.3 TRANSPOSING SUSTAINABILITY CRITERIA FROM BIOENERGY TO HYDROGEN: ONE SIZE FITS ALL?

As mentioned in the Introduction to this chapter, EU law is in the process of transposing the bioenergy sustainability criteria to local production as well as imports of renewable hydrogen. This move avoids drafting specific sustainability criteria for hydrogen and circumvents time-consuming political negotiations both between EU MSs and with third parties. However, it relies on the assumptions that (i) bioenergy provisions can easily and clearly be applied to hydrogen, otherwise creating an issue in terms of intelligibility of the law, and that (ii) the potential sustainability impacts of renewable hydrogen production are like those created by the production of bioenergy to avoid a mismatch.[103]

Firstly, regarding the application of bioenergy provisions to hydrogen. As mentioned in the Introduction, the rGD proposal provides that articles 29, 29a and 30 of RED III, setting the sustainability criteria for bioenergy, apply to renewable gases.[104] Renewable gases encompass RFNBOs, which encompass renewable hydrogen. Hydrogen produced through the electrolysis

98 Ibid 767; Taotao Yue, 'EU Regulation of the Sustainability of Biofuels' in *Different Paths towards Sustainable Biofuels? A Comparative Study of the International, EU, and Chinese Regulation of the Sustainability of Biofuels* (Intersentia, 2018) 95, 112; Jennifer Franco and others, 'Assumptions in the European Union biofuels policy: Frictions with experiences in Germany, Brazil and Mozambique' (2010) 37(4) J Peasant Stud 661, 668.

99 Afionis and Stringer 117.

100 Robert Ackrill and Adrian Kay, 'EU biofuels sustainability standards and certification systems – How to seek WTO-compatibility' (2011) 62(3) J Agric Econ 551, 560.

101 Jeremy de Beer and Stuart J Smyth, 'International trade in biofuels: Legal and regulatory issues' (2012) 13(1) Estey Centre Journal of International Law and Trade Policy 131, 140.

102 Konopacky 423–427. Or at least argue that the European Parliament restrained itself on the matter and that it is unsure whether the WTO would have rejected social criteria or not, see Carsten Daugbjerg and Alan Swinbank, 'Globalization and new policy concerns: The WTO and the EU's sustainability criteria for biofuels' (2015) 22(3) J Eur Public Policy 429, 442.

103 The resulting rules would also apply to 'green' ammonia and methanol, when produced from renewable hydrogen.

104 rGD proposal, art 8 (1).

of water and fed with electricity from renewable sources falls under this category and therefore the sustainability criteria, as detailed in Section 10.2.2, should apply to its production in the EU as well as its import, if this product is to benefit from subsidies and to count for the renewable energy targets of EU MSs. Therefore, the legal link between renewable gases in the rGD and the sustainability criteria in the RED is clear.

However, there is an interpretation issue with how to specifically apply the bioenergy sustainability criteria to hydrogen. For instance, article 29(3) RED III reads: 'Biofuels, bioliquids and biomass fuels produced from agricultural biomass ... shall not be made from raw material obtained from land with a high biodiversity value.' If one simply replaces bioenergy with renewable gases in this provision, then it focuses on such gases being produced from agricultural biomass, which does not make much sense as renewable hydrogen will be produced with water and electricity overwhelmingly from hydropower, wind or solar power. In fact, the EU, in its common political agreement of 14 December 2023 on the new revised Gas Directive, only takes these two (wind and solar) into account for the production of renewable hydrogen and defines renewable hydrogen produced from biomass as biogas in recital 9 of the proposal.[105] Whether or not this is the end point and will find its way into the *Official Journal of the European Union* remains to be seen.

Coming back to article 29(3) RED III. If one considers that the whole provision part to be replaced with renewable gases is 'Biofuels, bioliquids and biomass fuels produced from agricultural biomass', then it would mean that hydrogen 'shall not be made from raw material obtained from land with a high biodiversity value'. It makes a bit more sense than the previous version but it is still not satisfactory.

Indeed, the raw material used for hydrogen is water. Taking a whole supply chain approach, one could also consider as raw materials the resources needed to construct wind turbines, solar panels or dams but these are difficult to trace and do not include the impacts during the operation of the renewable energy installation. A more coherent interpretation would require that the production of renewable gases does not harm land with high biodiversity value. In article 29(3), this means land that has or has had the status of primary forest, highly biodiverse forest, legally recognized protected natural areas, highly biodiverse grassland spanning more than one hectare, or heathland. In the case of renewable hydrogen, it may mean avoiding the electrolyser, the water source and the renewable energy installations being located within such areas. But this would probably be too restrictive, given that the impacts of electrolysers or water pumping or renewable energy installations do not systematically involve a change in (the whole) land use, as tends to be the case for bioenergy. Therefore, it may be necessary for the Commission to adopt more specific rules or at least a guideline to set a threshold above which it is considered that the land is too harmed for the renewable gas to be considered sustainable.

Secondly, unpacking the issue of the potential sustainability impacts of renewable hydrogen compared to bioenergy raises various points. The first is GHG emissions. Although renewable hydrogen is often perceived as emissions-free or with very low emissions, once the life cycle of electrolysers' and renewable energy installations' components is taken into account, hydrogen actually is 'an indirect greenhouse gas whose warming impact is both widely overlooked and

[105] Recital 9 of Council of the European Union Interinstitutional file 2021/0425(COD) Proposal for a Directive of the European Parliament and of the Council on common rules for the internal markets in renewable and natural gases and in hydrogen (recast) – Analysis of the final compromise text with a view to agreement <https://data.consilium.europa.eu/doc/document/ST-16516-2023-INIT/en/pdf> accessed 2 January 2024.

underestimated'.[106] It is essential that hydrogen leakage and venting are tracked and limited as much as possible, given that it is a similar GHG to methane: it lasts in the atmosphere a couple of decades but its 'indirect warming potency per unit mass is around 200 times that of carbon dioxide'.[107] In this regard, RED III sets a GHG savings criteria specifically for RFNBOs at 70 per cent.[108] The new regime between rGD and RED III is therefore consistent in this respect.

The other series of impacts where hydrogen has to be compared to bioenergy is the (direct or indirect) land use change that affects environmentally valuable types of land. As detailed in Section 10.2.2, bioenergy feedstock should not come from land with high biodiversity value, land with high carbon stock or peatlands. Such restrictions may be useful to avoid or limit some impacts of renewable hydrogen production. For instance, article 29 (3) (c) RED III might address the risks of biodiversity loss, especially from renewable energy installations, when located in areas designated by law or by the relevant competent authority for nature protection purposes, or for the protection of rare, threatened or endangered ecosystems or species.[109] However, this will (i) depend on the interpretation of the sustainability criteria in the case of hydrogen, as highlighted previously in this section, and (ii) only cover some impacts of the renewable hydrogen life cycle and not even the most important ones according to the literature, as detailed below.

Arguably, the first environmental concern when it comes to renewable hydrogen is the consumption of water. While water consumption to produce renewable hydrogen is minimal when compared to water consumption for other uses, such as farming,[110] it is still a prevalent local concern given the global hotspots for future renewable hydrogen production are usually water-scarce, with countries such as Chile, Morocco, Namibia or even for Global North countries Australia or Spain.[111] A solution to avoid conflicts around water supply could be to use desalinated water,[112] which only slightly increases the total electricity consumption and the final price,[113] or to directly use sea water, although the technology is not yet commercially available.[114] In any case, RED III's sustainability criteria only require reporting about the avoidance of excessive water consumption in areas where water is scarce,[115] not compulsory limits.

106 Ilissa B Ocko and Steven P Hamburg, 'Climate consequences of hydrogen emissions' (2022) 22 Atmos Chem Phys 9349, 9349.
107 Ibid 9350.
108 RED III, art 29a (1).
109 See for instance a hydrogen project in Argentina which plans to install between 400 and 1,600 wind turbines in a protected natural area (la meseta de Somoncurá), on the flightpath of condors. Claudia Olate, 'El impacto ambiental del proyecto de Hidrógeno Verde', *Agencia de Noticias Bariloche* (27 November 2022) <www.anbariloche.com.ar/noticias/2022/11/27/87659-el-impacto-ambiental-del-proyecto-de-hidrogeno-verde> accessed 22 February 2023.
110 Rebecca R Beswick, Alexandra M Oliveira and Yushan Yan, 'Does the green hydrogen economy have a water problem?' (2021) 6(9) ACS Energy Lett 3167, 3168 (hereinafter: Beswick, Oliveira and Yan); IEA, 'Global Hydrogen Review 2021' (2021) 109 <www.iea.org/reports/global-hydrogen-review-2021> accessed 11 December 2023.
111 Robert Lindner, 'Green hydrogen partnerships with the Global South. Advancing an energy justice perspective on "tomorrow's oil"' (2023) 31(2) Sustain Dev 1038 (hereinafter: Lindner); Aurora Energy Research, 'Renewable hydrogen imports could compete with EU production by 2030' (24 January 2023) <https://auroraer.com/media/renewable-hydrogen-imports-could-compete-with-eu-production-by-2030/> accessed 11 December 2023 (hereinafter: Aurora Energy Research); Hydrogen Council, 'Global hydrogen flows: Hydrogen trade as a key enabler for efficient decarbonisation' (October 2022) 12 and 19.
112 Lindner 8.
113 Beswick, Oliveira and Yan 3168; Pau Farràs, Peter Strasser and Alexander J Cowan, 'Water electrolysis: Direct from the sea or not to be?' (2021) 5(8) Joule 1921, 1922.
114 IEA 109; Fei-Yue Gao, Peng-Cheng Yu and Min-Rui Gao, 'Seawater electrolysis technologies for green hydrogen production: Challenges and opportunities' (2022) 36 Curr Opin Chem Eng 1.
115 See Section 10.2.2.

The second environmental concern when it comes to renewable hydrogen is the combination of all sorts of environmental impacts along the supply chain to produce renewable hydrogen, especially the impacts of mining for the electrolyser's materials as well as for the renewable energy installations,[116] and the impacts of the siting of the latter during construction and operating life.[117] These are indirect impacts, but they may be massive given the vast quantity of electricity necessary for the production and import of 20 million tonnes of hydrogen/year by 2030 according to European policy.[118] Some of these impacts may be countered in protected areas, as mentioned previously in this section, but all the impacts in non-protected areas may be ignored and renewable energy installations already have a history of local environmental impacts when poorly developed.[119] In such cases, the sustainability criteria should be broadened to ensure sustainable hydrogen production.

Finally, renewable hydrogen presents the risk of social impacts along its supply chain. Once more, the quantity of electricity to be produced from renewable sources implies a massive development in some countries foreseen as ideal renewable hydrogen suppliers to Europe, such as Morocco.[120] This can delay progress in access to electricity for local populations in some areas as well as the decarbonization of the country's electricity mix.[121] The need for such a quantity of large-scale projects also entails a high risk of negative social impacts, including poor labour practices, (indigenous) land grabbing and many types of human rights violations,[122] as here again shown by a history of social injustices created by poorly developed renewable energy installations.[123] Even though the inclusion of social sustainability criteria for bioenergy has been ruled out so far, mainly due to WTO law,[124] the inclusion of renewable hydrogen under this regime makes the case for this inclusion even more pressing.

Another possible interpretation of the application of RED III's sustainability criteria that strongly diverges from the developments in this section is to consider that as RED III's article 29 is entitled 'Sustainability and greenhouse gas emissions saving criteria for biofuels, bioliquids

[116] See Laura J Sonter and others, 'Renewable energy production will exacerbate mining threats to biodiversity' (2020) 11 Nat Commun 1.

[117] Floris Swennenhuis, Vincent de Gooyert and Heleen de Coninck, 'Towards a CO2-neutral steel industry: Justice aspects of CO2 capture and storage, biomass- and green hydrogen-based emission reductions' (2022) 88 ERSS 1, 5 (hereinafter: Swennenhuis, de Gooyert and de Coninck).

[118] For the policy target, see European Commission, 'Communication from the Commission to the European Parliament, the European Council, the Council, the European Economic and Social Committee and the Committee of the Regions, REPowerEU Plan' SWD(2022) 230 final, 7. About the required electricity production, see Bauke Baumann, 'Green hydrogen from Morocco – no magic bullet for Europe's climate neutrality', Heinrich Boll Stiftung Brussels (9 February 2021) <https://eu.boell.org/en/2021/02/09/green-hydrogen-morocco-no-magic-bullet-europes-climate-neutrality> accessed 11 December 2023 (hereinafter: Baumann); Corporate Europe, 'Hydrogen from North Africa – a neocolonial resource grab: The reality of EU green hydrogen import plans' (17 May 2022) <https://corporateeurope.org/en/2022/05/hydrogen-north-africa-neocolonial-resource-grab> accessed 11 December 2023.

[119] Abidur Rahman, Omar Farrok and Md Mejbaul Haque, 'Environmental impact of renewable energy source based electrical power plants: Solar, wind, hydroelectric, biomass, geothermal, tidal, ocean, and osmotic' (2022) 161 RSER 1.

[120] Aurora Energy Research; Baumann.

[121] Swennenhuis, de Gooyert and de Coninck 5; Kevin J Dillman and Jukka Heinonen, 'A "just" hydrogen economy: A normative energy justice assessment of the hydrogen economy' (2022) 167 RSER 1, 5; Abdoulaye Ballo and others, 'Law and policy review on green hydrogen potential in ECOWAS countries' (2022) 15 Energies 1, 11.

[122] See for instance for Morocco, Lindner 9; and for Brazil, Christian Brannstrom and Adryane Gorayeb, 'Social challenges of green hydrogen in the Global South' Alternative Policy Solutions (26 July 2022) <https://aps.aucegypt.edu/en/articles/802/social-challenges-of-green-hydrogen-in-the-global-south> accessed 11 December 2023.

[123] Max Lacey-Barnacle, Rosie Robison and Chris Foulds, 'Energy justice in the developing world: A review of theoretical frameworks, key research themes and policy implications' (2020) 55 Energy Sustain Dev 122.

[124] See Section 10.2.3.

and biomass fuels', it explicitly excludes RFNBOs and would only apply to biogas (understood as a component of 'biomass fuels')[125] as per the writing of article 8 (1) and 2 (2) of the rGD. In this case, article 8 (1) could be criticized for its lack of clarity. In addition, specific sustainability criteria would have to be adopted at an unspecified date, leaving the sector in a limbo.

10.4 CONCLUSION

With the adoption in 2023 of RED III and the rGD, renewable hydrogen should now be subject to bioenergy's sustainability criteria provisions. It follows the same overall principles: applicable whether produced in the EU or imported and compulsory to get public support and to count towards MSs' renewable energy targets. Yet applying the bioenergy sustainability criteria one-on-one to renewable hydrogen creates some issues. While the legal linkage between rGD and RED III and the GHG emissions reductions is clear, the final interpretation of the application of the sustainability criteria related to land use remains vague. Looking at the content of these land use criteria, some of them appear useful to tackle some environmental impacts of the supply chain behind the production of renewable hydrogen, essentially when it takes place in protected natural areas. However, for developments outside these areas, for water consumption in water-scarce areas and for social impacts, the bioenergy sustainability criteria are unfit.

Actually, these loopholes in existing sustainability criteria also fail to address similar impacts from bioenergy, as long noted by academics and NGOs. As mentioned in Section 10.2.3, in 2016 the European Commission rejected the inclusion of some of these issues in the sustainability criteria due to the industry complaining about the administrative burden that these additional criteria would cause. Yet the case of renewable hydrogen adds more weight to these demands, even if they increase the administrative burden. Social issues must also be tackled. It was mentioned that WTO law is an obstacle, but some scholars think it would be possible to include such criteria, especially based on the requirements that are already widely used in private certification schemes.[126] Otherwise, the EU would have to negotiate bilateral agreements including social criteria with its anticipated main providers. In both environmental and social cases, low sustainability criteria threaten the long-term acceptance and therefore sufficient supply of renewable hydrogen to the EU.

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Konopacky J, 'Refueling biofuel legislation: Incorporating social sustainability principles to protect land rights' (2012) 30(2) Wis Int Law J 401

[125] RED II, art 2 (27). Unmodified by RED III.
[126] Konopacky 423–427.

Lindner R, 'Green hydrogen partnerships with the Global South. Advancing an energy justice perspective on "tomorrow's oil"' (2023) 31(2) Sustain Dev 1083
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Mensah J, 'Sustainable development: Meaning, history, principles, pillars, and implications for human action: Literature review' (2019) 5(1) Cogent Soc Sci 1
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11

Public Participation in the Hydrogen Economy

Lessons Learned from the Northern Netherland Hydrogen Valley

Lorenzo Squintani and Stan Schouten

11.1 INTRODUCTION

As underlined by the Hydrogen Strategy for a Climate Neutral Europe and the REPowerEU programmes,[1] both discussed in Chapter 2 by Hancher and Suciu in this book, the development of a hydrogen economy is considered of strategic importance for the achievement of the European Union (EU) climate goals by both the EU and several of its Member States. As for any socio-technical transition, the development of the hydrogen economy requires careful policy and regulatory drafting, as well as the concrete implementation of projects affecting people's living environment. Public participation is mandated under international, European and national law to ensure that the hydrogen economy best fits within the environmental and societal needs of the interested regions.

Public participation, defined as collaborative participation where project proponents or policymakers invite citizens to discuss and decide together upon policies and projects affecting the environment, can indeed improve the quality of decisions and their ability to generate consensus, and thus acceptability,[2] although some practitioners might experience it as a time-consuming exercise. Moreover, public participation is regarded as a pillar of environmental democracy under the Rio Convention,[3] and the Aarhus Convention, which establishes rights and obligations for its signatory parties in order to spur *participatory* democracy (articles 6–8 of the Convention).[4]

Both the EU and all of its Member States are party to the Convention and have adopted legislation to implement it, as will be discussed further below. However, some discrepancies between the requirements of the Convention and the legal frameworks of certain Convention

[1] European Commission, 'A hydrogen strategy for a climate-neutral Europe', COM(2020)301; Communication on REPowerEU: Joint European Action for more affordable, secure and sustainable energy, COM(2022) 108 final (8 March2022), with Annexes and Communication on Options.

[2] Jonas Ebbesson, 'The Notion of Public Participation in International Environmental Law' (1998) 8 YB of Intl Environmental L 51.

[3] United Nations, Rio Declaration on Environment and Development, UN Doc. A/CONF.151/26 (vol. I); 31 ILM 874 (1992).

[4] United Nations, Convention on Access to Information, Public Participation in Decision-Making and Access to Justice in Environmental Matters (Aarhus, Denmark, 25 June 1998, UN Treaty Series 2161), p. 447.

Parties have already been discussed in the literature.[5] Besides, empirical evidence suggests that a major problem with the implementation of the Convention concerns the manner in which such frameworks are applied in *practice*.[6] There are, as of today, no studies focusing on public participation with a view to the development of the hydrogen economy, at the level of compliance of the regulatory frameworks with the Convention or at the level of the application of participatory rights in practice.

This chapter aims to close that gap by answering how the EU and national standards on public participation have been shaped and applied in practice in the development of the hydrogen economy when looking at them from the perspective of the Aarhus Convention.[7] We present here the results of the case study focusing on the Netherlands, which hosts the first fully fledged hydrogen valley of the EU, namely the Northern Netherlands Hydrogen Valley (so-called HEAVENN project).[8]

After presenting the EU and Aarhus Convention frameworks for public participation and showing their points of convergence and discrepancies (Section 11.2), we will discuss the policy framework shaping the Northern Netherlands Hydrogen Valley (Section 11.3). Specific focus will be placed on the organization of public participation in the setting up of policy documents, plans and strategies by public and semi-public bodies[9] in this valley, as the lacunas in the drafting and application of the regulatory framework on public participation in the field of the hydrogen economy become most visible here. Although studies on public perceptions about hydrogen are yet to deliver accurate empirical data,[10] it can be expected that hydrogen storage will be the hydrogen-value-chain aspect most prone to attract societal debate. Accordingly, Section 11.3 will focus on an ongoing public participation procedure regarding hydrogen storage in depleted salt caverns in the Hydrogen Valley in the northern Netherlands. In Section 11.4, we will discuss the potential implications of our findings and conclude accordingly. In doing so, this chapter will provide data for comparative purposes and for the further development of the conceptual and applied frameworks for the hydrogen economy.

[5] As regards the EU itself, Ludwig Krämer, 'The EU and Public Participation in Environmental Decision-Making' in Jerzy Jendróska and Magdalena Bar (eds.), *Procedural Environmental Rights: Principle X in Theory and Practice* (Intersentia, 2017) pp. 121–141; for Spain, José I. Cubero Marcos and Unai A. Gorriño, 'Controversies about Projects or Plans Passed by Law in Spain' in Bernard Vanheusden and Lorenzo Squintani (eds.), *EU Environmental and Planning Law: Aspects of Large-Scale Projects* (Intersentia, 2016) pp. 119–142; and for Italy, Barend Vanheusden, 'The Implementation of the Second Pillar of the Aarhus Convention in Italy: The Need for Reform and for Introduction of the So-Called "Deliberative Arenas"', in Vanheusden and Squintani (eds.), pp. 143–165.

[6] For an example from Belgium related to air quality, Eva Wolf and Wouter van Dooren, 'How Policies Become Contested: A Spiral of Imagination and Evidence in a Large Infrastructure Project' (2017) 50(3) Policy Sciences 449; for another example about renewable energy sources, Sanne Akerboom, *Between Public Participation and Energy Transition: The Case of Wind Farms* (PhD thesis, Amsterdam, 2018).

[7] It should be noted that in this chapter we do not differentiate between public participation of the general public and that specifically of environmental non-governmental organizations (ENGOs), since for the findings presented in this study this difference is irrelevant.

[8] HEAVENN stands for H2 Energy Applications in Valley Environments for Northern Netherlands, see <https://heavenn.org/> accessed November 2023.

[9] The concept of semi-public bodies within the context of this chapter is explained in Section 11.2.3 below.

[10] For initial empirical data from Germany see, Johann J. Häußermann, Moritz J. Maier, Thea C. Kirsch, Simone Kaiser and Martina Schraudner, 'Social Acceptance of Green Hydrogen in Germany: Building Trust through Responsible Innovation' (2023) 13(22) ESS <https://doi.org/10.1186/s13705-023-00394-4> accessed 25 November 2023.

11.2 THE EU LEGAL FRAMEWORK FOR PUBLIC PARTICIPATION IN ENERGY MATTERS

11.2.1 *General Issues: Lacunas in the EU Framework for Public Participation on Hydrogen Plans and Programmes*

Public participation in energy matters is covered by the general framework on public participation in environmental matters. This is due to the fact that energy policy and activities usually, if not always, have implications for the environment.[11] In the EU legal order, public participation is, firstly, explicitly envisaged under article 11(1) of the Treaty on European Union (TEU), stating that EU institutions shall give citizens and representative associations the opportunity to make known and publicly exchange their views in all areas of Union action. This also includes energy. Furthermore, specifically on energy and environmental themes, the EU framework has been created in light of the Aarhus Convention.

This Convention is a so-called mixed agreement,[12] to which EU Member States and the EU itself are parties. The provisions of the Convention thus rank higher than EU secondary law, but lower than the Treaties.[13] Moreover, the provisions of the Convention have primacy over conflicting national rules.[14] This is also true regarding those provisions that have not yet been implemented by the EU legislator.[15] This finding is relevant as EU law has still not fully implemented the Convention, as has been discussed elsewhere.[16]

Relevant for this study is the fact that the Aarhus Convention prescribes public participation for all (national) plans and programmes on the environment, and thus also those on the hydrogen economy. The main directive implementing the Aarhus Convention with a view to its application at a national level, the so-called Aarhus Directive,[17] does not cover the actual EU energy law framework. Nor are the Renewable Energy Sources Directive[18] and the Gas[19] and

[11] Kars J. de Graaf and Lorenzo Squintani, 'Sustainable Development, Principles of Environmental Law and the Energy Sector' in Martha M. Roggenkamp, Kars J. de Graaf and Ruven Fleming (eds.), *Energy Law, Climate Change and the Environment* (Edward Elgar, 2021) pp. 41–45.

[12] On mixed agreement see, e.g., Jan H. Jans and Hans H. B. Vedder, *European Environmental Law: After Lisbon* (Europa Law, 2012) pp. 71–74.

[13] Consolidated version of the Treaty on the Functioning of the European Union (TFEU) [2009] C 306/1 art 216(2); Case 104/81 *Hauptzollamt Mainz v C.A. Kupferberg & Cie KG a.A. (Kupferberg)* ECLI:EU:C:1982:362; Case C-344/04 *International Air Transport Association and European Low Fares Airline Association v Department for Transport (IATA and ELFAA)* ECLI:EU:C:2006:10, paras 35–36.

[14] Jacqueline M. I. J. Zijlmans, *De doorwerking van natuurbeschermingsverdragen in de Europese en Nederlandse rechtsorde* (Sdu uitgevers, 2011) p. 45.

[15] Case C-240/09 *Lesoochranárske zoskupenie VLK v Ministerstvo životného prostredia Slovenskej republiky* ECLI:EU:C:2011:125 (*Zoskupenie*).

[16] Lorenzo Squintani and Goda Perlaviciute, 'Access to Public Participation: Unveiling the Mismatch between What Law Prescribes and What the Public Wants' in Marjan Peeters and Mariolina Eliantonio (eds.), *Research Handbook on EU Environmental Law* (Edward Elgar, 2020) pp. 133–147.

[17] Council Directive 2003/35/EC providing for public participation in respect of the drawing up of certain plans and programmes relating to the environment and amending with regard to public participation and access to justice Council Directives 85/337/EEC and 96/61/EC [2003] OJ L156/17.

[18] Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources (recast) (Text with EEA relevance) PE/48/2018/REV/1 OJ L 328, 21 December 2018, pp. 82–209.

[19] Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC (Text with EEA relevance) OJ L 211, 14 August 2009, pp. 94–136.

Electricity[20] directives listed regarding the scope of application of the Aarhus Directive, to mention just a couple of examples from energy law. The proposed directive on gas and hydrogen also lacks a provision aimed at amending the Aarhus Directive.[21] The proposal does not, alternatively, contain ad hoc provisions on public participation. Public participation in the development of hydrogen markets will thus not be mandated under these pieces of EU secondary law. The Strategic Environmental Assessment (SEA) Directive, which covers public participation in plans and programmes relating to energy, only addresses public participation when such plans and programmes are likely to have *significant* environmental effects.[22] Under the Aarhus Convention, any plan or programme *relating* to the environment must be subject to public participation, even when it does not have potential serious negative effects on it.[23] The EU framework for public participation in the hydrogen economy is thus deficient.

This does not mean that the EU and its Member States do not have to comply with the Convention on these aspects. Decision 2005/370/EC has made the Convention part of the EU *acquis communautaire*.[24] As mentioned above, this means that the Convention is, *in its entirety*, binding upon the EU and its Member States, as recognized by the Court of Justice.[25]

In the rest of this contribution, given the broader and more elaborated scope of the provisions of the Convention and the great overlap between the wording of its provisions and the pieces of EU legislation most directly aimed at implementing them,[26] the Convention is used as the basis to explain public participation in the development of the hydrogen economy. The focus will be on the importance of ensuring public participation with a view to policies, plans and programmes (Section 11.2.2), including when these are set up by semi-public bodies (Section 11.2.3). Of course, the Aarhus Convention only pursues minimum harmonization,[27] which means that the EU and its Member States can decide to go beyond such a minimum, a practice called green-plating.[28]

[20] Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU (recast) (Text with EEA relevance.) PE/10/2019/REV/1 OJ L 158, 14 June 2019, pp. 125–199.

[21] Proposal for a Directive of the European Parliament and of the Council on common rules for the internal markets in renewable and natural gases and in hydrogen (recast), COM(2021) 803 final.

[22] Council Directive 2001/42/EC on the assessment of the effects of certain plans and programmes on the environment [2001] OJ L197/30.

[23] Commission, 'Implementation of Directive 2001/42 on the Assessment of the Effects of Certain Plans and Programmes on the Environment' (Implementation Guide), pp. 174–175. See also Aarhus Convention Compliance Committee (ACCC), Report concerning the European Union (2 October 2012), ECE/MP.PP/C.1/2012/12.

[24] Council Decision 2005/370/EC on the conclusion, on behalf of the European Community, of the Convention on access to information, public participation in decision-making and access to justice in environmental matters [2005] OJ L124/1.

[25] For art 9(3) of the Convention, which has not been transposed into EU secondary law, see *Zoskupenie* (2011).

[26] Council Regulation (EC) 1367/2006 on the application of the provisions of the Aarhus Convention on access to information, public participation in decision-making and access to justice in environmental matters to community institutions and bodies [2006] OJ L264/13; Council Directive 2003/4/EC on public access to environmental information and repealing Council Directive 90/313/EEC [2003] OJ L41/26; Council Directive 2003/35/EC providing for public participation in respect of the drawing up of certain plans and programmes relating to the environment and amending with regard to public participation and access to justice Council Directives 85/337/EEC and 96/61/EC [2003] OJ L156/17; Council Directive 2004/35/EC on environmental liability with regard to the prevention and remedying of environmental damage [2004] OJ L143/56.

[27] United Nations, *The Aarhus Convention an Implementation Guide* (United Nations Economic Commission for Europe E 13 II E 3) 2014, 42, 50, 67 (Implementation Guide); ACCC, Report concerning Hungary (31 January 2004), ACCC/C/2004/4, para 18.

[28] Lorezo Squintani, *Beyond Minimum Harmonisation – Green-Plating and Gold-Plating of European Environmental Law* (Cambridge University Press, 2019) pp. 13–71.

11.2.2 *Specific Issues: The Importance of Ensuring Public Participation as Regards Policies, Plans and Programmes*

This section shows the importance of ensuring public participation early in the chain of decision-making on the hydrogen economy. It focuses on public participation at the level of policies, plans and programmes, and unveils the shortcomings of the EU framework in this regard. Public participation is regulated under three provisions of the Convention: article 6, regarding specific activities significantly affecting the environment; article 7, on plans, programmes and policies; and article 8, dealing with executive regulations and other generally applicable and legally binding rules. Although this chapter focuses on policies, plans and programmes on hydrogen, this provision cannot be understood in isolation from article 6. This is because, for plans and programmes, article 7 refers back to certain obligations set out under article 6.[29] We will thus first introduce article 6.

The public participation legal framework set out in article 6 is more detailed in comparison to those for plans and programmes and for policies. It consists of eight categories of obligations. First, it establishes a *notification* duty. Properly informing the public concerned[30] – either by a public notice, such as a newspaper announcement, or an individual notice, such as a letter – is essential for effective participation in the decision-making procedure.[31] To this extent, the notification must include all relevant information about the project and the public participation procedure. Second, the responsible party, which could also be a private party, should set *reasonable time frames* to inform the public concerned and to allow for a response. The Convention does not define the concept of 'reasonable time frames' and this could vary in accordance with the kind of activity under scrutiny.[32] Third, the procedure should take place *when all options are possible* and participation can be *effective*. Under this provision, the concepts of 'early engagement' and 'effective participation' are linked to the moment in the decision-making process in which public participation is organized. What matters is that 'events on the ground', such as the availability of certain technological choices,[33] have not effectively eliminated alternative options.[34] This does not mean that during the establishment of specific activities the public concerned must be able to comment upon options that were subjected to an earlier public participation procedure.[35] For example, options that have been subjected to public participation in the context of establishing a plan or programme do not need to be subjected to public participation during the adoption of specific activities implementing such a

[29] Article 8 on executive regulations and other generally applicable and legally binding rules only establishes 'soft obligations', that is, best efforts obligations Implementation Guide (2014), p. 181, which immediately clarifies that these obligations are still enforceable under article 9(3) of the Convention), and it allows participation by the general public to be organized via representative consultative bodies. It thus allows deviation from the focus on the concept of public participation discussed in this chapter. Accordingly, this provision is not further analysed.

[30] On what constitutes an appropriate notification method, see ACCC, Report concerning Belarus (12 May 2011), ECE/MP.PP/2011/11/Add.2, para 86; ACCC, Report concerning Armenia (12 May 2011), ECE/MP.PP/2011/11/Add.1, para 70; ACCC, Report concerning Lithuania (12 May 2011), ECE/MP.PP/2008/5/Add.6, para 67; ACCC, Report concerning France (8 February 2011), ECE/MP.PP/C.1/2009/4/Add.1, para 41.

[31] This obligation requires also informing the public in other countries if the activity under scrutiny can significantly affect the environment in that country, for example in the context of nuclear energy, ACCC, Report concerning Czech Republic (29 December 2016), ECE/MP.PP/C.1/2017/3), paras 71–72.

[32] Implementation Guide (2014), p. 143.

[33] Report concerning Lithuania (2011), p. 74.

[34] Implementation Guide (2014), p. 145.

[35] Report concerning Lithuania (2011), p. 71.

plan or programme.[36] Fourth, *private initiators* should be encouraged to engage in public participation prior to a permit application. Public authorities, however, should retain control of and responsibility for the procedure.[37] Fifth, the public concerned must be able to *access all relevant information*, in accordance with the provisions on access to information under the Convention.[38] Sixth, the public must be allowed to *submit views*. This provision represents the embodiment of public participation – that is, the ability to express a view, or arguably even a feeling,[39] in writing or orally, to the discretion of the public.[40] Seventh, the responsible authority should *take the views* expressed by the public *into due account*, therefore ensuring a 'real voice' to the public. However, this does not mean that it has to align the decision to such views.[41] According to the European Commission, this duty 'means that the Commission will duly consider the comments submitted by the public and weigh them in the light of the various public interests in issue'.[42] Basically, this duty means, in legal terms, that a decision-maker must show why a particular comment was rejected on substantive grounds.[43] Still, it does not amount to a right of the public to veto the decision, according to the Aarhus Convention Compliance Committee (ACCC).[44] The eighth, and final, obligation is that the decision-maker should *inform the public* about the final decision and how the views have been taken into account.[45]

The legal framework for public participation procedures as regards plans and programmes build on the framework for decisions on specific activities but is less extensive and specific. Firstly, the Convention does not define the concepts of 'plans' and 'programmes' concerning the environment. These instruments can take a variety of forms.[46] In the majority of the cases, plans and programmes are meant to provide a framework for adopting decisions about specific activities. Secondly, obligations regarding public participation procedures on plans and programmes refer explicitly to the second (reasonable time frames), third (early engagement) and seventh (real voice) obligations listed above. They refer also to the need to ensure *transparency*, *fairness* and *access to information*. Although the first, fifth, sixth and eighth obligations, indicated under article 6, can easily be read into the concepts of fairness, transparency and access to information, the different formulation of such obligations denotes the presence of more discretionary powers for public authorities on how to fulfil them than in the context of decisions concerning specific activities.

36 Ibid.

37 Ibid, p. 82.

38 On this topic see, e.g., Moritz Von Unger, 'Access to EU Documents: An End at Last to the Authorship Rule?' (2007) 4 *J for Eur Environmental & Planning L* 440; and Jerzy Jendrośka, 'Citizen's Rights in European Environmental Law: Stock-Taking of Key Challenges and Current Developments in Relation to Public Access to Information, Participation and Access to Justice' (2012) 9(1) J for Eur Environmental & Planning L 71.

39 Alexandra Aragão, 'When Feelings Become Scientific Facts: Valuing Cultural Ecosystem Services and Taking Them into Account in Public Decision-Making' in Lorenzo Squintani, Jan Darpö, Luc Lavrysen and Peter-Tobias Stolland (eds.), *Managing Facts and Feelings in Environmental Governance* (Edward Elgar, 2019) pp. 53–80.

40 Implementation Guide (2014), p. 153.

41 ACCC, Report of the Compliance Committee on its Twenty-fourth meeting (8 February 2011), ECE/MP.PP/C.1/2009/4, para 29.

42 European Commission, 'Access to Information, Public Participation and Access to Justice in Environmental Matters at Community Level – A Practical Guide' <http://ec.europa.eu/environment/aarhus/pdf/guide/AR%20Practical%20Guide%20EN.pdf> accessed 24 January 2024.

43 Implementation Guide (2014), p. 155.

44 ACCC, Report concerning European Union and the United Kingdom of Great Britain and Northern Ireland (13 January 2014), ECE/MP.PP/C.1/2014/5, para 93.

45 ACCC, Report concerning Spain (8 February 2011), ECE/MP.PP/C.1/2009/8/Add.1, para 100.

46 Krämer (2017); see also Lorenzo Squintani and Marleen van Rijswick, 'Improving Legal Certainty and Adaptability in the Programmatic Approach' (2016) 28 *Journal of Environmental Law* 443.

From a legal perspective, plans and programmes are not adopted in a vacuum but should fit within the existing policy framework. Under the Aarhus Convention, environmental policies can be defined as 'a course or principle of action adopted or proposed by an organization or individual'.[47] Yet this concept remains officially undefined. From the perspective of public participation, article 7, last sentence, of the Convention shows the high level of freedom left to the Convention Parties in this area. There are no specific legal requirements in this regard. Most significantly, the duty to organize public participation procedures at a moment in time in which all options are still open does not apply to policies. This consideration holds true also for the duty to take due account of the views and feelings of the public.[48] As these two obligations aim at ensuring 'early engagement' and 'real voice' during public participation procedures, their absence underlines that, under the Convention, there are no explicit legal requirements aiming at ensuring that public participation as regards policies are *effective*.

This finding is particularly relevant when we consider that the content of decisions about specific activities depends on the higher-level instruments in the decision-making chain, namely plans and programmes, and policies. Besides, options discussed during the adoption of a policy, a plan or a programme do not need to be made subject to public participation during the adoption of implementing measures,[49] as indicated. At the same time, policies influence the room for input during the setting up of plans and programmes, which in turn influences the room for input during the adoption of concrete actions. Policy choices expressed in policy documents can determine that in practice certain options are no longer available at the level of decisions about specific actions.

The above shows the importance of ensuring public participation early in the chain of decision-making about the hydrogen economy, thus at the level of policies, plans and programmes.

11.2.3 *Specific Issues: Ensuring Public Participation by Semi-Public Bodies*

In certain Member States, such as the Netherlands, the development of the hydrogen economy is carried further by a collaboration of public and private bodies, with the latter at times being invested with powers going beyond those of private parties, as further discussed in Section 11.3 below.

In this regard, it should be noted that article 7 of the Aarhus Convention applies vis-à-vis parties that establish plans and programmes. Not only acts adopted by public bodies fall under article 7 of the Aarhus Convention. In certain cases, also policies, plans and programmes which are adopted by what national law considers private law bodies are covered by article 7 of the Convention. This is due to the fact that the concept of a public body is interpreted broadly in the context of the Aarhus Convention and EU law. What is meant by the concepts of 'public body' or 'public authority' must be viewed from the so-called Foster jurisprudence.[50] This entails that private law parties can also be qualified as public bodies from the perspective of EU law if they have powers and competences that go beyond those of ordinary private law parties. Transport system operators, distribution system operators and seaport authorities working on the

[47] Implementation Guide (2014), p. 180.
[48] Article 10.7 of the Dutch Environment and Planning Order (*Omgevingsbesluit*) will go beyond this standard by requiring public authorities to give account of how they involved the public in drafting environmental strategies and what the outcome of the procedure has been.
[49] Report concerning Lithuania (2011), p. 71.
[50] HvJEU C-188/89, A. *Foster e.a. tegen British Gas plc*, ECLI:EU:C:1990:313.

development of the hydrogen economy within their respective fields of operation can all be regarded as being public bodies for the purpose of the application of article 7 of the Aarhus Convention, even in those countries in which such bodies are set up as private companies, such as the Netherlands. The fact that under EU and national law such bodies are entrusted with powers that go beyond those of private parties qualifies them as public bodies under the Aarhus Convention and the EU law that implements it. We will call these kinds of public bodies semi-public bodies, to distinguish them from the traditional public bodies – that is, public law legal persons.

11.3 THE DEVELOPMENT OF THE HYDROGEN ECONOMY IN THE NETHERLANDS AND IN THE NORTHERN NETHERLANDS HYDROGEN VALLEY

11.3.1 *National Policies, Plans and Programmes on Hydrogen*

The current policy framework for hydrogen in the Netherlands is comprised of a multitude of letters by the Minister of Economics and Climate, 'working plans' drafted by working groups, and other documents. The Dutch National Hydrogen Programme 2022–2025[51] and the related Dutch Hydrogen Roadmap,[52] set up by a working group composed of public and private stakeholders, can be considered the main plans and strategies for the hydrogen economy. In these documents, the Netherlands sets the goal of 500 megawatt (MW) electrolyser capacity by 2025. For the period after 2031, plans exist for electrolysers on both land and at sea. For instance, by 2031 the Netherlands should have the biggest (500 MW) offshore hydrogen production plant in the world.[53] This production capacity needs to be supported by a fitting hydrogen infrastructure. The idea is to reuse the current natural gas infrastructure available, which minimizes the new infrastructure that needs to be built. However, the war in Ukraine complicates the initial plans, as the natural gas pipelines are currently necessary for delivery from west to east, and are thus not available for conversion to hydrogen transport.[54]

The National Hydrogen Programme underlines the importance of public acceptability for developing a hydrogen economy.[55] Yet public participation is only mentioned as regards the *project* level, by informing the general public on those decisions that have already been made.[56] In fact, neither of these documents have been drawn up following a public participation procedure. Only stakeholders active in the field of hydrogen were invited to contribute to the working sessions which led to the programme. No public participation was organized.[57]

Besides these two programmatic documents, the Dutch Programme for the Energy Infrastructure (Programma Energiehoofdstructuur) sets out a spatial planning framework, regulating the spatial utilization of the Dutch territory for hydrogen infrastructure.[58]

[51] CSWW – cross-sectorale werkgroep waterstof, *Werkplan Nationaal Waterstof Programma 2022–2025* (7 July 2021).
[52] Dutch National Hydrogen Programme (NWP), *Hydrogen Roadmap for the Netherlands* (30 November 2022).
[53] Rijksoverheid, *Windpark boven Groningen beoogd als's werelds grootste waterstof op zee productie in 2031* (20 March 2023) <https://rijksoverheid.nl/onderwerpen/duurzame-energie/nieuws/2023/03/20/windpark-boven-groningen-beoogd-als-s-werelds-grootste-waterstof-op-zee-productie-in-2031> accessed August 2023.
[54] Minister voor Klimaat en Energie Rob A. A. Jetten (Ministerie van Economische Zaken en Klimaat) *Voortgang waterstofbeleid* (2 December 2022), p. 7.
[55] CSWW, *Werkplan Nationaal Waterstof Programma 2022–2025*, p. 17.
[56] Ibid.
[57] Staatssecretaris Yeşilgöz-Zegerius (EZK – Klimaat en Energie), Kamerbrief bij werkplan Nationaal Waterstof Programma, November 2021, Overheid Identificatienr: 00000001003214369000.
[58] Rijksoverheid, *Ontwerp-Programma Energiehoofdstructuur: Ruimte voor een klimaatneutraal energiesysteem van nationaal belang* (July 2023), p. 21.

It includes a partially binding spatial plan with specified general areas in which provinces should determine where hydrogen infrastructure (such as electrolysers, and storage facilities in depleted salt caverns) can be located. This document was drafted by the government, following the so-called Participatory Value Evaluation method, and the government adhered to the formal consultation procedure (in Dutch: *zienswijze procedure*).[59] While the Participatory Value Evaluation is a way to investigate the preferences of a group of people on various policy options, given a fixed budget,[60] the consultation procedure allows anyone to submit their opinion or concerns about (part of) a plan.

Regarding the development of hydrogen in the northern Netherlands, the Dutch Programme for Energy Infrastructure indicates a clear preference for using salt caverns for underground hydrogen storage.[61] It is also mentioned specifically that, given the recent history of mining endeavours in the north of the Netherlands which caused earthquakes and social unrest, public participation in the development of these storage facilities would need extra attention and would require 'a fundamentally different approach than the natural gas extraction in Groningen'.[62] This brings us to the Northern Netherlands Hydrogen Valley.

11.3.2 *Hydrogen Policies, Plans and Programmes in the Northern Netherlands Hydrogen Valley*

The HEAVENN project in the northern Netherlands is a six-year project that created the first region to be recognized as a hydrogen valley and to receive the accompanying EU subsidy. A hydrogen valley is a concept established by the EU for projects that successfully link hydrogen production through an effective transportation system to its various end uses. A hydrogen valley serves as a demonstration site of a profitable and holistic business model for green hydrogen.[63] HEAVENN's main goal is exactly that: to create replicable business models while maximizing the abundant solar and wind energy available in the region and using green hydrogen across the entire value chain. In that way, the northern Netherlands serves as a showcase for green hydrogen development within the EU. The region covers three Dutch provinces: Friesland, Groningen and Drenthe. Most hydrogen activities take place in Groningen. We therefore analyse the policy, plans and programmes of the province of Groningen from the perspective of public participation in the next section.

11.3.3 *Hydrogen Policies, Plans and Programmes of the Province of Groningen*

The main policy document on hydrogen in the province of Groningen is the Climate Agenda of the Province of Groningen for 2030.[64] This policy document sets out, among others, the goals of

[59] Ibid, p. 21.
[60] Niek Mouter, Paul Koster and Thijs Dekker, 'Contrasting the Recommendations of Participatory Value Evaluation and Cost–Benefit Analysis in the Context of Urban Mobility Investments' (2021) 144 TRPAPP 54–73.
[61] Rijksoverheid, *Ontwerp-Programma E nergiehoofdstructuur: Ruimte voor een klimaatneutraal energiesysteem van nationaal belang* (3 July 2023), p. 66.
[62] Ibid.
[63] Clean Hydrogen Partnership, 'REPowering the EU with Hydrogen Valleys: Clean Hydrogen Partnership Invests EUR 105.4 Million for Funding 9 Hydrogen Valleys across Europe' (31 January 2023) <https://clean-hydrogen.europa.eu/media/news/repowering-eu-hydrogen-valleys-clean-hydrogen-partnership-invests-eur-1054-million-funding-9-2023-01-31_en> accessed August 2023.
[64] Provincie Groningen, *Klimaatagenda Provincie Groningen 2030* (2020). Also the Environmental Plan of the Province of Groningen has a passage which is relevant for hydrogen, indicating namely that stating that the Province sees the storage of gases in depleted salt caverns, existing or future ones, as favourable for spurring sustainability, Provincie

the province in the field of hydrogen for 2030. The goals are expressed in a broad fashion, in terms of 'supporting initiatives in the field of hydrogen',[65] 'use of hydrogen as energy carrier',[66] 'reserving space for onshore pipelines for transporting hydrogen',[67] 'improving the business case for hydrogen',[68] 'strengthening the hydrogen value chain'[69] and 'execution of hydrogen train pilot'.[70] Participation is considered an important aspect of the further development and implementation of energy policies in the region, but the Climate Agenda as such was not subject to public participation. The province only invited stakeholders and experts to express their comments on the Climate Agenda.[71]

Another general policy document referring to hydrogen in the province of Groningen is the Regional Energy Strategy (*Regionale Energie Strategie* – RES). The RES was developed by the province, municipalities and water boards of the province of Groningen. It was developed in two phases, RES 1.0 and RES 2.0.[72] Neither of the two documents set out specific goals or actions as regards hydrogen, but simply refer to the development of the hydrogen economy in general terms.[73] Neither document was open for public participation.

The same is true for the Investment Plan on Hydrogen presented by public and private parties in the provinces of Groningen and Drenthe in 2020.[74] Most importantly, this document indicates the storage project in Zuidwending, north-east Groningen, as one of those belonging to the Northern Netherlands Roadmap to 2030,[75] and covered by the Investment Plan.[76] The choice of the location for the first hydrogen storage facility in depleted salt caverns seems thus to have taken place by the time this document was established. There is no trace of public participation.

In June 2023, the province of Groningen presented its Provincial Multi-year Programme on Energy and Climate Infrastructure 1.0 (Provinciaal Meerjarenprogramma Infrastructuur Energie en Klimaat), which implements the Dutch Programme for Energy Infrastructure, discussed in Section 11.3.1 above.[77] At the moment, this programme only focuses on electricity. Hydrogen is referred to in several places, but no specific spatial choice is expected till 2025 when version 2.0 of the programme will be published.[78]

Groningen. 'Geconsolideerde Omgevingsvisie' (June 2022), p. 129 <https://provinciegroningen.nl/fileadmin/user_upload/Documenten/Beleid_en_documenten/Omgevingsvisie/Geconsolideerde_Omgevingsvisie_juni_2022.pdf> accessed September 2023. The reference to 'gases' can cover also hydrogen in gas form.

65 Provincie Groningen, *Klimaatagenda Provincie Groningen* 2030, p. 20.
66 Ibid, p. 22.
67 Ibid, p. 31.
68 Ibid, p. 32.
69 Ibid.
70 Ibid, p. 44.
71 This information is based on the webpage of the province of Groningen about the hearing concerning the agenda held in the province on 9 September 2020 <https://provinciegroningen.nl/actueel/nieuws/nieuwsartikel/provinciale-staten-houden-hoorzitting-over-groningse-klimaatagenda-2030/> accessed September 2023.
72 Both documents are available on the website of the Groningen RES <https://resgroningen.nl/default.aspx> accessed September 2023. The documents themselves do not have a specific identifier, except than Groningen RES 1.0 and Groningen RES 2.0.
73 E.g. Groningen RES 1.0, p. 23.
74 Various authors, *Investeringsplan Waterstof Noordnederland* 2020, October 2020 <https://provinciegroningen.nl/actueel/dossiers/energietransitie/waterstof/> accessed September 2023.
75 Ibid, p. 25.
76 Ibid, p. 42.
77 Provincie of Groningen, *Provinciaal Meerjarenprogramma Infrastructuur Energie en Klimaat* (June 2023) <https://ipo.nl/thema-s/klimaat-en-energie/energietransitie-pmieks/> accessed September 2023.
78 Ibid.

Overall, similar to the national level, the province of Groningen's policies, plans and programmes for hydrogen include several macro-level policy choices, which have been established without any visible public participation. After having assessed the actions of public bodies, we will now look at what semi-public bodies in the hydrogen valley of the northern Netherlands have done with their plans and programmes for the hydrogen economy from the perspective of public participation.

11.3.4 *Hydrogen Policies, Plans and Programmes of Semi-Public Bodies: Gasunie*

In addition to the delegated powers of the provinces, private actors are also broadly vested with public functions in the Dutch energy market. In the field of hydrogen, Nederlandse Gasunie N.V. (Gasunie) plays a major role in the development of the hydrogen infrastructure, as discussed in detail in Chapter 17 in this book, by Broersma, Jäger and Holwerda. Gasunie will be the transport system operator responsible for the hydrogen transportation grid in the Netherlands.[79] HyNetwork Services (HNS) and EnergyStock are two subsidiary companies of Gasunie tasked by the Dutch government to develop the hydrogen network and hydrogen storage, respectively.[80] The Gasunie group (Gasunie and its subsidiaries) have thus been entrusted with powers that go beyond those of private parties and can be qualified as a semi-public body, as also evident from the discussions by Broersma, Jäger and Holwerda in Chapter 17.[81]

The main policy framework within which HNS operates is the Dutch Hydrogen Roadmap, discussed in Section 11.3.1 above. In 2023, HNS proposed amendments to it.[82] These were presented in a hybrid webinar, the recordings of which are available online, and those who had an interest, without further defining what this 'interest' might have meant, could submit their comments to the proposed amendments for four weeks starting on 23 July 2023. At the time of writing, the received comments and their implementation are not available, but HNS indicates that it will publish such information unless the party submitting the comment indicates that the comment should be treated as confidential.[83]

With a view to hydrogen storage, the Dutch Hydrogen Roadmap indicates the goal of having between 750 and 1,000 gigawatt/hours (GWh) of hydrogen in salt caverns by 2030.[84] As indicated in the plan itself, this means that three or four salt caverns will be filled with hydrogen. The first caverns will be in Zuidweinding, in the north of the Netherlands, within the hydrogen valley. At the time of writing, the possible locations of the other three hydrogen caverns is still being studied.[85]

As permission for the first storage facility, the salt cavern in Zuidwending (project called Energiebuffer Zuidwending), was covered by the State Coordination Regulation (Rijkscoördinatieregeling), the public participation procedure followed the formal consultation (*zienswijze*) procedure,[86] under the responsibility of the Ministry for Economic Affairs and

[79] Minister voor Klimaat en Energie Rob A. A. Jetten (Ministerie van Economische Zaken en Klimaat) *Ontwikkeling transportnet voor waterstof* (29 June 2022) p. 1.
[80] Ibid.
[81] In particular, article 10d (1)(2) Gaswet (Gas Act).
[82] Hynetwork Services, 'Consultatie conceptvoorstel aanpassing uitrolplan landelijke waterstofnetwerk' <https://hynetwork.nl/over-hynetwork-services/uitrolplan> accessed November 2023.
[83] Ibid.
[84] Nationaal Waterstof Programma, *Routekaart Waterstof* (2022), p. 57.
[85] EnergyStok, *The Project* <https://hystock.nl/en/about-hystock/the-project> accessed November 2023.
[86] This procedure is enshrined in Section 3.4 of the Dutch General Administrative Law Act (*Algemene Wet Bestuursrecht*).

Climate. This procedure was opened in April 2023 and closed at the end of May 2023.[87] All received public input is available on the website of the Ministry, by means of an anonymized bundle report. This report shows that people had remarks about macro policy options, such as the alleged unreasonableness of investing in hydrogen,[88] and the need to develop the caverns elsewhere in the Netherlands.[89] At the time of writing, the responses to these remarks are not available.

Still, in 2022, prior to the formal participation procedure, Gasunie's subsidiary responsible for the development of hydrogen storage facilities, EnergyStock, published a participation plan (*Participatieplan*).[90] In that plan, EnergyStock defines the targeted audience groups as local residents, the government and administrative bodies, companies, NGOs, nature associations and other social parties.[91] Most importantly, this plan indicates the main focus of the participation procedure.[92] It also indicates that the participation procedure will *not* concern the location of the project as the cavern at the current location is already in use by the exploiting parties (Nobian and EnergyStock) and is the most suitable one for the project.[93] This shows that this macro-level policy option was not the subject of the participation procedure. This option was adopted when publishing the National Hydrogen Programme and related roadmap, discussed in Section 11.3.1 above. Apparently this policy option is not open to debate at the level of specific decisions.

Under the Aarhus Convention, it is fine not to discuss policy options at the level of specific decisions during a public participation procedure, as explained in Section 11.2 above. This is, however, only true when the macro-level policy options were subject to a participatory process when settled. As indicated in Section 11.3.1, this was not the case when the National Hydrogen Programme and related roadmap were established.[94] This option should, therefore, be open to the participatory process at the level of the specific project.

11.4 STANDING OF DRIFT SAND: A DEFICIENT PARTICIPATORY PROCESS FOR MACRO-LEVEL POLICY OPTIONS

The development of hydrogen infrastructure presented above shows the existence of a complex framework of policy, programmes and plans adopted by national and local authorities, as well as by semi-public bodies. The analysis presented in this book shows shortcomings in the drafting and implementation of the regulatory framework on public participation as regards the development of a hydrogen economy at all levels of governance, from the EU to the local level.

[87] This information is available on the website of RVO, 'Energiebuffer Zuidwending: Project Hystock Waterstofopslag' (11 May 2022) <https://rvo.nl/onderwerpen/bureau-energieprojecten/lopende-projecten/zuidwending> accessed November 2023.

[88] Inspraakpunt Bureau Energieprojecten, Inspraakbundel Zienswijzen op concept Notitie Reikwijdte en Detailniveau Energiebuffer Zuidwending: Project Hystock Waterstofopslag', Anonymised Zienswijze number: 202300884.

[89] Ibid, Anonymised Zienswijze number: 202301267.

[90] EnergyStock, 'Voornemen en Voorstel voor Participatie voor het project Energiebuffer Zuidwending: project HyStock Waterstofopslag (uitvoerende partij: EnergyStock)' (2022) <https://rvo.nl/sites/default/files/2022-06/Voornemen-en-Voorstel-voor-Participatie-Energiebuffer-Zuidwending-Hystock_0.pdf> accessed 18 September 2023.

[91] Ibid.

[92] Ibid; specifically, the position of the injection and extraction points, the layout of the terrain, whether the facility for injection and extraction will be developed and how it fits within the landscape and environment surrounding it, and matters concerning safety and nuisance of the project and the related construction works.

[93] Ibid.

[94] The specific location of Zuidwending was also included in the Dutch Programme for Energy Infrastructure, which was open to public participation. However, this occurred in 2023, thus after the participation plan for the project was established in 2022.

The lack of explicit requirements for public participation in the EU regulatory framework for renewable energy in general, and energy production and transport in particular, is echoed by the lack of a participatory process for the establishment of the National Hydrogen Programme and related National Roadmap. Also at regional level, the policies, plans and programmes for the development of the hydrogen economy in Groningen do not show the presence of public participation. The macro-level policy options concerning investments in the hydrogen economy, the shape of the hydrogen pipeline network, the goals as regards hydrogen storage and the location of the first depleted salt caverns to be used for such storage were decided at these levels, without public participation. This means that the policy options decided at these levels of decision-making did not benefit from the insights of the general public. The potential benefits of a participatory process as regards these macro-level policy options – substantively better, more democratic and greater acceptability – were thus left unexploited.

We showed that participatory processes were initiated at the project level for the hydrogen storage facility at Zuidwending. The outcomes of this decision-making process are still pending, but it was striking to see that the participatory plan of EnergyStock mentioned that the selection of Zuidwending as a hydrogen storage location was not part of the participatory procedure. During the formal consultation procedure, people clearly expressed remarks about such a macro-level policy option, as well as other macro-level policy options. It is too soon to make a final judgement about the compatibility of this procedure with the legal framework on public participation established under the Aarhus Convention. At the time of writing, it is not known if the comments about the macro-level policy options will be addressed. If not, the provisions of the Aarhus Convention would be breached.

Still, the lack of proper participatory processes by the establishment of the macro-level policy options at the national and regional levels remain concerning even if this specific procedure appears to comply with the Aarhus Convention requirements. Public participation contributes to better, democratically embedded and more acceptable policies, with potential benefits for their implementation at a project level, although practitioners might see it as potentially time-consuming.

To enjoy these potential benefits, it is important that the Aarhus Convention requirements on public participation are applied in full, at all levels of government, including in case of plans and programmes from semi-public bodies. Macro-level policy options can then be subject to public participation when they are drafted and thus easy to change, rather than when they are implemented at project level, often by different parties than those who can shape macro-level policy options. Finally, the visibility of the duty of public participation in the context of the development of the hydrogen economy would benefit from a clearer framework on public participation at EU level. The existing EU regulatory framework, specifically the Aarhus Directive and/or the Gas Directive now, or once repealed to cover renewable and natural gases and hydrogen, should be amended accordingly.

FURTHER READING

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PART III

Regulating Hydrogen Production

12

Offshore Production and Transport of Green Hydrogen

A Case Study on Denmark and the Netherlands

Liv Malin Andreasson

12.1 INTRODUCTION

The interest in green hydrogen production in the North Sea is gaining momentum. The extent to which coastal states can regulate activities in the North Sea depends on whether the activities take place in the territorial sea or in the maritime zones beyond.[1] The territorial sea is considered part of the land territory and thus of the sovereignty of coastal states under the United Nations Convention on the Law of the Sea (UNCLOS).[2] Beyond the territorial sea, coastal states have been granted sovereign rights to explore and exploit hydrocarbons on their continental shelf (CS)[3] and to develop renewable energy in their exclusive economic zone (EEZ) if they have declared one.[4] The seabed of the North Sea is one CS and all North Sea states have declared an EEZ.[5] Hence, the offshore exploitation of hydrocarbons and renewable sources is subject to the sovereign rights and functional jurisdiction of the coastal states of the North Sea.[6]

Based on their functional jurisdiction over the CS, Denmark and the Netherlands have produced large quantities of hydrocarbons from more than 200 offshore platforms.[7] Due to the gradual depletion of offshore hydrocarbon resources and the need to meet EU and national

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1 For a detailed overview of the international law of the sea, see Donald R. Rothwell, Tim Stephens, *The International Law of the Sea* (Hart, 2016).

2 United Nations Convention on the Law of the Sea, Montego Bay, 1982.

3 United Nations Convention on the Continental Shelf, Geneva, 1958.

4 United Nations Convention on the Continental Shelf and UNCLOS have been signed and ratified by Denmark and the Netherlands.

5 Several delimitation agreements have been concluded between the coastal states bordering the North Sea, see Catherine Redgwell, 'International Regulation of Energy Activities' in Martha Roggenkamp et al. (eds.), *Energy Law in Europe – National, EU and International Regulation* (Oxford University Press, 3rd ed., 2016), p. 58.

6 Sovereign rights are understood as a limited set of rights that exist only where coastal states have jurisdiction over certain activities and functions specified in UNCLOS. This is referred to as 'functional jurisdiction', see *Yearbook of the International Law Commission* (United Nations, vol. II, 1956), p. 297.

7 On the Danish CS, there are fifty-five hydrocarbon production platforms, none of which have yet been decommissioned, see Energy Agency, 'Om olie og gas' (2021) <https://ens.dk/ansvarsomraader/olie-gasproduktion/om-olie-og-gas> accessed 6 September 2022; on the Dutch CS, there are 160 hydrocarbon production platforms, 50 of which

climate change targets, Denmark and the Netherlands are increasingly focusing on the development of offshore renewable energy, in particular offshore wind. The ambition of the EU is to deploy 300 gigawatts (GW) of offshore wind by 2050.[8] Currently, approximately 6.5 GW of offshore wind capacity has been installed in the Danish and Dutch North Sea, with the aim of reaching 105 GW by 2050.[9] Such a large increase in offshore wind generation faces many challenges, such as ensuring sufficient capacity to bring the electricity ashore and managing intermittency and supply–demand imbalances to avoid negative prices.[10] One potential solution to these challenges is the offshore conversion of wind energy into hydrogen.[11] Hydrogen serves a dual purpose in this context, both as a means of storing the electricity generated by offshore wind farms and as a direct energy carrier.

While commercial-scale hydrogen production in the North Sea has not yet been realised, many of the surrounding countries are actively exploring its offshore potential. Denmark and the Netherlands are particularly important in this regard, having implemented policies to promote offshore hydrogen production to facilitate their large-scale offshore wind energy ambitions.[12] The focus of this chapter is on the offshore production of hydrogen from offshore wind energy by electrolysis and the transport of this hydrogen to shore via pipelines. Although attempts have been made to convert electricity to hydrogen onshore, Denmark and the Netherlands recognise that this option does not solve the problem of a potential capacity shortage in offshore electricity cables.[13]

The following section reviews the general classification of hydrogen and provides a technical background to the concept of offshore power-to-gas. This is followed by an analysis of the EU and national policy frameworks relevant to the offshore production and transport of green hydrogen (Section 12.3). Finally, a comparative assessment of the Danish and Dutch legal frameworks pertaining to the offshore production and transport of green hydrogen is provided (Section 12.4). This assessment focuses on the extent to which the national legal frameworks constitute a barrier to the development of green hydrogen in the North Sea. Importantly, the legal challenges faced by Denmark and the Netherlands in relation to this development are indicative of the wider legal challenges that all North Sea states may face in similar endeavours.

have already been decommissioned, see Noordzeeloket, 'Olie- en gaswinning' (2022) <www.noordzeeloket.nl/functies-gebruik/olie-gaswinning/> accessed 6 September 2022.

[8] European Commission, 'An EU Strategy to Harness the Potential of Offshore Renewable Energy for a Climate Neutral Future' (Communication) COM(2020) 741 final (hereinafter: Offshore Renewable Energy Strategy).

[9] The Danish North Sea is estimated to have the potential for 35 GW of offshore wind by 2050, see Climate Agreement on Green Power and Heat 2022: A Greener and Safer Denmark (*Klimaaftale om grøn strøm og varme 2022: Et grønnere og sikrere Danmark*) of 25 June 2022; the Dutch North Sea is estimated to have the potential for 70 GW of offshore wind by 2050, see Parliamentary Letter Offshore Wind Energy 2030–2050 (*Kamerbrief windenergie op zee* 2030–2050) of 16 September 2022, DGKE-E/22174505 (hereinafter: Parliamentary Letter Offshore Wind Energy).

[10] Jan Matthijsen et al., 'The Future of the North Sea – The North Sea in 2030 and 2050: A Scenario Study' (PBL Netherlands Environmental Assessment Agency, No. 3193, 2018), pp. 11–12.

[11] Liv Malin Andreasson, 'The Regulatory Framework for Green Hydrogen Developments in the North Sea' in Martha Roggenkamp, Catherine Banet (eds.), *European Energy Law Report* (Intersentia, vol. XIV, 2021); Liv Malin Andreasson, Martha Roggenkamp, 'Regulatory Framework: Legal Challenges and Incentives for Developing Hydrogen Offshore' (North Sea Energy Programme, deliverables 2.2 and 2.3, 2020).

[12] For Denmark, see Climate Agreement for Energy and Industry etc. 2020 (*Klimaaftale for energi og industri mv. 2020*) of 22 June 2020 (hereinafter: Danish Climate Agreement), p. 3; and Government Strategy for Power-to-X (*Regeringens strategi for power-to-x*) of 15 December 2021 (hereinafter: Danish Power-to-X Strategy), p. 15. For the Netherlands, see National Climate Agreement (*Klimaatakkoord*) of 28 June 2019 (hereinafter: Dutch Climate Agreement), p. 166; and Government Strategy on Hydrogen (*Kabinetsvisie waterstof*) of 30 March 2020 (hereinafter: Dutch Hydrogen Strategy), p. 8.

[13] Danish Climate Agreement; Danish Power-to-X Strategy; Dutch Climate Agreement; Dutch Hydrogen Strategy.

12.2 CLASSIFICATION OF HYDROGEN AND OFFSHORE POWER-TO-GAS TECHNOLOGY

Hydrogen is currently mainly derived from fossil fuels, while renewable hydrogen accounts for less than 1 per cent of the total hydrogen production worldwide.[14] Due to its potential to reduce carbon dioxide (CO_2) emissions in the chemical, industrial, transport, heating and cooling sectors, and as an alternative to manage the intermittency of renewable energy sources, many countries view renewable hydrogen as a viable option. Hydrogen can be classified as grey, blue or green depending on how it is produced. As an energy carrier, hydrogen emits only water and water vapour when burned.[15] However, its production can be CO_2 intensive. The classification of hydrogen can vary between countries, but it is generally considered 'grey' when produced using fossil fuels, such as through steam methane reforming.[16] If the CO_2, a by-product of hydrogen production from fossil fuels, is captured and permanently stored, the resulting hydrogen is often classified as 'blue'.[17] Hydrogen produced from renewable sources is commonly referred to as 'green'.[18] Interestingly, the European Commission uses different terminology. While the industry commonly uses colour coding to classify hydrogen, the European Commission distinguishes between low-carbon hydrogen (effectively blue) and renewable hydrogen (effectively green).[19] The criteria set by the EU for classifying hydrogen as renewable are explained in more detail below.

There are several options for producing green hydrogen offshore. By integrating offshore hydrocarbon and offshore wind energy systems, existing hydrocarbon production platforms can be used to convert (surplus) wind energy into hydrogen.[20] In the Danish and Dutch North Sea several hydrocarbon platforms (and the associated physical infrastructure) will eventually reach the end of their economic lifetime and will have to be removed.[21] The prospective development of offshore hydrogen will give these platforms a new purpose before eventually having to be permanently removed, depending on their lifetime for hydrogen production or other potential future uses.[22] The use of such platforms for hydrogen production could therefore defer the decommissioning costs incurred by Denmark and the Netherlands.[23] In addition to the possibility of using (disused) offshore hydrocarbon platforms, new offshore platforms or artificial

14 International Energy Agency (IEA), 'Hydrogen' (2022) <www.iea.org/reports/hydrogen> accessed 1 October 2022. See also IEA, 'Global Hydrogen Review 2023' (2023), pp. 64–65 <www.iea.org/reports/global-hydrogen-review-2023> accessed 19 October 2023.

15 International Renewable Energy Agency, 'Green Hydrogen: A Guide to Policy Making' (2020), p. 10.

16 IEA, 'The Future of Hydrogen – Seizing Today's Opportunities' (2019), p. 34.

17 IEA, 'Energy Technology Essentials Hydrogen Production & Distribution' (2007) 4, table 1; Robert Howarth, Mark Jacobson, 'How green is blue hydrogen?' (2021) 9 Energy Science & Engineering 1676, p. 1677.

18 IEA (2007), table 1; IEA (2019), p. 34.

19 See Ruven Fleming, 'Green Hydrogen Developments in the EU: Cross-Border Cooperation between Germany and the Netherlands' in Martha Roggenkamp, Catherine Banet (eds.), *European Energy Law Report* (Intersentia, vol. XIV, 2021). See also Chapter 2 by Hancher and Suciu in this book.

20 Russell McKenna et al., 'Analysing long-term opportunities for offshore energy system integration in the Danish North Sea' (2021) 4 Advances in Applied Energy, p. 2.

21 Article 60(3) UNCLOS.

22 The PosHYdon project is the first initiative in the Netherlands where an electrolyser will be installed on an operational offshore hydrocarbon platform. The hydrogen produced will be transported to shore via the existing gas pipeline, see 'PosHYdon' (2022) <https://poshydon.com/en/home-en/> accessed 13 October 2022.

23 The cost of removing hydrocarbon infrastructure in the North Sea is estimated to be between €390 billion and €690 billion, see World Energy Council, 'The North Sea Opportunity' (2017), p. 8.

islands can be developed for hydrogen production.[24] Such platforms and islands can serve as hubs, collecting energy from nearby wind farms and converting it into hydrogen.[25]

Denmark and the Netherlands are exploring the possibility of locating wind farms further offshore.[26] These wind farms can be connected to the onshore electricity grid either via alternating current (AC) or direct current (DC) cables. While AC cables become economically unviable beyond 100 km from shore and energy losses are excessively high, DC cables minimise energy losses but increase overall development costs.[27] It is therefore vital to find the most cost-effective and resilient method of transporting offshore wind energy to shore. In addition to using electricity cables, hydrogen can be produced from offshore wind energy and then transported to shore using existing or newly developed gas pipelines.[28] As the cost of using existing gas pipelines or developing new ones is often lower than constructing new DC cables, hydrogen transport is an economically viable option, especially for offshore wind farms located far from the coast.[29]

As mentioned, this chapter is dedicated to examining the legal framework for offshore production of hydrogen by electrolysis and its transport by pipeline. The discussion will focus on the offshore deployment of electrolysers, the development of dedicated hydrogen pipelines and the use of (disused) offshore hydrocarbon infrastructure for these purposes. However, it should be noted that the supply of water and electricity is essential for the electrolysis process. The water supply can be facilitated by converting seawater to demineralised water[30] and the electricity supply can be facilitated by connecting offshore electrolysers to the onshore grid, the offshore grid or offshore wind farms.[31] Recognising that the latter aspect plays a role in determining the classification of hydrogen, a brief discussion of the conditions under which hydrogen can be classified as renewable in the EU follows.

Connecting offshore electrolysers directly to offshore wind farms is theoretically considered a simpler means of ensuring renewable hydrogen production. This is because it is more difficult to ensure the renewable nature of the electricity in cases where electrolysers are connected to the onshore or offshore grid. This issue has been addressed by the European Commission in two Delegated Acts adopted in 2023.[32] These Acts establish criteria to ensure that the hydrogen

[24] Offshore Renewable Energy Strategy, p. 1.

[25] Ceciel Nieuwenhout, Liv Malin Andreasson, 'The legal framework for artificial islands in the northern seas' (2024) 39 International Journal of Marine and Coastal Law, 41.

[26] For Denmark, see Danish Maritime Authority, 'Maritime Spatial Plan' (Maritime Spatial Plan Secretariat, 2021), p. 8 <https://havplan.dk/portalcache/api/v1/file/en/30a6ed4a-e332-4d2e-8389-dd20c13c1494.pdf> accessed 8 January 2023. For the Netherlands, see 'North Sea Programme 2022–2027' (2022) (hereinafter: North Sea Programme 2022–2027), pp. 101–103 <www.noordzeeloket.nl/en/policy/north-sea-programme-2022-2027/> accessed 12 October 2022.

[27] Mehmet Bilgili et al., 'Offshore wind power development in Europe and its comparison with onshore counterpart' (2011) 15 Renewable and Sustainable Energy Reviews 905.

[28] The use of existing natural gas pipelines for hydrogen transport is seen as a promising option, but would require some modifications to the pipelines, such as pressure control and material compatibility, see European Union Agency for the Cooperation of Energy Regulators, 'Transporting Pure Hydrogen by Repurposing Existing Gas Infrastructure: Overview of Existing Studies and Reflections on the Conditions for Repurposing' (2021).

[29] Peng Hou et al., 'Optimizing investments in coupled offshore wind-electrolytic hydrogen storage systems in Denmark' (2017) 359 Journal of Power Sources 186; International Renewable Energy Agency, 'Hydrogen from Renewable Power: Technology Outlook for the Energy Transition' (2018); Aya Taieb, Mostafa Shaaban, 'Cost Analysis of Electricity Transmission from Offshore Wind Farm by HVDC and Hydrogen Pipeline Systems' (2019) IEEE PES GTD Grand International Conference and Exposition Asia (GTD Asia) 632.

[30] For a detailed understanding of the legal implications associated with the desalination of seawater, see Chapter 5 by Taylor in this book.

[31] Andreasson (2021), pp. 298–299.

[32] Commission Delegated Regulation (EU) 2023/1184 of 10 February 2023 supplementing Directive (EU) 2018/2001 of the European Parliament and of the Council by establishing a Union methodology setting out detailed rules for the

produced is derived from renewable energy sources and results in a greenhouse gas emission reduction of at least 70 per cent. In particular, the Additionality Delegated Act provides detailed rules for determining when electricity used to produce hydrogen is considered renewable.[33] Three criteria have been introduced to confirm the renewable status of hydrogen. First, the additionality criteria aim to link increased hydrogen production to the expansion of new renewable electricity generation.[34] As such, the Act requires hydrogen producers to enter into power purchase agreements with new and unsupported renewable electricity generation installations.[35] Secondly, the temporal and geographical correlation criteria ensure that hydrogen is produced when and where renewable electricity is available.[36] For the offshore area, the geographical correlation condition is met if the renewable electricity installation under the power purchase agreement is located in an offshore bidding zone[37] interconnected with the bidding zone where the electrolyser is located.[38] As a result of these legislative changes, it is now possible to determine when hydrogen produced by offshore electrolysers qualifies as renewable hydrogen, regardless of whether the electrolysers are connected directly to renewable electricity installations or to the grid.

12.3 EU AND NATIONAL POLICIES FOR OFFSHORE HYDROGEN

The European Commission has put forward a number of initiatives to promote renewable hydrogen, including the European Green Deal[39] and the Hydrogen Strategy.[40] Some of the key actions proposed in these initiatives are to increase the demand and supply of hydrogen and to design a legal framework to enable this.[41] With the ambition to deploy at least 40 GW of renewable hydrogen by 2030,[42] the Hydrogen and Decarbonised Gas Market Package was adopted, to inter alia, facilitate the integration of renewable gases into the existing natural gas system.[43] The intention is to refine the principles of the current EU Directive 2009/73/EC (2009 Gas Directive) and to extend its scope to include hydrogen infrastructure.

production of renewable liquid and gaseous transport fuels of non-biological origin [2023] OJ L 157/11 (hereinafter: Additionality Delegated Act); Commission Delegated Regulation (EU) 2023/1185 of 10 February 2023 supplementing Directive (EU) 2018/2001 of the European Parliament and of the Council by establishing a minimum threshold for greenhouse gas emissions savings of recycled carbon fuels and by specifying a methodology for assessing greenhouse gas emissions savings from renewable liquid and gaseous transport fuels of non-biological origin and from recycled carbon fuels [2023] OJ L 157/20.

33 Article 1 Additionality Delegated Act. ‘Renewable fuels of non-biological origin’ is defined as ‘liquid and gaseous fuels the energy content of which is derived from renewable sources other than biomass’, see Article 2(36) Directive (EU) 2023/2413 of the European Parliament and of the Council of 18 October 2023.

34 Articles 4(4) and 5 Additionality Delegated Act.

35 Ibid., Article 5.

36 Ibid., Articles 6 and 7.

37 ‘Bidding zone’ is defined in Article 2(65) Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast) [2019] OJ L 158/54.

38 Article 7(1)(c) Additionality Delegated Act.

39 European Commission, ‘The European Green Deal’ (Communication) COM(2019) 640 final.

40 European Commission, ‘A Hydrogen Strategy for a Climate-Neutral Europe’ (Communication) COM(2020) 301 final (hereinafter: EU Hydrogen Strategy).

41 For a detailed overview of the proposed initiatives to promote renewable hydrogen in the EU, see Chapter 2 by Hancher and Suciu in this book.

42 EU Hydrogen Strategy, p. 3.

43 European Commission, ‘Regulation of the European Parliament and of the Council on the internal markets for renewable and natural gases and for hydrogen (recast)’ (Proposal) COM(2021) 804 final (hereinafter: Recast Gas Regulation); European Commission, ‘Proposal for a Directive of the European Parliament and of the Council on common rules for the internal markets in renewable and natural gases and in hydrogen’ (Proposal) COM(2021) 803 final (hereinafter: Recast Gas Directive).

However, none of these initiatives explicitly address the offshore development of renewable hydrogen. Such development was first promoted in the Offshore Renewable Energy Strategy, which proposes concrete ways to support the long-term sustainable development of the offshore energy sector.[44] In this communication, the European Commission stresses that offshore hydrogen production is a viable option for bringing renewable energy generated offshore to the mainland.[45] It recognises that innovative projects, such as offshore hydrogen production and artificial energy islands, face particular challenges because the current legal framework was not designed with such projects in mind.[46]

Denmark and the Netherlands are at the forefront of promoting the development of renewable hydrogen and have adopted a vision for the future role of hydrogen in the energy system in their national hydrogen strategies. By 2030, Denmark intends to develop an electrolysis capacity of 4–6 GW and the Netherlands aims for an installed electrolysis capacity of 3–4 GW.[47] However, it is not specified whether these indicative targets will be developed onshore and/or offshore. While neither Denmark nor the Netherlands have adopted specific hydrogen legislation, greater clarity on the regulation of hydrogen, and in particular hydrogen networks, can be expected in the future. Denmark has taken steps to amend its Gas Supply Act[48] to facilitate the integration of renewable gases, including hydrogen, into the natural gas system.[49] Conversely, the Netherlands has not (yet) proposed concrete measures to integrate hydrogen into its current natural gas legislation. However, the government has provided insights into the potential regulatory framework for the hydrogen market and related networks.[50]

12.4 COMPARATIVE ASSESSMENT OF NATIONAL LEGAL FRAMEWORKS RELEVANT TO THE OFFSHORE DEVELOPMENT OF GREEN HYDROGEN INFRASTRUCTURE

Given the intentions of Denmark and the Netherlands to promote the offshore development of green hydrogen, this section provides a comparative analysis of their legal frameworks governing the offshore infrastructure required for the production and transport of green hydrogen. It also identifies potential legal barriers that could hinder the offshore deployment of such infrastructure.

12.4.1 *Offshore Hydrogen Production*

While the Netherlands is exploring the possibility of using (disused) offshore hydrocarbon infrastructure for hydrogen production and transport,[51] Denmark is focusing on developing new offshore infrastructure or an artificial island for power-to-hydrogen applications.[52] Four

[44] Offshore Renewable Energy Strategy, p. 14.
[45] Ibid.
[46] Ibid.
[47] Danish Power-to-X Strategy, p. 5; Dutch Hydrogen Strategy, p. 7.
[48] Gas Supply Act (*Gasforsyningsloven*) No. 423 of 19 April 2023.
[49] Act Amending the Gas Supply Act, the Energinet Act and the Electricity Supply Act: Regulation of Hydrogen, Reorganisation of Energinet, CO_2 Storage, etc. (*Forslag til lov om ændring af lov om gasforsyning, lov om Energinet og lov om el- forsyning: regulering af brint, omorganisering af Energinet,* CO_2*-lagring m.v.*) (hereinafter: Act Amending the Gas Supply Act), pp. 17–18.
[50] Parliamentary Letter Advance Planning and Hydrogen Market Development (*Voortgang ordening en ontwikkeling waterstofmarkt*) of 29 June 2022, DGKE/22229490; Parliamentary Letter Development of Hydrogen Transport Network (*Ontwikkeling transportnet voor waterstof*) of 29 June 2022, DGKE-E/22263775.
[51] Dutch Hydrogen Strategy, p. 8; Parliamentary Letter Offshore Wind Energy, p. 13.
[52] Danish Climate Agreement, p. 3.

possible approaches to the deployment of offshore electrolysers are therefore envisaged: (i) on existing offshore hydrocarbon platforms that are still in operation; (ii) on existing offshore hydrocarbon platforms that are no longer in operation; (iii) on new offshore platforms; and (iv) on artificial energy islands. These four options are assessed in the following sections.[53]

Hydrogen Production on Existing Operational Hydrocarbon Platforms

This section focuses on the legal framework pertaining to the installation of an electrolyser on an operating offshore hydrocarbon platform. The Subsoil Act (Denmark)[54] and the Mining Act (the Netherlands)[55] regulate the offshore extraction of hydrocarbons, including the installations and equipment necessary for such extraction. According to these laws, a hydrocarbon licence is required in order to extract these resources from the seabed.[56] The question that arises is whether the existing licence also permits the installation and operation of an electrolyser.[57] However, as the definitions of 'raw material' (Subsoil Act) and 'mineral' (Mining Act) exclude hydrogen from their scope of application, an electrolyser cannot be installed on an operational offshore hydrocarbon platform under the current licence.[58] While the holder of such a licence may request modifications, such modifications do not extend to cover other activities or minerals.[59] As a result, the Subsoil Act and the Mining Act provide no guidance on the use of an operational offshore hydrocarbon platform for purposes other than hydrocarbon activities.

The next question is therefore whether there are any other national laws governing the installation of an electrolyser on such a platform. In the Netherlands, the only alternative would be a permit under the Environment and Planning Act,[60] which regulates (the development of) offshore activities, unless these activities are governed by sector-specific laws, such as the Mining Act. For the purposes of this chapter, sector-specific laws refer to laws tailored to regulate specific offshore energy activities, such as hydrocarbon exploitation and wind energy generation. A law that regulates all offshore (energy) activities that are not governed by sector-specific laws, is referred to in this chapter as a general legal framework.

According to the Environment Activities Decree[61] – which further defines the scope of the Environment and Planning Act – the development of an offshore electrolyser would be subject to a restricted area permit. If an electrolyser is installed on an existing offshore hydrocarbon installation, the activity falls within the restricted area of that installation and requires a permit in accordance with Articles 7.46 and 7.47(1) of the Environment Activities Decree.[62] This restricted area includes the offshore hydrocarbon installation and a radius of 500 metres around it.[63] Therefore, if hydrogen is to be produced on an operational offshore hydrocarbon platform, the relation and interplay between the hydrocarbon licence and the restricted area permit needs to be clarified. In contrast, in Denmark there is currently no explicit legal basis and therefore no general permitting regime for offshore activities that are not regulated by sector-specific laws.[64]

[53] Electrolysers can also be integrated into offshore wind turbines. However, as this option is not addressed in the Danish or Dutch policy frameworks, it is beyond the scope of this chapter.
[54] Subsoil Act (*Undergrundsloven*) No. 1533 of 16 December 2019.
[55] Mining Act (*Mijnbouwwet*) of 31 October 2002.
[56] Section 2 and Chapter 3 Subsoil Act (Denmark); Articles 1(a) and 6 Mining Act (the Netherlands).
[57] Andreasson (2021), p. 305.
[58] Section 2 Subsoil Act (Denmark); Article 1(a) Mining Act (the Netherlands).
[59] Sections 5(1) and 10(3) Subsoil Act (Denmark); Article 18(2) Mining Act (the Netherlands).
[60] Environment and Planning Act (*Omgevingswet*) of 23 March 2016 (as adopted on 1 January 2024).
[61] Environment Activities Decree (*Besluit activiteiten leefomgeving*) of 3 July 2018.
[62] Article 5.1(2)(f)(5°) Environment and Planning Act.
[63] Article 3.7 Environment and Planning Decree (*Omgevingsbesluit*) of 3 July 2018.
[64] Danish Maritime Authority (2021), p. 7.

In the absence of a specific hydrogen law and a general legal framework for offshore activities, it is uncertain which rules apply to the development of offshore electrolysers in Denmark.[65]

Reuse of Non-operational Hydrocarbon Platforms for Hydrogen Production

This section focuses on the legal framework pertaining to the reuse of non-operational offshore hydrocarbon platforms for hydrogen production. The question is whether the current legislation allows for such reuse and, if so, for what purposes. The Subsoil Act (Denmark) and the Mining Act (Netherlands) places an obligation on the licence holder to remove abandoned or disused offshore hydrocarbon platforms.[66] However, following amendments to the Dutch Mining Act, the reuse of such platforms is now possible.[67] Once an offshore hydrocarbon platform is fully or partially out of operation, the licence holder is required to notify the Minister of Economic Affairs and Climate Policy.[68] Although the term 'out of operation' is not defined, a literal interpretation implies that the platform is no longer used for the extraction of natural gas.[69] Following the notification, the licence holder must submit a removal plan[70] or apply for an exemption from this requirement.[71] If an exemption is granted, the obligation to remove the platform is postponed for a period of time to be determined by the Minister.[72] However, there is no specific indication as to the length of time for which this may be granted.[73] An exemption can also be sought for the reuse of offshore gas pipelines.[74] A number of options have been identified for the reuse of offshore hydrocarbon infrastructure, including underground storage of CO_2 and hydrogen activities.[75] The reuse of such infrastructure for purposes other than those for which it was originally intended is subject to the standard permitting procedures applicable to the specific type of reuse activity.[76] As mentioned in the previous section, a restricted area permit must be obtained before any offshore hydrogen activities can be carried out in the Dutch North Sea.

Similarly, Denmark has explored the possibility of reusing offshore hydrocarbon platforms. However, the provisions on the removal of such infrastructure in the Subsoil Act have not been amended to cover reuse.[77] As in the Netherlands, removal is subject to a decommissioning plan.[78] Such a plan must be submitted to and approved by the Danish Energy Agency in accordance with the Guidelines on Decommissioning Plans for Offshore Oil and Gas Facilities

[65] Andreasson (2021), p. 308.
[66] Section 33 Subsoil Act (Denmark); Article 44 Mining Act (the Netherlands).
[67] Articles 44a and 44b Mining Act. See also Act Amending the Mining Act (removing or reusing mining works and investment deductions) (*Wet tot wijziging van de Mijnbouwwet (het verwijderen of hergebruiken van mijnbouwwerken en investeringsaftrek)*) of 27 January 2021, Official Gazette 2021, No. 92.
[68] Article 44 Mining Act and Articles 60(1) and 61 Mining Decree (*Mijnbouwbesluit*) of 6 December 2002.
[69] See Decree Amending the Mining Decree (removing or reusing mining works) (*Besluit tot wijziging van het Mijnbouwbesluit (het verwijderen of hergebruiken van mijnbouwwerken)*) of 11 November 2021, Official Gazette 2021, No. 573 (hereinafter: Decree Amending the Mining Decree), pp. 16–17.
[70] A removal plan must at least describe how and when the platform will be removed and must be approved by the Minister, see Article 44a Mining Act and Articles 60(1) and 61 Mining Decree.
[71] Articles 44a and 44b Mining Act.
[72] Ibid., Article 44b(1).
[73] Decree Amending the Mining Decree, p. 18.
[74] Ibid., p. 16.
[75] Ibid., pp. 18–19.
[76] Ibid., pp. 19–20.
[77] Clara Greve Brett, 'Regulation of Infrastructure Decommissioning in the Danish Offshore Oil and Gas Sector' in Martha Roggenkamp, Catherine Banet (eds.), *European Energy Law Report* (Intersentia, vol. XIII, 2020), p. 350.
[78] Section 32a(2) Subsoil Act.

or Installations.[79] Interestingly, the guidelines stipulate that the plan must specify 'the (parts of) installations being converted to another use or continuing operations as part of another development'.[80] Consequently, the reuse of offshore hydrocarbon infrastructure appears to be an option under these guidelines.[81] So far, the Danish Energy Agency has only mentioned that some of the offshore hydrocarbon infrastructure could be retained for alternative purposes, including natural gas and CO_2 storage.[82] Notably, the Danish government has decided to cancel all future licensing rounds for hydrocarbon production and to cease existing production by 2050,[83] which may allow for the reuse of offshore hydrocarbon infrastructure. However, such reuse would require amendments to the Subsoil Act to establish the legal basis and relevant regulations. In both Denmark and the Netherlands, the infrastructure, together with the decommissioning obligation, will have to be transferred from the hydrocarbon licence holder to the hydrogen permit holder. It is therefore necessary to clarify the type of permit required and how responsibilities, including future removal, will be transferred to the new permit holder in the case of two different entities.[84]

Development of New Platforms for Hydrogen Production

To facilitate offshore hydrogen production, new offshore platforms can be constructed to accommodate electrolysers. In the Netherlands, the construction of such platforms would require a restricted area permit.[85] However, in contrast to the above scenarios, if the platform is developed outside the restricted area of an offshore installation, a permit for construction activities within the restricted area of the North Sea is required in accordance with Articles 7.16 (1)(a) and 7.17(1)(b) of the Environment and Planning Decree.[86] The process of obtaining a restricted area permit is non-competitive and involves an applicant seeking permission to use a designated area of the North Sea or a designated area around an installation in the North Sea. The competent authority will only grant a permit if the activity meets certain conditions set out in Section 8 of the Environment Quality Decree.[87] Additional conditions may be imposed, including requirements to remove, compensate for or mitigate adverse effects on the North Sea.[88] In contrast, as mentioned above in the section 'Hydrogen Production on Existing Operational Hydrocarbon Platforms', there is currently no general permitting regime in Denmark for offshore activities that are not regulated by sector-specific legislation.

In both the Netherlands and Denmark, legislation tailored to sector-specific activities, such as hydrocarbon activities, includes detailed provisions for infrastructure development, operation and safety. The lack of sector-specific legislation for offshore hydrogen infrastructure may therefore create uncertainty about the rules that apply to such infrastructure. To address this

[79] These guidelines include the required content of a decommissioning plan, see Centre for Energy Resources, 'Section 32a: Guidelines on Decommissioning Plans for Offshore Oil and Gas Facilities or Installations' (2018).

[80] Ibid., p. 9.

[81] McKenna (2021).

[82] Danish Energy Agency, 'Denmark's Oil and Gas Production – and Subsoil Use' (2009) <https://ens.dk/sites/ens.dk/files/OlieGas/oil_and_gas_in_denmark_2009.pdf> accessed 23 October 2023.

[83] Agreement on the Future of Oil and Gas Extraction in the North Sea (*Aftale om fremtiden for olie- og gasindvinding i Nordsøen*) of 3 December 2020 <https://kefm.dk/aktuelt/nyheder/2020/dec/bred-aftale-om-nordsoeens-fremtid> accessed 27 October 2022.

[84] Andreasson (2021), p. 308.

[85] Article 5.1(2)(f)(2) Environment and Planning Act.

[86] The North Sea restricted area is defined and geographically delimited in Article 2.18 and Annex III Environment and Planning Regulation (*Omgevingsregeling*) of 21 November 2019.

[87] Environment Quality Decree (*Besluit kwaliteit leefomgeving*) of 3 July 2018.

[88] Article 8.85 Environment Quality Decree.

uncertainty, specific rules for the development, operation and safety of offshore electrolysers could be included in existing legislation, such as hydrocarbon legislation, or through the adoption of a specific hydrogen law.

Development of Artificial Energy Islands for Hydrogen Production

Like naturally formed islands, artificial islands can serve to collect the electricity generated by offshore wind farms, host electrolysers that convert the electricity into hydrogen and enable the transport of hydrogen to the mainland via pipelines.[89] The infrastructure required to collect electricity from offshore wind farms (such as transformer and converter stations) and hydrogen production installations (such as electrolysers), typically demands a substantial amount of space.[90] Given these space requirements, the development of an island for these purposes may be a more technically feasible and cost-effective solution than the deployment of large modular offshore platforms for electricity and hydrogen infrastructure.[91]

Denmark plans to construct an artificial energy island in the North Sea to enable large-scale development of offshore wind energy and the production and supply of green hydrogen.[92] At the end of 2021, Denmark adopted the Act on the Design and Construction of an Energy Island in the North Sea.[93] The Act is an important step in the realisation of the island, as it establishes the overall legal framework for its construction and provides broad authority for the preparation and design of the island.[94] However, as the Act only regulates the construction of the island, the conditions for its operation and use are less clear. One example is the development of the energy infrastructure on and around the island. This includes hydrogen infrastructure, which is not covered by the provisions of the Act.[95] Furthermore, contrary to the cost-effectiveness argument above, the Danish government has decided to postpone the tender for the island.[96] The decision is based on concerns about the high cost of the current island design, which has led the government to investigate alternative design options.[97] No concrete information has yet been provided on what these options might be.

Similarly, the Dutch government recognises that the cost-effective integration of more offshore wind energy and the offshore production of green hydrogen may require the establishment of energy hubs, including an artificial energy island.[98] However, there are no concrete

[89] As part of their sovereign rights, coastal states have the exclusive right to construct, authorise and regulate the construction, operation and use of artificial islands in their EEZ. There are some differences in the rules applicable to artificial islands and installations with regard to the justification for their construction and the decommissioning obligations, see Articles 60(1) and 60(3) UNCLOS.

[90] Nieuwenhout and Andreasson (2024), p. 41.

[91] Ibid.

[92] Danish Climate Agreement, p. 3: Danish Power-to-X Strategy, p. 17.

[93] Act on the Design and Construction of an Energy Island in the North Sea (*Lov om projektering og anlæg af en energiø i Nordsøen*) No. 2379 of 14 December 2021.

[94] Section 1 Act on the Design and Construction of an Energy Island in the North Sea. The expected location of the energy island is included in Appendix 1 of the Act.

[95] Section 1(3) Act on the Design and Construction of an Energy Island in the North Sea.

[96] Danish Energy Agency, 'The Danish Energy Agency Sets Time to Tender for the Energy Island in the North Sea and Maintains the Overall Schedule' (2022) <https://via.ritzau.dk/pressemeddelelse/the-danish-energy-agency-sets-time-to-tender-for-the-energy-islandin-the-north-sea-and-maintains-the-overall-schedule?publisherId = 13560521&releaseId = 13654832> accessed 24 October 2023.

[97] Offshore Wind, 'Danish Government Postpones Tender for North Sea Energy Island, Current Concept Found to Be Too Expensive' (28 June 2023) <www.offshorewind.biz/2023/06/28/danish-government-postpones-tender-for-north-sea-energy-island-current-concept-found-to-be-too-expensive/> accessed 24 October 2023.

[98] Dutch Climate Agreement, p. 166.

plans for such developments.[99] Furthermore, no specific legislation has been adopted in the Netherlands for the construction of an artificial energy island. Although the Environment and Planning Act is relevant to the construction of the island,[100] it does not provide clarity on how such an island should be operated and used, or how the hydrogen infrastructure to be developed on it should be regulated.[101]

12.4.2 *Offshore Hydrogen Transport*

Having discussed the options of using (disused) hydrocarbon platforms, constructing new platforms or developing artificial islands for offshore hydrogen production, it is necessary to consider the transport of the hydrogen to shore, where it can be consumed, stored or reconverted. Three alternatives for offshore hydrogen transport by pipeline are envisaged: (i) using operational natural gas pipelines – that is, blending hydrogen with natural gas; (ii) repurposing disused natural gas pipelines to exclusively transport hydrogen; and (iii) developing new dedicated hydrogen pipelines.[102] These three options are assessed in the following sections.

Transport via Existing Natural Gas Pipelines

In cases where electrolysers are installed on operational offshore hydrocarbon platforms, existing pipelines can theoretically be used to transport hydrogen to shore. However, the characteristics of the gas transported through these pipelines changes when hydrogen is blended with natural gas.[103] Offshore pipelines transporting natural gas to the onshore transmission network usually qualify as upstream pipelines and regulation of such pipelines is limited. In Danish and Dutch gas legislation, no gas quality standards have been adopted for such pipelines.[104] Nevertheless, upstream pipeline operators must ensure that the gas they deliver to the onshore transmission network meets the entry specifications (gas quality standards) applicable to that network.[105] If the gas delivered to the onshore transmission network cannot be processed to meet the entry specifications, the upstream pipeline operator has the discretion to reject the off-specification gas.[106] Hence, unless onshore gas quality standards are met, and it is not technically feasible to upgrade or change the gas quality at the onshore entry point, hydrogen transport in upstream pipelines is unlikely to be accepted.[107] The primary issue arising from this is whether Danish

[99] An assessment framework for artificial islands has been adopted in the North Sea Programme 2022–2027, pp. 139–140.
[100] See Articles 7.16(1) and 7.17(1)(b) Environment Activities Decree.
[101] For a detailed analysis of the regulation of artificial islands in the Netherlands, see Nieuwenhout and Andreasson (2024), pp. 65–71.
[102] Hydrogen transport by vessel is a fourth option, but this chapter focuses only on pipeline transport.
[103] Hydrogen and natural gas have different characteristics, such as calorific value, density, burning velocity, flow properties and interaction with the grid, see Burcin Cakir Erdener et al., 'A review of technical and regulatory limits for hydrogen blending in natural gas pipelines' (2023) 48 International Journal of Hydrogen Energy 5595–5617.
[104] See Section 6(32) Gas Supply Act, Section 1(3) Gas Safety Act (*Gassikkerhedsloven*) no. 61 of 30 January 2018 and Section 1(1) Executive Order on Gas Quality (*Bekendtgørelse om gaskvalitet*) No. 230 of 21 March 2018 (Denmark); Article 1.1(c) Gas Act (*Gaswet*) of 22 June 2000 and Article 1 Ministerial Decree on Gas Quality (*Regeling Gaskwaliteit*) of 11 July 2014 (the Netherlands).
[105] Gas quality standards for upstream gas pipelines are included in the transport agreement concluded between the operator of the pipeline and the gas producer requesting access, see Andreasson (2021), p. 311.
[106] Upstream pipeline operators can deny access to third parties where there is an incompatibility with technical specifications which cannot reasonably be overcome, see Article 34 2009 Gas Directive.
[107] Andreasson (2021), p. 311.

and Dutch gas legislation allows hydrogen to be injected into the onshore transmission network.[108]

In view of the influence of EU gas legislation on the regulation of the Danish and Dutch natural gas networks, it is important to first assess this legislation. Pipelines serving downstream transport of natural gas are regulated by the 2009 Gas Directive.[109] Although its title and scope indicate that it applies only to natural gas, 'other types of gases' are subject to the provisions of the Directive if they can be 'technically and safely injected into, and transported through, the natural gas system'.[110] Currently, EU gas standards do not include rules on the permissible concentration of hydrogen in the downstream natural gas network. As a result, the permitted concentration of hydrogen in national gas networks varies considerably and in a number of EU Member States hydrogen injection is not (yet) allowed.[111] To harmonise cross-border gas flows, the EU proposes a threshold of up to two vol.% hydrogen content at interconnection points.[112] Although the EU leaves it up to its Member States to decide whether to allow hydrogen blending in their gas networks, this proposal essentially means that from 2025 network operators will be obliged to accept at least this hydrogen content at interconnection points.

The applicability of national gas legislation to the injection of hydrogen into the natural gas network depends on how the term 'gas' is defined in the Gas Supply Act (Denmark) and the Gas Act (the Netherlands).[113] One common prerequisite in these laws is that the gas to be injected into the natural gas networks must consist primarily of methane or another substance equivalent to methane.[114] This would not be the case if a high concentration of hydrogen is injected. To determine whether an acceptable concentration of hydrogen has been adopted, it is necessary to consult national gas quality regulations. Although the amended Danish Gas Supply Act, opens up the possibility of blending hydrogen into the natural gas network,[115] no specific threshold for the hydrogen content has been set.[116] However, in principle it should be possible to specify the permitted hydrogen content, though this would require amendments to the Danish Gas Safety Act and the Executive Order on Gas Quality.[117] By contrast, in the Netherlands, 0.5 mol.% hydrogen is allowed in certain parts of the natural gas network.[118, 119] In view of the promotion of hydrogen blending in natural gas networks, it remains to be seen whether a new proposal will be made to increase the hydrogen content threshold at national level.

108 Ibid., p. 310.
109 Article 1(1) Gas Directive.
110 Ibid., Article 1(2).
111 Hydrogen Europe, 'Hydrogen Europe Vision on the Role of Hydrogen and Gas Infrastructure on the Road Toward a Climate Neutral Economy – A Contribution to the Transition of the Gas Market' (2019), p. 14.
112 Article 20 Recast Gas Regulation.
113 Section 2 Gas Supply Act (Denmark); Article 1.1(b) Gas Act (the Netherlands).
114 Sections 2(1) and 6(3) Gas Supply Act and Section 1 Executive Order on Gas Quality, see also Act Amending the Gas Supply Act, p. 10 (Denmark); Article 1.1(b) Gas Act and Article 1 Ministerial Decree on Gas Quality (the Netherlands).
115 Sections 2(1), 6(3), 6(26) and 6(32) Gas Supply Act.
116 See Act Amending the Gas Supply Act, p. 10 and 17–18. See also Section 27(1) Executive Order on Gas Quality, which only sets out requirements for the quality of hydrogen to be injected into the natural gas distribution network.
117 Act Amending the Gas Supply Act, p. 10.
118 While mol.% is based on the weight of each of the gas components per volume, vol.% is the percentage of a given gas in terms of the total volume of the mixture.
119 See Appendix 1–5 Ministerial Decree on Gas Quality.

Transport via Repurposed Natural Gas Pipelines

Similar to the reuse of offshore hydrocarbon platforms, offshore gas pipelines repurposed for hydrogen transport may no longer be considered pipelines under national hydrocarbon laws.[120] This raises the question of whether it is permissible to reuse such pipelines for the transport of hydrogen and what the applicable legal regime would be. Since pipelines are not considered to be installations, the obligation to remove installations under UNCLOS does not apply.[121] Yet the removal obligation may be extended to pipelines which are considered to be part of (production) installations.[122] As mentioned above in the section 'Reuse of Non-operational Hydrocarbon Platforms for Hydrogen Production', such installations and pipelines may be reused for purposes other than those for which they were originally intended. Given that reuse only postpones the decommissioning of pipelines, the legislator is confronted with the same issues as described for the reuse of offshore hydrocarbon platforms. In addition, when such pipelines are reused for hydrogen transport, gas quality requirements still need to be met as these pipelines are connected to the onshore transmission network.

Offshore natural gas pipelines have been authorised under the Subsoil Act (Denmark) and the Mining Decree (the Netherlands).[123] Again, the same situation arises as for the reuse of offshore hydrocarbon platforms. Such pipelines will no longer be subject to the provisions of these laws if they are repurposed for hydrogen transport. Not only would a new permit have to be applied for, but the pipelines would no longer be subject to the operational and safety requirements of these laws.[124] However, some clarity has been provided in Denmark by the amended Gas Supply Act, which is discussed in more detail in the next section.

Development of New Hydrogen Pipelines

An alternative to the use of (disused) offshore natural gas pipelines is the development of new offshore hydrogen pipelines.[125] However, there is currently no dedicated onshore hydrogen network to which such pipelines can be connected. Until such a network is in place, hydrogen can be delivered directly to onshore customers, such as industrial clusters, via direct pipeline connections. As amendments to the Danish Gas Supply Act have effectively brought hydrogen within its regulatory scope and the Act applies in its entirety to the EEZ, it applies to hydrogen pipelines directly connecting offshore electrolysers to onshore customers.[126] The development of such pipelines is subject to approval by the Minister for Climate, Energy and Utilities.[127]

The Danish Gas Supply Act also lays down rules for upstream pipeline networks. This includes pipelines operated or constructed as an integral part of gas production installations, and those used to transport gas from such installations to onshore landing terminals.[128] Although

[120] Sections 2 and 17 Subsoil Act (Denmark); Articles 1(a) and 1(ag) Mining Act and Article 94 Mining Decree (the Netherlands).

[121] It is within the competence of coastal states to determine whether offshore pipelines have to be removed once disused, see Article 60(3) UNCLOS.

[122] Martha Roggenkamp, 'Re-using (Nearly) Depleted Oil and Gas Fields in the North Sea for CO_2 Storage: Seizing or Missing a Window of Opportunity?' in Catherine Banet (ed.), *The Law of the Seabed: Access, Uses, and Protection of Seabed Resources* (Brill-Nijhoff, 2020), p. 460.

[123] Section 17 Subsoil Act (Denmark); Article 94 Mining Decree (the Netherlands).

[124] Relevant safety laws and regulations generally do not cover the transport of hydrogen or do not apply to the offshore area, see Section 2 Offshore Safety Act (*Offshoresikkerhedsloven*) No. 125 of 6 February 2018 (Denmark); Articles 1.1 and 2 Decree on External Pipeline Safety (*Besluit externe veiligheid buisleidingen*) of 24 July 2010 (the Netherlands).

[125] UNCLOS recognises the right of all states to lay submarine pipelines on the CS, see Article 79(1) UNCLOS.

[126] Section 17 Gas Supply Act.

[127] Ibid., Sections 6(4), 6(25) and 6(26).

[128] Ibid., Section 6(24).

the term 'gas production installations' is not explicitly defined, it is reasonable to interpret it as including electrolysers used for the production of hydrogen.[129] Pipelines transporting hydrogen from offshore electrolysers to onshore landing terminals are therefore likely to fall within the definition of upstream pipelines.[130] The Minister for Climate, Energy and Utilities is responsible for issuing rules on access to such pipelines.[131] However, the Gas Supply Act does not contain any provisions requiring prior authorisation for the development of such pipelines. The Subsoil Act, which applies to upstream natural gas pipelines, provides for such authorisation, but does not cover upstream hydrogen pipelines.[132]

In contrast, the Dutch Gas Act only applies to hydrogen insofar as it can technically and safely be injected into the existing natural gas network.[133] Consequently, dedicated hydrogen pipeline infrastructure is not covered by the provisions of the Act. Therefore, neither the provisions on direct pipelines[134] nor those on upstream pipelines[135] provide a legal basis for the development of offshore hydrogen pipelines. Instead, the legal basis for the development of dedicated offshore hydrogen pipelines would be the general permitting regime described above in the section 'Development of New Platforms for Hydrogen Production'. However, there are no specific regulations governing the operation and safety of such pipelines as there are for natural gas pipelines.

12.5 CONCLUSIONS

Green hydrogen, which is expected to play a key role in achieving net-zero CO_2 emissions by 2050, is being actively promoted by Denmark and the Netherlands. This coincides with their plans for large-scale offshore wind developments, where the offshore production and transport of hydrogen will be an important support to these efforts. The comparative assessment of the Danish and Dutch policy and legal frameworks for offshore green hydrogen production and transport infrastructure highlights two key points: first, both countries are committed to promoting green hydrogen production, but detailed plans for onshore and offshore hydrogen development have yet to be defined; second, neither Denmark nor the Netherlands has implemented specific hydrogen legislation. The successful offshore implementation of a green hydrogen infrastructure depends on the existence of a robust and enabling legal framework. However, as the analysis shows, the offshore development of green hydrogen in Denmark and the Netherlands faces challenges due to legal uncertainties. Whether using (disused) offshore hydrocarbon platforms or developing new offshore platforms or artificial islands for hydrogen production, specific legal arrangements are needed. These arrangements should address and remove uncertainties related to reuse, permitting procedures, operational responsibilities and safety concerns. The analysis suggests that the simplest regulatory option may be to install electrolysers on existing offshore hydrocarbon platforms. This is because most of the necessary infrastructure is already in place and this approach is being considered in both countries, albeit to varying degrees.

129 Ibid., Sections 2(1), 6(1) and 6(3).
130 Ibid., Section 6(32).
131 Ibid., Section 21.
132 Sections 1 and 10(2) Subsoil Act.
133 Article 1(1)(b) Gas Act.
134 See Articles 1(1)(an) and 39h Gas Act.
135 Ibid.

The use of (disused) offshore natural gas pipelines for hydrogen transport faces legal challenges related to the definition of gas and the applicable gas quality standards in the Danish and Dutch gas legislation. Denmark has made progress in dealing with both the development of dedicated hydrogen transport infrastructure and the injection of hydrogen into the natural gas network by amending its Gas Supply Act, but there is still a need to clarify the permissible hydrogen content in the existing natural gas network. Conversely, the Netherlands has clarified the permissible hydrogen content in the existing natural gas network, but faces uncertainties due to the fact that its Gas Act does not apply to dedicated hydrogen transport infrastructure. These findings underline the importance of aligning national gas legislation with the forthcoming EU hydrogen regulation. Irrespective of the alternative chosen for the offshore transport of hydrogen by pipeline, it is essential that appropriate provisions are in place to address uncertainties regarding reuse, permitting procedures, operational responsibilities and safety concerns. Such provisions can be incorporated into existing gas legislation or through the adoption of specific hydrogen legislation.

The recommendations arising from the comparative assessment of the Danish and Dutch legal frameworks provide valuable guidance for other North Sea states interested in promoting offshore green hydrogen developments. These recommendations can be adapted to the specific needs of each country and their applicability will depend on factors such as the scale of planned offshore wind developments, the potential for repurposing hydrocarbon infrastructure and the existing regulatory framework for hydrogen. This tailoring to specific circumstances is also evident in the assessment of Denmark and the Netherlands. Both countries are making progress in supporting offshore hydrogen developments, but their approaches differ. Denmark is exploring the deployment of an artificial island for hydrogen production and has implemented legislation to facilitate this initiative. In contrast, the Netherlands appears to be prioritising the repurposing of offshore hydrocarbon infrastructure, and relevant legislation is now aligned with this strategy. However, despite the progress made, the legal challenges identified in both countries need to be addressed in order to create an attractive investment environment for offshore green hydrogen developments.

FURTHER READING

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13

How to Build Your Own Electrolyser

Pitfalls and Challenges of the Permitting Procedures in Finland

Elena Tissari

13.1 INTRODUCTION TO THE RENEWABLE HYDROGEN PERMITTING REGIME IN FINLAND

In Finland, permitting practices for renewable hydrogen electrolysers are only just starting to develop. Permitting procedures are still fragmented and there is no so-called one-stop shop for hydrogen electrolyser permits.[1] Several different permits by different authorities are required and the permit procedures are usually independent of each other.[2] This chapter investigates the current permitting regime and makes suggestions for improvements.

Complicated permit procedures can be a challenge for setting up new hydrogen electrolysers to produce renewable hydrogen in Finland. They can take a considerable amount of time and the permitting process is one of the key factors that significantly impacts decisions on investment in renewable hydrogen, according to a Finnish government study on the opportunities and limitations of the hydrogen economy and its development in Finland.[3] Because of this, a seamless permit procedure would work as an advantage to Finland and is something envisaged by the Finnish government.[4] A well-functioning and relatively easy permitting procedure will be an advantage in attracting foreign investment for renewable hydrogen electrolyser projects and can help Finland in meeting its renewable hydrogen production goals.[5]

Luckily, most permitting applications can be done online and the authorities can also be contacted digitally.[6] The different authorities dealing with permits in Finland are mainly municipal authorities and the Regional State Administrative Agency; for energy projects like

[1] Karoliina Rytkönen, 'Green Hydrogen Finland' (Bergmann Attorneys at Law, February 2023) <https://bergmann.fi/pdf/green_hydrogen_finland_2023.pdf> accessed 30 January 2024.

[2] Ibid.

[3] Leena Sivill et al., *Hydrogen Economy – Opportunities and Limitations* (Publications of the Government's Analysis, Assessment and Research Activities 2022) 77.

[4] Ministry of Economic Affairs and Employment, 'Government adopts resolution on hydrogen – Finland could produce 10% of EU's green hydrogen in 2030' (Finnish Government, 9 February 2023) <https://valtioneuvosto.fi/en/-//1410877/government-adopts-resolution-on-hydrogen-finland-could-produce-10-of-eu-s-green-hydrogen-in-2030> accessed 30 January 2024.

[5] Ibid.

[6] Centre for Economic Development, Transport and the Environment, *Uusiutuvan energian tuotantolaitosten lupamenettelyt ja muut hallinnolliset menettelyt: Menettelykäsikirja hakijoille* (Etelä-Pohjanmaa Centre for Economic Development, Transport and the Environment 2023) 5.

hydrogen production the Energy Agency is also relevant.[7] Usually, the permit procedure for industrial plants, such as electrolysers, consists of an environmental permit under the Environmental Protection Act (527/2014), a water use permit under the Water Act (587/2011), a building permit and possible changes to zoning under the Land Use and Building Act (132/1999). Several other permits, such as those related to safety, are also needed for building an electrolyser, but they will not be covered in this chapter.

As an example of a currently ongoing renewable hydrogen project permitting procedure time frame, it is estimated that the permitting process for a 200-megawatt hydrogen and synthetic methane production plant in Kristinestad will take approximately 1–1.5 years.[8] This project has already received some of the permits, including for water use, but is still missing a handful of permits, such as environmental, chemical and change in the zoning plans, which is needed for the realization of the plant.[9] Another ongoing renewable hydrogen project is a 300-megawatt hydrogen production plant in Kokkola producing hydrogen from renewable electricity and ammonia.[10] The permit process for this hydrogen plant, which will be Finland's biggest hydrogen plant, is estimated to take a total of three years.[11]

Public hearings or obtaining statements are often also part of permit procedures and can take extra time.[12] In order to stay within the project schedule, it is therefore important to get well acquainted with the permit procedures and plan accordingly.[13] It is usually foreseeable how long processing a particular permit can take – for example, the maximum time for processing the environmental and water use permits should be twelve months, in accordance with the amended Act on the Handling of Environmental Protection and Water Matters in the Regional Administrative Agency (898/2009).[14] However, it is not possible to know in advance whether the authorities are satisfied with all the documentation. This is one of the reasons why it is good to become well acquainted with the permit process and requirements and also why authorities offer guidance in filling in the applications.[15] This includes both extensive guidance documents online for filling in particular permits as well as the ability to schedule a meeting where the authorities help you apply for a permit in person.[16] The permit authorities are usually very approachable and available for answering questions; at least many foreign investment companies have praised their interactions with Finnish public authorities.[17]

7 Ibid.
8 Visa Noronen, '10 reasons why Germans are investing in the hydrogen industry in Kristiinankaupunki' (BotH2nia, 9 November 2022) <https://both2nia.com/en/news/10-reasons-why-Germans-are-investing-in-the-hydrogen-industry-in-Kristiinankaupunki> accessed 30 January 2024.
9 Ibid.
10 Visa Noronen, 'Analysis: wind, industry and hydrogen pipeline to bring Finland's largest hydrogen plant to Kokkola' (BotH2nia, 15 November 2022) <https://both2nia.com/en/news/Analysis-wind-industry-and-hydrogen-pipeline-to-bring-Finland-s-largest-hydrogen-plant-to-Kokkola> accessed 30 January 2024.
11 Ibid.
12 Claudia Greiner, 'Procedures and permits for industrial building projects in Finland' (Bergmann Attorneys at Law, September 2022) <https://bergmann.fi/e/article/procedures_permits_building_projects> accessed 30 January 2024.
13 Ibid.
14 Act on the Handling of Environmental Protection and Water Matters in the Regional Administrative Agency (898/2009) art. 2a.
15 Greiner, 'Procedures and permits for industrial building projects in Finland'.
16 Centre for Economic Development, Transport and the Environment, 'Uusiutuvan energian lupaneuvonta' (7 June 2023) <https://ely-keskus.fi/web/uusiutuvan-energian-lupaneuvonta/etusivu> accessed 30 January 2024.
17 OECD, 'Finland's business climate in the eyes of foreign investors' in OECD, *The Impact of Regulation on International Investment in Finland* (OECD Publishing 2021).

Because of these long permit processing times and their impact on investments, the government hopes for a smoother and faster permit process.[18] The National Climate and Energy strategy envisions a maximum one-year permit handling time for green projects.[19] This has already been passed by the government and introduced into legislation as a temporary amendment of the law on the handling of environmental protection and water matters in the Regional Administrative Agency (1144/2022).[20] It establishes a fast-track priority permit handling process for renewable energy projects that boost the green transition, including renewable hydrogen projects.[21] Section 13.4 of this chapter will cover the new fast-track procedure for renewable energy projects, which is also relevant for hydrogen electrolysers.

The following sections will detail which permits are necessary for renewable hydrogen electrolysers, starting with zoning, land use and building (Section 13.2) and then moving on to permits related to the environment (Section 13.3). At the end of this chapter, there will be a section covering the latest developments in the permitting regime relevant to renewable hydrogen electrolyser projects (Section 13.4). The following sections will also delve into the challenges of the permitting procedure which can act as pitfalls since they can deter investments in renewable hydrogen, and without investment new electrolysers cannot be built.

13.2 CHALLENGES OF THE PERMITTING PROCEDURES RELATED TO ZONING, PLANNING AND BUILDING

Land use planning in Finland is organized hierarchically.[22] At the top are national land use objectives that are set by the government.[23] The national land use objectives are binding, and the policy framework is established to offer guidance for land use for the whole country.[24] Regional land use plans are then created to guide regional development.[25] Based on the national objectives and regional land use plans municipalities will take the next steps in zoning and planning.

Municipalities are responsible for local master plans and local detailed plans.[26] Local master plans are made on the municipal level, which creates a general structure for the municipality.[27] Every municipality must prepare a local master plan.[28] Based on the Act on Municipalities (410/2015)[29] there exists the right to make a proposal for the municipality to draw up a plan.[30] So, for example, a renewable hydrogen production company could propose that the municipality draw

[18] Ministry of the Environment, 'Finland boosts green transition – in permit and appeal procedures priority given to investment projects' (8 September 2022) <https://ym.fi/-/vihrean-siirtyman-investointeja-vauhditetaan-etusijamenettelylla?languageId=en_US> accessed 30 January 2024.

[19] Ministry of Economic Affairs and Employment of Finland, *Carbon Neutral Finland 2035 – National Climate and Energy Strategy* (Ministry of Economic Affairs and Employment of Finland 2022) 29.

[20] Law on the temporary amendment of the law on the handling of environmental protection and water matters in the Regional Administrative Agency (1144/2022).

[21] Ibid., art. 2.

[22] OECD, 'The governance of land use: Country fact sheet Finland' (2017) <https://oecd.org/regional/regional-policy/land-use-Finland.pdf> accessed 30 January 2024.

[23] Ibid.

[24] Ibid.

[25] Land Use and Building Act (132/1999) art. 4.

[26] Ibid.

[27] Ibid.

[28] Ministry of the Environment, 'Land use planning' <https://ym.fi/en/land-use-planning> accessed 30 January 2024.

[29] Act on Municipalities (410/2015).

[30] Centre for Economic Development, Transport and the Environment, *Uusiutuvan energian tuotantolaitosten lupamenettelyt ja muut hallinnolliset menettelyt* 59.

up a local master plan to include zoning areas for hydrogen production. However, all decision power is still left to the municipality, which is responsible for drawing up such general plans.[31] The most specific form of planning is the local detailed plans, which outline which land plots can be used for certain activities and how buildings should be arranged.[32] It is also possible to request the municipality to make changes to the local detailed plans if necessary, but just as for local master plans, the municipality will have the power to decide to act on it or not.[33] The municipalities give planning permissions and issue building permits. They create building ordinances, which act as their primary tools to control construction.[34] Municipalities are therefore the most important actors regarding zoning and construction in Finland. The rules set out in the municipal building ordinances can vary significantly between different municipalities.

When creating the zoning plans, the zoning and planning authorities have to take into account various factors related to safety and environmental protection.[35] One condition is that industrial production plants are generally not allowed to be located near major groundwater areas,[36] due to concerns about pollution of the water supply.[37] Industrial areas are usually planned and zoned further from densely populated areas,[38] especially where hospitals and schools are located.[39] Additionally, proximity to areas important for nature is avoided.[40] This is due to possible hazards that the zoning authorities have to take into account.[41] The zoning authorities have to consider all these factors when they create their plans and therefore it is not up to the permit applicant. In zoning, the major decisions are made by the authorities and the applicant cannot usually choose a location that is not already designated for industrial purposes. The zoning plans in Finland are therefore quite rigid and it is important to consider them carefully: they need to allow the setting up of a new hydrogen production plant in the area.[42] Industrial production plants are only allowed in areas that are already reserved for industrial and storage operations.[43]

After permission from the municipality is received for the use of a plot of land dedicated to industrial purposes, a valid building permit under the Land Use and Building Act (132/1999) is always needed before any construction of the facility can take place.[44] The municipal construction authority will grant the building permit.[45]

When getting a zoning plan and a construction permit you mainly have to deal with the municipal authorities which are responsible for the local master plans and local detailed plans as

[31] Ibid. 58.
[32] Land Use and Building Act (132/1999) art. 4.
[33] Centre for Economic Development, Transport and the Environment, *Uusiutuvan energian tuotantolaitosten lupamenettelyt ja muut hallinnolliset menettelyt* 59.
[34] Ministry of the Environment, 'Land use planning'.
[35] Turvallisuus – ja kemikaalivirasto, 'Land-use planning' <https://tukes.fi/en/industry/land-use-planning> accessed 30 January 2024.
[36] Ibid.
[37] TUKES, *Tuotantolaitosten sijoittaminen* (Turvallisuus – ja kemikaalivirasto 2015) 25.
[38] Centre for Economic Development, Transport and the Environment, *Uusiutuvan energian tuotantolaitosten lupamenettelyt ja muut hallinnolliset menettelyt* 58.
[39] OECD, 'The governance of land use: Country fact sheet Finland'.
[40] Centre for Economic Development, Transport and the Environment, *Uusiutuvan energian tuotantolaitosten lupamenettelyt ja muut hallinnolliset menettelyt* 58.
[41] Turvallisuus – ja kemikaalivirasto, 'Land-use planning'.
[42] Ibid.
[43] Ibid.
[44] Land Use and Building Act (132/1999) art. 125.
[45] Ibid. art. 130.

well as the municipal building ordinance. Dealing almost exclusively with the municipal authorities can provide a couple of challenges that can hinder the setting up of electrolysers.

Firstly, many municipalities are quite small but still need to provide various and often specialized services.[46] This may lead to the municipal authorities being overloaded with tasks which can lead to longer permit approval and handling times.[47] Overdue permit processing times and long waits until approval is granted slow down investment projects and can lead to delays in investments because large amounts of capital are at a standstill.[48] Investors have felt that the processes taking a long time are particularly an issue with the approval of land use plans and with building permits.[49]

Another issue is that when things are decided on a municipal level, even when based on national objectives and guidelines, there will be large discrepancies between municipalities in what is permitted, and which conditions must be met, as well as how things are handled. This creates uncertainty for the investors.[50] Especially small and medium-sized enterprises view this uncertainty as a problem, and it is something that plays a negative role in their investment decisions.[51]

Also mentioned was that zoning plans created by zoning authorities are rigid and sometimes changing them can be difficult. Usually, industrial plants can only be set up on land that is already designated for industrial use in the zoning plans. There is a right to prompt the municipality to draw up specific plans or make necessary changes to already existing plans. But this is all at the discretion of the municipality and therefore there is no guarantee that they will decide to act on it. This could also be considered a factor that causes uncertainty, which can affect investment decisions – especially if the municipal authorities already have a lot on their hands due to their many responsibilities, which can negatively affect permitting and therefore investments. In such situations, it seems unlikely that the municipality would agree to change its original zoning plans. However, because large new investments also benefit the municipality and the local economy, municipalities should be willing to create space for industry and to draw up new plans if necessary. At least for some ongoing hydrogen projects, changes in the zoning plans were required and are now taking a long time to be approved.[52]

A further issue is that compared to zoning and planning in other countries, Finland has a high level of regulation and operational restrictions, which may constitute a barrier for investment.[53] However, this is less so for energy project development than for other industrial projects as in Finland there are no separate burdensome sector-specific regulations for energy projects, which exist in many other countries and can present a challenge.[54]

Long waiting times and bureaucracy are identified as particular issues in the Finnish zoning and construction permit regime by investors and are therefore the biggest challenge in the

[46] Jürgen Pucher, Haris Martinos and Wolfgang Schausberger, *Obstacles to Investments at Local and Regional Level* (European Union, the Committee of the Regions 2016) 39.

[47] OECD, 'Finland's business climate in the eyes of foreign investors'.

[48] Satu Räsänen, Jari Huovinen and Kati Ruohomäki, 'EK:n yrityskysely: Viranomaisprosessit nopeutuneet – silti 2,7 miljardin investoinnit kesken lupakäsittelyssä' (Confederation of Finnish Industries, 31 January 2019) <https://ek.fi/ajankohtaista/tiedotteet/ekn-yrityskysely-viranomaisprosessit-nopeutuneet-silti-27-miljardin-investoinnit-kesken-lupakasittelyssa/> accessed 30 January 2024.

[49] OECD, 'Finland's business climate in the eyes of foreign investors'.

[50] Ibid.

[51] Ibid.

[52] Noronen, '10 reasons why Germans are investing in the hydrogen industry in Kristiinankaupunki'.

[53] Pucher, Martinos and Schausberger, *Obstacles to Investments at Local and Regional Level* 46.

[54] Ibid.

permitting process.[55] Changes are currently being made to the system, which should bring some improvements. Based on a proposal that was adopted by the Parliament on 1 March 2023, the Land Use and Building Act (132/1999) will be amended and renamed the Zoning Act.[56] The amendments and new title come into force on 1 January 2025.[57] A new separate Building Act will also enter into force on 1 January 2025.[58] The new amendments aim at smoothing the construction process, boosting a circular economy and digitalization as well as improving the quality of construction.[59] Making the initial permitting process smoother would be an integral part of facilitating the construction process as a whole and it is hoped that when the amendments come into force they will have the desired effect.

13.3 PERMITS RELATED TO THE ENVIRONMENT AND THEIR CHALLENGING BUREAUCRACY

One of the most important types of permits needed for a hydrogen electrolyser is the environmental permit. Any activities that can negatively affect the environment require an environmental permit under the Environmental Protection Act (527/2014).[60] An environmental permit is needed for activities that affect water, air or soil, as well as activities that cause any noise or vibrations.[61] A precondition for receiving the environmental permit is that the activities do not cause health concerns or significant environmental pollution, or risk causing such pollution.[62] An environmental permit is necessary for energy projects as well as the production of steel and chemicals,[63] which are often tied together with renewable hydrogen production in Finland. The EU Industrial Emissions Directive (2010/75/EU)[64] is transposed to Finnish law mainly in the Environmental Protection Act (527/2014) and not as a separate act or decree, which is why considerations and assessments about emissions are part of the environmental permit.[65] Information about possible emissions, their effects and efforts at mitigation are required as part of the process of applying for an environmental permit; assessments on emissions are still required, but not under a separate permit. A renewable hydrogen electrolyser project also needs a water permit under the Water Act (587/2011) because large amounts of water are used for the electrolysis to produce renewable hydrogen and because a large hydrogen plant may have effects on water bodies on or surrounding the property where it is to be located.[66]

The environmental permit needs to be applied for digitally, at the regional state administrative authority or a municipal environmental protection authority,[67] depending on the size of the project.[68] Because renewable hydrogen electrolysis projects need both a water use permit and an

[55] OECD, 'Finland's business climate in the eyes of foreign investors'.
[56] Environmental Committee, 'Valiokunnan mietintö YmVM 27/2022 vp – HE 139/2022 vp' (Parliament of Finland 2023).
[57] Ibid.
[58] Ibid.
[59] Ibid.
[60] Environmental Protection Act (527/2014) art. 27.
[61] Government Decree on Environmental Protection (713/2014) art. 3 (6).
[62] Environmental Protection Act (527/2014) art. 2.
[63] Ibid. art. 27 & Annex 1.
[64] Directive 2010/75/EU of the European Parliament and of the Council of 24 November 2010 on industrial emissions (integrated pollution prevention and control) (Recast) [2010] OJ L 158/25.
[65] Environmental Protection Act (527/2014).
[66] Water Act (587/2011) art. 3.3(2).
[67] Environmental Protection Act (527/2014) art. 39.
[68] Government Decree on Environmental Protection (713/2014) art. 1 & art. 2.

environmental permit, the permit needs to be applied for at the Regional State Administrative Authority.[69] If both an environmental permit and a water use permit are needed for the project, they can be applied for together and as a result only one permit is provided.[70] The reason these particular permits can be applied for together is that they are handled by the same authority and have some overlapping elements, especially in terms of environmental protection of waters and waterways. As stated earlier, the permitting process is still very fragmented; however, as the environmental and water permits cover similar things to an extent, they are a special case of permits that can be applied for at the same time.[71]

The environmental permit application needs to include basic information about the operator, the name of the facility, its location and the industry it is part of.[72] Other information that must be provided as part of the permit application is, for example, an assessment of the activity's effects on the surrounding nature and environment,[73] as well as a summary of the activities for which the permit is intended; this information will be used for the purpose of presenting the application to the public as part of the public consultation process related to permit applications.[74] For electrolyser permits, information on the fuels used, their storage, preservation and consumption, as well as the energy used or produced and the use of water is also relevant,[75] as is information on the raw materials, chemicals and other materials needed for production.[76] The same goes for their storage, preservation and consumption,[77] along with an assessment of the efficiency of the usage of energy and materials.[78] The necessity for these items will depend on which specific type of electrolyser will be used, for example whether any chemicals are involved in the process.

What information the environmental permit application needs to include is quite comprehensive, but this only symbolizes the fact that Finland takes environmental protection very seriously. However, strict environmental protection also brings more bureaucracy. A lot of bureaucracy can act as a barrier to investment.[79] One reason suggested for why bureaucracy negatively affects investment is that bureaucracy is interested in maximizing its own scope and influence and therefore has adverse effects on the incentives for investment.[80] This is how it is modelled in public choice literature.[81] Another point of view, also from public choice literature, proclaims that governments' coercive activities, such as licensing or permitting, act as restrictions and divert efforts away from investment.[82] Therefore, economic theory shows that bureaucracy can deter investment so that increased bureaucracy regarding environmental permits can be considered a difficulty for building new renewable hydrogen electrolysers.

There are other concerns with environmental permits that may also influence investment decisions. The more thorough the permit application documentation the better the chances of the permit being granted the first time around; it also makes the process easier for the authorities, as they do not need to request additional materials and information, which could delay the

[69] Water Act (587/2011) art. 2.22.
[70] Ympäristö, 'Ympäristölupa' <https://ymparisto.fi/fi/luvat-ja-velvoitteet/ymparistolupa> accessed 30 January 2024.
[71] Ibid.
[72] Government Decree on Environmental Protection (713/2014) art. 3 (1).
[73] Ibid. art. 3 (8).
[74] Ibid. art. 3 (4).
[75] Ibid. art. 3 (2).
[76] Ibid. art. 3 (3).
[77] Ibid. art. 3 (3).
[78] Ibid. art. 3 (4).
[79] Eliezer B. Ayal and Georgios Karras, 'Bureaucracy, investment, and growth' (1996) 51 Economics Letters 233, 1.
[80] Ibid. 6.
[81] Ibid.
[82] Ibid.

permit process. A delayed permit is also a disadvantage for the investors,[83] as already discussed to some extent when the influence of zoning and building permits on investment decisions was covered. In general, the Finnish permit process seems to be mainly designed from the point of view of the authorities, making it as easy and efficient as possible for them, rather than for the stakeholders who need the permits. To promote the building of more hydrogen electrolysers, the permit process should consider the stakeholders more.

There have been already some improvements in this regard as the Confederation of Finnish Industries (EK) has conducted surveys on how investors feel about the Finnish regulatory and permitting regime.[84] The companies were also able to give their opinions on how the permitting regime should be improved and which improvements they considered the most significant.[85] Particular points of complaint by investors were the long permitting times and increased bureaucracy related to the environmental permits.[86] The potential investors who took part in the survey wished in particular for legislative changes.[87] The government took note of this and implemented some changes in the form of a temporary amendment to the existing law.[88] This will be discussed in the next section.

13.4 ACCELERATED PERMITTING PROCEDURE FOR GREEN TRANSITION PROJECTS: AN IMPROVEMENT OR A PITFALL?

The permitting process in Finland is generally rather fragmented; however, for hydrogen projects, Finland aims to have a seamless permitting process in place in order to attract renewable hydrogen production and especially investments in renewable hydrogen production.[89] Part of this aim is the temporary legislative amendment presented in this section. The new priority procedure for green transition projects will be applied to environmental and water permits for renewable hydrogen electrolysers,[90] according to which the processing time should be a maximum of twelve months.[91]

The Finnish Parliament has passed a law on temporary amendment of the law on the handling of environmental protection and water matters in the Regional Administrative Agency (1144/2022). The temporary amendment adds Article 2a to the Act on the Handling of Environmental Protection and Water Matters in the Regional Administrative Agency (898/2009).[92] This temporary amendment provides a fast-track procedure for investment projects accelerating the green transition.[93] The Finnish Ministry of the Environment defines green

83 OECD, 'Finland's business climate in the eyes of foreign investors'.
84 Räsänen, Huovinen and Ruohomäki, 'EK:n yrityskysely: Viranomaisprosessit nopeutuneet'.
85 Satu Räsänen and Jari Huovinen, 'EK:n lupajärjestelmäkyselyn tulokset' (Confederation of Finnish Industries, January 2019) <https://ek.fi/wp-content/uploads/L ?upajarjestelmakysely ?_infografiikka.pdf> accessed 30 January 2024.
86 OECD, 'Finland's business climate in the eyes of foreign investors'.
87 Räsänen and Huovinen, 'EK:n lupajärjestelmäkyselyn tulokset'.
88 Law 1144/2022.
89 Ministry of the Environment, 'Finland boosts green transition'.
90 Law 1144/2022 art. 2a (3).
91 Regional State Administrative Agency, 'Vihreä siirtymä – nopeampaa käsittelyä ympäristö- ja vesitalouslupahakemuk sille Etelä-Suomen aluehallintovirastossa' (11 April 2023) <https://avi.fi/tiedote/-/tiedote/69972864> accessed 30 January 2024.
92 Law 1144/2022 art. 2a.
93 Ministry of the Environment, 'Hallituksen esitys eduskunnalle eräiden vihreän siirtymän hankkeiden väliaikaista etusijaa aluehallintovirastojen lupakäsittelyssä vuosina 2023–2026 ja hallintotuomioistuimissa vuosina 2023–2028 koskevaksi lainsäädännöksi' (Finnish Government, 2022) <https://valtioneuvosto.fi/hanke?tunnus=YM019:00/2022> accessed 30 January 2024.

transition as 'a shift towards economically sustainable growth and an economy that is not based on fossil fuels and overconsumption of natural resources'.[94] This definition is quite fitting for renewable hydrogen production by electrolysis.

The temporary amendment will be in place between 2023 and 2026 and it covers permits under the Environmental Protection Act (527/2014) and the Water Act (587/2011), which are handled by the regional state administrative agencies.[95] Overall, as well as permit handling, the fast-track procedure will also apply to appeals concerning the permits in administrative courts.[96] This amendment further brings the Finnish legislation in line with EU Regulation 2020/852[97] establishing a framework to facilitate sustainable investment.[98]

With regard to renewable hydrogen, the fast-track procedure will apply to permit applications concerning 'the production and utilization of hydrogen, with the exception of the production of hydrogen from fossil fuels'.[99] Therefore, it will cover projects installing electrolysers for renewable hydrogen production. This definition only singles out hydrogen production from fossil fuels, but not hydrogen produced by nuclear energy, which is also carbon neutral, despite not generally falling under the definition of renewable hydrogen. Therefore, even electricity from nuclear energy could be used to run the electrolyser and it could still be considered a renewable hydrogen project in the Finnish context.

The main reason for proposing this amendment is that the biggest hindrance to large renewable energy and infrastructure development, such as renewable hydrogen projects, is usually the permitting process, which can take a considerable amount of time.[100] Another benefit of the law is that while projects supporting a green transition get priority, projects that cause harmful environmental impacts will not benefit from the fast-track permit handling.[101] This means that green energy projects can be realized more quickly than carbon-intensive energy projects.[102]

To qualify as an investment project boosting a green transition, the project has to follow the 'do no significant harm' principle.[103] The obligation not to cause significant harm is a key principle of international environmental law,[104] but it is new to Finnish environmental legislation.[105] The do no significant harm principle is part of the EU taxonomy for sustainable financing and is used as a condition of receiving funding under the EU Recovery and Resilience Facility.[106] Under the do no significant harm principle the project cannot cause harm to any of the six objectives of the EU taxonomy on environmental sustainability, laid down in Article 17 of the EU Regulation 2020/852: (1) climate change mitigation; (2) climate change

94 Ministry of the Environment, 'What is the green transition?' (2022) <https://ym.fi/en/what-is-the-green-transition> accessed 30 January 2024.
95 Law 1144/2022.
96 Ministry of the Environment, 'Finland boosts green transition'.
97 Regulation (EU) 2020/852 of the European Parliament and of the Council of 18 June 2020 on the establishment of a framework to facilitate sustainable investment and amending Regulation (EU) 2019/2088 [2020] OJ L 198/13.
98 Law 1144/2022 art. 2a.
99 Ibid. art. 2a(3).
100 OECD, 'Finland's business climate in the eyes of foreign investors'.
101 Ministry of the Environment, 'Hallituksen'.
102 Ibid.
103 Law 1144/2022 art. 2a.
104 Pierre-Marie Dupuy and Jorge E. Viñuales, *International Environmental Law* (2nd ed., Cambridge University Press 2018) 140.
105 Marius Schultén, 'The Finnish government proposes fast-tracking of green transition projects – How will this impact the renewable energy sector in Finland?' (HPP Attorneys, 22 November 2022) <https://hpp.fi/en/articles/the-finnish-government-proposes-fast-tracking-of-green-transition-projects-how-will-this-impact-the-renewable-energy-sector-in-finland/> accessed 30 January 2024.
106 Regulation (EU) 2020/852 amending Regulation (EU) 2019/2088 [2020] OJ L 198/13, art. 1.

adaptation; (3) the sustainable use and protection of water and marine resources; (4) circular economy; (5) pollution prevention and control; and (6) the protection and restoration of biodiversity and ecosystems.[107]

However, in the context of Finnish permit applications, the do no significant harm principle is applied in a context that is outside the EU reporting obligation.[108] This means that the technical evaluation criteria established by the EU regulation for the do no significant harm principle does not have to be applied here. Instead, a different assessment method will be applied.[109] This will include assessing the permit application in the context of the do no significant harm principle through different technical, scientific and legal questions.[110] This means that while the do no significant harm principle can be found in the EU taxonomy and largely follows the same definitions in the Finnish permitting context, the technical criteria used for the assessment are different to what is in place at the EU level.

The use of the do no significant harm principle and having a separate assessment criterion for it is new in the permitting context and adds an additional layer of assessment to the permitting process because before the permit application is processed the applicant must prove it complies with the do no significant harm principle. The permit authorities also have to determine that the application meets the do no significant harm criteria as well as the other criteria that qualify the permit for prioritized permit processing, which is all on top of the normal permit procedure for environmental and water permits.[111] As this needs to be done on a project-by-project basis, it might initially delay the permit process rather than speeding it up; this is a new layer of assessment, and standardized interpretation of such assessment criteria usually takes time to be established in practice.[112] This has created concerns among legal professionals, as they fear that the application of the do no significant harm principle could create a bottleneck and water down some of the positive impacts of the fast-track procedure and its effect on the timelines for the realization of renewable energy projects.[113]

A key benefit of the fast-track procedure is to ensure that investments can proceed without delay. To do this, the maximum permit processing times are shortened. If the time to get the necessary permits is shorter, the projects can be realized faster. If projects can be up and running faster, that means production can start sooner, and the investment will be recouped faster. This will be a benefit for the investors, who have complained of long permit processing times with the result that investments are at a standstill.[114] However, some legal professionals are already wary about how fast-track procedure will play out in reality as the concept is new, and it adds two additional assessment steps:[115] an assessment on whether the project is eligible for the fast-track

[107] Ibid. art. 17.
[108] Satu Pohja and Netta Skön, 'Vihreän siirtymän hankkeiden etusija lupamenettelyissä – kuka mahtuu mukaan?' (*Fondia*, 23 January 2023) <https://fondia.com/fi/fi/ajankohtaista/artikkelit/vihreaen-siirtymaen-hankkeiden-etusija-lupamenettelyissae-kuka-mahtuu-mukaan> accessed 30 January 2024.
[109] Ibid.
[110] Ibid.
[111] Schultén, 'The Finnish government proposes fast-tracking of green transition projects'.
[112] Ibid.
[113] Ibid.; Matias Wallgren et al., 'Plan to speed up green transition investing by providing temporary priority processing and expedited appeals – statements can be issued' (Castrén & Snellman, 3 June 2022) <https://castren.fi/blogandnews/blog-2022/Plan-to-speed-up-green-transition-investing-by-providing-temporary-priority-processing-and-expedited-appeals-statements-can-be-issued/> accessed 30 January 2024.
[114] OECD, 'Finland's business climate in the eyes of foreign investors'.
[115] Schultén, 'The Finnish government proposes fast-tracking of green transition projects'; Wallgren et al., 'Plan to speed up green transition investing'.

process in the first place – does it meet the criteria of a renewable energy project that boosts green transition – and whether it meets the technical and scientific criteria of the do no harm principle, which is new in the context of the Finnish permitting landscape. As there is no standardized practice for these assessments and they are both new, it will take some time for the authorities to get used to them and create their assessment standards. This is why it is likely that when the fast-track procedure is first in place, it might in effect lead to further delays instead of, as intended, speeding up the permit process for environmental and water permits.

However, if the faster procedure for environmental and water permits works as intended and ends up benefiting investors and therefore attracting more investment in renewable hydrogen electrolysers it can be deemed a welcome improvement in the challenging permit procedure. It will, though, take some years before any actual results can be seen on whether the amendment was beneficial or not in terms of investments into renewable hydrogen production, and this will be a point for future research on this topic.

13.5 CONCLUSION

To conclude, there are a couple of essential points that need to be made. The Finnish permitting landscape remains fragmented and many different permits are needed. Positive notes are that most permits can be applied for easily online, but a number of attachments in the form of different assessments, plans and statements are required, which is deemed bureaucratic by investors. Long permit approval times are also named by investors as barriers to investment and are a problem for both building and environmental permits. Issues with the permitting regime influence the investment decisions of small and medium-sized enterprises in particular, as the long waiting times and bureaucracy affect them the most.

One of the main types of permits that are necessary for renewable hydrogen electrolyser projects and that are covered in this chapter are zoning permissions and building permits under the Land Use and Building Act (132/1999). This process mainly takes place on the municipal level, which can have some drawbacks for efficiency and negatively influence investment decisions. This is because small municipalities are responsible for many specialized tasks which can lead to long permit approval times for building permits.

Another important group of permits that are necessary for the realization of renewable hydrogen electrolyser projects are permits related to the environment. These are environmental and water permits. If a new production plant is set up that only produces renewable hydrogen, a separate emissions permit is not necessary. That is only needed in cases where the same installation also produces something else that falls under the requirements. Obtaining an environmental permit is highly bureaucratic, which can be a barrier to investment into renewable hydrogen.

Recently a law on the temporary amendment of the law on the handling of environmental protection and water matters in the Regional Administrative Agency (1144/2022) was passed which aims at easing the permit procedure for green investment projects, including hydrogen electrolysers, and addresses some of the issues with the permitting regime. The most important takeaways from the amendment are that it applies to environmental and water permits and it sets the maximum permit processing time at twelve months. This is a step in the right direction to improve the permitting process for renewable hydrogen electrolysers, and it is hoped that it will have the intended effect on boosting investments in this area.

Despite some improvements, a number of potential issues remain that may influence investment decisions in renewable hydrogen in a negative way have been identified in this study.

FURTHER READING

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Law on the temporary amendment of the law on the handling of environmental protection and water matters in the Regional Administrative Agency (1144/2022)

Ministry of Economic Affairs and Employment of Finland, *Carbon Neutral Finland 2035 – National Climate and Energy Strategy* (Ministry of Economic Affairs and Employment of Finland 2022)

OECD, 'Finland's business climate in the eyes of foreign investors' in *OECD The Impact of Regulation on International Investment in Finland* (OECD Publishing 2021)

Jürgen Pucher, Haris Martinos and Wolfgang Schausberger, *Obstacles to Investments at Local and Regional Level* (European Union, the Committee of the Regions 2016)

Leena Sivill et al., *Hydrogen Economy – Opportunities and Limitations* (Publications of the Government's Analysis, Assessment and Research Activities 2022)

14

Giving Hydrogen the Green Light and Putting It on the Fast-Track?

Consenting Hydrogen Developments in Aotearoa New Zealand

Jennifer Campion

14.1 INTRODUCTION

Readers who enjoyed science lessons at school may recall an experiment in which hydrogen is made by applying a direct current to water and then seeing bubbles of hydrogen and oxygen.[1] This process – called 'electrolysis' – uses electricity to split water into its two component molecules, hydrogen and oxygen; hydrogen gas can then be stored and used like a battery to generate electricity when required.[2] This reaction takes place inside an electrolyser and is the process by which low-carbon, renewable-energy-derived 'green' hydrogen is made.[3] However, before the science classroom result can be replicated on an industrial scale, concerns around safety, purity of product and reliability of technology must be addressed.[4] Because of this, there are strict safety design standards for electrolysers, which must conform to the standards required by the country of installation.[5] Developers of electrolytic hydrogen projects must also obtain the necessary resource consents and permits.

[1] For a recap of this experiment, see: KiwiCo, 'Splitting water', available at <https://kiwico.com/diy/stem/quick-easy-experiments/splitting-water> accessed 21 February 2024.

[2] Advantages include the long-term storage of potential renewable energy. Disadvantages include the significant energy lost through the electrolysis: ENGIE, 'How does hydrogen power work?', available at <https://engie.com.au/home/about-engie/education/how-does-hydrogen-power-work> accessed 21 February 2024.

[3] Electrolysers consist of an anode and a cathode separated by an electrolyte, and they range in size from small, appliance-size equipment (which can support small-scale distributed hydrogen production) to large-scale, central production facilities, which can be tied directly to renewable electricity producing facilities. See US Department of Energy, 'Hydrogen production: Electrolysis', available at <https://energy.gov/eere/fuelcells/hydrogen-production-electrolysis> accessed 21 February 2024.

[4] See a discussion of the challenge and opportunities hydrogen generated from electrolysis see: M. T. Ahad, M. M. H. Bhuiyan, A. N. Sakib, A. Becerril Corral, A. Siddique, 'An overview of challenges for the future of hydrogen' (2023) 16 (20) Materials 6680, available at <https://doi.org/10.3390/ma16206680> accessed 21 February 2024.

[5] In one submission responding to the New Zealand Hydrogen *Vision*, it was noted that '[g]reen Hydrogen production (electrolysis method) relies on importing and setting up specialist, expensive hydrogen production plant (e.g. Hydrogenics from Belgium)', and that '[g]enerally, the following plant items and site infrastructure items need specialist technical design inputs in the development of a remote, stand-alone Green Hydrogen electrolyser production facility: Feed water to Electrolyser; Electrolyser drain outlet; Electrolyser to Compressor; Compressor to Filling station; Filling station to cylinder trailer; Nitrogen panel electrolyser/compressor/trailer filling station; All system vents (Hydrogen, Oxygen, Nitrogen); AC power in to the plant; AC power LV to Electrolyser/Compressor; Backup power; Instrument air system; General site movement's assessment': WSP, 'WSP submission on a vision for hydrogen in New

This chapter discusses the permitting regime for electrolysers in New Zealand. Two types are currently used on a large scale in New Zealand: alkaline (AEL) and polymer electrolyte membrane (PEM) electrolysers.[6] Both PEM and AEL electrolysers use an electric current to split water molecules into hydrogen and oxygen, but they use different types of electrolyte solution and different materials for the membrane and electrodes.[7] The type of electrolyser used will depend on the project's needs, although PEM electrolysers are often preferred, because they offer greater flexibility.[8] Irrespective of what type of electrolyser is chosen, resource consent will be needed before the project can proceed. This chapter asks what permits will be needed and what processes must be followed in order for an electrolytic hydrogen project to receive resource consent.

New Zealand may not initially seem the most 'obvious' choice for examining the way in which electrolytic hydrogen projects are permitted. After all, many states are currently considering how low-carbon, renewable-energy-derived 'green' hydrogen can support decarbonisation goals, and are investigating what may be the most appropriate applications and transition pathways for hydrogen within their energy systems and economies, and a number of national hydrogen strategies and polices have been published recently.[9] New Zealand is no exception, having published its *Vision for Hydrogen in New Zealand* Green Paper in September 2019.[10] However, unlike those states which are considering a range of hydrogen options,[11] New

Zealand', October 2019, at 20, available at <https://mbie.govt.nz/dmsdocument/10629-wsp-a-vision-for-hydrogen-in-new-zealand-green-paper-submission-pdf> accessed 21 February 2024 (hereinafter: WSP).

6 NIWA, 'New Zealand's EnergyScape: Transitioning to a hydrogen economy: Hydrogen research strategy for facilitating the uptake of hydrogen as an energy carrier in New Zealand', May 2009, at 24, available at <www.mcguinnessinstitute.org/wp-content/uploads/2021/12/CRL-Stage-5-Hydrogen-Research-Strategy.pdf> accessed 21 February 2024. A range of emerging electrolyser technologies are also being explored, although capability is limited; the appeal of these is that they may be able to provide improved conversion efficiency and assist the integration of hydrogen energy into existing energy systems.

7 PEM electrolysers use a proton exchange membrane as the electrolyte, which allows protons (positively charged hydrogen ions) to pass through the membrane while blocking other ions. This allows for high ionic conductivity and efficient hydrogen production. PEM electrolysers also use platinum-based electrodes, which are expensive but have a long lifespan and high activity. They are also relatively compact and require low operating pressures, making them relatively easy to integrate into existing systems. In contrast, AEL electrolysers use an alkaline solution as the electrolyte, which allows for a higher rate of hydrogen production, but which can be corrosive. AEL electrolysers also use cheaper, more durable electrodes (made from, for example, nickel and iron). Alkaline electrolysers can take up to fifty minutes to get up to full operating speed, compared to less than five minutes for PEM (which causes the electrodes to have a shorter lifespan) and they are generally less efficient than PEM electrolysers and require higher operating pressures. However, they can operate using a variety of water sources, including seawater and wastewater, as they are less sensitive to impurities in the feedwater. This can reduce the need for expensive water treatment systems. In general, PEM electrolysers are more efficient and have faster response times and longer lifespans, but they are also more expensive and require pure water and electricity as inputs.

8 PEM electrolysers are well-suited for applications that require rapid changes in hydrogen production.

9 These strategies can be accessed from 'National Hydrogen Strategies and Roadmap Tracker', maintained by Colombia University's Centre for Global Energy Policy, available at <https://energypolicy.columbia.edu/publications/national-hydrogen-strategies-and-roadmap-tracker/> accessed 21 February 2024. See also Pasquale Marcello Falcone, Michael Hiete, Alessandro Sapio, 'Hydrogen economy and sustainable development goals: Review and policy insights' (2021) 31 Current Opinion in Green and Sustainable Chemistry 100506.

10 Ministry of Business, Innovation and Employment, 'A vision for hydrogen in New Zealand', September 2019, available at <https://mbie.govt.nz/dmsdocument/6798-a-vision-for-hydrogen-in-new-zealand-green-paper> accessed 21 February 2024 (hereinafter: Ministry of Business, Innovation and Employment).

11 Green hydrogen is produced by the electrolysis of water, using renewable electricity; it currently accounts for 4 per cent of hydrogen production: A. Nicita, G. Maggio, A. P. F. Andaloro, G. Squadrito, 'Green hydrogen as feedstock: Financial analysis of a photovoltaic-powered electrolysis plant' (2020) 45(20) International Journal of Hydrogen Energy 11395, available at <https://doi.org/10.1016/j.ijhydene.2020.02.062> accessed 21 February 2024. The low percentage is directly related to the high cost of hydrogen production using renewable energy compared with other processes using fossil fuels: A. G. Olabi, Mohammad Ali Abdelkareem, Mohamed S. Mahmoud, Khaled Elsaid,

Zealand's focus is firmly on green hydrogen,[12] which means the resource consent process for electrolysers is critical to New Zealand's hydrogen ambitions.[13] The *Vision* indicated the government's intention to develop a hydrogen roadmap;[14] an Interim Hydrogen Roadmap was released in August 2023, with a final Hydrogen Roadmap anticipated by the end of 2024.[15] These policy documents signal New Zealand's desire to position itself as a hydrogen exporter (and to contribute to the decarbonisation of other energy markets, particularly in Asia),[16] with the domestic hydrogen opportunity largely supplementing existing renewable energy activities.[17] Even so, developments in New Zealand are still at an early stage and the green hydrogen market in New Zealand is a 'nascent industry'.[18] Indeed, the existing hydrogen market in New Zealand is dominated by major industrial manufacturers (methanol production, ammonia and urea

Khaled Obaideen, Hegazy Rezk, Tabbi Wilberforce, Tasnim Eisa, Kyu-Jung Chae, Enas Taha Sayed, 'Green hydrogen: Pathways, roadmap, and role in achieving sustainable development goals' (2023) 177 Process Safety and Environmental Protection 664, available at <https://doi.org/10.1016/j.psep.2023.06.069> accessed 21 February 2024. For an analysis of the 'green-ness' of national hydrogen strategies, see Wenting Cheng, Sora Lee. 'How green are the national hydrogen strategies?' (2022) 14(3) Sustainability 1930, available at <https://doi.org/10.3390/su14031930> accessed 21 February 2024.

[12] Although hydrogen produced from fossil fuels and industrial processes may play a role in the transition of New Zealand's regions and existing industries, the *Vision* envisions a future where New Zealand is using renewable energy to produce green hydrogen.

[13] It must be pointed out that hydrogen derived from electrolysis may not be green hydrogen: hydrogen is considered green when the electricity used is from renewable sources. However, much of the electricity generated in New Zealand comes from renewable sources, which supports New Zealand's green hydrogen focus.

[14] The firm Castalia was engaged to develop a hydrogen supply, demand and export model; their report was released in June 2022: Castalia, 'New Zealand hydrogen scenarios' (2022), available at <https://mbie.govt.nz/dmsdocument/20118-new-zealand-hydrogen-scenarios-pdf> accessed 21 February 2024.

[15] Ministry of Business, Innovation and Employment, 'Interim Hydrogen Roadmap', August 2023, available at <https://ena.org.nz/assets/9927-Interim-Hydrogen-Roadmap-AUG23.pdf> accessed 21 February 2024. The Interim Roadmap feeds into broader energy strategy, with a New Zealand Energy Strategy expected in 2024, and aligns with other projects, including the Gas Transition Plan, Energy Market Measures project, Offshore Renewable Energy regulatory framework project and the New Zealand Battery Project. Hydrogen's potential to support a just transition is also recognised, as it may offer sustainable growth opportunities to regions with economies that have previously been reliant on the fossil fuel industry; in New Zealand, the H2 Taranaki Roadmap envisions a low-emissions hydrogen sector in the Taranaki region, which has previously been a focus of New Zealand's oil and gas production. See New Plymouth District Council, Venture Taranaki Trust, and Hiringa Energy, 'H2 Taranaki Roadmap' (2019), available at <https://venture.org.nz/assets/H2-Taranaki-Roadmap.pdf> accessed 21 February 2024.

[16] Hydrogen may be particularly attractive to those countries that are comparatively 'renewables-poor' (for example, Japan and South Korea) and which may need to import renewable energy to decarbonise their economies. New Zealand has signed hydrogen cooperation agreements with Singapore, Japan and South Korea; see the 'international collaboration' section of the Ministry of Business, Innovation and Employment' webpage 'Hydrogen in New Zealand', available at <https://mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-strategies-for-new-zealand/hydrogen-in-new-zealand/> accessed 21 February 2024.

[17] New Zealand already generates a significant proportion (82 per cent) of electricity from renewable energy resources (see Ministry of Business, Innovation and Employment, 'Energy in New Zealand 2022 shows a strong share of renewable energy', 18 August 2022, available at <https://mbie.govt.nz/about/news/energy-in-new-zealand-2022-shows-a-strong-share-of-renewable-energy> accessed 21 February 2024), so the role of hydrogen in supporting decarbonisation will be different in New Zealand than it is in other states, and will be focused on decarbonisation of 'hard to abate' sectors, such as steel-making, shipping and aviation, and other industrial processes (e.g., fertiliser, high temperature boilers) and decarbonisation of heavy transport (e.g., substituting diesel). However, New Zealand has a 'dry year problem', which means fossil fuels are relied on to supplement hydro-electricity and ensure sufficient electricity is generated – something green hydrogen may help to ameliorate. Nevertheless, recent analysis indicates that: 'even with highly optimistic assumptions about how cheaply hydrogen can be produced, hydrogen will be a substantially more expensive means of meeting consumers' heating needs than direct electric options': Concept Consulting, 'Which way is forward? Analysis of key choices for New Zealand's energy sector' (2022), available at <https://concept.co.nz/uploads/1/2/8/3/128396759/which_way_is_forward.pdf> accessed 21 February 2024.

[18] PwC, 'New Zealand's hydrogen regulatory pathway' (2022), available at <https://mbie.govt.nz/dmsdocument/25671-new-zealand-hydrogen-regulatory-pathway> accessed 21 February 2024 (hereinafter: PwC 2022).

production, refining and steel production) and the majority of hydrogen is produced in-house from domestic natural gas via steam methane reforming facilities, with a smaller proportion of electrolytic hydrogen for steel production.[19]

Because electrolysers are the hydrogen production devices with the most potential to support environmentally friendly, green hydrogen developments, consideration of the requirements for obtaining resource consent for an electrolytic hydrogen project offers a useful entry point for consideration of the way that New Zealand's regulatory framework for hydrogen supports its green hydrogen *Vision*. More immediately, the chapter makes a practical contribution to the hydrogen transition in New Zealand by setting out the current process for obtaining resource consent for electrolytic hydrogen projects.

Although there is no specific, dedicated regime for permitting electrolysers in New Zealand, a range of requirements must be met, particularly in relation to health and safety. Some of these are set out in legislation, while others, particularly technical specifications, are contained in standards.[20] Because compliance with these requirements will need to be demonstrated through the resource consent application process, this chapter focuses on that process, and notes these requirements in relation to it.

For context, the chapter begins with a brief overview of New Zealand's hydrogen regulatory environment (Section 14.2). It then considers New Zealand's resource management framework (Section 14.3), before discussing the specific requirements for resource consent for electrolytic hydrogen projects, with reference to a successful recent resource consent application (Section 14.3.2). The chapter then notes concerns about the efficacy of the resource consent process for supporting hydrogen developments, and suggested reforms (Section 14.4), before offering concluding remarks.

14.2 REGULATING HYDROGEN IN NEW ZEALAND

Despite current and planned hydrogen developments, there is no dedicated, hydrogen-specific regulatory framework for the production, transportation and storage of hydrogen in New Zealand.[21] Instead, a range of legislation, regulations and industry standards may be applicable.[22] For example, the Gas Act 1992 provides the legislative framework for the regulation, supply and use of gas in New Zealand, including hydrogen, and the protection of public health and safety and property.[23] Equally significant for electrolytic hydrogen projects is the Electricity Act 1992, which regulates the supply and use of electricity, and sets out safety requirements to

[19] See the discussion in Ministry of Business, Innovation and Employment.

[20] Standards are agreed specifications for products, processes, services and performance. They are generally voluntary but can also become legal requirements when cited in Acts, regulations or other legislative instruments.

[21] The firm Ernst & Young has noted that '[i]n our interactions with overseas investors, we hear: 'We are not considering investing in New Zealand as it is not a focus of the government, and there is no strategy in place. The lack of direction is impacting investor sentiment': Angela Ogier, Christina Houlihan, 'Could the New Zealand Hydrogen opportunity be closer than we think?' (2022), available at <https://ey.com/en_nz/energy-resources/could-the-new-zealand-hydrogen-opportunity-be-closer-than-we-think> accessed 21 February 2024.

[22] The range of regulations includes planning and resource management, electricity and gas, and health and safety rules and legislation.

[23] The Gas Act 1992 does not explicitly cover hydrogen, although it does cover biogas, coal gas and refinery gas, as well as natural gas. Nevertheless, hydrogen as a gas is classified as a permitted hazardous substance by the Environmental Protection Authority, and as a gas for fuel, it is covered by the Gas Act 1992. Related regulations are the Gas (Safety and Measurement) Regulations 2010; Gas (Levy of Industry Participants) Regulations 2020; Gas (Downstream Reconciliation) Rules 2008; Gas (Switching Arrangements) Rules 2008; Gas Governance (Compliance) Regulations 2008; Gas Governance (Critical Contingency Management) Regulations 2008.

protect electrical workers and the public.[24] The Health and Safety at Work Act 2015 sets out principles, duties and rights in relation to workplace health and safety, and covers hazardous activities, workplaces and facilities, while the Hazardous Substances and New Organisms Act 1996 covers storage and use of gas containers.[25] The Land Transport Act 1998 governs technical aspects of land transport and vehicle safety and provides for the safe transport of dangerous goods.[26]

In the Interim Roadmap the government committed to developing regulations to enable safe operation of hydrogen projects, and is focused on 'making changes needed to enable safe use of near-term activities such as production, storage and distribution, and applications like heavy road transport'.[27] To date, regulatory reform has been largely focused on amending provisions relating to natural gas to include coverage of hydrogen, and on ensuring adequacy of health and safety regulations, including hydrogen safety standards.[28] Recent consideration of how well New Zealand's current regulations,[29] standards[30] and health and safety requirements will cover anticipated hydrogen developments has identified the need for regulatory reform.[31]

A recent review concluded that hydrogen can generally be accommodated within the purpose of existing legislation, but the fit is imperfect and two significant issues arise: firstly, 'the novel uses and forms of hydrogen [cause] potential misalignment across legislation';[32] and, secondly, some legislative provisions are 'too prescriptive and therefore [exclude] hydrogen and its requirements'.[33] The review concluded that 'all proposed [hydrogen] activities were covered

[24] These requirements are supplemented by the Electricity (Safety) Regulations 2010, which provide for the management of electrical hazards by setting out requirements covering electrical safety, design, construction, installation, prevention of damage and the supply and use of electricity (including generation connected to electrolysers).

[25] Both Acts may require amendment to ensure they adequately cover the production, injection, transportation and use of hydrogen and hydrogen blends: FirstGas, 'Bringing zero carbon gas to Aotearoa: Hydrogen feasibility study – summary report' (2020), at 42, available at <https://cms.firstgas.co.nz/assets/Uploads/Documents/Firstgas-Group_Hydrogen-Feasibility-Study.pdf> accessed 21 February 2024 (hereinafter: FirstGas 2020).

[26] The Act is supplemented by the Land Transport Rule: Dangerous Goods 2005, which sets out requirements relating to quantity, packaging, labelling and marking, documentation, segregation, procedures, training and responsibility.

[27] The regulatory regimes in scope include (but are not limited to): the Health and Safety at Work (Hazardous Substances) Regulations 2017; the Electricity (Safety) Regulations 2010; the Gas (Safety and Measurement) Regulations 2010; the Land Transport Rule: Dangerous Goods 2005; and the Land Transport Rule: Vehicle Dimensions and Mass 2016.

[28] For more on this, see FirstGas 2020.

[29] In February 2022, the government engaged the firm PwC to undertake a review of existing regulatory frameworks; PwC assessed the regulatory frameworks against seven 'fit for purpose' criteria drawn from Treasury's 'Government Expectations for Good Regulatory Practice' guidelines and, in July 2022, PwC's review was released: PwC 2022. Contemporaneously, the Hydrogen Regulators Working Group was formed in April 2022; PwC worked directly with this group during the development of the report.

[30] Standards New Zealand investigated integrating hydrogen into New Zealand's energy landscape; its report, the Hydrogen Standards Review, was released slightly later, in May 2023: Standards New Zealand: 'Hydrogen standards review: Integrating hydrogen into New Zealand's energy landscape' (2023), available at <https://standards.govt.nz/assets/documents/news/hydrogen-report-v2.pdf> accessed 21 February 2024. The report recommends the direct adoption of fifteen international standards, as well as the modified adoption of an additional eight others and progressive updates to twenty Australia/New Zealand joint standards as well as the revision of eight New Zealand-specific standards.

[31] WorkSafe New Zealand established a working group to ensure the risks to health and safety in adopting new hydrogen technologies are adequately managed, regulatory gaps are identified, and regulatory barriers to industry adopting new hydrogen technologies are determined: Ministry of Business, Innovation and Employment, 'Hydrogen in New Zealand', available at <https://mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-strategies-for-new-zealand/hydrogen-in-new-zealand/> accessed 21 February 2024.

[32] PwC 2022, at 49; the example given is whether hydrogen is 'a gas used as a fuel under the Gas Act [1992] or ... an engine fuel under the Energy (Fuels, Levies and References Act) [1989])'.

[33] Ibid, at 49.

by legislative purpose ... [but] the existing regulatory frameworks fell short on fundamental criteria'.[34] Nevertheless, although 'none of [New Zealand's] regulatory frameworks are strictly "fit for purpose" to facilitate the future hydrogen economy ... many of the issues that need to be resolved are not urgent or are relatively minor changes'.[35]

The review identified forty-four Acts and ninety-three Regulations and Rules that are potentially relevant to hydrogen.[36] There is not scope in this chapter to discuss all of these regulations in detail, but an application for resource consent for an electrolytic hydrogen project will, in particular, need to demonstrate how the project will comply with requirements concerning safety, so these regulations are briefly addressed in the context of resource consent applications.

14.3 OBTAINING RESOURCE CONSENT FOR ELECTROLYTIC HYDROGEN PROJECTS

Before constructing and operating an electrolytic hydrogen project in New Zealand, resource consent will need to be obtained. Depending on the size, location and type of the intended development, a hydrogen project may require a number of resource consents. In addition to obtaining consents for hydrogen projects, developers may also need to obtain them for the renewable energy projects that provide electricity for the electrolysis that converts water to hydrogen: for example, electricity generated from wind farms.[37] These consents are issued under the Resource Management Act 1991, which is the main piece of legislation that regulates the environmental impacts of activities in New Zealand.[38] Thus, consent applications are primarily concerned with the way the environment may be affected and the way resources, such as water, will be used in the hydrogen development, rather than with the technical specifications of the electrolyser. That said, a range of regulations apply to the safe operation of electrical equipment, especially where this will be occurring in a potentially hazardous environment, so technical specifications and details of how the project will comply with these requirements will be included with the application. Building consents may also be needed to construct the hydrogen facility.

14.3.1 *Resource Management Act 1991*

Since its enactment, the Resource Management Act 1991 (RMA) has played a central role in regulating the development of renewable energy generation in New Zealand.[39] Despite this, the

[34] Ibid, at 44.
[35] Ibid, at 49.
[36] Ibid, at 44. Of these, thirty-two Acts were mapped to the hydrogen value chain, with these grouped into four categories: safety; use of hydrogen; markets and measurements; and infrastructure and resources.
[37] Ibid, at 52, noting that consent applications for offshore wind farms in the exclusive economic zone must be made with the EPA under the Exclusive Economic Zone (EEZ) and Continental Shelf (Environmental Effects) Act (2012). If the wind farm lies in a Coastal Marine Area, there will be impacts under the RMA for regional councils. Submarine infrastructure may need protection under Submarine Cables and Pipelines Protection Act (1996).
[38] See the Environment Guide's overview of the Resource Management Act 1991, available at <https://environmentguide.org.nz/rma/> accessed 21 February 2024. Under the RMA, environmental management is guided by the principles set out in Part 2 of the Act and the policies set out in any national and regional policy statements, which together provide the context in which decisions are made on whether or not to allow activities.
[39] The Resource Management Act 1991 is one of the main regulatory tools governing the operation of New Zealand's renewable energy system; the others are the Electricity Industry Participation Code 2010 (which governs the operations of electricity market participants) and the Emissions Trading Scheme (which incentivises investment in renewable energy ahead of fossil fuels by requiring carbon emitters to obtain and surrender emissions units to match the emissions from their operating activities).

RMA has been criticised for failing to achieve its purpose, for inadequately protecting the environment and for not enabling development.[40] At the time of writing, new legislation had recently been enacted that was intended to replace the RMA over the next decade.[41] This would have produced a significantly different environmental management regime; however, following a change in government in late 2023, this legislation was repealed, with further reform expected in future.[42]

The RMA's purpose is to ensure that natural and physical resources are managed sustainably.[43] The RMA does this in a decentralised way by requiring regional and district councils to manage natural and physical resources in their area.[44] These councils must prepare district or regional plans, which provide a framework for development in their region or district.[45] This means that, although the RMA provides the consenting framework, the consents are needed because of regional plans as well as national regulations. Additionally, the local plans and policies governing resource management can differ between districts and regions, and there may also be differences within a district, city or region. Complicating this interplay, the effects that certain activities may have on resources are managed through a hierarchy of planning documents developed under the RMA, which contain policies, standards and rules that prescribe whether an activity is permitted, or requires resource consent, or if it is prohibited.[46] These include National Environment Standards and National Policy Statements and Regional Policy Statements, as well as plans and strategies under other legislation.[47] Sometimes these National Environment Standards will override local rules to ensure a consistent set of rules across all councils. Thus, national direction balances localised decision-making; however, the different priorities of these policies may have to be reconciled.[48] This has particular relevance for

[40] See Resource Management Review Panel, 'New directions for resource management in New Zealand: Report of the Resource Management Review Panel: Summary and key recommendations', available at <https://environment.govt.nz/publications/new-directions-for-resource-management-in-new-zealand-report-of-the-resource-management-review-panel-summary-and-key-recommendations/> accessed 21 February 2024. Both the former (Labour) government and the recently elected (National-led) government are committed to resource management reform; however, their views on how best to do this are quite different.

[41] The Spatial Planning Act 2023 and the Natural and Built Environment Act 2023 came into effect on 24 August 2023 and was repealed on 23 December 2023.

[42] Resource Management (Natural and Built Environment and Spatial Planning Repeal and Interim Fast-track Consenting) Act 2023. While the repeal signals a reversion to the RMA provisions, the Government has confirmed it will retain the fast-track consenting provisions pending the introduction of further legislation.

[43] Resource Management Act 1991, s 5.

[44] New Zealand has eleven regional councils, sixty-one city or district councils and six unitary councils.

[45] Resource Management Act 1991, ss 64 and 73. See the Environment Guide's sections on 'District Plans' (available at <https://environmentguide.org.nz/rma/planning-documents-and-processes/district-plans/> accessed 21 February 2024) and 'Regional Plans' (available at <https://environmentguide.org.nz/rma/planning-documents-and-processes/regional-plans/> accessed 21 February 2024).

[46] The Environment Guide's section on 'Planning documents and processes' provides a useful overview: available at <https://environmentguide.org.nz/rma/planning-documents-and-processes/> accessed 21 February 2024.

[47] Resource Management Act 1991, ss 45 and 59. See the Environment Guide's section on 'National policy statements' (available at <https://environmentguide.org.nz/rma/planning-documents-and-processes/national-policy-statements/> accessed 21 February 2024) and 'Regional Policy Statements' (available at <https://environmentguide.org.nz/rma/planning-documents-and-processes/regional-policy-statements/> accessed 21 February 2024). The National Policy Statement for Renewable Electricity Generation 2011 is particularly relevant to renewable energy resource consent applications.

[48] For example, the National Policy Statement for Freshwater Management 2020 generally seeks to prioritise the health and well-being of freshwater ecosystems. However, the National Policy Statement for Renewable Electricity Generation recognises that there may be a need for an activity in a freshwater environment and allows regulatory authorities to give appropriate consideration to the benefits of hydro-generation when setting limits on water use, as well as requiring decision makers to have regard to the contributions and operational requirements of New Zealand's five largest hydro-generation schemes.

hydrogen developments because, on the one hand, national policy is being developed to support green hydrogen but, on the other, the regulations that will determine whether a project is consented to are much more localised. This may not be particularly problematic where a region is intended to be a 'hydrogen hub', but it does mean developers who are considering locating projects in different regions may be subject to different requirements in each region. For this reason, it has been suggested that a National Environment Standard for hydrogen would be helpful.[49]

The RMA classifies activities into six primary categories: 'permitted', 'controlled', 'restricted', 'discretionary', 'discretionary, non-complying' and 'prohibited'.[50] These categories determine whether a resource consent is required for particular activities. Rules in regional and district plans determine within which category an activity falls. The RMA prescribes the type of consent required and the process for obtaining a resource consent.[51] Types of resource consents include land use consents,[52] subdivision consents,[53] coastal permits,[54] water permits[55] and discharge permits.[56] For an electrolytic hydrogen project, the consent application would be expected to include land use consents, water permits and discharge permits. The duration of land use consents is unlimited, unless specified in the consent; the duration of other types of consent is a maximum of thirty-five years or the time specified in the consent.[57] The holder of a resource consent must comply with its conditions, which may include monitoring and reporting requirements.[58] Consents may be transferred.[59]

Because these consents relate to resource use, they do not deal with health and safety issues. These issues are instead governed by legislation: for example, the Electricity (Safety) Regulations 2010 provide for the management of electrical hazards by setting out requirements covering electrical safety, design, construction, installation, prevention of damage and the supply and use

[49] Ministry of Business, Innovation and Employment, 'Analysis of hydrogen vision submissions', undated, available at <https://mbie.govt.nz/dmsdocument/11343-analysis-of-hydrogen-vision-submissions> accessed 21 February 2024.

[50] Resource Management Act 1991, Part 6 s 87A.

[51] Ibid, Part 6 ss 87AA–139A. A resource consent provides permission to carry out an activity that would otherwise contravene ss 9, 11, 12, 13, 14, 15, 15A or 15B of the RMA, so long as it complies with any conditions attached to the consent.

[52] Ibid, ss 9 and 13, which authorise the use of land or the bed of a lake or river in a manner which contravenes a district rule, regional rule or national environmental standard.

[53] Ibid, s 11, which authorises the subdivision of land that is not expressly allowed by a rule in a district plan or national environmental standard.

[54] Ibid, s 12, which authorises any reclamation, structure, deposit or disturbance of the foreshore or seabed within the coastal marine area that is not expressly allowed by a rule in a regional coastal plan or national environmental standard.

[55] Ibid, s 14, which authorises the taking, use, damming or diversion of any water in a manner that contravenes a regional rule or national environmental standard.

[56] Ibid, s 15, which authorises discharge of contaminants to water or land unless the discharge is expressly allowed by a regional plan or national environmental standard.

[57] Ibid, s 123.

[58] The council may issue an abatement notice for breach of the conditions of a resource consent; or any person may apply to the Environment Court for an enforcement order requiring a consent holder to comply with the conditions of a resource consent (ss 314 and 322 of the Resource Management Act 1991). Contravention of an abatement notice or enforcement order is an offence (s 338 of the Resource Management Act 1991).

[59] Land use consents and subdivision consents attach to the land and need not be formally transferred. Coastal permits can be transferred to another person by written notice to the council that granted the permit. Water permits can be transferred to any owner or occupier of the site in respect of which the permit is granted, by written notice to the council that granted the permit. A discharge permit can be transferred to any owner or occupier of the site in respect of which the permit is granted, or to any person if the transfer is permitted by a regional plan: see ss 134 to 137 of the Resource Management Act 1991.

of electricity (including generation connected to electrolysers). Electrolysers will need to be certified as compliant with these Regulations and certifications must be achieved prior to the project becoming operational.[60] Similarly, the Health and Safety at Work (Hazardous Substances) Regulations 2017 provide for the management of hazardous substances by setting our requirements for labelling and signage, storage, separation distances, control of substances and emergency preparation.[61] Compliance with these Regulations will be demonstrated by a Location Compliance Certificate, which must be provided by an approved New Zealand certifier.[62] And the Pressure Equipment, Cranes and Passenger Ropeways Regulations 1999 provide for the management of pressure equipment, and prescribe requirements for design, verification, manufacturing, inspection, certification, operation and maintenance. Again, compliance with these Regulations will be demonstrated by certification by an approved New Zealand certifier.[63] Even though these safety requirements are prescribed by legislation, they also arise within the scope of the consent process because a risk management process and assessment will be prepared and included with the documents in the resource consent application to fulfil the information requirements under the relevant district plan.

An application for resource consent can be made to the district council or regional council that administers the district or regional plan under which the resource consent is required.[64] The application must be accompanied by an assessment of environmental effects.[65] The council will determine whether the application will be publicly notified.[66] If the application is not publicly notified, it will take up to 20 working days; if the application is publicly notified, submissions can be lodged and a hearing held, which can take up to 130 working days.[67] The council will issue a decision and the applicant and any submitters have a right of appeal to the Environment Court against that decision.[68]

When determining resource consent applications, consenting authorities must consider the environmental impacts of allowing the activity, as well as any mitigating or offsetting proposals.[69] Public support for, and opposition to, the application must also be considered. The RMA encourages public participation; this means that some projects have faced significant opposition

[60] Certification will be carried out by the electrical installer, and will include an Electrical Inspection Certificate for hazardous areas and high voltage; a Certificate of Compliance; and an Electrical Safety Certificate. See WorkSafe's guidance on the 'Design, construction and inspection of high voltage electrical installations' (2017), available at <https://worksafe.govt.nz/topic-and-industry/electricity/installations-and-networks/high-voltage-electrical-installations/design/> accessed 21 February 2024.

[61] It has been observed that the Hazardous Substances Regulations and Pressure Regulations are 'very strict and don't always align with appropriate international standards': see WSP, at 6.

[62] See WorkSafe, 'Location compliance certificates' (2022), available at <https://worksafe.govt.nz/topic-and-industry/hazardous-substances/certification-authorisation-approvals-and-licensing/certification-of-sites/location-test-certificates/> accessed 21 February 2024.

[63] These certifications include: a Design Verification Certificate; a Fabrication Inspection; an Inspection Certificate; a Type Certification; an Equipment Certification of Conformity; a Hydrotest Certificate; and a Certificate of Competence. See WorkSafe, 'Pressure equipment, cranes and passenger ropeways regulations' (2017), available at <https://worksafe.govt.nz/laws-and-regulations/regulations/hse-pressure-equipment-cranes-and-passenger-ropeways-regs/> accessed 21 February 2024.

[64] Where an activity requires resource consents from more than one authority, joint hearings may be held: Resource Management Act 1991, s 102.

[65] Ibid, Schedule 4.

[66] Ibid, s 95.

[67] The key sections of ibid are ss 95, 97, 101, 101B, 103A, and 115.

[68] Ibid, s 120.

[69] Ibid, s 104.

and applicants can become involved in protracted hearing and appeal processes.[70] For hydrogen projects, safety can be a particular concern; even where an applicant can demonstrate compliance with health and safety regulations, safety concerns may still engender public opposition to a hydrogen project.

The RMA also requires consideration of the values and interests of the Indigenous Māori people when determining applications for resource consents.[71] Court assessments of the adverse effects the proposed land use would have on Māori values, interests and their relationship to their ancestral lands has resulted in the refusal of consent for some renewable energy projects.[72] Māori opposition could have particular significance for hydrogen projects for two reasons. Firstly, many Māori tribes own, or have rights over, land adjacent to renewable energy sources or facilities. This may enable them to locate hydrogen production facilities on their own land, but they may also be opposed to these developments.[73] Secondly, freshwater has enormous significance to Māori, and their views on using it for electrolysis will need to be considered: analogously, in relation to hydro-electric power, tribal spokespersons have noted that 'the water itself might be renewable, the rivers themselves are not'.[74] Māori opposition to an electrolytic hydrogen project could result from opposition to the renewable energy activities that power the electrolysis, rather than opposition to the hydrogen project per se, as was seen in the following recent example of an opposed application for resource consent. This example also demonstrates the resource consents that may be needed for electrolytic hydrogen projects.

70 For example, in respect of wind farm developments, objections have focused on factors such as landscape effects, visual impacts, blade reflections, turbine noise and ecology.

71 Decision makers are required, when exercising functions and powers under the RMA, to: (a) recognise the relationship of Māori and their culture and traditions with their ancestral lands, water, sites, *wāhi tapu* (sacred places, sites or places subject to long-term ritual restrictions on access or use) and other *taonga* (treasures or things of value, including socially or culturally valuable objects, resources, phenomena, ideas and techniques) as a matter of national importance; (b) have particular regard to *kaitiakitanga* (the exercise of guardianship); and (c) consider the principles of the Treaty of Waitangi, which is the treaty between the British Crown and the Indigenous Māori people, first signed on 6 February 1840, which established British sovereignty over New Zealand (although this is contested), and which is the basis for the New Zealand government's relationship with Māori – a relationship which is framed in terms of a partnership, based upon the 'principle of the Treaty', a concept which continues to evolve (see *New Zealand Māori Council* v. *Attorney-General* [1987] 1 NZLR 641, and subsequent cases).

72 For example, *Unison Networks Ltd* v. *Hastings District Council* [2011] NZRMA 394 (HC). Opposition to electrolytic hydrogen projects may not be a principled objection to hydrogen developments, but may instead stem from opposition to the renewable energy project that powers the electrolysis.

73 For example, the geothermal power company Tuaropaki Power Company (which owns the Mokai Geothermal Power Station near Taupō) is partly owned by the Tuaropaki Ahu Whenua Trust. For more on this see J. Campion, 'Transformation through translation? Sustainable energy democracy, Indigenous values and the challenge of transforming the energy sector' in R. Fleming, K. Huhta, L. Reins (eds.), *Sustainable Energy Democracy and the Law*. (Brill: Leiden, 2021). See also K. Beasy, S. Lodewyckx, F. Gale, 'An analysis of emerging renewable hydrogen policy in Australia through an energy democracy lens' (2023), available at <https://ssrn.com/abstract=4369289> accessed 21 February 2024, for a discussion on how hydrogen developments may also be able to support energy democracy initiatives.

74 J. L. MacArthur, S. Matthewman, 'Populist resistance and alternative transitions: Indigenous ownership of energy infrastructure in Aotearoa New Zealand' (2019) 43 Energy Research and Social Science 16–24, 20. In light of this, the view expressed by the New Zealand government in the *Vision for Hydrogen* (at 30) that 'Green hydrogen, as a fuel created from water using the sun or the wind, has a life cycle that begins and ends with water, and is thus a technology that is consistent with [Māori] perspective[s]' seems a little naïve. See also the discussion in Richard Meade, 'Role of Māori in the Transition to a Low-Emissions Economy' (Ministry for the Environment, 2021), available at <https://environment.govt.nz/assets/publications/Cognitus-Maori-Role-in-Low-Emissions-Transition-2021_06_05.pdf> accessed 21 February 2024.

14.3.2 *Example: Hiringia Energy Limited and Ballance Agri-Nutrients Limited Resource Consent Application*

Hiringa Energy Limited and Ballance Agri-Nutrients Limited entered into a Joint Development Agreement to build facilities that use wind-powered electricity generation to produce green hydrogen and baseload renewable electricity for the Ballance Plant, which uses natural gas to produce ammonia and urea.[75] Hiringia and Ballance applied to establish a renewable wind energy facility and associated hydrogen production, storage, offtake and refuelling infrastructure.[76] Seven resource consents had previously been issued by the Taranaki Regional Council for the Ballance Plant, which covered the taking of water for the project as well as discharges to air, land and water.[77] Although specific consents were not sought for the electrolyser, it was described in the application along with the green hydrogen activities the project will support and that way received scrutiny and approval, as part of the resource consent application.

The application demonstrates the significance of regional plans to resource consent applications in New Zealand. Although the RMA provides the consenting framework, the consents are needed because of regional plans as well as national regulations: the applicants sought consents under the South Taranaki District Plan (2015) and the Regional Fresh Water Plan for Taranaki, as well as the Resource Management (National Environmental Standards for Freshwater) Regulations 2020 and the Resource Management (National Environmental Standard for Assessing and Managing Contaminants in Soil to Protect Human Health) Regulations 2011.[78]

The application was made under the COVID-19 Recovery (Fast-Track Consenting) Act 2020. This fast-track consenting approach has been retained beyond the COVID pandemic, and is now discussed.

14.4 RESOURCE MANAGEMENT ACT REFORM

During the COVID-19 pandemic, a temporary fast-track consenting process was introduced.[79] Following this experience, a more permanent fast-track process was introduced in the Natural

[75] The application and related documents can be accessed from the Environmental Protection Authority page, available at <https://epa.govt.nz/fast-track-consenting/referred-projects/kapuni/application/> accessed 21 February 2024.

[76] Background is set out in the application, available at <https://epa.govt.nz/assets/Uploads/Documents/Fast-track-consenting/Kapuni-Green-Hydrogen/191149-COVID-19-RA-Consent-Application-and-AEE-Final_27-Aug-21.pdf> accessed 21 February 2024. Electricity produced by the wind farm would be transmitted to the Ballance Plant via underground cables, with 'up to 5 MW (2,000 kg per day) of green hydrogen production from electrolysis being generated'.

[77] Had these not already been granted, they would have needed to be included in the application. In January 2021, Ballance was granted a variation to two of these water permits to allow for a small amount of some of the water take under these existing permits to be used to make hydrogen in association with the project. Because the proposal was within the consented volumes, no increase to the consented water take volumes was required.

[78] Consents were required covering discharge of stormwater and sediment into surface water or onto or into land in circumstances where sediment from soil disturbance may enter water (in relation to the proposed earthworks); to discharge of contaminants or water into surface water (in relation to dewatering of turbine foundations); to take and use water from a well or bore (gain, in relation to dewatering of turbine foundations); and for construction, placement and use of any structure that is not permitted or controlled under the plan, which related to a proposed culvert within the tributary of a stream on the wind turbine site.

[79] The COVID-19 Recovery (Fast-Track Consenting) Act 2020 came into effect on 9 July 2020 and was repealed on 8 July 2023. Essentially, the Act provided for a process to fast-track projects aimed at stimulating the economy. Under the Act, expert consenting panels were appointed to decide on each fast-track application. The panels had similar powers to consenting authorities under the RMA, but followed an abridged process: available at <https://epa.govt.nz/fast-track-consenting/ftca/about/> accessed 21 February 2024. For example, the Act stated that expert consenting

and Built Environment Act 2023; although this Act has now been repealed,[80] the fast-track process has been retained.[81] The process has two application steps: firstly, a referral application, which involves applying to use fast-track consenting; and, secondly, a substantive application, which involves applying for resource consent or lodging a notice of requirement.[82] If the fast-track application is unsuccessful, the application may still proceed on the standard track. For successful fast-track applications, this is expected to reduce consenting time by an average of eighteen months per project.[83]

Does this support New Zealand's hydrogen aspirations? In principle, the fast-track process should reduce the problems of time and cost. However, even if the consent is granted promptly, it can still be challenged. As noted, both general public and Indigenous opposition can be a significant hurdle for hydrogen projects. For example, in the Hiringia and Ballance application referred to above, the fast-tracked consent was granted despite objections from environmental groups and some local Māori (who objected to the proposed location of the wind turbines), who then appealed against the granting of the project's resource consent.[84] In the High Court decision to dismiss the appeal, the Court held that the expert panel had 'properly considered' the application.[85] That decision was also appealed; the appeal was dismissed in December 2023.[86] Despite the applicant's eventual success in court, the litigation highlights the delays that hydrogen projects can face if a project is not supported, and – because the resource consent application in that example was a fast-track application – also highlights the limitation of the fast-track consenting process to achieve the desired efficiencies in energy development. The appeal against the consent being granted has eroded the temporal gains that the fast-track consent process offers, which suggests that consenting process abridgements that are designed to deliver procedural efficiencies to resolve substantive concerns over resource development may only be effective where a renewable energy project is supported (or at least not significantly opposed) by the community. This is not something that can necessarily be addressed via refinements to the consenting process; consultation and engagement with stakeholders may prove more effective. This may be a particular consideration for hydrogen projects, which can face significant public opposition.[87]

Of course, public opposition is not the only reason for delays in the consenting process. Obtaining consent for hydrogen developments may be particularly challenging because of regulatory uncertainty. It has been observed that New Zealand's '[r]egulation relating to use of

panels must not give public or limited notification about a consent application or notice of requirement. However, panels must invite written comments from some people or groups listed in the Act.

80 The Natural and Built Environment Act 2023 was repealed by the Resource Management (Natural and Built Environment and Spatial Planning Repeal and Interim Fast-Track Consenting) Act 2023.

81 Resource Management (Natural and Built Environment and Spatial Planning Repeal and Interim Fast-Track Consenting) Act 2023, Schedule 1, Clause 8.

82 As with the approach taken under the COVID-19 Recovery (Fast-Track Consenting) Act 2020, an expert consenting panel is appointed to decide on the substantive application for each fast-track project. See the Environmental Protection Authority, 'Overview: Fast-track consenting under the Natural and Built Environment Act 2023', available at <https://epa.govt.nz/fast-track-consenting/nbea/overview/> accessed 21 February 2024. A list of fast-tracked projects can be found on the Environmental Protection Authority website: <https://epa.govt.nz/fast-track-consenting/fast-track-projects/> accessed 21 February 2024.

83 RNZ, 'Government refers wind and solar projects for fast-track consenting', 7 August 2023, available at <https://rnz.co.nz/news/political/495294/government-refers-wind-and-solar-projects-for-fast-track-consenting> accessed 21 February 2024.

84 *Te Korowai o Ngāruahine Trust* v. *Hiringa Energy Ltd* [2022] NZHC 2810, (2022) 24 ELRNZ 269.

85 Ibid, at [315].

86 *Greenpeace Aotearoa Incorporated* v. *Hiringa Energy Ltd* [2023] NZCA 672.

87 See the discussion of public opposition in Lorenzo Squintani and Stan Schouten's Chapter 11 in this book.

green hydrogen in infrastructure and resource management is the [regulatory] area posing the most uncertainty' for hydrogen developers.[88] A consequence of the many considerations that consenting authorities must take into account has been that applications take time to process – and projects can be held up, with the delay sometimes being significant, until consent is obtained.[89] Uncertainty over the way the existing regulatory frameworks permit and constrain hydrogen activities exacerbates this situation; consequently, 'hydrogen projects meeting a specific set of criteria of being nationally significant may experience streamlined risk assessment and resource consent processes', whereas 'it may be more difficult for local authorities to consider the unique risks of hydrogen and it may be better for a central body, such as the [Environmental Protection Authority], to manage the consenting process ... [which] would reduce the burden on Councils in understanding the unique risks associated with hydrogen'.[90]

This need for a consistent, national body-led approach was also picked up in the submissions received following the release of the *Vision* Green Paper, with several supporters of hydrogen noting 'the lack of a clear regulatory framework for hydrogen' and raising 'issues about uncertainty with regulatory coverage, regulatory boundaries, consenting under the RMA and what standards are relevant'.[91] A National Environment Standard covering hydrogen was recommended by some submitters, who suggested that this could ensure consistent rules and guidelines for hydrogen use across different territorial authorities.[92]

The suggestion of a National Environment Standard for hydrogen, and for a national-level agency to consider hydrogen resource consent applications, highlights the limitations of the localised decision-making process developed under the RMA to support New Zealand's national hydrogen *Vision* – and the limitations of improvements, such as the streamlined, fast-tracked consenting approach, to address delays in processing consent applications which are rooted in uncertainty over the application of current regulations to hydrogen activities. The suggestion is a sensible one and, along with updates to regulatory coverage to ensure hydrogen activities are within the scope of current legislation, regulations and standards, may provide sufficient regulatory changes to support the hydrogen *Vision*. However, without community support, hydrogen may not achieve its potential either. Any changes to the consent process must still provide for community engagement and participation. Regulatory certainty must be achieved through consenting processes that support national hydrogen policies while taking account of community concerns.

14.5 CONCLUDING REMARKS

This chapter asked the question 'which permits or resource consents are needed in order to build and operate an electrolyser in New Zealand?' and identified resource consents that may be needed and the process for applying for these. Implicit in that discussion is the broader question of whether 'New Zealand's resource consenting regime supports its hydrogen *Vision*?' Although legislation is in place that facilitates hydrogen development, there is still uncertainty and

[88] PwC 2022, at 13.

[89] Ian Llewellyn, 'Greenpeace accused of derailing emissions reductions', 6 December 2022, available at <https://businessdesk.co.nz/article/law-regulation/greenpeace-accused-of-derailing-emissions-reductions> accessed 21 February 2024.

[90] PwC 2022, at 53.

[91] Ministry of Business, Innovation and Employment, 'Analysis of Hydrogen Vision submissions', undated, available at <https://mbie.govt.nz/dmsdocument/11343-analysis-of-hydrogen-vision-submissions> accessed 21 February 2024.

[92] Ibid, at 6.

complexity. For resource consents, uncertainty can cause delays, which may frustrate the very progress the *Vision* is promoting. This is something that should be considered as further reform of New Zealand's resource management framework occurs.

Ultimately, New Zealand is interested in developing its hydrogen capacity and has the potential to do this successfully. But, to achieve this, a supportive regulatory regime that facilitates the desired hydrogen developments will be needed. While, in theory, hydrogen appears to be within the scope of existing regulations, a hydrogen-specific framework would help tremendously with removing uncertainties and the delays these can cause.

FURTHER READING

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Ministry of Business, Innovation and Employment, 'A vision for hydrogen in New Zealand', September 2019, available at <https://mbie.govt.nz/dmsdocument/6798-a-vision-for-hydrogen-in-new-zealand-green-paper> accessed 21 February 2024

'Hydrogen in New Zealand', available at <https://mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-strategies-for-new-zealand/hydrogen-in-new-zealand/> accessed 21 February 2024.

'Interim Hydrogen Roadmap', August 2023, available at <https://ena.org.nz/assets/9927-Interim-Hydrogen-Roadmap-AUG23.pdf> accessed 21 February 2024

PwC, 'New Zealand's hydrogen regulatory pathway', July 2022, available at <https://mbie.govt.nz/dmsdocument/25671-new-zealand-hydrogen-regulatory-pathway> accessed 21 February 2024

Resource Management Review Panel, 'New directions for resource management in New Zealand: Report of the Resource Management Review Panel: Summary and key recommendations', available at <https://environment.govt.nz/publications/new-directions-for-resource-management-in-new-zealand-report-of-the-resource-management-review-panel-summary-and-key-recommendations/> accessed 21 February 2024

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PART IV

Regulating Hydrogen Transport

15

Accelerating Permission

Hydrogen Transport and Storage Regulation – A German Case Study

Cathérine Jansen

15.1 INTRODUCTION

German efforts to exploit the potential of hydrogen to accomplish the energy transition have in recent months seen significant acceleration. Following an update to the National Hydrogen Strategy (NWS) in July 2023,[1] the government recently doubled down on a decision to construct the basic and most important parts of the hydrogen network – the *core* network – which constitutes a crucial element of the wider infrastructure required to put hydrogen to use.

Legally, this is to be brought about via an amendment to the Energy Industry Act (EnWG) in article 28r EnWG-E.[2] Projects approved under this article are deemed to be necessary for the energy industry and in the overriding public interest provided they are commissioned by 2030. Further plans are underway to legally accelerate the permission procedure for projects related to core network construction.[3] The crucial issue of hydrogen storage is also acknowledged in both the recent amendment and the underlying strategy and is the subject of a separate concept currently being developed by the Federal Ministry for Economic Affairs and Climate Protection.[4]

More broadly, and beyond these new plans to swiftly bring about a new core network (the full mapping of which has yet to occur[5]), it is fair to say that a well-functioning planning and approval law is of paramount importance for the development of a hydrogen infrastructure.[6] Against this background, the following legal discussion focuses on those equally crucial parts of the hydrogen infrastructure that are not expected to be part of the new proposals and are subject to the existing planning and approval laws of energy plants.

1 NWS <www.bmwk.de/Redaktion/EN/Publikationen/Energie/the-national-hydrogen-strategy.pdf?__blob = publicationFile&v = 6> accessed 28 September 2023; NWS Update <www.bmbf.de/SharedDocs/Downloads/de/2023/230726-fortschreibung-nws.pdf?__blob = publicationFile&v = 1> accessed 11 December 2023 (hereinafter: NWS Update).

2 BR-Drs. 579/23 24; 'EnWG-E' clarifies the current draft status of the provision, which is expected to come into force by the end of 2023.

3 Zeit Online, 'Energiewende' <www.zeit.de/wirtschaft/2023-11/wasserstoff-robert-habeck-netz-leitungen-energie> accessed 11 December 2023.

4 NWS Update.

5 FNB Gas, 'Wasserstoff-Kernnetz' <https://fnb-gas.de/en/hydrogen-core-network/> accessed 11 December 2023.

6 M Kohls, 'Planung und Zulassung von Energieanlagen' in C Theobald, J Kühling (eds) *Energierecht* (C H Beck, 118th edn 2022) ch 130 para 2–2a (hereinafter: Kohls).

Here, project developers face a significant number of sectoral regulations that are interconnected and can only be understood if their interdependencies are taken into account.[7] Importantly, Germany's law of energy plants is not self-contained or uniformly codified.[8] Depending on the classification, energy plants fall within the scope of application of the EnWG and/or another law and thus within the competence of the energy supervisory authority and/or other supervisory authorities.[9] Crucially, the EnWG includes provisions for expediting the development of hydrogen infrastructure, which can only be applied if the EnWG is applicable to the respective project. As will be shown below, this might not always be the case.

Moreover, Germany has two types of permission procedures – formal and simplified.[10] Public participation is required during the formal but not during the simplified procedure,[11] making the first more time-consuming.[12] To assess the relevant permit requirements, the competent authority must first be aware of the proposed energy installation.

To this end, the so-called administrative opening control requires the developer to inform the authority of the project and/or submit an application for permission before constructing and operating an energy plant.[13] With regard to the administrative opening control, a fundamental distinction must be made between the obligation to notify and the obligation to obtain a permit. The obligation to notify provides authorities with the necessary information, whereas permission obligations subject the construction and/or operation of an energy facility to a state permit.[14]

It is against this wider background of policy dynamism and domestic legal mechanisms that this chapter examines the matter of accelerated permission procedures for the construction of much-needed hydrogen infrastructure. Following this introduction, the chapter is structured into five further sections. Section 15.2 will examine the permission regime for the construction of new hydrogen pipelines. Section 15.3 then shifts the focus to the repurposing of existing natural gas pipelines for the transportation of hydrogen. Section 15.4 directs attention to another important hydrogen infrastructure component and delves into the permission regime for the construction of hydrogen storage. Section 15.5 does the same with a view to the repurposing of cavern storage from natural gas to hydrogen. Building upon these sections, a final conclusion and outlook will be presented in Section 15.6.

15.2 THE PERMISSION REGIME FOR THE CONSTRUCTION OF PURE HYDROGEN PIPELINES

This section will show that new construction projects in Germany are subject to stringent approval procedures, with little to no option for project developers to benefit from acceleration procedures. Further, it will illustrate that there is no single legal framework exclusively dedicated

[7] Ibid.

[8] M Lang, 'Einleitung und Grundlagen' in F Säcker, M Ludwigs (eds) *Berliner Kommentar zum Energierecht* (dfv Mediengruppe, 5th edn 2022) ch 3 para 1.

[9] C Theobald, 'EnWG § 3' in C Theobald, J Kühling (eds) *Energierecht* (C H Beck, 119th edn 2023) para 110.

[10] Kohls 18.

[11] Ibid 19.

[12] As part of the public participation process, anyone must be given the opportunity to raise objections to the project within a certain time frame. Participation can range from the publication of a project to the display of documents and the right to comment, possibly even to the organisation of a hearing. The aim is to ensure a fair procedure in which the individual is not merely the object of state decisions; see A Lippert, 'Die Bedeutung der Öffentlichkeitsbeteiligung bei großen Infrastrukturvorhaben' (2013) 24 ZUR 203, 204.

[13] Kohls 2–13.

[14] Ibid 3–5; C Schrader, 'BNatSchG § 17' in L Giesberts, M Reinhardt (eds) *BeckOK Umweltrecht* (C H Beck, 65th edn 2023) para 8.

to energy plants, such as the construction of hydrogen pipelines and their associated facilities. Instead, the interconnectedness of numerous sector-specific provisions that may potentially apply will be looked into.

15.2.1 *Regional Planning*

When it comes to constructing new hydrogen pipelines, the requirements of regional planning processes must be taken into account. Key provisions include the allocation of energy plants and conflict resolution between such plants and other land uses.[15]

The regional planning procedure, as outlined in article 15 Regional Planning Act (ROG), can play an important role in the planning of energy facilities in the absence of comprehensive planning requirements.[16] Pursuant to article 1 No. 14 Regional Planning Ordinance (RoV), a regional planning procedure is required for gas pipelines of more than 300 mm diameter. As per article 43l (7) EnWG, the term 'gas pipelines' in article 1 No. 14 RoV explicitly includes hydrogen networks. It follows from the legislative documents that the wording 'with a diameter of more than 300 mm' is to be understood as the inside diameter as the nominal width.[17] This clarification is necessary because in engineering, diameters of pipelines are defined for the outer diameter.[18] This difference in understanding can lead to problems of application in practice.[19]

In this context, the literature raises the question whether, in the case of an interconnection of several hydrogen pipelines with different nominal diameters, one pipeline section with a diameter of more than 300 mm is sufficient for the fulfilment of the legal requirements, in this case article 1 No. 14 RoV in conjunction with article 43l (7) EnWG, or whether the predominant share of such pipelines in a network is decisive.[20]

While the wording seems to indicate that a single pipeline cannot fulfil the definition of a 'network', the legislator's explanatory memorandum (as well as the 'network' term in article 2 (2) of Directive 2009/73/EC) support the assumption that a single pipeline section is in fact sufficient to fulfil the definition of a 'network' and thus opens up the scope of section 1 No. 14 RoV.[21] The argument against this reading is that, given the legislator's intention to create a framework for the accelerated development and expansion of hydrogen networks, the implementation of regional planning procedures, which have so far not been necessary for gas supply networks, could also be avoided for hydrogen networks.[22] For the time being, there is a stronger case for assuming that a section of pipeline with a diameter of more than 300 mm is sufficient to meet the legal requirements and therefore the terms hydrogen pipeline and hydrogen network are to be understood synonymously.

[15] Kohls 191.
[16] Ibid 216.
[17] BT-Drs. 15/4068 8.
[18] A Bala, 'Das Erfordernis der Planfeststellung bei betrieblichen Baumaßnahmen an Gasversorgungsleitungen' (2016) 95 RdE 493.
[19] S Riege, 'Die Umstellung von Gasversorgungsleitungen für den Wasserstofftransport' (2021) 10 EnWZ 387, 389 (hereinafter: Riege).
[20] S Riege, M Schacht, 'EnWG § 43l' in L Assmann, M Pfeiffer (eds) *BeckOK EnWG* (C H Beck, 6th edn 2023) para 81 (hereinafter: Riege, Schacht).
[21] BT-Drs. 19/27453 118; M Pfeiffer, 'EnWG § 3 Nr. 39a' in L Assmann, M Peiffer (eds) *BeckOK EnWG* (C H Beck, 6th edn 2023) paras 6–7.
[22] Riege, Schacht 81.

Accelerating regional planning procedures was the subject of a recent legislative resolution by the German Federal Parliament.[23] Long procedures are not only economically detrimental to project developers and investors but they also impede a swift energy transition.[24] The acceleration provisions include leveraging enhanced digitisation in participation procedures, reducing redundant amendments to draft plans, and refining plan maintenance rules to bolster planning and investment assurance.[25] Additionally, efforts aim to enhance cohesion between regional planning and approval processes, ultimately streamlining the overall procedure.[26]

Against the backdrop of the legislator's intention to quickly develop and expand Germany's hydrogen infrastructure amid sustained high expansion demand for the energy transition, expediting regional planning through the recent resolution holds potential for notable simplification and optimisation.

As mentioned above, the regional planning procedure has a broad geographical scope. For the more concrete approval of projects, the plan approval procedure is relevant, and will be discussed next.

15.2.2 *Plan Approval*

Large infrastructure projects often lead to conflicts of interest. To carefully weigh up all interests and take the best possible account of those affected, there is a plan approval procedure in Germany. It involves extensive participation by the authorities and, in most cases, the public.[27] Decisions on large-scale projects have to be made based on a single procedure to ensure that all relevant facts and interests are taken into account and an appropriate balance is struck.[28] The plan approval procedure is thus designed as a one-stop shop in that it includes all other official decisions required for the project's implementation.[29] This so-called concentration effect ensures that further public law permissions are not required for the energy facility, according to article 75 (1) 1 Administrative Procedures Act (VwVfG).[30]

Whether or not a plan approval procedure is required is determined by the relevant sectoral law.[31] The legal basis for the plan approval procedure can be found in articles 72–78 VwVfG.[32] For planning approval concerning the construction of hydrogen pipelines, article 43 and following EnWG contain special provisions. Explicit reference to articles 72–78 VwVfG is made in article 43 (4) EnWG, which shows the mentioned interdependence between the sectoral regulations and the general provisions in the law of energy plants.

Plan Approval Decision and Plan Authorisation

The planning approval authority can either be decided by means of a plan approval decision (article 74 (1) VwVfG) or a plan authorisation (article 74 (6) VwVfG). The plan authorisation

[23] BR-Drs. 95/23.
[24] H Schmitz, M Lehrian, 'Verfahrensbeschleunigung durch oder trotz Raumordnung – Das Raumordnungsverfahren im Kontext aktueller und geplanter Beschleunigungsgesetze' (2023) 46 ZfBR 221.
[25] BT-Drs. 20/4823 17.
[26] Ibid.
[27] Kohls 145.
[28] Ibid.
[29] M Wickel, 'VwVfG § 75' in R Strömer (ed) *Verwaltungsrecht Handkommentar* (Nomos, 5th edn 2021) para 19.
[30] Kohls 102.
[31] Ibid 145.
[32] The procedure can also be found in the procedural laws of the federal states which largely correspond to those of the federal government. Only more specific regulations of sectoral laws take precedence over the general regulations, e.g. art. 43 et seq. EnWG contain special regulations for the plan approval of energy line projects.

substitutes the plan approval decision and thus, like the latter, enables the execution of the project described in the submitted plan.[33] The main difference between the two procedures is the exclusion of mandatory public participation from the plan authorisation procedure, leading to a faster process by comparison.[34] Due to the interplay with Annex 1 No. 19.2 Environmental Impact Assessment Act (UVPG) as per article 43l (2) EnWG, public participation may be mandatory if the construction of a hydrogen pipeline requires an environmental impact assessment (EIA). That is the case when length and diameter exceed certain values. If there is an obligation to carry out an EIA, public participation within the meaning of article 73 VwVfG is mandatory according to article 3 and 18 (1) UVPG. In this case, the option of an accelerated plan authorisation is ruled out because the requirements of article 74 (6) VwVfG are not met, and a planning approval decision is required. The same applies if a regional planning procedure is mandatory, since it too requires public participation and thus excludes the application of section 74 (6) VwVfG (see Section 15.2.1).[35] As the procedural provisions of the UVPG (which will be discussed below under Section 15.2.3) and ROG supplement the general procedural provisions of the VwVfG, the interplay of the different laws applicable becomes apparent.

Mandatory Plan Approval

The legal consequences of obtaining planning approval, as set out in article 43c EnWG in conjunction with article 75 VwVfG, encompass granting permission for the project, while taking into consideration all affected interests. As a result of the concentration effect of article 75 (1) 1 VwVfG, no additional official decisions are required.[36]

For hydrogen pipelines, a planning approval pursuant to article 43 EnWG might be applicable, provided they are 'gas supply pipelines' with a diameter exceeding 300 mm. According to article 43l (1) 1 EnWG, 'the term gas supply pipeline in part 5 of the law also includes hydrogen networks'. Moreover, article 43l (2) EnWG determines that the planning approval process applies to the construction, operation, and modification of hydrogen pipelines with a diameter exceeding 300 mm.[37] Thus, all provisions of the EnWG on plan approval apply to hydrogen networks with a diameter exceeding 300 mm.

In accordance with article 43 (3) EnWG, the consideration of plan approval for a project necessitates the inclusion of both public and private interests that are affected by the project.[38] The weighing of interests is a decision-making instrument in German administrative law. It involves the special circumstance that a permit can be granted or an intervention legitimised even though the interests or rights of others are affected. Here, the weighing process must take into account municipal, as well as environmental concerns in relation to the public law permission for an energy pipeline project.[39] It is important to note that article 43l (1) 2 EnWG features a so-called overriding public interest for the construction of hydrogen

[33] H-J Peters et al, 'UVPG § 65' in H-J Peters, S Balla, T Hesselbarth (eds) *Gesetz über die Umweltverträglichkeitsprüfung* (Nomos, 4th edn 2019) para 11 (hereinafter: Peters et al).

[34] N Kämper 'VwVfG § 74' in J Bader, M Ronellenfitsch (eds) *BeckOK VwVfG* (C H Beck, 59th edn 2023) para 131; W Huck, 'VwVfG § 74' in M Müller, W Huck (eds) *Beck'sche Kompakt Kommentare Verwaltungsverfahrensgesetz* (C H Beck, 3rd edn 2020) paras 66–67.

[35] It's unlikely that the acceleration provision of § 74 (7) 1 VwVfG will apply to hydrogen pipeline construction due to their significant importance in infrastructure projects.

[36] Riege, Schacht 21.

[37] S Riege, 'EnWG § 43' in L Assmann, M Pfeiffer (eds) *BeckOK EnWG* (C H Beck, 6th edn 2023) para 57.5–60.

[38] S Missling et al, 'EnWG § 43' in C Theobald, J Kühling (eds) *Energierecht* (C H Beck, 118th edn 2022) para 98.

[39] Ibid 103–104.

pipelines. This overriding public interest privilege is limited until 31 December 2025. Therefore, in situations where protected interests need to be balanced, priority should be given to hydrogen pipelines, at least until the end of 2025.[40] In view of the typical length of the planning approval procedure and (if necessary) a preceding regional planning procedure,[41] however, the duration of the overriding public interest privilege seems to be too short and the legislator should reconsider extending the privilege beyond 2025.

Facultative Plan Approval or Mandatory Plan Authorisation

Project developers have the option to voluntarily submit an application for planning approval under article 43l (3) 1 EnWG, when a planning approval procedure is not mandatory because the pipeline's diameter does not exceed 300 mm as stipulated by article 43l (2) and 43 EnWG in conjunction with article 43l (1) 1 EnWG.

One argument in favour of seeking planning approval is the concentration effect, which eliminates the need to apply for individual approvals from numerous authorities.[42] Another is the early transfer of ownership as specified in article 44b EnWG and the possibility of commencing construction early under article 44c EnWG. Conversely, as long as the provision of article 43l (1) 2 EnWG on the overriding public interest for the construction of hydrogen pipelines is in force, it may be possible to secure the necessary individual permits more easily compared to undergoing a time-consuming planning approval procedure.

Additionally, the regulation of article 65 (2) UVPG must be taken into account, according to which the project requires planning authorisation if no EIA is required. For the construction of hydrogen pipelines with a diameter of less than 300 mm, for which there is no obligatory plan approval procedure and for which the general preliminary examination or site-specific examination of the individual case indicates that no EIA is necessary, project developers have the choice of whether they want to carry out a facultative plan approval under the EnWG or a plan authorisation under the UVPG.

In the case of a facultative plan approval under the EnWG, the advantage over plan authorisation under the UVPG would be that the specific acceleration regulations under energy law would apply.[43] However, the legal privilege under article 43l (1) 2 EnWG only applies until 31 December 2025. In contrast, plan authorisation offers advantages over plan approval in that it has the same legal effect without having to comply with the time-consuming requirements associated with the plan approval process, such as the public participation procedure under article 73 VwVfG.[44] To conclude, developers must promptly establish the appropriate and optimal procedure for their project to capitalise on the benefits of the procedure that best suits their respective project plans.

Finally, if a plan approval procedure is carried out, environmental concerns are included in the concentration effect; if not, such concerns must be addressed separately. The following section therefore examines what in all cases is part and parcel of the permission procedure.

[40] F Allolio et al, 'Studie zum Rechtsrahmen einer zukünftigen Wasserstoffwirtschaft' (2022) legal study commissioned by the Fraunhofer Institute for Energy Infrastructures and Geothermal Energy, 39 (hereinafter: Allolio).

[41] The process can take several years. This depends in particular on the intensity of public participation, the possible preparation of expert opinions by citizens' initiatives, the processing of objections and comments by the authorities and, if necessary, further coordination and plan amendments.

[42] Allolio 36.

[43] M Elspas et al, 'Die neuen Regelungen im EnWG zum Wasserstoff' (2021) N&R 258, 264 (hereinafter: Elspas).

[44] Peters et al 11; Elspas 264.

15.2.3 *Environmental Law*

Various attempts to unify German environmental law have so far failed, which means German environmental law is splintered and consists of various sectoral laws.[45] As a result, the many sectoral environmental laws that focus on specific environmental areas – such as the UVPG, as well as nature conservation law, water resources law, or forest law – must be taken into account individually when constructing hydrogen pipelines.

The Federal Immission Control Act (BImSchG) is another law which aims to protect various aspects of the environment.[46] The BImSchG is limited to general requirements. It is only through sub-legislative concretisation in numerous implementing ordinances that these become manageable for legal application. One of those is the 4th Ordinance on the Implementation of the BImSchG (4. BImSchV), which plays a constitutive role in determining the types of installations subject to permission. As the transportation of hydrogen is not listed in its Annex 1, an emission control permit is not required here.

Interestingly, hydrogen-specific provisions can only be found for the EIA. However, the legal privilege outlined in article 43l (1) EnWG, which establishes the overriding public interest privilege until 31 December 2025 for the construction of hydrogen pipelines, may play a decisive role in balancing processes with individual environmental laws.

The construction and operation of a gas supply pipeline require an EIA if length and diameter exceed certain values, according to No. 19.2 of Annex 1 to the UVPG. Article 43l (2) 1 EnWG stipulates that Annex 1 No. 19.2 UVPG is applicable to hydrogen networks. The EIA obligation varies depending on whether it is mandatory (projects in column 1 of Annex 1) or determined through an official preliminary assessment (projects in column 2 of Annex 1).[47] For hydrogen grids with a length over 40 km and a diameter over 800 mm, the EIA is mandatory according to Annex 1 No. 19.2.1 of the UVPG in conjunction with article 43l (2) 2 EnWG. In the case of hydrogen networks with pipelines having a diameter between 300 mm and 800 mm, new projects require a preliminary assessment under article 7 UVPG.[48]

The purpose of the preliminary assessment is to check, in a relatively quick and inexpensive way, whether or not an EIA is required for projects that could have an abstract or concrete significant environmental impact.[49] A distinction is made between two types of preliminary assessment: a general preliminary assessment (article 7 (1) 1 UVPG) and a site-specific preliminary assessment (article 7 (2) UVPG). The latter corresponds to a large extent to the former, but with the possibility of a reduced assessment programme.[50] The preliminary assessment will be particularly helpful for projects where large parts of the natural gas pipelines can be repurposed for hydrogen and only a few new pipelines with diameters between 300 mm and 800 mm need to be built to complement the network.

However, it must be acknowledged that the EIA authorisation process, in general, is quite time-consuming. Between 2009 and 2021 the average time from application to decision was

[45] Umweltbundesamt, 'Umweltgesetzbuch' <www.umweltbundesamt.de/umweltgesetzbuch#grunde-fur-ein-umweltgesetzbuch> accessed 6 December 2023.

[46] Act on the Prevention of Harmful Effects on the Environment Caused by Air Pollution, Noise, Vibration and Similar Phenomena (Federal Immission Control Act – BImSchG) <www.bmuv.de/fileadmin/Daten_BMU/Download_PDF/Luft/bimschg_en_bf.pdf> accessed 30 June 2024.

[47] Kohls 36a.

[48] Further details can be found in Nos. 19.2.2 to 19.2.4 of Annex 1 to the UVPG.

[49] J Tepperwien, 'UVPG § 7' in A Schink, O Reidt, S Mitschang (eds) *Umweltverträglichkeitsprüfungsgesetz Umwelt-Rechtsbehelfsgesetz* (C H Beck, 2nd edn 2023) para 1.

[50] Ibid 15; the programme is set out in article 7 (2) UVPG.

16.8 months.[51] This clearly poses a challenge for the intended rapid development of a hydrogen infrastructure in Germany and will need to be addressed further by policy-makers going forward, in the interest of accelerating the permission procedure. One area where such acceleration has arguably occurred is pipeline rights and land use agreements, to which the following section is devoted.

15.2.4 *Pipeline Rights and Land Use Agreements*

Pipeline-based energy supply often requires the use of land that is owned by third parties.[52] While public law permissions primarily address public law concerns, they do not account for potential conflicts with the private rights of third parties, such as land ownership. As a result, construction and operation[53] of gas supply pipelines require civil law approval in addition to public law permits.

For pipeline rights to properties that are not dedicated as public transport routes, such as licence agreements, limited personal easements or other agreements that do not provide for the registration of a limited personal easement, article 113a (1) EnWG determines that existing approvals for gas supply pipelines are, when in doubt, to be interpreted in a manner that includes the construction and operation of hydrogen pipelines. However, if it can be concluded from the agreement that the third party did not wish to authorise hydrogen pipelines on its property, or would not have had it been asked to do so, there is no doubt about interpretation, and therefore no applicability of article 113a (1) EnWG.

Pipeline rights on public transport routes, so-called land use agreements within the meaning of article 46 EnWG, are regulated in article 113a (2) and (3) EnWG. If a network operator has a land use agreement as defined by article 46 EnWG for gas pipelines, this contract also applies to the transport and distribution of hydrogen, but only until the end of its term, according to article 113a (2) EnWG.[54] However, article 113a (3) EnWG establishes the right of hydrogen network operators to request land use agreements from municipalities if the current contract period has come to an end. In effect, this imposes a contracting obligation on the latter, alleviating the burden of contract negotiations for new projects.[55] Moreover, article 113a (3) EnWG stipulates that the conditions of land use agreements for hydrogen pipelines may not be less favourable than those of land use agreements for gas pipelines.[56]

Only when new contracts are concluded do developers need to take action; it is only new contracts with private parties that are not subject to special regulations. Overall, article 113a EnWG enables the gradual expansion and development of hydrogen networks without delays caused by legal uncertainties in contract interpretation or required contract negotiations.[57]

[51] Federal Environment Agency, 'Genehmigungsverfahren 2009–2021' (2023) <https://umweltbundesamt.at/uvpsup/?verfahrensmonitoring?/vm-dauer/gv-dauer> accessed 28 September 2023.

[52] A Bartsch, E Ahnis, 'Leitungsrechte in der Energiewirtschaft: Die beschränkte persönliche Dienstbarkeit' (2014) 11 IR 122; Riege 394.

[53] Civil law approvals to operate pipelines often arise from limited personal easements, art. 1090 et seq. German Civil Code [BGB]. Currently, limited personal easements are registered in the cadastre for the construction and operation of 'gas, long-distance gas or natural gas pipelines'; see BR-Drs. 165/21 160; BT-Drs. 19/27453 137.

[54] Elspas 266.

[55] Allolio 44.

[56] BT-Drs. 19/27453 138; Elspas 266.

[57] BR-Drs. 165/21 160; T Börker et al, 'Auswirkungen der EnWG-Novelle 2021 auf wegerechtliche Gestattungen für Wasserstoffnetze' (2021) 18 IR 197, 199.

Having assessed the permission regime for the *construction* of hydrogen pipelines, we will now turn to the issue of *repurposing* existing natural gas pipelines for the transportation of this promising carrier of energy.

15.3 THE PERMISSION REGIME FOR REPURPOSING PIPELINES

As the new EnWG amendment and the revised NWS emphasise,[58] Germany is banking heavily on the repurposing of natural gas pipelines for hydrogen. Given the decline in fossil fuels required to achieve climate targets, it is logical to use the existing natural gas infrastructure for hydrogen transport. As this section will demonstrate, from a permission point of view, this approach is already flanked by energy legislation that existed prior to the recent EnWG amendment.

15.3.1 *Plan Approval Procedure*

The most important planning law regulation for accelerating the establishment and expansion of hydrogen networks is the regulation governing procedural simplifications for the repurposing of existing gas supply pipelines to hydrogen, which is outlined in article 43l (4) EnWG.[59] Article 43l (4) and (5) EnWG provide a special lever. They extend the scope of official approvals for natural gas pipelines and their ancillary facilities to hydrogen transportation. This is subject to the requirement that the initial natural gas pipeline approvals were integrated in a plan approval procedure and do not require an emission control permit[60] (see Section 15.2.3), and had been based on the EnWG or another law.[61] According to article 43l (4) 2 EnWG, the transferability applies not only to previous official approvals, but also to pipelines that were subject only to a notification procedure. Accordingly, these gas supply systems are allowed to be repurposed for hydrogen without a plan approval procedure.[62]

According to article 43l (4) 3 EnWG in conjunction with article 113c (3) EnWG, there is a mandatory notification requirement for repurposing. The notification, along with necessary safety assessment documents and an expert report verifying compliance with the technical rules of the German Technical and Scientific Association for Gas and Water (DVGW),[63] must be submitted to the competent authority at least eight weeks before the repurposing begins.[64] The authority then has an eight-week window to confirm that there are no objections to the repurposing (article 43l (4) 3 EnWG in conjunction with article 49 (1) EnWG).

Article 113c (3) EnWG does not differentiate between gas pipelines of different pressure levels or different lengths and diameters, extending the official preventive control to all gas pipelines that are to be repurposed. Scholars have questioned the proportionality of this

[58] Article 28r (2) EnWG-E; NWS Update 14; FNB Gas <www.bundesnetzagentur.de/DE/Fachthemen/ElektrizitaetundGas/Wasserstoff/Kernnetz/Downloads/Antragsentwurf_FNB.pdf?__blob = publicationFile&v = 3> accessed 11 December 2023.

[59] Elspas 264.

[60] The transportation of natural gas via pipelines is not listed in the 4. BImSchV.

[61] Allolio 31.

[62] Building law permissions and nature conservation permissions also extend to the transport of hydrogen under § 43l (4) and (5) EnWG.

[63] The main task of the Association is to draw up the technical regulations that ensure the safety and reliability of gas and water supply in Germany. Legislation grants the DVGW worksheets the status of generally recognised technical rules. The users can therefore assume with legal certainty that compliance with the rules equates to compliance with public law regulations.

[64] Allolio 32.

extension of regulatory control, arguing that it restricts the technical self-administration of the gas industry enshrined in article 49 EnWG and brings about additional bureaucracy.[65] This can be countered by the fact that article 49 EnWG actually provides for the operator's own responsibility to comply with the technical rules, so that the authority only takes action in exceptional cases, namely when the operator clearly fails to meet its responsibilities.[66] The obligation to notify and the requirement to obtain an expert's opinion during the repurposing process therefore serve to ensure safety during the transitional phase.[67]

Until recently it was assumed that technical modifications would be necessary when repurposing natural gas pipelines for the use of hydrogen.[68] However, a current research project by the DVGW, which investigated the fracture-mechanical material behaviour of natural gas steel pipelines, demonstrated their suitability for hydrogen transmission.[69] Should modifications nevertheless become necessary, these may fall under the requirements of either article 43l (2) EnWG or article 43f EnWG.

According to article 43l (2) EnWG, the modification of hydrogen pipelines with a diameter of more than 300 mm requires planning approval. The modification of pipelines with a diameter of 300 mm or less is subject to a facultative plan approval procedure (as discussed earlier in this chapter). That said, article 43l (4) EnWG determines that for modifications and extensions of natural gas pipelines for the transport of hydrogen, article 43f EnWG remains unaffected, according to which a notification procedure can replace the planning approval procedure in cases of insignificant modifications or extensions.

The determining factor for article 43f (1) EnWG to be triggered is that a 'modification' is made and that this modification is considered to be 'insignificant'. There is no legal definition of the term 'modification'.[70] Whether a 'modification' occurred must be based on the previous approval decision and interpreted on the basis of the approved version of the plant, including all ancillary provisions, application documents and procedures.[71] In the literature, Riege concludes that the more detailed the authorisation documents are, the more likely repurposing measures will be considered a significant deviation, while the more general the description of the installation is, the more likely a notification procedure will be approved.[72] Further, article 43f (1) EnWG allows for the assumption of 'insignificance of a modification or extension' if (i) an EIA is not required, (ii) other public interests are not affected, and (iii) the rights of third parties are not affected or appropriate agreements are concluded. To this end, article 43f (2) No. 1 in conjunction with article 43l (4) EnWG stipulates that for 'modifications and extensions' to repurpose natural gas pipelines for hydrogen, an EIA is not necessary (if the requirements of article 43f (2) EnWG are met).[73] Pursuant to article 43f (4) 5 in conjunction with article 43f (2) 1 No. 1 EnWG, no examination of the rights in property of others is required for the modifications and extensions of gas supply pipelines in question. The permitting for repurposing

65 M Pfeiffer, '§ 113c EnWG' in L Assmann, M Peiffer (eds) BeckOK EnWG (C H Beck, 6th edn 2023) para 7.
66 BT-Drs. 19/27453 83.
67 S Grüner, 'EnWG § 113c' in K Bourwieg, J Hellermann, G Hermes (eds) *Energiewirtschaftsgesetz Kommentar* (C H Beck, 4th edn 2023) para 2.
68 Allolio 32; Riege 391.
69 DVGW, 'Project SyWeSt H2' <www.dvgw.de/medien/dvgw/forschung/berichte/g202006-sywesth2-steel-dvgw.pdf> accessed 11 December 2023.
70 BT-Drs. 19/27453 132.
71 Ibid; Riege, Schacht para 25; Riege 391; Allolio 32.
72 Riege 391.
73 For details see G Hermeier, J Hilsmann, 'EnWG § 43f' in L Assmann, M Pfeiffer (eds) *BeckOK EnWG* (C H Beck, 6th edn 2023) para 29.

pipelines with a diameter exceeding 300 mm can thus be streamlined and simplified by usage of the notification process.[74]

It must be noted, though, that the notification procedure can only replace the planning approval procedure if it would be necessary without the requirements of article 43f EnWG. That means cases of facultative planning approval are excluded from the scope of applications.[75] This result affects modifications made to pipelines with a diameter of 300 mm or less, according to article 43l (2) EnWG. Developers of pipelines with these diameters must therefore obtain the necessary permissions individually unless they opt for a facultative plan approval procedure. This leads to the, rather peculiar, result that the modification of the larger diameter pipelines, which might have more impact than the smaller ones, can be approved through a simple notification procedure, while the smaller ones have to obtain individual approvals for the modification.

Although article 43f (4) 4 EnWG provides for an official decision deadline of one month, in practice this deadline will often not be met due to lack of personnel.[76] In this situation, there is no fictitious approval that would allow the developer to start the repurposing project after a certain period of time.[77] In fact, the resources of the authorities determine the decision deadline. In the event that the deadline is exceeded, developers may only file an action for failure to act pursuant to article 75 Administrative Court Procedures Code (VwGO).[78] However, from a technical point of view, the essential parameters of an existing gas supply pipeline, such as its route, outside diameter, or length, remain unchanged in case of repurposing.[79] Against this backdrop, the obligation for planning approval for the modification of pipelines seems unreasonable, as does the lack of a fictitious approval in the case of insignificant modifications to pipelines.

Before moving on to the matter of land use agreements, an important aspect of the aforementioned environmental law pertaining to the repurposing of pipelines (as opposed to their construction, see Section 15.2.3) merits a brief discussion.

15.3.2 *Environmental Impact Assessment*

The use of an EIA when repurposing pipelines differs from the case of the construction of a pipeline. As the EIA is always conducted as an integral part of an official approval procedure, according to article 4 UVPG, it requires a so-called carrier procedure, and thus a procedure in which it is embedded.[80] However, if the procedural simplification of article 43l (4), (5) EnWG applies, as is the case with repurposing of gas pipelines, such a carrier procedure is lacking.[81] Consequently, article 43f (2) No. 1 EnWG specifies that an EIA is not necessary for the modification or expansion of gas supply pipelines for hydrogen transport under article 43l (4) EnWG. This allows for quick repurposing while still requiring a notification and thus allowing the competent authority an intervention to prohibit the repurposing due to safety concerns.[82]

74 Elspas 265; Allolio 33.
75 Riege 389.
76 Allolio 33; Riege 393.
77 J-C Pielow, 'EnWG § 43f' in F Säcker (ed) *Berliner Kommentar zum Energierecht* (dfv Mediengruppe, 4th edn 2019) para 15; Allolio 33; Riege 393.
78 Ibid 15.
79 BT-Drs. 19/27453 132.
80 H Hentschke, '§ 17 Zulassung von Anlagen' in M Dombert, K Witt (eds) *Münchener Anwalts Handbuch Agrarrecht* (C H Beck, 3rd edn 2022) para 21.
81 BT-Drs. 19/28407 3; Riege, Schacht 41.
82 D Benrath, 'Reine Wasserstoffnetze: Macht der Gesetzgeber seine Hausaufgaben?' (2021) 10 EnWZ 195, 198 (hereinafter: Benrath); Hermeier 16.

In the literature, Benrath raises concerns about the exclusion of an EIA in cases of repurposing.[83] He argues that if the pipeline is used for hydrogen instead of natural gas, this could alter the risk profile for the pipeline operation, and the environmental impacts of potential incidents should be taken into account alongside the normal operational burdens.[84] A blanket exemption from the EIA would be contrary to the existing system.[85] This argument can be refuted when there is no additional adverse environmental effect resulting solely from the change of medium in the pipeline.[86] As long as the essential parameters such as the route and the diameter of the pipeline do not change, it is reasonable to exempt the repurposing of a gas network to hydrogen from the EIA obligation.

While an EIA is a critical tool for identifying and evaluating environmental impacts and ensuring compliance with environmental regulations, it must be noted that the preceding approval procedure for the natural gas pipeline will already have featured an EIA. Therefore, in the case of mere repurposing where modifications, if necessary, are made solely on the inside of the pipelines or the pressure they are operated with is altered, the omission of a second EIA seems justified. Moreover, in light of the time-intensive nature of such a procedure, the omission of an EIA will significantly support the intended rapid expansion of a hydrogen infrastructure in Germany.

15.3.3 *Land Use Agreements*

When repurposing natural gas pipelines for the transport of hydrogen, project developers will regularly be confronted with the fact that the existing civil law contracts with landowners for the construction and operation of the pipelines do not refer to hydrogen.[87] Therefore, in the event of disagreement with the landowner over the inclusion of the repurposed pipeline in the scope of the agreement, the relevant agreement will have to be interpreted.[88] As demonstrated above, article 113a (1) EnWG contains an interpretation rule in favour of the developer (see Section 15.2.4).

Pipeline rights on public transport routes, so-called land use agreements within the meaning of article 46 EnWG, are regulated by article 113a (2) and (3) EnWG. These agreements will continue to be valid for the transport and distribution of hydrogen until their agreed term expires (see Section 15.2.4). It has to be said that repurposed pipelines may no longer meet the requirements of article 46 EnWG, which pertains to the concession award for energy supply networks in municipal areas.[89] During the initial phase of the hydrogen ramp-up, these conditions may no longer be met, particularly for hydrogen networks initially serving only individual industrial enterprises and extending beyond municipal boundaries.[90] To this end, article 113a (2) ensures ongoing revenues for municipalities even if the pipelines no longer serve end consumers within municipal areas, while enabling network operators to utilise the repur-

83 Benrath 198.
84 Ibid.
85 Ibid.
86 BT-Drs. 19/27453 132.
87 Elspas 266.
88 Ibid.
89 M Pfeiffer, 'EnWG § 46' in L Assmann, M Pfeiffer (eds), *BeckOK EnWG* (C H Beck, 6th edn 2023) para 47; C Theobald, J Schneider, 'EnWG § 46' in C Theobald, J Kühling (eds) *Energierecht* (C H Beck, 118th edn 2022) para 28.
90 BT-Drs. 19/28407 28.

posed pipelines without encountering significant bureaucratic obstacles.[91] It is only at the end of the agreed term that the parties will need to enter into a new agreement, which must offer terms no less favourable than those of the previously existing contracts (article 113a (3) EnWG), as discussed above in Section 15.2.4.

Following the analysis of the legal regime for repurposing pipelines, we now turn to the subsequent challenge of hydrogen storage.

15.4 THE PERMISSION REGIME FOR HYDROGEN STORAGE CONSTRUCTION

Storage is a key part of the required hydrogen infrastructure. Due to natural fluctuations in renewable energy production from sources like wind and solar, efficient storage options are crucial to balance out these fluctuations and meet demand.[92] Hydrogen can be stored above ground or underground. Both options are subject to different permission requirements. Cavern storage and pore storage are the two primary underground storage options (above-ground storage for considerable amounts of hydrogen is restricted due to technical limitations and high costs).[93] Higher injection and withdrawal rates render cavern storage more efficient than pore storage.[94] While the former can be fully repurposed to hydrogen, use of the latter requires further research.[95] Therefore, here the focus will be directed at the legal regime for salt cavern storage.

It is important to acknowledge that large-scale underground storage of hydrogen has not yet been pursued in Germany, and there exists no definitive legal framework.[96] Presently, only pilot projects are underway, indicating an early stage of development.[97]

As established in the Introduction, the EnWG includes provisions for expediting the development of hydrogen infrastructure, which can only be applied if the EnWG is applicable to the respective project. The EnWG, however, is not applicable underground and does not cover the construction of salt caverns used for storing hydrogen. Instead, German mining law is applicable. As will be shown, mining law does not yet provide for any special regulation concerning hydrogen. The following sections consider the *construction* of salt caverns for hydrogen storage, before then turning to the *repurposing* of existing natural gas salt caverns for hydrogen purposes.

Salt cavern storage facilities for hydrogen are 'underground storage' facilities within the meaning of mining law. Article 4 (9) Federal Mining Act (BBergG), defines 'underground storage' as a facility that is employed for the subterranean storage of gases, liquids, and solid substances, excluding water. The utilisation of containerless storage techniques is mandatory to

[91] Ibid.

[92] P Adam et al, 'Wasserstoffinfrastruktur – tragende Säule der Energiewende. Umstellung von Ferngasnetzen auf Wasserstoffbetrieb in der Praxis' (2020) Whitepaper 19.

[93] BT-Drs. 8/1315 76; M Warnecke, S Röhling, 'Untertägige Speicherung von Wasserstoff – Status quo' (2021) Z Dt Ges Geowiss 1 <www.deutsche-rohstoffagentur.de/DE/Themen/Nutzung_tieferer_Untergrund_CO2Speicherung/Downloads/2021_Speicherung_Wasserstoff.pdf?__blob=publicationFile&v=2> accessed 10 December 2023 (hereinafter: Warnecke, Röhling); The limitation in above-ground storage arises from the low-pressure conditions that impose constraints on hydrogen storage densities, resulting in the requirement for substantial storage volumes and substantial investment costs. Consequently, this option becomes unattractive from a cost–benefit perspective.

[94] Warnecke, Röhling; Nationaler Wasserstoffrat, 'Die Rolle der Untergrund-Gasspeicher zur Entwicklung eines Wasserstoffmarktes in Deutschland' (2021) <www.wasserstoffrat.de/fileadmin/wasserstoffrat/media/Dokumente/2022/2021-10-29_NWR-Grundlagenpapier_Wasserstoffspeicher.pdf> accessed 4 June 2023 (hereinafter: Nationaler Wasserstoffrat).

[95] Ibid.

[96] Project H2-UGS, 'Leitfaden Planung, Genehmigung und Betrieb von Wasserstoff-Kavernenspeichern' (2022) 527 (hereinafter: Project H2-UGS).

[97] INES, 'Positionspapier' <https://energien-speichern.de/wp-content/uploads/2023/10/20231006_INES-Positionspapier_Vorschlaege-Marktrahmen_Entwicklung-H2-Speicher.pdf> accessed 6 December 2023.

bring underground hydrogen storage facilities within the scope of the BBergG.[98] This is the lever for the inclusion of cavern storage facilities for gaseous hydrogen in the scope of the Act.[99]

Article 126 (1) BBergG lists specific regulations that are applicable to underground storage. According to article 51 (1) in conjunction with article 126 (1) 1 BBergG, the permitting of construction and management of underground storage facilities is only possible on the basis of operating plan procedures.[100] The various types of operating plans are regulated by article 52 BBergG. The type of operating plan procedure largely determines the scope and duration of the approval process, with projects not subject to EIA being approved significantly faster than those having to go through public participation.[101]

Pursuant to article 126 (1) BBergG in conjunction with article 51 and following BBergG, underground storage facilities require a *main operating plan* under mining law. The main operating plan is an essential and constitutive part of the permit for the commencement of mining operations and cannot be replaced by other plans under mining law.[102] It forms the operational and technical basis for the construction and management of the operation.

In addition, the preparation of a *framework operating plan* is required under article 52 (2a) BBergG in conjunction with article 126 (1) BBergG, and a plan approval procedure is needed for its approval if a project requires an EIA pursuant to the ordinance under article 57c BBergG in conjunction with article 4 and following UVPG. The relevant ordinance is the Environmental Impact Assessment Ordinance Mining (UVP-V-Bergbau). Article 1 UVP-V-Bergbau lists the operations which require an EIA. Hydrogen is currently not listed there. However, this is seen as a regulatory gap that is to be closed by a current draft of an amendment to the ordinance.[103] According to the draft, the same requirements will apply to the storage of hydrogen as in the case of storage of natural gas. The current lack of legal certainty as to when an EIA is necessary for underground hydrogen storage facilities will thus be eliminated. Therefore, the construction of underground salt cavern storage for hydrogen will be subject to an EIA under mining law and therefore require planning approval. In conclusion, a main operating plan and additionally a framework operating plan will have to be drawn up.

The current draft amendment to the UVP-V-Bergbau underlines the early stage of a framework for underground hydrogen storage. Hydrogen-specific regulations that would support accelerated permission procedures for underground storage, as they exist for pipelines, are not provided for by current mining law. Having said that, the German government is currently working on a hydrogen storage strategy that is supposed to be finalised by 2024.[104]

Following this discussion of the permitting regime for pure and newly built hydrogen storage, we will now turn to the question of repurposing existing natural gas storage.

[98] H Weller, U Kullmann, 'BBergG § 126' in U Kullmann (ed) *NomosKommentar Bundesberggesetz* (Nomos, 1st edn 2012) para 2; Allolio 48.
[99] BT-Drs. 8/1315 76; M-L Weiss, 'Das Bergrecht und seine energiewirtschaftlichen Bezüge' in C Theobald, J Kühling (eds) *Energierecht* (C H Beck, 118th edn 2022) ch 137 para 177 (hereinafter: Weiss).
[100] Weiss 181.
[101] Project H2-UGS 526.
[102] Weiss 64.
[103] BR-Drs. 561/23.
[104] BMWK, 'Anfrage' <www.bmwk.de/Redaktion/DE/Parlamentarische-Anfragen/2023/09/9-449.pdf?__blob=publicationFile&v=4> accessed 11 December 2023.

15.5 THE PERMISSION REGIME FOR REPURPOSING EXISTING SALT CAVERN STORAGE FROM NATURAL GAS TO HYDROGEN

From a technical point of view, it is possible to fully repurpose salt cavern storage from natural gas to hydrogen.[105] Legally, the repurposing of underground natural gas storage facilities will require an amendment to the operating plan, article 52 (4) 2 BBergG.[106] The amendment, like the original operating plan, requires official approval.[107] As mentioned above, hydrogen-specific acceleration provisions do not currently exist but are being developed.

Although the official approval granted for the cavern storage for natural gas could potentially be transferred to the storage of hydrogen through a notification procedure,[108] the current legal framework does not provide for such an approval to be transferred. The underlying assumptions, namely that (1) all necessary approvals have already been granted for the previous use for natural gas; (2) the relevant procedures conducted; and (3) the risk profile does not change in line with the medium in the storage facility or pipeline, are similar to the discussions earlier in this chapter. To sum up: a provision on the repurposing of natural gas storage in the BBergG would greatly benefit the intended accelerated expansion of the hydrogen infrastructure.

15.6 CONCLUSION AND OUTLOOK: FROM INTENTIONS TO IMPLEMENTATION

The imperative to swiftly develop Germany's hydrogen infrastructure is evident and German policy-makers' legislative intentions are clear. With the pressing need for an energy transition and the legislators' explicit goal of establishing an accelerated framework for hydrogen infrastructure development, the government's recent decision to construct a hydrogen *core* network, accompanied by an acceleration law, sets the right course. This core network will be the first step in establishing the full-blown infrastructure that hydrogen use requires.

The aim of the second step of hydrogen infrastructure planning is a nationwide, meshed hydrogen network. Among the existing regulatory provisions for the construction of new pipelines, article 113a EnWG concerning easement agreements offers a pathway for project developers to circumvent the laborious and costly contract negotiation process under specified conditions. This provision stands out as an exception by providing vital support for the rapid scaling up of a hydrogen infrastructure.

The broader regulatory landscape, notably article 43l (1) 2 EnWG, which asserts the paramount public interest in hydrogen projects during the balancing process, falls short. Its application ceases as early as 31 December 2025, implying potential invalidity when regional planning or plan approval procedures, which are inherently time-intensive, are required. This limitation, coupled with the recognised protracted nature of the EIA process, presents a palpable impediment to the prompt development of the hydrogen infrastructure envisioned in Germany. Relief will be brought about for projects that will be part of the core network. Article 28r EnWG-E stipulates that these projects are considered to be in the overriding public interest provided they are commissioned by 2030.

Considering this, article 43l (4), (5) EnWG emerges as a pivotal regulation significantly facilitating the establishment and expansion of hydrogen networks. It governs procedural

105 Nationaler Wasserstoffrat.
106 Allolio 50.
107 H Weller, U Kullmann, 'BBergG § 52' in U Kullmann (ed) *NomosKommentar Bundesberggesetz* (Nomos, 1st edn 2012) para 6.
108 As is the case for repurposing of pipelines under article 43l (4), (5) EnWG.

simplifications specifically for the repurposing of existing natural gas supply pipelines for hydrogen. By contrast, the construction of new pipelines necessitates the navigation of a complex web of permissions under diverse laws, underscoring the streamlined notification procedure for repurposing projects as an advantageous alternative.

Turning to hydrogen storage, an astonishing absence of hydrogen-specific regulation for underground cavern storage must be observed, even though such facilities play a critical role in maintaining grid stability and providing essential system services. However, things are changing. While storage systems were a minor consideration in NWS 2020, they feature more prominently in the updated NWS. Further, the amendment to the UVP-V-Bergbau is under way. It provides a degree of clarity regarding the matter of underground hydrogen storage. Moreover, the government is currently working on its first hydrogen storage strategy.

Considering the pressing need for establishing a hydrogen infrastructure to reach climate targets, recent legal developments could be game changers. They demonstrate that Germany is serious about promoting hydrogen and developing it into an important pillar of climate-neutral energy supply.

As Germany strives for a prominent global position in hydrogen technologies, the development of its hydrogen infrastructure will significantly shape its energy landscape, aiding a sustainable, low-carbon future. Streamlined and expedited permission procedures for pipelines and storage facilities will be key to aligning ambitious policy intentions with implementation goals. Picking up speed, then, will be pivotal to ensure that Germany's hydrogen economy soars high rather than glides low, fuelling even more ambitious transition objectives in the process.

FURTHER READING

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16

Goal-Setting Approaches to the Regulation of Hydrogen Transport

A Case Study from France

Kleopatra-Eirini Zerde

16.1 INTRODUCTION

16.1.1 *French Political Aspirations for Hydrogen*

In France, more than 900,000 tons of hydrogen are consumed each year for refining of petrol fuels, producing chemicals and ammonia for fertilizers as well as in the steel and cement industry and heavy transport.[1] Up to 98 per cent of that hydrogen is produced by fossil fuels (brown/grey hydrogen),[2] which adds 11.5 tonnes of carbon dioxide (CO_2) emissions in France.[3] Moreover, it is important to note that a part of this hydrogen is 'co-produced', meaning it is a side product of industrial processes and generated during the processing of oil cuts in refineries or the gasification of coal in steel factories or steam reforming of natural gas, making these industries in part self-sufficient.[4]

France prides itself on being one of the first countries to identify the full potential of hydrogen.[5] Already back in 2015, article 121 of the French Energy Transition Law (No. 2015-992)[6] identified hydrogen as a solution to climate change and put the obligation

The information and views set out in this chapter are those of the author and do not necessarily reflect the official opinion of the employer.

1 France Hydrogène, 'Livre blanc pour l'élection présidentielle 2022: faire de la France un leader de l'hydrogène renouvelable ou bas-carbone' (2021), 7–8 <https://france-hydrogene.org/publication/livre-blanc-pour-lelection-presidentielle-2022-faire-de-la-france-un-leader-de-lhydrogene-renouvelable-ou-bas-carbone/> Accessed 20 December 2022.

2 ADEME, 'Transition(s) 2050. Choisir maintenant. Agir pour le climat' (2021), 513 <https://transitions2050.ademe.fr/> Accessed 20 December 2022.

3 Ministère de la Transition énergétique, 'Plan de déploiement de l'hydrogène pour la transition énergétique' (Ministry of Ecological and Solidarity Transition, 'Hydrogen deployment plan for the energy transition') (2018), 1. Translation by the author <https://ecologique-solidaire.gouv.fr/sites/default/files/Plan_deploiement_hydrogene.pdf> Accessed 21 December 2022.

4 ADEME (2021), 513.

5 Ministère de l'économie, des finances et de la souveraineté industrielle et numérique, 'Accélérer le déploiement de l'hydrogène, clé de voûte de la décarbonation de l'industrie – Dossier de Presse' (2023), 5 <https://presse.economie.gouv.fr/02022023-dossier-de-presse-accelerer-le-deploiement-de-lhydrogene-cle-de-voute-de-la-decarbonation-de-lindustrie/> Accessed 20 September 2023.

6 Loi relative à la transition énergétique pour la croissance verte (TEPCV) (Law on Energy Transition for Green Development). Translation by the author <https://legifrance.gouv.fr/loda/id/JORFTEXT000031044385/> Accessed 31 December 2022.

on the government to submit to Parliament a plan for the development of the storage of renewable energy using decarbonized hydrogen. Moreover, the law specifically asked for the deployment of an infrastructure of hydrogen distribution stations and the adaptation of regulations to enable the deployment of these new hydrogen applications, such as the conversion of electricity into gas.[7] This plan was finally published in June 2018, being the first official French hydrogen deployment plan.[8] Its aim is to support the development of low-carbon hydrogen with the purpose of decarbonizing the industrial sector, the transport sector (road, rail and so on) and to develop storage capacities and stabilize the energy networks.[9]

In September 2020, France published its National Hydrogen Strategy in which it announced over €7 billion up to 2030 for low-carbon hydrogen deployment, with €3.4 billion planned for the period 2020–2023.[10] In February 2022, almost €2 billion was added to the previous amount with the *France 2030 Plan*, bringing total government investment in hydrogen to €9 billion.[11] In November 2022, the revision of the French hydrogen strategy by the end of the first half of 2023 was announced, focusing on hydrogen hubs and expertise in hydrogen-related equipment, but nothing had been published by autumn 2023.[12]

The creation of France's national strategy on hydrogen has been a long-term project. The crucial investment decisions by France were based on the knowledge and experience gathered before 2018 by the hydrogen projects created all over the country with the support of the regions and industrial players. Since 2016, ADEME[13] has launched quite a few[14] calls for tenders relating to hydrogen,[15] while a new call under the 'Hydrogen Territorial Ecosystems' programme was launched in May 2023 with a budget of €175 million to finance the production and distribution of hydrogen and the deployment of vehicles.[16]

From all the above, the prospect of hydrogen for decarbonization and for achieving climate neutrality in France becomes clear. This chapter will focus on one of the important parameters needed for hydrogen deployment, namely the transport of hydrogen. Specifically, the aim is to determine whether or not the French legal system includes provisions aiming at accommodation and facilitation of the transport of hydrogen, which could help France with its ambition to achieve its energy transition goals. Transport of hydrogen plays a crucial role in the French

7 Translation by the author.
8 Ministère de la Transition énergétique, Plan de déploiement de l'hydrogène pour la transition énergétique (2018).
9 Ibid, 9–14.
10 Ministère de la Transition énergétique, 'Stratégie nationale pour le développement de l'hydrogène décarboné en France – Dossier de Presse' (Ministry of Energy Transition, 'National Strategy for the Development of Decarbonized Hydrogen in France – Press file') (2020), 7. Translation by the author <https://entreprises.gouv.fr/fr/strategies-d-acceleration/strategie-nationale-pour-developpement-de-l-hydrogene-decarbone-france#:~:text=Son%20souhait%20est%20de%20d%C3%A9velopper,'%C3%A9mergence%20d'%C3%A9nergies%20renouvelables> Accessed 27 December 2022.
11 Anonymous, 'Pourquoi la France mise sur l'hydrogène' (Why is France betting on hydrogen?) (2022) French government's webpage. Translation by the author <https://gouvernement.fr/actualite/pourquoi-la-france-mise-sur-lhydrogene> Accessed 15 September 2023.
12 Ministère de l'économie, 'Industrie: vers une nouvelle stratégie hydrogène pour la France' (Industry: towards a new French hydrogen strategy). Translation by the author <https://economie.gouv.fr/industrie-nouvelle-strategie-hydrogene-pour-la-france> Accessed 18 October 2023.
13 The French Agency for Ecological Transition <https://ademe.fr/en/frontpage/> Accessed 18 January 2023/
14 Engie, 'Appel à projets "Territoires Hydrogènes"' (2016) <https://engie.com/journalistes/communiques-de-presse/territoires-hydrogenes-france> Accessed 18 January 2023.
15 France Relance/appel à projets Écosystèmes territoriaux Hydrogène (2021) <https://presse.ademe.fr/2021/04/france-relance-appel-a-projets-ecosystemes-territoriaux-hydrogene.html> Accessed 10 January 2023.
16 Ministère de l'économie, 'Hydrogène: un nouvel appel à projets et 175 millions d'euros supplémentaires pour développer la filière' (2023) <https://economie.gouv.fr/hydrogene-un-nouvel-appel-projets-et-175-millions-deuros-supplementaires-pour-developper-la-filiere#> Accessed 18 October 2023.

decarbonization plan as it can support innovation, ensure that all points of demand nationally are supplied, and also offers France a potentially central role in cross-border hydrogen trade.

16.1.2 *Rule- and Goal-Setting Approaches to Legislation*

Furthermore, the chapter aims to determine whether or not French authorities follow a rules-based or goal-based theory regarding the adopted legislation on hydrogen and specifically energy transport. When choosing the appropriate regulatory approach, various factors are taken into consideration, such as the desired allocation of risks, the incentives and behaviour of regulatees as well as enforcement approach and style, and the capacity and expertise of the regulator.[17] A rules-based approach to legislation is the classic way of establishing rules with the description of specific conduct that is desired or not.[18] This theory, regardless of the advantages that it may present – for example, predictability, stability, comfort in planning[19] – has been criticized as inflexible and restrictive. That led to the creation of an opposite regulatory trend, where instead of the rules, certain goals, outcomes, principles or standards are set without prescribing how regulatees need to achieve these goals and outcomes. Even though there is no common agreement on the term for this approach,[20] in this chapter, 'goal-setting approach' will be used.[21] The goal-setting approach is perceived by many as offering flexibility, shifting the focus away from a strict rule on the desired outcomes and a box-ticking mentality to a situation where regulatees are involved in considering the best way to achieve the outcome.[22] Which of the two regulatory approaches was followed when putting in place the rules for hydrogen transport in France will be considered in the following sections.

16.2 HYDROGEN IN FRANCE

16.2.1 *The Different Types of Hydrogen in France*

Internationally, a spectrum of colours (white to grey)[23] is used to provide information related to the energy sources and technical procedures used to produce hydrogen. In the French 'Hydrogen deployment plan for the energy transition', published in 2018, a first effort to differentiate the types of hydrogen in France can be seen. In this text, renewable hydrogen is defined as hydrogen produced via electrolysis without the use of fossil fuels, whereas decarbonized hydrogen is hydrogen produced from fossil methane with the CO2 from the production procedure captured and stored underground.[24]

Ambiguity about what is considered to be renewable and decarbonized hydrogen under the French system vanished with the adoption of Ordinance No. 2021-167 of 17 February 2021 on

[17] C. Decker, *Goals-Based and Rules-Based Approaches to Regulation* – BEIS Research Paper No. 8 (2018), 5 <https://papers.ssrn.com/sol3/papers.cfm?abstract_id = 3717739> Accessed 30 January 2023.

[18] S. J. A. ter Borg and W. S. R. Stoter, "Is Goal-Based Regulation Consistent with the Rule of Law?" in M. Sellers and T. Tomaszewski (eds.), *The Rule of Law in Comparative* 57 *Perspective, Ius Gentium: Comparative Perspectives on Law and Justice* 3 (C Springer Science+Business Media B.V. 2010).

[19] Decker (2018), 22.

[20] Other terms used in bibliography: standards-based regulation; performance-based regulation; principles-based regulation; outcomes-focused regulation; goals-based regulation.

[21] Decker (2018), 14–16.

[22] Ibid, 21.

[23] N. Marchant, 'Grey, blue, green – why are there so many colours of hydrogen?' (2021) <https://weforum.org/agenda/2021/07/clean-energy-green-hydrogen/> Accessed 17 September 2023.

[24] Ministère de la Transition énergétique, Plan de déploiement de l'hydrogène pour la transition énergétique (2018).

hydrogen.[25] Article L811-1 (as amended by article 81 of Law 2023-175) of Book VIII of the French Energy Code,[26] originally introduced by the Ordinance, defines three types of hydrogen: renewable, low-carbon and carbon-based hydrogen. These are distinguished by greenhouse gas emissions and by the primary energy source used for production.[27]

- Renewable hydrogen is 'produced either by electrolysis using electricity from renewable energy sources as defined in Article L. 211-2, or by any other technology using exclusively one or more of these same renewable energy sources and not conflicting with other uses allowing their direct recovery. This electricity may be supplied as part of an individual or collective self-consumption operation as defined in Articles L. 315-1 and L. 315-2. In all cases, its production process emits, per kilogram of hydrogen produced, a quantity of carbon dioxide equivalents less than or equal to a threshold'.
- Low-carbon hydrogen is hydrogen 'whose production process generates emissions less than or equal to the threshold for the qualification of renewable hydrogen, without being able, however, to receive this latter qualification, because it does not meet the other criteria'.
- Carbon-based hydrogen is 'hydrogen that is neither renewable nor low-carbon'.

From the above, it is clear that renewable hydrogen in France is considered to be hydrogen produced by using electricity from renewable energy sources via electrolysis and other production processes like steam reforming of biogas or the thermolysis of biomass. Therefore, going back to the colour spectrum, it can be deduced that French renewable hydrogen is mainly equivalent to *green* hydrogen. As far as the other categories are concerned, abiding by the same CO_2 threshold but also using non-renewable sources for production leads to the conclusion that yellow,[28] pink[29] and blue hydrogen are found under the low-carbon hydrogen definition in France. Lastly, hydrogen that does not conform to either of the first two categories is viewed as carbon-based (grey, brown and black), such as hydrogen produced by steam reforming of natural gas (around 11 $kgCO_2/kgH_2$), coal gasification (20 $kgCO_2/kgH_2$) or electrolysis using carbon-based electricity mixes.[30] It is important to note that this third category could potentially include hydrogen produced not only by fossil fuels but also by renewable sources if the emissions of their production process are above the $kgCO_2eq/kgH_2$ threshold. According to France Hydrogène,[31] an example could be hydrogen produced from biomass or biogas, depending on the nature of the inputs used and the associated carbon footprint, or depending on the methane leaks taken into account upstream.[32]

France Hydrogène drafted a table correlating the different 'colours' of hydrogen with the new definitions of the French legal system, which confirm those presented above.[33] Renewable is

[25] 'Ordonnance no. 2021-167 du 17 février 2021 relative à l'hydrogène', JORF (Governmental Gazette) No. 0042/18.02.2021 <www.legifrance.gouv.fr/jorf/id/JORFTEXT000043148001/> Accessed 20 December 2022.

[26] Code de l'énergie (2011), Version of 10 November 2023 (French Energy Code) <https://legifrance.gouv.fr/codes/texte_lc/LEGITEXT000023983208?etatTexte=VIGUEUR&etatTexte=VIGUEUR_DIFF> Accessed 19 September 2023.

[27] Article 5 of the Ordinance No. 2021-167.

[28] Hydrogen produced via electrolysis by the electricity of the grid which is considered a mix produced by renewables and fossil sources.

[29] Hydrogen produced via electrolysis by electricity produced from nuclear energy.

[30] France Hydrogène, 'Que faut-il retenir de l'ordonnance sur l'hydrogène? (What should we remember about the hydrogen ordinance?)' (2021). Translation by the author <https://france-hydrogene.org/press_release/que-faut-il-retenir-de-lordonnance-sur-lhydrogene/> Accessed 10 September 2023.

[31] Private organization with more than 450 members, bringing together the stakeholders of the French hydrogen sector across the entire value chain <https://france-hydrogene.org/en/qui-sommes-nous/> Accessed 7 September 2023.

[32] See France Hydrogène, 'Que faut-il retenir de l'ordonnance sur l'hydrogène?' (2021).

[33] France Hydrogène, 'PARLONS HYDROGÈNE! Tout savoir (ou presque) sur l'hydrogène' (We speak about Hydrogen! All (or almost all) you need to know on hydrogen) (2022), 5. Translation by the author <https://france-hydrogene.org/publication/parlons-hydrogene/> Accessed 15 September 2023.

'green hydrogen', low-carbon is 'pink, yellow and blue hydrogen' and carbon-based is 'grey, brown and black hydrogen'. Lastly, it is interesting to note that the table includes no correlation for turquoise hydrogen. Turquoise hydrogen is usually produced via pyrolysis of natural gas using energy that was not produced by renewable sources together with solid black carbon.[34] Since the by-product, black carbon, can be used for purposes like enriching the soil or for the construction of other products such as tyres, its handling can be considered similar to carbon capture, utilization and storage (CCUS) of CO2 in the production of blue hydrogen and therefore turquoise hydrogen should be considered as low-carbon hydrogen. However, if the energy driving the pyrolysis is from renewable sources and/or the feedstock for the pyrolysis is biomethane and not natural gas, the production of turquoise hydrogen becomes zero-carbon and carbon-negative respectively,[35] making turquoise renewable hydrogen.

The threshold of the CO2 equivalent and the method of its calculation, were set via the relevant decree finally published in July 2024.[36] The greenhouse gas emissions threshold for qualifying hydrogen as renewable or low-carbon is set at 3.38 kg of CO2 equivalent per kg of hydrogen produced,[37] which corresponds to the benchmark of a 70% reduction in greenhouse gas emissions compared with a fossil equivalent[38] introduced by the recast Gas Directive (EU)2024/1788.[39]

For renewable hydrogen, greenhouse gas emissions from production, input supply, processing, transport, distribution, end use and carbon capture and geological storage are counted and they are determined in accordance with the rules for calculating greenhouse gas emissions from hydrogen set out in the Annex[40] to European Delegated Regulation 2023/1185,[41] whereas the methodology for low-carbon hydrogen is presented in the Annex of the French order,[42] but includes all the life-cycle steps listed also for renewable hydrogen. Lastly, from the above, we notice that pink hydrogen is considered low-carbon hydrogen, whereas the fact that the order includes for counting only emissions from the production that are stored geologically[43] and not others like captured and then used in industrial process, seems to exclude blue hydrogen from this category.[44]

34 Florence School of Regulation, 'Between green and blue: A debate on turquoise hydrogen' (2021) <https://fsr.eui.eu/between-green-and-blue-a-debate-on-turquoise-hydrogen/> Accessed 20 December 2022.

35 Ibid.

36 Arrêté du 1er juillet 2024 précisant le seuil d'émissions de gaz à effet de serre et la méthodologie pour qualifier l'hydrogène comme renouvelable ou bas-carbone, JORF (Governmental Gazette) n°0157/4-07-2024 (Order of 1 July 2024 specifying the greenhouse gas emission threshold and the methodology for qualifying hydrogen as renewable or low-carbon). <https://www.legifrance.gouv.fr/loda/id/LEGITEXT000049872383/2024-07-05/#LEGITEXT000049872383> Accessed: 25 July 2024

37 Ibid., article 1.

38 A. Hubert and Is. Smets, «Hydrogène bas carbone : une définition, quatre points de tension» (Low-carbon hydrogen: one definition, four points of tension). (2024) Contexte <https://www.contexte.com/article/energie/le-projet-de-definition-de-lhydrogene-bas-carbone-concocte-par-la-commission-europeenne_196659.html> Accessed: 24 August 2024.

39 Article 2(11) of the Directive (EU) 2024/1788 of the European Parliament and of the Council of 13 June 2024 on common rules for the internal markets for renewable gas, natural gas and hydrogen, amending Directive (EU) 2023/1791 and repealing Directive 2009/73/EC, OJ L, 2024/1788, 15.7.2024.

40 Ibid. 36, Article 2.

41 COMMISSION DELEGATED REGULATION (EU) 2023/1185 of 10 February 2023 supplementing Directive (EU) 2018/2001 of the European Parliament and of the Council by establishing a minimum threshold for greenhouse gas emissions savings of recycled carbon fuels and by specifying a methodology for assessing greenhouse gas emissions savings from renewable liquid and gaseous transport fuels of non-biological origin and from recycled carbon fuels, JO L 157, 20.6.2023.

42 Ibid. 36, Article 3.

43 Ibid. 36, Annex par. 5.

44 Ph. Marcangelo-Leos, «Hydrogène renouvelable ou bas-carbone : le seuil de qualification et la méthodologie sont fixés», (2024). <https://www.banquedesterritoires.fr/hydrogene-renouvelable-ou-bas-carbone-le-seuil-de-qualification-et-la-methodologie-sont-fixes> Accessed 25 August 2024.

16.2.2 *Transport of Hydrogen*

At a global level hydrogen can be transported mainly via three means: trucks, ships and pipelines.[45] The optimal form of transport depends on the end use and the targeted destination.[46] Usually, the use of the existing gas network, after being retrofitted (ensuring leakage prevention, for example), is the optimal choice for medium-distance transportation.[47] Away from pipeline grids, the supply of refuelling stations alongside major road arteries requires the use of alternative forms of transport, with trucks being the most popular option.

As mentioned before, France based its national hydrogen strategy on three pillars for which hydrogen is considered the solution for decarbonization: industry, the energy system and heavy transport. It becomes clear then that there will be a need to deliver massive production of renewable and low-carbon hydrogen throughout the country to the points of consumption. This is one of the main reasons why the transport of hydrogen in France must be looked into. Moreover, due to its geographical location (between the southern Europe producers/exporters and the northern importers), the existing gas infrastructure and interconnections with most of its neighbours, plus the availability (present and planned) of low-emission electricity, France can easily transition to become a hydrogen hub.[48] However, interestingly enough, regardless of the role that France can play in hydrogen transport across Europe and the cross-border hydrogen trade, French hydrogen plans have not included, at least not yet, specific measures for cross-border transport or hydrogen imports and focus mostly on internal production and industry hubs.[49] Nevertheless, transport of hydrogen is crucial for its plans for nationwide decarbonization and that is why it is examined.

Transport of Hydrogen (Road, Rail and Water Transport)

This section will present the rules applicable for the transport of hydrogen for road, rail and sea transport. In these cases, the French legal system is very clear, classifying hydrogen (regardless of means of production and end use) as a dangerous material and therefore imposing the rules that are applicable to other dangerous materials. Dangerous goods or hazardous materials are substances and articles the carriage of which is prohibited or is authorized only under specific conditions, due to health and safety reasons.[50]

The rules on the national or international transport of dangerous goods by road, rail and inland waterways in France can be found in the 'TMD Decree' (Arrêté Transports de Marchandises Dangereuses) (Decree of 29 May 2009 as amended).[51] Specifically, the TMD Decree deals with the application of the Agreement concerning the International Carriage of Dangerous Goods by Road (ADR), the Regulation for International Transport of Dangerous Goods by Railway (RID) and

[45] Hydrogen Council, McKinsey & Company, 'Hydrogen Insights 2021: A perspective on hydrogen investment, deployment and cost competitiveness' (2021), 19 <https://hydrogencouncil.com/en/hydrogen-insights-2021/> Accessed 10 January 2023.

[46] Ibid.

[47] Ibid.

[48] GRTgaz & Teréga. 'Hiver 2022–2023: Le système gaz français devrait faire face à la demande en s'appuyant sur la gestion prudente des stocks et la sobriété de tous les consommateurs. Communiqué de Presse' (Winter 2022–2023: The French gas system should be able to cope with demand thanks to prudent management of stocks and sobriety on the part of all consumers. Press release) (2022). Translation by the author <https://grtgaz.com/medias/communiques-de-presse/perspectives-systeme-gazier-hiver-2022> Accessed 5 October 2023.

[49] See Ministère de la Transition énergétique, 'Stratégie nationale pour le développement de l'hydrogène décarboné en France (2020).

[50] Definitions in ADR, RID and ADN Agreements and TMD Decree.

[51] Arrêté du 29 mai 2009 relatif aux transports de marchandises dangereuses par voies terrestres (dit 'arrêté TMD') (Decree of 29 May 2009 on the transport of dangerous goods by land (known as the 'TDG Decree')).

the European Agreement on the International Carriage of Dangerous Goods by Inland Waterways (ADN).[52] These agreements follow a similar pattern. Each agreement contains a table that pairs the list of identified dangerous materials under their United Nations (UN) number with the requirements applied for the transport of this substance. This is a four-digit number that identifies dangerous goods, hazardous substances and articles (such as explosives, flammable liquids, toxic substances) in the framework of international transport, assigned by the United Nations Committee of Experts on the Transport of Dangerous Goods.[53] Specifically for road transport, the ADR contains two Annexes, with Annex A laying down the packaging and labelling requirements and Annex B containing the conditions for the construction, equipment and operation of the vehicle carrying the dangerous good. The RID, which deals with the rail transport of dangerous goods, is appended (Appendix C) to the Convention concerning international transport by train (COTIF, Convention relative aux transports internationaux ferroviaires).

In these conventions, the following are most important in relation to the transport of hydrogen: UN 1049-Hydrogen compressed, UN-1966-Hydrogen liquified/refrigerated, UN 2034-compressed hydrogen and methane admixtures, UN 3166-Vehicle, flammable gas powered or vehicle, flammable liquid powered or vehicle, fuel cell, flammable gas powered or vehicle, fuel cell, flammable liquid powered and UN 3468-Hydrogen in a metal hydride storage device.[54] The TMD Decree establishes some general obligations for the transport of all dangerous goods, regarding labelling, packaging and documentation of the dangerous goods, the obligation to have a security adviser (article 6 of the TMD) and to provide special training to employees (L 4141-1 and following of the Labour Code).[55] Under the above UN numbers, hydrogen, whether in gaseous or liquid state, is categorized under class 2, with the principal characteristic as flammable. Each agreement has its own obligations, but they are largely similar regarding weight, packaging and labelling.

Concerning the distribution of hydrogen in refuelling stations, the provisions of ADR and RID, transposed via the TMD Decree, initially did not regulate products used as energy feedstock or fuel inside vehicles. This changed with the adoption of the ministerial decree of 22 October 2018[56] establishing new headings under the Installations Classified for

[52] Articles 3 and 4 TMD Decree.

[53] ADR (2023), Vol. 1, p. 52 <https://unece.org/transport/standards/transport/dangerous-goods/adr-2023-agreement-concerning-international-carriage> Accessed 2 October 2023.

[54] ADR (2023), 87–88, 100, 206, 208; RID (2011), 87 <https://otif.org/en/?page_id = 172> Accessed 3 October 2023; ADN (2021), 229.

[55] Code du travail (French Labour Code) <https://legifrance.gouv.fr/codes/section_lc/LEGITEXT000006072050/LEGISCTA000006178070/#LEGISCTA000006178070> Accessed 29 January 2023.

[56] Arrêté du 22 octobre 2018 relatif aux prescriptions générales applicables aux installations classées pour la protection de l'environnement soumises à déclaration sous la rubrique n° 1416 (station de distribution d'hydrogène gazeux) de la nomenclature des installations classées et modifiant l'arrêté du 26 novembre 2015 relatif aux prescriptions générales applicables aux installations mettant en œuvre l'hydrogène gazeux dans une installation classée pour la protection de l'environnement pour alimenter des chariots à hydrogène gazeux lorsque la quantité d'hydrogène présente au sein de l'établissement relève du régime de la déclaration pour la rubrique no 4715 et modifiant l'arrêté du 4 août 2014 relatif aux prescriptions générales applicables aux installations classées pour la protection de l'environnement soumises à déclaration sous la rubrique no. 4802 (Decree of 22 October 2018 relating to the general requirements applicable to installations classified for the protection of the environment subject to declaration under heading 1416 (hydrogen gas distribution station) of the nomenclature of classified installations and amending the Order of 26 November 2015 on the general requirements applicable to installations using gaseous hydrogen in an installation classified for environmental for the protection of the environment to fuel gaseous hydrogen-powered trolleys when the quantity of hydrogen present in the establishment falls under the declaration regime for heading no. 4715 and amending the order of 4 August 2014 on the general requirements applicable to installations classified for the protection of the environment subject to declaration under heading No. 4802). Translation by the author <https://legifrance.gouv.fr/jorf/id/JORFTEXT000037519292> Accessed 15 January 2023.

Environmental Protection (ICPE, Installations classées pour la protection de l'environnement) regulation (heading number 1416[57] on hydrogen distribution in refuelling stations for mobility applications).

The above shows that the rules on the transport of dangerous material have already been applicable to the transport of hydrogen outside pipelines for many years, without any specific adaptation or modification. The framework for the transport of dangerous goods is highly detailed and meticulous and explains to the regulatees in advance what actions are permissible, leaving almost no margin. The rules-based approach to legislation, that is clearly followed here, is a logical choice in cases such as the transport of dangerous goods legislation where safety with ex ante prohibition of certain actions is the only option.

Hydrogen Transport by Pipelines

The transport of hydrogen via grid connection is a key aspect of future hydrogen-based economies, especially for transport of large quantities.[58] The hydrogen can be integrated into the natural gas grid by injection as an admixture, by using it to produce synthetic methane to then be injected into the natural gas grid or by the creation of or conversion to 100 per cent hydrogen networks.[59] Synthetic methane is renewable synthetic gas produced by combining CO2 with hydrogen (methanation).[60] France, due to its geographical position, has a high incentive to secure proper hydrogen infrastructure that could be part of a pan-European network, since it would be able to export locally produced hydrogen to its neighbours but also import renewable hydrogen from other countries where its production is more economically advantageous (for example, Spain).[61]

The right of injection and transport of hydrogen in the gas grid was officially established with the adoption of Ordinance No. 2021-167/17.02.2021 and specifically part III of the newly established Book VIII of the French Energy Code, dedicated to the transport and distribution of hydrogen. Articles L831-1 and L832-1 of the Energy Code set a framework for the transport and distribution of hydrogen in autonomous transport networks, specially dedicated to hydrogen, and separate from those for natural gas. The idea behind the creation of dedicated hydrogen grids in France is that with the expected decline in demand for natural gas over the next decades, the existing, extensive natural gas grid could be used for the transport and distribution of hydrogen, after performing the necessary technical adjustments. The idea of using the existing infrastructure is financially attractive, a fact already well recognized; as Anthony Mazzenga, director for renewable hydrogen and gas of GRTgaz, recently declared: 'a grid adapted for hydrogen will cost 2 to 3 times less than a new grid dedicated to hydrogen'.[62] Western Europe

[57] ICPE, '1416. Stockage ou emploi d'hydrogène' <https://aida.ineris.fr/reglementation/1416-stockage-emploi-dhydrogene> Accessed 1 October 2023.

[58] M. Ball and M. Weeda, 'The hydrogen economy – vision or reality?' International Journal of Hydrogen Energy 40 (2015), 7910.

[59] Kantor, 'Assist the European Union Agency for the Cooperation of Energy Regulators in assessing the energy transition aspects as applicable to gas infrastructure – Possible regulation of hydrogen networks' (2021), 8 <https://acer.europa.eu/en/Gas/Documents/ACER%20H2%20Paper_%20vFinal_clean.pdf> Accessed 17 January 2023.

[60] Terega, 'What is synthetic methane?' <www.terega.fr/en/lab/what-is-synthetic-methane/> Accessed 25 January 2023.

[61] A. Wang, S. Yordanova and R. Capaldi, 'Competitiveness of France: Role of hydrogen transport and storage infrastructure' (2021), 21 <https://guidehouse.com/news/energy/2021/dedicated-hydrogen-infrastructure-in-france?lang=en> Accessed 29 January 2023.

[62] F. Gouty, 'Un réseau adapté à l'hydrogène coûte deux à trois fois moins cher qu'un réseau neuf' <https://actu-environnement.com/ae/news/hydrogene-anthony-mazzenga-grtgaz-adaptation-reseau-gaz-interview-39744.php4> Accessed 24 October 2022.

already features a hydrogen-dedicated pipeline network of almost 2,000 km running through France, the Benelux and Germany.[63]

The right to use natural gas pipelines to transport hydrogen was established for the first time by Ordinance No. 2021-167/17.02.2021, which created articles L831-2 and L832-2 of the Energy Code. Specifically, these articles extend the obligations of gas network operators to include hydrogen transport: in the case of injection of hydrogen into natural gas transmission and distribution networks, they 'shall implement the necessary measures to ensure the proper functioning and balancing of the networks, the continuity of the natural gas transmission and delivery service and the safety of people and property'.[64]

These newly established articles strengthen the pre-existing right to access of other gases into gas systems, which was established a few years before. Originally, article 94 of Law No. 2018-938/30.10.2018[65] modified article L. 111-97 of the French Energy Code to establish the right of injection of biogas into the natural gas transport and distribution system.

The same article was amended again by article 49 of the Law on Energy and Climate (Law No. 2019-1147/8.11.2019) so that the scope of the article now also includes hydrogen and other renewable gases. It becomes clear from the report on the discussions of the French National Assembly[66] before the adoption of the Law on Energy and Climate that the extension of the right to access the gas network is important for the producers of renewable hydrogen and will further support the deployment of renewable and low-carbon hydrogen.[67]

The new wording of article L. 111-97 is:

> Subject to preserving the proper functioning and security level of natural gas infrastructures, a *right of access* to the natural gas transmission and distribution facilities and to liquefied natural gas (LNG) installations, including facilities providing ancillary services, is guaranteed by operators who use them for customers, to the *producers of renewable gases, low-carbon hydrogen*[68] and recovery gas as well as suppliers and their agents, under conditions defined by contract.[69]

Therefore, owners and/or operators of hydrogen production installations – since the term producers, which is used, does not distinguish between the two – gained the right to access the natural gas systems, which entails their right to use, in line with the ruling of the ECJ in the *Sabatauskas* case.[70] However, it is important to note that this right to use depends on the technical safety criteria imposed, determining the gas quality.[71] The connection will depend on the fulfilment of the technical standards needed for the injection and the capacity of the network, since no obligation to prioritize the hydrogen injection projects has been established (first come, first served system). Therefore, it can be deduced that the rules regarding the

[63] Terega, 'Transport d'hydrogène, comment Teréga organise son réseau?' <www.terega.fr/nos-activites/hydrogene/transport-dhydrogene-comment-terega-organise-son-reseau/> Accessed 30 January 2023.

[64] Amended articles L. 431-6-4 and L. 432-14 of the French Energy Code.

[65] Law No. 2018-938 of 30 October 2018 for the balance in the trade relations in the agriculture and food sector and healthy, sustainable and accessible food for all.

[66] Together with the Senate (Sénat), they constitute the two bodies of the French Parliament.

[67] A. Cellier, 'Rapport au nom de la commission des affaires économiques, sur le projet de loi relatif à l'énergie et au climat (nos 1908 et 2032) TOME III' (Report on behalf of the Committee on Economic Affairs, on the Draft Law on Energy and Climate (Nos. 1908 and 2032) – PART III) (2019), 266 <www.assemblee-nationale.fr/dyn/15/comptes-rendus/seance> Accessed 25 January 2023.

[68] Emphasis by the author.

[69] Translation by the author.

[70] ECJ C-239/07 Julius Sabatauskas and others (2008) ECR II-7253, 41–42.

[71] Ruven Fleming and Gijs Kreeft, 'Power-to-gas and hydrogen for energy storage under EU energy law' in Martha Roggenkamp and Catherine Banet (eds.) *European Energy Law Report XIII* (Insertia 2019) 119.

injection of hydrogen into the natural gas grid establish a general guideline for preserving the proper functioning and safety of the grid without setting down a more detailed framework – following a goal-based regulatory approach, where the goal is the safe injection of hydrogen within the natural gas grid, but leaving the relevant actors to determine how exactly this will be succeeded.

Technical Conditions for Injecting Hydrogen into Natural Gas Networks

In accordance with articles L-433-13, L-453-4 and R-433-14 of the French Energy Code,[72] transmission system operators (TSOs) and gas distribution system operators (DSOs) issue and make public the guidelines concerning the technical conditions for safe injection that apply to pipelines and connections for gas transmission, distribution and storage facilities, which must be respected by actors in the gas market in order to ensure the safety of the grid.[73] GRTgaz and Teréga at the transmission level and GrDF at the distribution level issued their own codes where their rights and obligations are defined as well as the technical prescriptions applicable to their grids.[74] All three documents include articles on the technical rules that gases other than natural gas have to comply with (articles 7.1.2 and 5.1.2 respectively).[75] There are provisions on the level of impurities of the gas (concerning Hg, Cl, F, NH_3 and so on). The level of H_2 in the gas grid is set at 6 per cent (molar) admixture at most.[76] Moreover, the other gases must comply with the general technical conditions that are also imposed on natural gas – that is, Wobbe index, total sulphur content, density and others.[77] Interestingly, hydrogen injected into the gas grid was initially considered to be an impurity in the gas system,[78] which has changed recently.

The report produced by gas infrastructure operators to determine the technical and economic conditions for injecting hydrogen into the networks, based on measure 7 of the French hydrogen plan, shows that hydrogen blended at a rate of 6 per cent (volume) can be achieved in most networks, excluding cases where sensitive structures or installations are present at the customers' end.[79] However, to achieve a share of 10 per cent or even 20 per cent of hydrogen in the networks, significant investment is needed.[80] Moreover, the percentage of blended hydrogen cannot be the same nationally.[81] The volume of injectable hydrogen and the issues that this

72 French Energy Code, L.433-13, L.453-4, R.433-14.

73 French Energy Code, L. 111-97.

74 For GRTgaz: Code operationnel de reseau-acheminement – piece A2 (Transmission Code) (2018) <https://grtgaz.com/vous-etes/client/expediteur/CORe> Accessed 28 October 2022.

For Teréga: Prescriptions techniques applicables au raccordement d'un ouvrage tiers au réseau de transport de gaz naturel de Teréga (Technical specifications applicable to the connection of a third-party facility to Teréga's natural gas transmission network) (2017) <https://assets.ctfassets.net/ztehsn2qe34u/65HfNcZoc63wtG9vOvXMz/2cd7e9c78966a5a0610c57b2ec1f8336/Annexe_1_-_Prescriptions_techniques_transport-TEREGA.pdf> Accessed 20 October 2023.

For GrDF: Prescriptions techniques du distributeur GrDF (Technical prescriptions for the distributor GrDF) (2017) <www.seolis.net/wp-content/uploads/2021/07/PRESCRIPTIONS-TECHNIQUES-DU-DISTRIBUTEUR-GAZ-NATUREL-SEOLIS.pdf> Accessed 28 October 2022.

75 GRTgaz Transmission Code 2018, 8/Teréga technical prescriptions, 11–13 and technical prescriptions for the distributor GrDF, 8.

76 Ibid.

77 GRTgaz Transmission Code 2018, table at 8.

78 EE Consultant, HESPUL and SOLAGRO, 'Etude portant sur l'hydrogène et la méthanation comme procède de valorisation de l'électricité excédentaire (ADEME 2014), 104 <www.actu-environnement.com/media/pdf/news-23161-etude-powertogs-ademe-grdf-grtgaz.pdf> Accessed 10 October 2022.

79 P. Chambon et al., 'Conditions techniques et économiques d'injection d'hydrogène dans les réseaux de gaz naturel' (Rapport final Juin 2019), 21<https://francegaz.fr/conditions-techniques-et-economiques-dinjection-dhydrogene-dans-les-reseaux-de-gaz-naturel/> Accessed 11 October 2023.

80 Ibid.

81 Ibid.

injection may cause depend, for example, on the specific characteristics of an area (sub-zone of the grid), the nature of pipelines, the presence or not of aquifer storage tanks, the gas quality and the possibility for proper metering, network equipment, network capacity and types of customers connected.[82]

The proportion of up to 6 per cent of pure hydrogen that may be injected into the grid provides an answer to the question whether or not it is allowed to admix gases in the grid which at the entry point do not fully comply with the technical gas specifications, but they become compliant at the exit point due to the mixing with the pre-existing gases in the gas grid. The GRHYD pilot project[83] was able to demonstrate that the injection of a gas mixture composed of up to 20 per cent hydrogen (by volume) into new natural gas distribution networks is technically possible, and Jupiter 1000[84] safely injected up to 1 per cent hydrogen (by volume) and could reach a theoretical limit of 6 per cent in the transport system.

Guarantees of Origin

Lastly, since France aims to use hydrogen to decarbonize many of its energy systems and processes, it is important to mention the provisions on traceability and guarantee mechanisms established by Ordinance No. 2021-167.[85] According to article 821-3 of the French Energy Code, a guarantee of origin is issued to attest the origin of the renewable or low-carbon hydrogen produced, if it is likely to be mixed with another type of hydrogen or gas between stages or if the guarantee issued during its production is likely to be sold independently of the hydrogen produced.[86] The system of guarantees of origin for hydrogen is modelled upon the existing system for biogas (article L. 445-3 and following the French Energy Code) and can play an important role in development and deployment of renewable and low-carbon hydrogen, even if mixed with other gases. However, the guarantee of traceability of article L-821-2 is issued for renewable or low-carbon hydrogen produced and not mixed with another type of hydrogen or gas and that has been physically delivered to the buyer or final consumer.

From the French Energy and Climate Law as well the National Hydrogen Strategy, there is a clear need to increase the deployment of renewable and low-carbon hydrogen for the decarbonization of the energy system and heavy transport. However, since there is no certainty on the exact technical conditions that need to be fulfilled, the French legislators opted to set the general goal of injecting hydrogen into the grid and leaving market players responsible for fulfilment, while keeping the network's security. Moreover, when setting the traceability and guarantee of origin system, the legislator is pretty precise regarding the system and how it should function, and even established a specific authority to handle and supervise the system (Chapter V of Book VIII of the French Energy code). The goal-setting approach that is followed in view of the right of injection of hydrogen is a good way to achieve the purpose of hydrogen integration into gas systems while ensuring system safety, for which there are still many uncertainties. The

[82] Ibid, 21.

[83] GRHYD (Gestion des Réseaux par l'injection d'HYdrogène pour Décarboner les energies – Network Management by injecting HYdrogen to Decarbonize energies) is one of the first French power-to-gas demonstrators, located at Dunkirk, where hydrogen produced by electricity from wind is injected in the natural gas distribution grid.

[84] Jupiter 1000 is the first French power-to-gas demonstrator at an industrial level, which aims at testing the injection of hydrogen and SNG into the natural gas transport system together with a carbon capture unit that provides for the CO_2 needed for the methanation and SNG production. R. Boughriet, 'Jupiter 1000: la première installation de Power to gas est mise en service en France' (2020) Actu Environnment <https://actu-environnement.com/ae/news/jupiter-1000-grt-gaz-hydrogene-35040.php4> Accessed 14 October 2022.

[85] Title II of Book VIII of the French Energy Code.

[86] Art. 821-3 of the French Energy Code.

goal-setting approach is arguably the best choice in facing technological change and can facilitate technological innovation by allowing regulatees the freedom to experiment,[87] as happened in the case of France with the development of numerous pilot projects.

16.3 CONCLUSION

The goal of this chapter was to examine how the existing French legal system accommodates the transport of hydrogen and to scrutinize the regulatory approach followed.

France finally took the first important step towards the establishment of a specific framework related to hydrogen with the adoption of Ordinance No. 2021-167/17.02.2021. Hydrogen (low-carbon and renewable) and the related technologies, such as power-to-gas have been at a central position in the future energy plan for France and have been viewed as important solutions for decarbonization by stakeholders in both the private and public sector. Even though there were some pre-existing elements concerning the regulation of hydrogen transport, they were largely confined to the general rules for transport of dangerous materials. For the hydrogen sector to blossom and to play the role that was envisioned for the French energy transition, some specific elements are needed for hydrogen (specific rules on the types of hydrogen, transport, sale and so on), which has been noted by the private sector over the years.

Besides the existing modes of transporting hydrogen (road, rail, water), France takes great interest in the injection of hydrogen – and especially of green hydrogen – into grids to transport the gas from the hubs of production. For the use of the existing gas network for hydrogen transport, it was concluded that a right to access for hydrogen and renewable gas to the gas grid was adopted a few years ago, opening the way for hydrogen and synthetic natural gas (SNG) injection. The adoption of Ordinance 2021-167 creates the legal leeway for both: a hydrogen-only transport and distribution system as well as the obligation for TSOs and DSOs to take the appropriate measures to ensure the proper functioning and balancing of the gas systems when hydrogen is injected. In terms of numbers, testing for injection of hydrogen admixed with natural gas up to 20 per cent yielded positive results. There now is the clear need to follow up on this quickly by changing the safety regulations and including this technical possibility into law by raising the amount of admissible hydrogen to the natural gas grid from 6 to 20 per cent.

From a regulatory techniques perspective, the approach followed in the case of hydrogen legislation in France is currently moving away from the prescriptive technical rules, such as the rules on the transport of dangerous goods, and towards the setting of important targets – that is, hydrogen injection with respect to the proper function and security of the grid. This latter approach leaves it to the market participants to determine, based on the individual characteristics, how safety in the grid can be achieved.

All in all, the analysis indicates that the decision on regulatory approaches is not a one-time decision: each time for every part of the system, which approach is most suited to reach a given regulatory objective must be considered. In case of hydrogen injection, the adoption of the goal-setting approach is considered a success for the French legislator as it provided leeway to each network operator to experiment based on their particularities. Even though there are still some important legal gaps in existing legislation and ambivalences that need to be resolved, France can be viewed as a positive example for how using a suitable regulatory approach can have a real effect on the quality and speed of adaptation of the legal system to a new energy carrier.

87 Decker (2018), 21.

FURTHER READING

M. Ball and M. Weeda, 'The hydrogen economy-vision or reality?' in International Journal of Hydrogen Energy 40 (2015), 7910

P. Chambon et al, 'Conditions techniques et économiques d'injection d'hydrogène dans les réseaux de gaz naturel' (Rapport final Juin 2019) 39 <https://afgaz.fr/conditions-techniques-et-economiques-dinjection-dhydrogene-dans-les-reseaux-de-gaz-naturel/> accessed 11 October 2023

Francesco Dolci et al, 'Incentives and legal barriers for power-to-hydrogen pathways: An international snapshot', International Journal of Hydrogen Energy 44, 23 (2019), 11394–11401

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Hydrogen Council, McKinsey & Company, 'Hydrogen Insights 2021: A Perspective on Hydrogen Investment, Deployment and Cost Competitiveness' (2021) <https://hydrogencouncil.com/en/hydrogen-insights-2021/> accessed 10 January 2023

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17

The Development of Hydrogen Infrastructure in the Netherlands and Third-Party Access

Maaike Broersma, Philipp Jäger and Marijn Holwerda

17.1 INTRODUCTION

Both the EU[1] and the Netherlands[2] have recently announced their ambitions on the production and consumption of (renewable) hydrogen. The European Commission has proposed legislation on hydrogen by means of a recast of the Gas Directive[3] and the Gas Regulation,[4] the so-called Decarbonisation Package, in December 2021.[5] The EU has also taken other steps to increase the use of (renewable) hydrogen.[6] With its experience in hydrogen production, strategic location near the North Sea, potential for offshore wind energy production and extensive onshore natural gas (gas) pipeline network, combined with the expected substantial consumption of hydrogen domestically and in neighbouring countries, the Netherlands has a good starting position for developing a hydrogen economy both at home and in the wider EU.

A significant increase in hydrogen production and consumption in the Netherlands will require the development of large-scale hydrogen infrastructure such as hydrogen transport and

[1] The target for the EU is at least 40 GW of renewable hydrogen electrolysers and the production of 10 million tonnes of hydrogen, both by 2030, EU Commission, 'EU hydrogen strategy for a climate-neutral Europe', Communication to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions, COM(2020) 301 final, p. 6 <https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52020DC0301> accessed 22 October 2023.

[2] The target for the Netherlands is 4 GW electrolyser capacity in 2030 and 8 GW electrolyser capacity in 2032, Dutch Minister of Climate and Energy Policy, 'Vormgeving instrumentarium hernieuwbare waterstof' (Set up instruments renewable hydrogen) (letter to the Dutch Parliament, 23 June 2023) <https://open.overheid.nl/documenten/9b957903-442d-4ca3-9aba-d73b6785cf6e/file> accessed 22 October 2023.

[3] European Commission, 'Proposal for a Directive of the European Parliament and of the Council on Common Rules for the Internal Market in Renewable and Natural Gases and in Hydrogen', COM (2021) 803 final (15 December 2021) (hereinafter: COM (2021) 803).

[4] European Commission 'Proposal for a Regulation on the internal markets for renewable and natural gas and for hydrogen (recast)', COM 804 final (15 December 2021) (hereinafter: COM (2021) 804).

[5] The EU Decarbonisation Package is discussed in depth in Chapter 2 by Leigh Hancher and Simina Suciu.

[6] Such as the revision of Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources <https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32018L2001> accessed 22 October 2023, where the final text has been agreed before summer 2023 and which is awaiting adoption into law, 'Outcome of Proceedings', European Council, 19 June 2023 (10794/23) <www.consilium.europa.eu/media/65109/st10794-en23.pdf> accessed 22 October 2023, and the rules on hydrogen infrastructure, discussed further here.

storage infrastructure. This chapter examines the development of such infrastructure in the light of recent EU proposals for so-called third-party access to new and repurposed infrastructure. For clarity's sake, when talking about the development of hydrogen infrastructure, we also refer to the later operation of such infrastructure, even when not explicitly stating so.

N.V. Nederlandse Gasunie (Gasunie), together with its group companies, is active in the development of hydrogen infrastructure in the Netherlands and northern Germany. Gasunie is wholly owned by the Dutch state and one of its group companies operates the Dutch high-pressure natural gas network. Gasunie also operates other natural gas infrastructure.

Below, we will briefly discuss the plans of Gasunie and the Dutch government for the development and operation of hydrogen transport, storage and import infrastructure (Section 17.2). Thereafter, we will give a concise overview of the current Dutch legal framework regulating the hydrogen infrastructure activities Gasunie is developing (Section 17.3). Finally, we will discuss the European Commission's proposals on third-party access to the different forms of hydrogen infrastructure as well as its proposals for (possibly) exempting new hydrogen infrastructure (Section 17.4). In doing so, we will try and give a first assessment of how these proposals could impact the development of hydrogen infrastructure in the Netherlands, with a focus on hydrogen transport and storage infrastructure. We aim to give the reader an idea of how the different possible regimes for third-party access to hydrogen infrastructure could impact the development of such infrastructure and what challenges could arise for an energy infrastructure company like Gasunie.

17.2 HYDROGEN INFRASTRUCTURE ACTIVITIES IN THE NETHERLANDS

In the northern part of Germany and in the Netherlands, Gasunie acts as a transmission system operator of a high-pressure gas network as well as, through its group companies,[7] an operator of gas storage and gas import infrastructure. In the remainder of this chapter, we will refer to the activities of Gasunie group companies as Gasunie activities.

Besides its more traditional energy infrastructure activities, Gasunie partakes in the Dutch and EU energy transition by developing renewable hydrogen projects. Gasunie hydrogen activities consist of a wide set of initiatives for the development and operation of hydrogen transport, storage and import infrastructure, which will now be discussed in turn.

17.2.1 *Transport*

In 2021, a study conducted by several organisations in the Netherlands showed that it is possible and, from a societal point of view, desirable to reuse the Gasunie gas transport network for hydrogen transport.[8] The existing network could be reused to transport hydrogen and connect future hydrogen consumers, suppliers and storage.[9] The gas transport network would be gradually freed up to accommodate the increasing need for transporting hydrogen. This reuse would be more cost effective than the development of new hydrogen transport pipelines and

[7] Such as the gas storage EnergyStock in the north of the Netherlands and the LNG terminals GATE in the harbour of Rotterdam and EemsEnergyTerminal in the harbour of Eemshaven in the north of the Netherlands.

[8] HyWay 27, 'Hydrogen transmission using the existing natural gas grid? Final report for the Ministry of Economic Affairs and Climate Policy', June 2021 <www.rijksoverheid.nl/documenten/kamerstukken/2021/06/30/kamerbrief-over-ontwikkeling-transportnet-voor-waterstof> and <www.hyway27.nl/en/latest-news/hyway-27-realisation-of-a-national-hydrogen-network> both accessed 22 October 2023.

[9] Ibid, pp. 8 and 56 et seq.

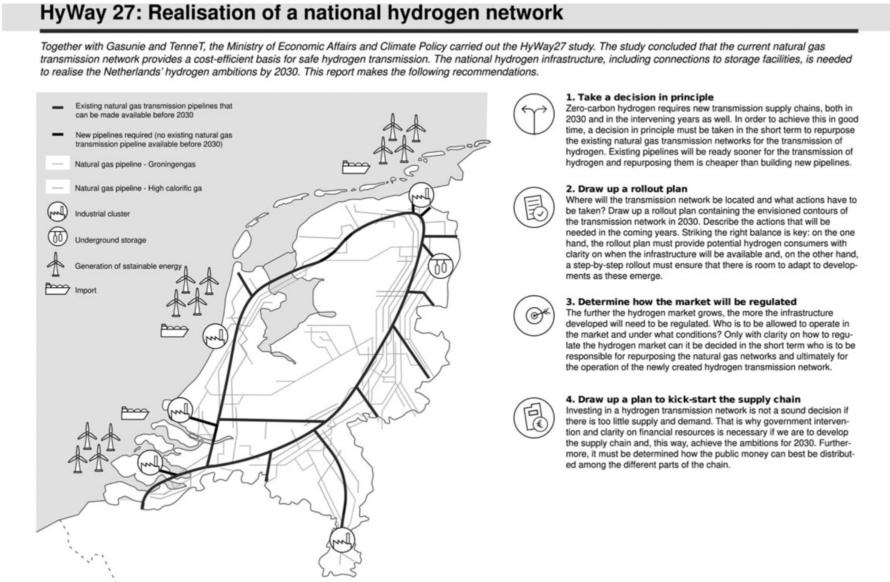

FIGURE 17.1 HyWay 27: Realisation of a national hydrogen network
Source: HyWay 27, 'Hydrogen transmission using the existing natural gas grid? Final report for the Ministry of Economic Affairs and Climate Policy', June 2021, p. 11 <www.rijksoverheid.nl/documenten/kamerstukken/2021/06/30/kamerbrief-over-ontwikkeling-transportnet-voor-waterstof>

would require an investment of around €1.5 billion.[10] The main recommendations of the study are displayed in Figure 17.1.[11]

Based on the HyWay 27 report, the Dutch State Secretary of Economic Affairs and Climate (State Secretary) indicated in a letter to the Dutch parliament that a hydrogen transport network would be necessary for a CO_2-free hydrogen chain and that as far as possible it should be based on reuse of existing gas pipelines. The State Secretary also announced a plan for the rollout of the national hydrogen transport network and indicated the intention to request Gasunie to develop this network and free up gas pipelines for reuse.[12]

In June 2022, the Dutch government proclaimed that HyNetwork Services, a Gasunie group company, is to develop and operate a dedicated nationwide hydrogen transport network. The investments would have to be made for the, yet to be developed, different hydrogen markets. However, it would not be an option to defer these investments to a later time, because the planned projects for hydrogen production, storage and import require such a hydrogen transport network to be available in order to be realised. The Dutch government has reserved a maximum of €750 million for the development of the hydrogen transport network. The network will connect the major Dutch industrial clusters and storage facilities, and with the neighbouring countries; it is expected to be fully operational by 2030, at the latest.[13]

[10] Ibid, pp. 9 and 71 et seq.

[11] HyWay 27, 'HyWay 27: realisation of a national hydrogen network', June 2021 <www.hyway27.nl/en/latest-news/hyway-27-realisation-of-a-national-hydrogen-network> accessed 14 January 2024.

[12] Dutch State Secretary of Economic Affairs and Climate Policy – Climate and Energy Policy, 'Ontwikkeling transportnet voor waterstof' (Development transport network for hydrogen) (letter to the Dutch Parliament, 30 June 2021) <https://open.overheid.nl/documenten/ronl-66d67edc-8d97-42e5-9f61-c4bc4bf5a1c6/pdf> accessed 22 October 2023.

[13] Dutch Minister of Climate and Energy Policy, 'Ontwikkeling transportnet voor waterstof' (Development transport network for hydrogen) (letter to the Dutch Parliament, 29 June 2022) <https://open.overheid.nl/repository/ronl-

In July 2023, the Minister of Climate and Energy Policy informed the Dutch Parliament of the progress being made on the development of the hydrogen transport network. He indicated that several steps had been taken to centralise the permitting process (*Rijkscoordinatieregeling*). Furthermore, the planned routing of the hydrogen transport network had to be partly changed, due to two recent developments. First, the war in Ukraine changed natural gas flows, meaning that certain gas pipelines would only become available for reuse at a later time than initially planned. Second, the planned routing had to be aligned with a recently initiated project for the transport of several commodities (including hydrogen) from Rotterdam harbour to the Ruhr area in Germany (Delta Rijn Corridor).[14]

The development and operation of the hydrogen transport network is expected to have a learning-by-doing character. This means that in the first period the network will be developed in stages and as a linear connection. The pipelines will have fewer connections to other pipelines than in the existing gas transport network. The hydrogen transport network will, at first, due to its linear setup, not have any rerouting possibilities. This means that the operational behaviour of the first hydrogen transport network users will have considerable influence on the integrity of the hydrogen transport network. For example: the consequences of the feeding in of hydrogen that does not comply with the quality specifications, as published, could be felt throughout the whole hydrogen value chain.

17.2.2 *Storage*

Hydrogen storage is considered an integral part of the development of the hydrogen value chain. The Dutch National Hydrogen Programme, a public–private hydrogen collaboration, foresees a hydrogen storage demand of 750–1,000 gigawatt hours (3–4 salt caverns) for 3–4 gigawatts (GW) electrolyser capacity in 2030 in the Netherlands.[15] In Germany, expectations of future demand for hydrogen storage are even higher.[16]

Hydrogen storage activities focus on the development and operation of large-scale underground hydrogen storage connected to hydrogen transport networks in both the Netherlands and Germany. The idea is to create flexibility and provide hydrogen market players a tool for dealing with both short-term and long-term fluctuations in hydrogen supply and demand. Another function of hydrogen storage will be to increase the security of supply in the energy system as a whole and the socio-economic benefits by allowing the storage of electricity produced and its conversion to hydrogen in a period of over-production of electricity (from renewable sources) and to use that hydrogen to produce electricity in a period of under-production (from renewable sources).[17] The first Gasunie hydrogen storage will be developed in the north of the Netherlands

5pt>> accessed 22 October 2023 (hereinafter: Dutch Minister of Climate and Energy Policy, letter 29 June 2022).

14 Dutch Minister of Climate and Energy Policy, 'Voortgang ontwikkeling transportnet voorwaterstof' (Progress development transport network for hydrogen) (letter to the Dutch Parliament, 3 July 2023) <https://open.overheid.nl/documenten/6c20acd7-2d88-47e7-8f52-15573c75da95/file> accessed 22 October 2023 (hereinafter: Dutch Minister of Climate and Energy Policy, letter 3 July 2023).

15 Nationaal Waterstof Programma, 'Routekaart Waterstof' (November 2022) <https://open.overheid.nl/repository/ronl-4e9a5511ce0f4193c14ef14fe7f820838b84fb03/1/pdf/routekaart-waterstof.pdf> accessed 22 October 2023.

16 Demand for hydrogen storage of at least 5 TWh, see German Nationaler Wasserstoffrat, 'Wasserstoffspeicher-Roadmap 2030 für Deutschland', p. 2 <www.wasserstoffrat.de/fileadmin/wasserstoffrat/media/Dokumente/2022/2022-11-04_NWR_Stellungnahme_Wasserstoff-Speicher-Roadmap.pdf> accessed 22 October 2023.

17 European Commission, Energy Transition Expertise Centre (ENTEC), 'The role of renewable H_2 import & storage to scale up the EU deployment of renewable H_2', 28 February 2022 <https://energy.ec.europa.eu/publications/role-renewable-h2-import-storage-scale-eu-deployment-renewable-h2_en> accessed 22 October 2023.

and the first cavern is expected to be fully operational in 2028. Three more caverns are planned to be operational after 2030.[18]

17.2.3 *Import*

Hydrogen import activities in the Netherlands consist of the development and operation of hydrogen terminal infrastructure for ships in both the Netherlands and Germany, currently with a focus on the ports of Rotterdam, Eemshaven (both in the Netherlands) and Brunsbüttel (Germany).[19] The import of renewable hydrogen[20] is seen by the Dutch government as essential for meeting expected future demand for such hydrogen.[21] By combining hydrogen with nitrogen to create ammonia, it can be transported, stored and converted into green hydrogen in larger quantities. Another possibility is to transport hydrogen via ships by use of so-called liquid organic hydrogen carriers (LOHC), which are essentially organic compounds that may store hydrogen as reversible chemical bonds.

17.2.4 *Offshore*

In May 2022, Denmark, Germany, Belgium and the Netherlands signed the so-called Esbjerg declaration, agreeing to develop the North Sea as a 'green power plant'. This will consist of multiple connected offshore energy projects and hubs, centring around large-scale offshore wind energy production, and electricity and hydrogen interconnectors. By 2030, the four EU Member States intend to produce at least 65 GW of offshore wind energy, increasing to at least 150 GW by 2050; 20 GW of the targeted offshore wind energy for 2030 is to be earmarked for onshore and offshore production of green hydrogen and these four countries look to expand the production even further for 2050.[22]

In December 2022, the Dutch government stated that it intends to assign to Gasunie the task of developing and realising an offshore hydrogen transport network.[23] This offshore hydrogen transport network will connect with the onshore network, thereby also connecting offshore infrastructure with onshore hydrogen storage infrastructure.

Having briefly sketched the different hydrogen activities, we will now turn to the Dutch legislative framework which regulates these activities.

[18] See the website of HyStock and in particular 'The project' <www.hystock.nl/en> accessed 22 October 2023.

[19] The ACE Terminal project in Rotterdam <www.aceterminal.nl/>, the EemsEnergyTermina, <www.eemsenergyterminal.nl/en> and the LNG Terminal in Brunsbüttel <www.gasunie.nl/en/news/new-step-in-development-of-lng-terminal-in-brunsbuettel> all accessed 22 October 2023.

[20] Renewable hydrogen is defined in Chapter 2 by Hancher and Suciu.

[21] Dutch Minister of Climate and Energy Policy, Minister of Economic Affairs and Climate Policy, Minister for Foreign Trade and Development Cooperation and Minister of Foreign Affairs, 'Energiediplomatie en import van waterstof' (Energy diplomacy and import of hydrogen) (letter to the Dutch Parliament, 2 June 2023) <https://open.overheid.nl/documenten/3b08e36c-7e15-430b-a5c6-2577fa9ca05f/file> accessed 22 October 2023.

[22] 'The Esbjerg Declaration on the North Sea as a Green Power Plan of Europe', by the Heads of State of Denmark, Belgium, the Netherlands and Germany, 18 May 2022 <https://open.overheid.nl/repository/ronl-1e299d084fbc5bfc2968d934ca2f4a97b3931d9f/1/pdf/Esbjerg_declaration_for_prime_ministers.PDF> accessed 22 October 2023.

[23] Dutch Minister of Climate and Energy Policy, 'Voortgang waterstofbeleid' (Progress hydrogen policy) (letter to the Dutch Parliament, 2 December 2022) <https://open.overheid.nl/repository/ronl-7c7b4555e9e760329c2a83ebef633fdac833dc18/1/pdf/voortgang-waterstofbeleid.pdf> accessed 22 October 2023.

17.3 THE NATIONAL LEGISLATIVE FRAMEWORK FOR HYDROGEN INFRASTRUCTURE ACTIVITIES

Alongside the obvious areas of law such as spatial planning law and competition law, the Dutch legislative framework for hydrogen activities in essence consists of the Dutch Gas Act. In June 2023, a draft for a new Energy Act was submitted to the Dutch Parliament, aimed at amending and merging the Gas Act with the Electricity Act 1998, to form a new, all-encompassing act.[24]

A two-stage process is foreseen, whereby in the current first stage the Gas Act and Electricity Act will be merged and in the second stage the amendments to the Gas Directive that the European Commission proposed in December 2021 in the so-called Decarbonisation Package[25] will be implemented into Dutch law, very likely in the Energy Act.[26] The latter will be initiated after these proposals have gone through the complete EU legislative process and have been enacted as EU law.

Currently it is foreseen that Gasunie will, under national law, be given the statutory task of developing and managing a nationwide onshore and offshore hydrogen transport network (see Section 17.2.1). Considering that the legislative recast process for the Gas Act is ongoing, and the outcome is not clear, our focus here is on the current Gas Act.

As a so-called sector-specific regulation, the Gas Act represents the Dutch transposition of the various EU Gas Directives, such as the current Gas Directive.[27] The Gas Act determines which tasks the Dutch gas transport network operator, Gasunie Transport Services (GTS), is to fulfil and which activities it may perform. Since 2019, the Gas Act has also contained a provision on the activities that Gasunie group companies, which form part of the same group as GTS, are allowed to perform in areas other than gas transport.

According to this provision, the Gasunie group, within the meaning of the Dutch Civil Code, shall mainly perform the tasks assigned to GTS by the Gas Act or any act based on it.[28] It is to mainly focus on the regulated activity of gas transport.[29] However, Gasunie group companies are allowed to perform a limited number of listed activities other than gas transport, mainly in the energy transition field.[30]

The Gas Act states that Gasunie group companies are allowed to develop and manage hydrogen pipelines or installations (*leidingen of installaties voor waterstof*), including the transport of hydrogen,[31] as long as the Dutch ownership unbundling rules are observed.[32] Even

[24] Wetsvoorstel Energiewet (Draft Energy Act), submitted to Dutch Parliament on 9 June 2023 <https://zoek.?officielebekendmakingen?.nl/dossier/kst-36378-2.pdf> accessed 22 October 2023.

[25] The EU Decarbonisation Package is discussed in depth in Chapter 2 by Hancher and Suciu.

[26] 'Memorie van Toelichting op de Energiewet' (Explanation on the Energy Act) pp. 5 and 6, submitted to Dutch Parliament on 9 June 2023 <https://zoek.?officielebekendmakingen?.nl/kst-36378-3.pdf> accessed 22 October 2023.

[27] EU Directive 2009/73/EC of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC (hereinafter: Directive 2003/55/EC).

[28] Article 10d (1) Gaswet (Gas Act).

[29] Dutch Minister of Economic Affairs, 'Wijziging van de Elektriciteitswet 1998 en van de Gaswet (voortgang energietransitie – Tweede Nota van Wijziging)' (Amendment to the Electricity Act 1998 and the Gas Act (progress energy transition) – Second declaration of amendment) 25 January 2018 <https://zoek.?officielebekendmakingen?.nl/kst-34627-22.pdf> accessed 22 October 2023 (hereinafter: Dutch Minister of Economic Affairs).

[30] Article 10d (2) Gaswet (Gas Act).

[31] We use unofficial translations of Dutch into English. To our knowledge, there is no official English translation of the Gaswet (Gas Act).

[32] The Dutch ownership unbundling rules stem from the Gas Directive and require a separation between the transport of gas on one side and the production and trade of gas on the other side. This is to guarantee non-discriminatory access to the Gasunie gas transport network. See article 10d (2) (e) of the Gaswet (Gas Act). The Dutch transposition

though the Gas Act speaks of pipelines *or* installations, the legislator's intention clearly has been to allow Gasunie to be involved in both types of infrastructure.[33]

Finally, the Gas Act gives the Minister of Economic Affairs and Climate Policy the authority to instruct GTS in case the provisions of the Gas Act, or any legislation based on them, are not adhered to.[34]

In addition, the Dutch Minister of Climate and Energy Policy intends to assign to Gasunie, until the proposed changes to the Gas Directive have been implemented in the new Energy Act, the service of general economic interest of developing and managing a nationwide hydrogen transport network (see Section 17.2.1).[35]

The concept of a service of general economic interest stems from EU state aid law.[36] The term refers to a service which cannot profitably be provided for by the market, but which an EU Member State would like to have carried out in the general (societal) interest.

Since the ruling of the European Court of Justice in the *Altmark* case, compensation from an EU Member State given to a company for providing a service of general economic interest does not constitute state aid within the meaning of article 107 of the Treaty on the Functioning of the EU, if four conditions are met.[37] One of these conditions is that the recipient has to have clearly defined public service obligations.

In a nutshell, at the time of writing, the Dutch legislative framework for hydrogen activities principally consists of the abovementioned provisions of the Gas Act, allowing companies belonging to the Gasunie group to develop and manage hydrogen pipelines and installations, including the transport of hydrogen itself. In addition, the Dutch Minister of Climate and Energy Policy will, through decisions on the hydrogen transport service of general economic interest, also determine part of the legislative framework for hydrogen transport activities, at least until the changes proposed by the European Commission in December 2021 have been transposed into Dutch law. As such, the service of general economic interest decision can be seen as a temporary elaboration of the broader framework of the Gas Act.

17.4 THIRD-PARTY ACCESS TO HYDROGEN INFRASTRUCTURE UNDER THE EU DECARBONISATION PACKAGE

On 15 December 2021, the European Commission proposed several changes to both the Gas Directive and EU Regulation 715/2009 (Gas Regulation), in order to include hydrogen in the EU's legislative framework on gas. These proposals have become known as the Decarbonisation Package.[38] As the European Commission's proposals for including hydrogen in the EU gas regulation are extensively discussed in Chapter 2 of this book, 'Hydrogen Regulation in Europe' by Hancher and Suciu, we will not get into their full details here.[39] Having said that, this chapter

of the ownership unbundling rules of EU Gas Directive may be found in the 'Besluit uitvoering onafhankelijkheid seisen energierichtlijnen' (Decision execution independence requirements energy directives) <https://wetten.overheid.nl/BWBR0031810/2014-08-01> accessed 22 October 2023. This is a decision by the Minister of Economic Affairs and Climate Policy, stemming from 2012. Importantly, the decision only looks at natural gas and electricity and not at hydrogen (production, trade and transportation).

33 See Dutch Minister of Economic Affairs.

34 Article 5 (2) Gaswet (Gas Act).

35 See Dutch Minister of Climate and Energy Policy, letter 29 June 2022.

36 See e.g. Herwig C. Hofmann and Claire Micheau, *State Aid Law of the European Union* (Oxford University Press 2016), p. 87 and further.

37 Case C-280/00 Altmark [2003] ECR I-07747.

38 See COM (2021) 803; and COM (2021) 804.

39 The EU Decarbonisation Package is discussed in depth in Chapter 2 by Hancher and Suciu.

will analyse one particular aspect, namely third-party access to hydrogen infrastructure, and the proposals for exempting new hydrogen infrastructure.

The European Parliament[40] and the Council of Ministers (Council)[41] have adopted their respective starting position for the trialogue in spring 2023. Negotiations between the European Parliament, the Council and the European Commission have started and are, at the time of writing, still ongoing. No clarity yet exists regarding the final versions. We base our appraisal on the Commission's original proposals only, paying attention to the starting position of the European Parliament and the Council where they differ from the Commission's original proposal. In doing so, we will also try and have a look at the European Commission's possible intentions behind the proposals.

The term third-party access refers to access to (energy) infrastructure by parties who do not control the relevant infrastructure. EU energy regulation traditionally differentiates between various third-party access regimes ranging from so-called *regulated* third-party access, whereby the national regulator sets the tariff and access conditions,[42] to so-called *negotiated* access, whereby the network operator and its customers are principally free to determine tariff and access conditions through commercial negotiations.

17.4.1 *Third-Party Access to Hydrogen Transport Networks*

Starting with the proposed third-party access regime for hydrogen transport networks, the European Commission proposes that as of 1 January 2031 (and the Council's starting position is as of 1 January 2036), all EU Member States shall have a system of regulated third-party access in place based on published tariffs, which are applied objectively and non-discriminatorily.[43] In the amended preamble to its proposal for a new Gas Directive, the European Commission indicates that 'as a result of the high capital expenditure required for their construction, hydrogen pipeline networks could constitute natural monopolies'.[44]

Until 31 December 2030 (until 31 December 2035 in the Council's starting position), EU Member States have the freedom to opt for a negotiated third-party access regime, whereby the network operator and its customers are obliged to negotiate 'in good faith'. If the EU Member

[40] European Parliament, Report on the proposal for a directive of the European Parliament and of the Council on common rules for the internal markets in renewable and natural gases and in hydrogen (recast) COM(2021) 803, 17 February 2023 <www.europarl.europa.eu/doceo/document/A-9-2023-0035_EN.pdf> and Report on the proposal for a regulation of the European Parliament and of the Council on the internal markets for renewable and natural gases and for hydrogen (recast) COM(2021) 804, 16 February 2023 <www.europarl.europa.eu/doceo/document/A-9-2023-0032_EN.pdf> both accessed 22 October 2023.

[41] EU Council, 'Proposal for a Directive of the European Parliament and of the Council on common rules for the internal markets in renewable and natural gases and in hydrogen (recast) – General approach', 28 March 2023 <https://data.consilium.europa.eu/doc/document/ST-7911-2023-INIT/en/pdf> and 'Proposal for a Directive of the European Parliament and of the Council on common rules for the internal markets in renewable and natural gases and in hydrogen (recast) – General approach', 28 March 2023 <https://data.consilium.europa.eu/doc/document/ST-7909-2023-INIT/en/pdf> (hereinafter: Proposed Gas Directive) both accessed 22 October 2031.

[42] Under a regime of regulated third-party access, the regulator usually also determines the allowed revenues to be recovered by the network operator by means of the tariffs charged to its customers. In other words, the regulator in such a system determines how much of its costs the network operator is allowed to earn back through its tariffs. On the concept, see e.g. Martha M. Roggenkamp, 'The concept of third party access applied to CCS' in Martha M. Roggenkamp and Edwin Woerdman (eds.), *Legal Design of Carbon Capture and Storage* (Intersentia 2009) 273, 281.

[43] See the proposed article 31 Gas Directive in the European Commission's proposal, COM (2021) 803, and the later date of 1 January 2036 for the requirement of regulated third-party access in the Council's starting position.

[44] COM (2021) 803, recital 66. Somewhat contrastingly, the European Commission in the explanatory memorandum to its proposals states that 'hydrogen infrastructure is likely to constitute a natural monopoly, resulting in non-competitive market structures', p. 7.

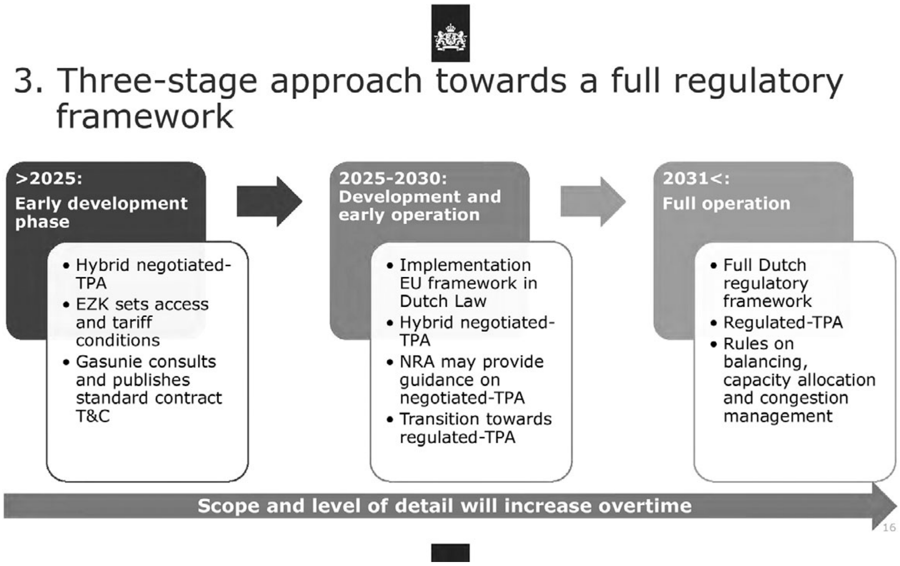

FIGURE 17.2 Three-stage approach towards a full regulatory network
Source: Gijs Kreeft, Ministry of Economic Affairs and Climate Policy, 'Policy framework conditions hydrogen transport', presentation given at the Hynetwork Services Information Session 'National Hydrogen Network and Hydrogen Contractual Framework', online 22 April 2022, slide 16. See 'Explanatory Slidepack Consultation' <www.hynetwork.nl/en/become-a-customer/contracts> accessed on 22 October 2023.

State opts to apply negotiated third-party access to the hydrogen transport network(s) until the end of 2030 (until the end of 2035 in the Council's starting position), the regulatory authorities of the Member States need to provide guidance for the network operator's customers as to how negotiated tariffs will be affected when regulated third-party access is introduced.[45]

In the Netherlands, the Minister of Climate and Energy Policy has indicated his intention to make use of the option to introduce a negotiated third-party access regime until 2031 and to determine the framework within which the conditions and tariffs for access and services are set up and HyNetwork Services has to negotiate with parties.[46] This so-called hybrid negotiated third-party access regime, which will be a combination of a regulated and negotiated third-party access regime,[47] will be applied under the earlier mentioned service of general economic interest (see Section 17.3), in advance of the implementation of the Decarbonisation Package. Once the provisions of the Decarbonisation Package have been implemented in the new Energy Act, this hybrid negotiated third-party access regime will gradually be transformed into a regulated third-party access regime with an advisory role for the Dutch regulator, the Netherlands Authority for Consumer and Markets (ACM). Roughly, the foreseen planning is as shown in Figure 17.2.

Considering that nationwide pipeline infrastructure, such as the natural gas transport networks in the various EU Member States, often forms a natural monopoly, it is understandable

[45] See article 31 COM (2021) 803.
[46] See Dutch Minister of Climate and Energy Policy, letter 29 June 2022, p. 10. The Minister has explicitly stated that this access regime will end in 2031, despite signals from the trialogue that the date in the Gas Directive will be moved from 2031 to 2036, see Dutch Minister of Climate and Energy Policy, letter 3 July 2023, p. 2.
[47] It will in essence be a third-party access regime that will be somewhere in between a true negotiated third-party access regime and fully regulated third-party access, through which some, but not all, of the terms and conditions set under a regulated third-party access regime are set by the Minister.

that the European Commission seeks to, in the end, have a regulated third-party access regime.[48] It also makes sense not to require EU Member States to immediately introduce such a regime as the different national hydrogen transport markets are yet to develop or, at best, have only just started developing. Too deep regulation (in the form of detailed network codes) at too early a stage could slow or even hamper the development of these markets.

What is more, there would simply be very little infrastructure to apply the regulation to in the first place. Think, for instance, of the very detailed EU regulation on gas transport capacity allocation,[49] which would make no sense at all to apply to the hydrogen transport markets in the coming years as these markets will simply be too immature and not yet liquid enough for such regulation to have any effect. From that perspective, the European Commission's approach seems sensible.

Nevertheless, for Gasunie, which is, as discussed in Section 17.2, in the middle of the development of a nationwide hydrogen transport network, it is also valuable to have sufficient legal certainty.[50] To be able to invest in such a network, Gasunie will need to have long-term financial commitments from customers. Such commitment usually comes in the form of long-term transport agreements, as has, in our experience, long been the practice in the EU gas transport sector.

The risk of a 'simple' negotiated third-party access regime, whereby Gasunie and its potential customers have almost complete commercial freedom in agreeing on tariff and access conditions, is that greatly (between customers) differing long-term hydrogen transport agreements are concluded which later (partly) prove not to be in line with the requirements of the then introduced regulated third-party access regime. This divergence could relate to the agreed tariff as well as to other conditions such as hydrogen quality, pressure and the like.

Therefore, a 'hybrid' negotiated third-party access regime that forms a step up to a fully regulated third-party access regime in 2031 seems to be a good option. By setting several of the key tariff and access conditions, the Dutch Minister of Climate and Energy Policy ensures a basic form of non-discriminatory third-party access to the hydrogen transport network while simultaneously providing both Gasunie and its customers some certainty that the long-term commitments accordingly entered into will not become obsolete as soon as a regulated third-party access regime applies. In addition, it provides for learning-by-doing experiences which can be used for the design and roll-out of the regulated third-party access regime as of 2031.

Nevertheless, considerable uncertainty remains for both Gasunie and its potential customers. Even though access conditions such as tariff and hydrogen quality are of great importance to both Gasunie and its potential customers, the exact roles of Gasunie and its potential customers are still to be developed, as are more detailed access conditions. This uncertainty will remain until a full-fledged regulatory third-party access regime has been introduced. Together with

[48] Natural monopoly infrastructure cannot economically be replicated. A natural monopoly, in other words, is a monopoly in a market that can be served at a lower cost by having only one producer rather than many producers. See William W. Sharkey, *The Theory of Natural Monopoly* (Cambridge University Press 1982) 2. A regime of regulated third-party access generally guarantees non-discriminatory third-party access to such natural monopoly infrastructure by setting the tariff, as well as other relevant access terms and conditions.

[49] Commission Regulation (EU) 2017/459 of 16 March 2017 establishing a network code on capacity allocation mechanisms in gas transmission systems and repealing Regulation (EU) No. 984/2013.

[50] As it is for its (potential) customers who will likely enter into hydrogen transport agreements for more than just a few years. The European Commission also seems to generally recognise this risk as it states in its explanatory memorandum that 'harmonising rules for hydrogen infrastructure at a later stage … would lead to … uncertainty for companies, especially where long-term investments in hydrogen production and transport infrastructure are concerned', COM (2021) 804, p. 6.

other, more external, uncertainties such as the availability of sufficient renewable wind energy for converting renewable electricity into 'green' hydrogen as well as the availability of sufficient subsidies, this will have an impact on the willingness to, on both sides, engage in long-term commitments in the current development phase.

17.4.2 *Third-Party Access to Hydrogen Storage*

The European Commission has proposed a system of regulated third-party access to hydrogen storages, which came as a surprise to companies active in the sector.[51] The European Commission notes the following in the proposed preamble to the revised Gas Directive:

> The availability of large-scale underground storage facilities is limited and distributed unevenly across Member States. In view of the potentially beneficial role for the functioning of hydrogen transport and markets, the access to such large-scale underground storages should be subject to regulated third-party access in order to ensure a level playing field for market participants.[52]

The European Commission's proposal is remarkable in at least two respects.

First, for gas storage, the Gas Directive leaves the choice between either negotiated or regulated third-party access to the Member States.[53] As hydrogen storage markets currently seem to be developing, we have no reason to assume that the structure of these markets would be very different from that of the gas storage markets. In that respect, the difference between the access regime for the two categories of storage is striking. It would only make sense to introduce a system of regulated third-party access in the case of (perceived) problems with regard to the hydrogen storage market structure. To date, we have no indications that such problems are likely to arise.

Second, the European Commission's argumentation as to large-scale underground (hydrogen) storage facilities being limited and distributed unevenly across EU Member States likewise holds for (potential) CO_2 storage (for the application of carbon capture and storage – CCS). Nevertheless, Directive 2009/31/EC (CCS Directive) appears to leave EU Member States the choice between the two third-party access regimes.[54]

The European Council has taken a more nuanced starting position. It would require negotiated third-party access in the start-up phase and would prescribe regulated third-party access only from 1 January 2036 onwards.[55]

But there is also a point to be made concerning the development of hydrogen storage infrastructure. The timeline for the development of hydrogen storage infrastructure mentioned above (Section 17.2.2) is based on the expected demand for storage services. The lead time that is required for developing hydrogen storage is relatively long and can easily take 6–8 years, as considerable time is required for the permitting processes of the underground activities and the above-ground facilities, for the preparation of the underground infrastructure such as assessing

[51] See the proposed article 33 Gas Directive, COM (2021) 803.
[52] See the proposed recital 72 Gas Directive, COM (2021) 803.
[53] See article 33 (1) Directive 2003/55/EC. In the European Commission proposal, COM (2021) 803, this is the new article 29 (1).
[54] See article 21 of the Directive 2009/31/EC of 23 April 2009 on the geological storage of carbon dioxide and amending Council Directive 85/337/EEC, European Parliament and Council Directives 2000/60/EC, 2001/80/EC, 2004/35/EC, 2006/12/EC, 2008/1/EC and Regulation (EC) No 1013/2006 (CCS Directive). Article 21 of the CCS Directive does not prescribe a particular third-party access regime and as such seems to leave the choice for a particular regime to the EU Member States.
[55] See the proposed article 33 (1) and (2) Gas Directive in the starting position of the Council, Proposed Gas Directive.

and monitoring the geological details, leaching a salt cavern and removing brine with a first fill of hydrogen.

Developers of hydrogen storage infrastructure need to take development decisions soon in order for hydrogen storage to be fully developed by the time the developing hydrogen markets needs hydrogen storage infrastructure. They need to take these decisions, even though hydrogen markets are still nascent and only a limited number of market participants in the different parts of the value chain have sufficient insight into their specific demand for storage services and are able and willing to commit at this early stage.

For developers of hydrogen storage infrastructure, legal certainty is crucial to proceed with their projects. The more freedom the developers of hydrogen storage have to enter into storage agreements with initial storage customers and the longer-term the commitment of the latter, the better these developers can mitigate the financial risks associated with the cost-intensive development of hydrogen storage. Likewise, early commitment of the hydrogen storage developer is crucial for storage customers to mitigate part of their commercial risk through certainty as to the storage products they will receive and the tariffs they will have to pay.

A regime of negotiated third-party access, as would be the case under the starting position of the European Council, but not pursuant to the European Commission and the European Parliament, would support the early development of hydrogen storage infrastructure as the developers of such infrastructure would have sufficient freedom to agree on long-term contracts with storage customers at an early stage, while complying with the obligations of non-discrimination and open access. However, the European Commission's proposal is rather aiming to apply a regulated third-party access regime. Such a strict regime may pose problems for the development of the hydrogen storage market, in particular due to the two following issues.

The first issue is that a regulated third-party access regime can only provide for a limited degree of certainty on the storage services and tariffs for the coming period. Only once the amended Gas Directive has been adopted and entered into force will the regulated third-party access regime be formally applicable and the regulator have the legal competence to approve the applicable tariffs for the storage services. Up to that moment, hydrogen storage developers and their customers will bear the risk that the tariff approved by the regulator at a later stage will differ from any agreement negotiated between the two at an earlier stage.

In this respect, developers of hydrogen storage infrastructure differ from hydrogen transport infrastructure developers. For the latter, the Member States may choose the negotiated third-party access regime for a transition period, but if they do so, 'the regulatory authorities shall provide guidance to hydrogen network users on how the negotiated tariffs will be affected when regulated third-party access is introduced'.[56]

Such guidance, as well as a transition period towards the regulated third-party access regime, will not be available for hydrogen storage infrastructure developers. This lack of certainty may result in potential storage customers delaying the contracting of storage services. A delay in the contracting of storage services may in turn delay the development of the hydrogen storage infrastructure. It may also create a bigger challenge for the developer to design storage infrastructure that will fully meet future market demand.

The second issue is that under a regulated third-party access regime the storage operator has limited possibilities to adapt the storage services to changing market demand. The storage operator can only provide a storage product once the tariff has been approved by the regulator.

[56] See the proposed article 31 (5) Gas Directive, COM (2021) 803.

This limitation on the ability to quickly adapt to market needs may pose problems, in particular in the phase of the market ramp-up when the storage customers have yet to learn in practice whether their anticipated need for specific storage services is justified by market reality or not.

17.4.3 *Third-Party Access to Hydrogen (Import) Terminals*

For hydrogen (import) terminals, EU Member States are, according to the European Commission's proposal to implement a system of negotiated third-party access, whereby the national regulators shall take the necessary measures for potential hydrogen terminal customers to be able to negotiate access to such terminals.[57] The term "hydrogen terminal" covers both an installation used for the transformation of liquid hydrogen or liquid ammonia into gaseous hydrogen as well as an installation used for the liquefaction of gaseous hydrogen.[58] The national regulators shall monitor access conditions and their impact on hydrogen markets and take measures where necessary to safeguard competition.

The starting position of the Council is less strict: it allows a Member State to apply a system of regulated instead of negotiated third-party access, without a compulsory end date for the negotiated third-party access.[59]

From what we currently see, it is our expectation that some of the parties currently active in the liquified natural gas (LNG) (import) terminals market will also be active in the hydrogen terminal market. In our opinion, the LNG terminals market is competitive and, accordingly, we expect no fundamental problems with regard to market structure in the future hydrogen terminals market. Apparently, the European Commission is of the same opinion. It expects competition not only between the various future hydrogen import terminals, but also between different means of hydrogen import.[60]

However, the European Commission leaves some leeway for national regulators to intervene by taking required measures should these markets not develop properly under a negotiated third-party access regime. This seems like a reasonable and prudent approach. Under the starting position of the Council, the Member State would be allowed to apply regulated third-party access.

17.4.4 *Exemptions for New Hydrogen Infrastructure*

The proposal for a revised Gas Regulation opens up the possibility of exempting certain new hydrogen infrastructure from specific rules of third-party access and unbundling.[61] This provision is similar to one in the existing Gas Directive for new gas infrastructure.[62] Several gas infrastructure projects have received such exemptions, such as the new floating terminal for LNG in Eemshaven, the Netherlands, and LNG terminals in Lubmin and Stade in Germany.[63]

[57] See the proposed article 32 Gas Directive, COM (2021) 803.
[58] See the proposed article 2 (8) of the Gas Directive, COM (2021) 803.
[59] See the proposed article 32 (1) in the starting position of the Council, Proposed Gas Directive.
[60] Justin Rosing DG ENER, 'Hydrogen and Gas Markets Decarbonisation Package – key elements to enable the development of dedicated hydrogen infrastructure and markets', presentation given at the Dutch Energy Law seminar, The Hague, 23 May 2022, slide 12.
[61] See the proposed article 60 (1) sentence 2 in the European Commission's proposal, COM (2021) 804.
[62] Article 36 of the current EU Gas Directive, Directive 2003/55/EC.
[63] Dutch Minister of Climate and Energy Policy 'Ontheffingsverlening aan EemsEnergyTerminal voor LNG-installatie, 30 June 2022, Staatscourant No. 18454, 14 July 2022, German Bundesnetzagentur, Decision of 17 November 2022 to exempt the LNG-installation 'Deutsche Ostsee' in Lubmin on the Baltic Sea Coast (BK7-22-086), German Bundesnetzagentur, Decision of 19 September 2022 to exempt the LNG installation in Stade (BK7-20-107 final).

Under the European Commission's proposal for the revised Gas Regulation, new hydrogen storage infrastructure may be exempted from the regulated third-party access regime, provided the conditions for exemptions are met. These are, in short, that the investment (1) enhances competition, (2) contributes to decarbonisation, (3) is of such a risk level that the investment would not take place without the exemption, (4) is undertaken by a person independent at least in legal form from the hydrogen system operator and (5) that the exemption is not detrimental to competition and other specified goals. The starting position of the European Parliament adds the requirement that demand-side solutions have been taken into account as possible alternatives.[64]

It is commendable that the European Commission proposed the possibility of exempting certain new hydrogen infrastructure from the requirements of third-party access under the proposed new Gas Directive. However, one of the exemption conditions seems to form a barrier for exempting new hydrogen infrastructure for which the final investment decision was taken before entry into force of the amended Gas Regulation and thus the coming into existence of the exemption possibility. It is the condition that the level of risk is such that the investment would not take place unless the exemption was granted.[65] At first sight, this condition seems to make it very difficult to argue, in cases where the final investment has already been made, that the investment in question has such a level of risk.

Obviously, this limiting of the exemptions would not help with the quick development of hydrogen markets. If we take the example of hydrogen storage: A hydrogen storage developer who intends to be a frontrunner by taking the necessary investment decision at an early stage before the amended Gas Regulation has been adopted and has come into force will have great difficulties in getting the new infrastructure exempted and very likely remain faced with a regulated third-party access regime. A hydrogen storage developer who makes an investment decision at a later stage, after the amended Gas Regulation entered into force, may receive an exemption under the amended Gas Regulation. Thus, the front runner is put in a more problematic situation than the party that waits.

This barrier could be removed by introducing a transitional provision for the exemption of new hydrogen infrastructure, where the investment decision was taken prior to the entering into force of the exemption possibility of the proposed recast Gas Regulation. The barrier could also be removed, as a side note, if the Council adopted as a starting position that the Member State can apply negotiated third-party access to hydrogen storage until 2036 (see Section 17.4.2). However, should the European Commission's proposal be adopted unchanged in this respect, this could prove to be a disincentive to the development of hydrogen storage markets at an early stage, which in turn could delay the development of hydrogen markets in general.

17.5 CONCLUSION

The regulatory framework for hydrogen infrastructure in general and the rules on third-party access in particular are in full development. Conducting business in a (rapidly) changing regulatory framework creates (legal) uncertainty and this uncertainty generally comes at a cost. Gasunie has chosen an early development (and consequent operation) of hydrogen infrastructure in the Netherlands to try and help kick-start the Dutch and EU hydrogen economy. The

[64] See the proposed article 60 (1) (ca) Gas Regulation in the starting position of the European Parliament, COM (2021) 803.

[65] See the proposed article 60 (1) sentence 3 (c) Gas Regulation, COM (2021) 804.

early development of hydrogen infrastructure against the backdrop of an outdated national legal framework and rapidly developing and highly uncertain EU rules creates several challenges.

When looking at the development of a nationwide Dutch hydrogen transport network and third-party access to such infrastructure, we see a gradual approach chosen by the EU and Dutch legislators trying to fill in the blanks until the network as well as a regulated third-party access regime develops. In general, we believe this is a sensible and workable approach from the perspective of the development (and subsequent operation) of such a network. The biggest challenge for Gasunie and its initial customers will be to create sufficient (legal) certainty on both sides as well as clear respective roles and divisions of responsibility, while reserving leeway for changes and adjustments.

As far as the development of hydrogen storage infrastructure is concerned, a different picture emerges. In contrast to the hydrogen transport infrastructure, there will possibly be no gradual transition to a regulated third-party access regime. Instead, hydrogen storage infrastructure could be governed by a regulated third-party access regime once the amended Gas Directive has been transposed into national law by the Dutch legislator. On the one hand, such a regime seems to offer too little flexibility and commercial freedom for both hydrogen storage infrastructure developers and their customers to ensure early development of such infrastructure. On the other hand, it will still take some time until such an access regime is fully in force. The lack of clarity concerning the precise content of the future regulated third-party access regime creates doubts, which may delay the development of hydrogen transport infrastructure. The lack of a transition provision for exempting new hydrogen storage infrastructure only adds to this uncertainty. This raises the question whether it would not be better to provide EU Member States with the option for a negotiated third-party access regime, as this is currently the case with gas and CO_2 storage.

FURTHER READING

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PART V

End Use of Hydrogen

18

The Regulation of Hydrogen in the Transport Sector

Focus on Refuelling Stations

Endrius Cocciolo

18.1 INTRODUCTION

The European Union (EU) has undertaken measures to reduce greenhouse gas (GHG) emissions and to become carbon neutral by 2050. It adopted several interconnected strategic frameworks to that end. These frameworks include the Energy System Integration Strategy (ESI),[1] the Hydrogen Strategy (HS),[2] and the Sustainable and Smart Mobility Strategy (SSM),[3] all of which are aligned with the European Green Deal (EGD).[4] These strategies designate transport as an end-use sector in which the use of hydrogen, particularly renewable hydrogen, should be promoted. This strategic orientation is intended to contribute to the broader effort to decarbonise the economy.

Global emissions from transport increased at an effective annual rate of 1.7 per cent between 1990 and 2022, surpassing emissions in every other end-use sector except industry, as highlighted by the International Energy Agency (IEA).[5] If net zero emissions are to be achieved by 2050, carbon dioxide emissions from the transport sector must begin decreasing by more than

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[1] Regulation (EU) 2021/1119 of the European Parliament and of the Council of 30 June 2021 establishing the framework for achieving climate neutrality and amending Regulations (EC) No 401/2009 and (EU) 2018/1999 (European Climate Law) OJ L243/1.

[2] Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions, 'Powering a climate-neutral economy: An EU strategy for energy system integration' (COM) 2020/299 final. Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions, 'A hydrogen strategy for a climate-neutral Europe' (COM) 2020/301 final (Hydrogen Strategy).

[3] Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions, 'Sustainable and Smart Mobility Strategy – putting European transport on track for the future' (COM) 2020/789 (hereinafter: Sustainable and Smart Mobility Strategy).

[4] Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions, 'The European Green Deal' (COM) 2019/640 final.

[5] International Energy Agency, 'Global CO2 emissions from transport by sub-sector in the Net Zero Scenario, 2000–2030' (2023) <https://iea.org/data-and-statistics/charts/global-co2-emissions-from-transport-by-sub-sector-in-the-net-zero-scenario-2000-2030-2> accessed 23 January 2024.

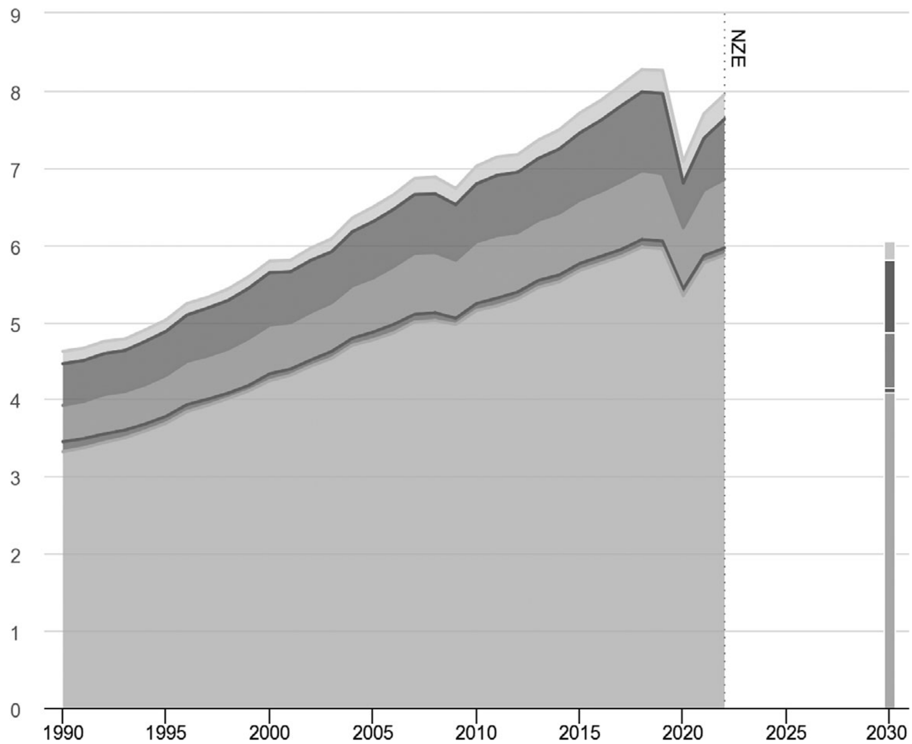

FIGURE 18.1 Global emissions from transport
Source: International Energy Agency, 'Global CO2 emissions from transport by sub-sector in the Net Zero Scenario, 2000–2030' (2023) <https://iea.org/data-and-statistics/charts/global-co2-emissions-from-transport-by-sub-sector-in-the-net-zero-scenario-2000-2030-2>.

3 per cent per annum by 2030.[6] Globally, road transport appears to be the primary source of emissions within that sector (Figure 18.1).[7]

GHG emissions in most sectors of the EU economy have been decreasing since 1990; transportation is an exception.[8] Road transport has emerged as the main cause of this exceptionalism. Carbon dioxide emissions from road transport increased by 21 per cent between 1990 and 2021.[9] Passenger cars and motorcycles account for 64 per cent of road-transport emissions. Heavy-duty trucks and buses contribute a substantial 27 per cent, while light-duty trucks account for 10 per cent of the total.[10] Analyses have revealed that the emissions patterns of the Member States of the EU are structurally convergent. If the emissions reduction goal is to be attained, EU policies should account for the structural factors that are specific to each country, and coordinated measures should be formulated accordingly.[11]

6 Ibid.
7 Ibid.
8 Ian Tiseo, 'Greenhouse gas emissions in the European Union 1990–2021, by sector' (Statista, 23 July 2023) <https://statista.com/statistics/1171183/ghg-emissions-sector-european-union-eu/#statisticContain>accessed 23 January 2024.
9 Destatis, 'Road transport: EU-wide carbon dioxide emissions have increased by 21% since 1990' (2023) <https://destatis.de/Europa/EN/Topic/Environment-energy/CarbonDioxideRoadTransport.html> accessed 23 January 2024.
10 Ibid.
11 Ángel Marrero and others, 'Convergence in road transport CO2 emissions in Europe (2021) 99 Energy Economics, 1, 16 <https://doi.org/10.1016/j.eneco.2021.105322> accessed 23 January 2024.

In the light of the foregoing, it should come as no surprise that the transportation sector has been identified as a potential 'new lead market' for hydrogen, particularly in instances in which electrification is infeasible.[12] For that potential to be harnessed, however, several technologies must first mature, and cost efficiency must improve. Other renewable and low-carbon fuels should also be utilised. The difficulties that attend on the formation of such a market were acknowledged in the 2020 SSM.[13] That strategy advocates for a gradual integration of fuel-cell vehicles into the mobility sector, and its focus is on the creation of an alternative fuel infrastructure. The SSM contends that the augmented deployment and utilisation of renewable and low-carbon fuels should be accompanied by the establishment of a comprehensive recharging and refuelling infrastructure to facilitate the widespread adoption of low- and zero-emissions vehicles across all modes of transportation. According to the SSM, constructing 500 of the envisaged 1,000 hydrogen stations by 2025 is a realistic target. The ultimate objective is to establish a dense yet widely dispersed infrastructure that will guarantee convenient access to all users and operators of heavy-duty vehicles.[14] However, in Europe, the number of hydrogen refuelling stations (HRSs) has not even approached half of the target. Currently, only 164 HRSs are available, with another 41 under construction at the time of writing. Most of those stations are in Germany, where 87 have been completed and 19 are under construction.[15] Germany aside, the rollout of HRSs at the Member State level is proceeding at an uneven and contradictory pace. Some national or sub-national governments are establishing support frameworks for hydrogen-based transport, while others are withdrawing from this technology; for instance, in September 2023, the Netherlands introduced a subsidy scheme for hydrogen used in transport.[16] Conversely, Denmark is set to shutter all of its hydrogen filling stations by the end of 2024, and it has suspended plans for new ones.[17] In France, a city that pioneered green hydrogen buses now intends to replace them with electric buses.[18]

The objectives of these European strategies, the attendant legal uncertainties, and the commitment of the EU to develop hydrogen-based transport markets and services, when taken in their totality, mean that there is a compelling case for regulatory intervention. Such an intervention would be crucial for the dismantlement of the barriers that presently obstruct the deployment of hydrogen technology. Given the adoption of the Fit for 55 Package,[19] several components of the legal framework for hydrogen are now in force. Those components include the revised Renewable Energy Directive (RED III),[20] the new Energy Efficiency Directive

[12] Gokce Mete and Leonie Reins, 'Governing new technologies in the energy transition: The hydrogen strategy to the rescue?' (2020) 14 Carbon and Climate Law Review 210, 224 (hereinafter: Mete and Reins).

[13] Sustainable and Smart Mobility Strategy.

[14] Ibid 5, 6.

[15] According to data from H2 Live <https://h2.live/en/tankstellen/> accessed 23 January 2024.

[16] Leigh Collins, 'Netherlands unveils €150m plan to subsidise hydrogen trucks, vans, buses and filling stations' (Hydrogen Insight, 29 September 2023) <https://hydrogeninsight.com/transport/netherlands-unveils-150m-plan-to-subsidise-hydrogen-trucks-vans-buses-and-filling-stations/2-1-1526684> accessed 23 January 2024.

[17] Maz Plechinger, *Alle brintstationer i Danmark lukke* (Energy Watch, 14 September 2023) <https://energiwatch.dk/Energinyt/Renewables/article16427393.ece> accessed 23 January 2024.

[18] Anne-Claire Poirier, 'Les bus à hydrogène ont fait leurs preuves mais ne correspondent pas à tous les besoins' (La Gazette, 9 November 2023) <https:// ?lagazettedescommunes ?.com/894648/les-bus-a-hydrogene-ont-fait-leurs-preuves-mais-ne-correspondent-pas-a-tous-les-besoins/> accessed 23 January 2024.

[19] Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions, '"Fit for 55": delivering the EU's 2030 Climate Target on the way to climate neutrality' (COM) 2021/550 final.

[20] Directive (EU) 2023/2413 of the European Parliament and of the Council of 18 October 2023 amending Directive (EU) 2018/2001, Regulation (EU) 2018/1999 and Directive 98/70/EC as regards the promotion of energy from renewable sources, and repealing Council Directive (EU) 2015/652 OJL 2413. The RED III sets a binding target of

(EED),[21] the Taxonomy Delegated Act,[22] and the Delegated Acts on Renewable Hydrogen.[23] Given the purpose of this chapter, special mention should be made of the recent Regulation 2023/1804 (Alternative Fuels Infrastructure Regulation – AFIR), which addresses the deployment of the alternative fuels infrastructure.[24]

The primary focus of this chapter is on the identification of barriers in the hydrogen value chain. Those barriers may impede the use of hydrogen in the decarbonisation of transport. In particular, the analysis that is presented here zooms into the HRS infrastructure that must be developed for a just and sustainable transition to occur. The chapter is structured as follows: Section 18.2 contextualises the European legislation on hydrogen for transport within the theoretical framework of 'infrastructure as the fabric of society', and presents the extant regulatory framework. Section 18.3 identifies the regulatory bottlenecks in the hydrogen value chain that pertain to hydrogen-based transport. Those bottlenecks have to do with production, transport, and storage. Section 18.4 concerns HRSs and the legal issues that affect their rollout. Finally, Section 18.5 provides a summary and charts several avenues for future research.

18.2 THEORETICAL AND REGULATORY FRAMEWORK

The SSM strategy asserts unequivocally that sustainable mobility and transport serve as 'enabler [s] for our economic and social life'.[25] They facilitate commutes as well as family and personal trips, they enable the movement of goods and services, they render manufacturing more efficient, and they strengthen territorial cohesion. Beyond its technical utility, infrastructure is valuable because of the services that it provides – 'infrastructure could be regarded as the fabric of society, on the one hand, because infrastructure provision literally connect[s] everybody, on the other hand, because infrastructure equip[s] every member of society with more or less equal development opportunities'.[26]

29 per cent for renewable energy consumption by 2030 in the transport sector, of which 5.5 per cent must be covered by advanced biofuels (generally derived from raw materials that are not produced from food crops) and renewable fuels of non-biological origin (mainly renewable hydrogen and synthetic fuels that are based on hydrogen). In addition, 1 per cent of the renewable energy that the transport sector consumes must come from renewable fuels of non-biological origin (Article 25 RED III).

[21] Directive (EU) 2023/1791 of the European Parliament and of the Council of 13 September 2023 on energy efficiency, amending Regulation (EU) 2023/955 OJL 231/1.

[22] Commission Delegated Regulation (EU) 2021/2139 of 4 June 2021, supplementing Regulation (EU) 2020/852 of the European Parliament and of the Council by establishing the technical screening criteria for determining the conditions under which an economic activity qualifies as contributing substantially to climate change mitigation or climate change adaptation and for determining whether that economic activity causes no significant harm to any of the other environmental objectives OJL 442/1.

[23] Commission Delegated Regulation (EU) 2023/1184 of 10 February 2023 supplementing Directive (EU) 2018/2001 of the European Parliament and of the Council by establishing a Union methodology setting out detailed rules for the production of renewable liquid and gaseous transport fuels of non-biological origin; Commission Delegated Regulation (EU) 2023/1185 of 10 February 2023 supplementing Directive (EU) 2018/2001 of the European Parliament and of the Council by establishing a minimum threshold for greenhouse gas emissions savings of recycled carbon fuels and by specifying a methodology for assessing greenhouse gas emissions savings from renewable liquid and gaseous transport fuels of non-biological origin and from recycled carbon fuels OJL 157/11.

[24] Regulation (EU) 2023/1804 of the European Parliament and of the Council of 13 September 2023 on the deployment of alternative fuels infrastructure, and repealing Directive 2014/94/EU OJL 234/1.

[25] Sustainable and Smart Mobility Strategy, 1.

[26] Margot Weijnen and Aad Correljé, 'Rethinking Infrastructure as the Fabric of a Changing Society with a Focus on the Energy System' in Margot Weijnen, Zofia Lukszo, and Samira Farahani (eds), *Shaping an Inclusive Energy Transition* (Springer 2021) 17, 48 <https://doi.org/10.1007/978-3-030-74586-8_2> accessed 23 January 2024 (hereinafter: Weijnen and Correljé).

For infrastructure to discharge all of those functions in an age of energy transformation,[27] it must become more complex, including through the construction of new refuelling stations. At the same time, that sophisticated infrastructure ought to be designed with the tenets of the just energy transition in mind;[28] otherwise, the hydrogen economy might exacerbate inequality in society. The spatial and temporal distribution of the benefits and costs of new technologies must be allocated equitably, and social needs, other than the legitimate demands of economic operators, must be acknowledged. It is also important that bottom-up participation be promoted within the decision-making frameworks that are devised in the course of the transition.[29]

The hydrogen refuelling infrastructure furnishes several paradigmatic examples of energy integration and of the interdependent infrastructural systems that typify energy-transition processes.[30] In the case of HRSs, physical, energy, and digital infrastructures are linked. As will become evident from the discussion that follows, the elements of the corresponding regulatory framework are tightly intertwined.

18.2.1 *The Alternative Fuels Infrastructure Regulation (AFIR)*

The significance of the AFIR lies in its comprehensiveness. It is a legal instrument that covers all transportation modes and a wide variety of alternative fuels.[31] The regulatory strategy is intended to contribute to climate neutrality. In addressing the deficiencies of the hydrogen refuelling infrastructure, the AFIR sets minimum mandatory national targets for the number of publicly accessible HRSs; those targets must be met by December 2030.[32]

According to Article 6 AFIR, the Member States are legally obliged to form HRS networks. For reasons of interoperability, the Member States must ensure that the stations in question have a minimum cumulative daily capacity of 1 tonne and that they are equipped with at least one 700-bar dispenser, which would allow light- and heavy-duty vehicles to be refuelled. The targets in the AFIR reflect the desire to create a dense network of HRSs along the Trans-European Transport Core Network (TEN-T; see Section 18.2.3 below). No two stations should be separated by more than 200 km. It should also be possible for hydrogen-powered vehicles to access refuelling stations in or near cities. Consequently, the AFIR requires the Member States to provide at least one publicly accessible HRS in all urban nodes, as defined by the TEN-T. The need for multimodal hubs for heavy-duty vehicles and other modes of transport should also be considered in determining the optimal locations of the HRSs. A single HRS in an urban node may fulfil the TEN-T requirements if the capacity targets are met. In addition, given the emergence of technologies such as liquid hydrogen, that infrastructure should be developed flexibly. The measures that will be adopted to advance the alternative fuels market and to complete the refuelling network must be delineated in national policy frameworks (Article 14

[27] According to Paterson, the 'energy transition needs to be reimagined as an energy transformation in order to emphasise the scale and pace of change required to meet climate, security, and equity objectives in a timely manner'. See John Paterson, 'Energy Law and Energy Transformation' in Ruven Fleming, Kars de Graaf, Leigh Hancer, and Edwin Woerdman (eds), *A Force of Energy: Essays in Energy Law in Honour of Professor Martha Roggenkamp* (University of Groningen Press 2022) 20 <https://doi.org/10.21827/61eff4099c992> accessed 23 January 2024.

[28] Raphael J Heffron, 'Energy justice – the triumvirate of tenets revisited and revised' (2023) 42(2) Journal of Energy and Natural Resources Law 227 <https://doi.org/10.1080/02646811.2023.2256593> accessed 27 July 2024.

[29] On the new concepts that have arisen from the energy transition, see Romain Mauger, 'Making Sense of Changing Concept for Energy Transition: An Energy Transition Concepts Nexus for the Development of Policy and Law' in Ruven Fleming, Kaisa Huhta, and Leonie Reins (eds), *Sustainable Energy Democracy and the Law* (Brill 2021) 28.

[30] Weijnen and Correljé 35.

[31] AFIR Recital 5 and Article 2(4).

[32] Ibid Article 6.

AFIR). The Member States are required to facilitate genuine and early public participation in the development of those national frameworks – the comprehensive involvement of members of the public other than industry stakeholders is crucial for preventing injustices. It should also be noted that the AFIR contains several provisions on the collection of data and the provision of digital services.

18.2.2 *The Trans-European Network for Energy (TEN-E)*

The TEN-E policy focuses on the interconnections between the energy infrastructures of the EU Member States. In this policy, eleven priority corridors and three thematic areas are identified as integral components of the network. In the updated TEN-E framework, these corridors span diverse geographic regions and various sectors, such as electricity, the offshore grid, and the hydrogen infrastructure. The 2022 revision of the TEN-E Regulation[33] aligned it with the climate-neutrality objectives that are outlined in the European Green Deal and the Climate Law. This revision establishes a framework for selecting infrastructure projects of common interest (PCIs)[34] in fields such as electricity, gas, hydrogen, and CO_2. Financial support is available from the Connecting Europe Facility (CEF).[35] The TEN-E Regulation also contains rules for determining the scope and governance of Ten-Year Network Development Plans (TYNDP). This framework facilitates cross-sectoral planning in gas and electricity, providing investors with a comprehensive overview of the optimal locations of electrolysers, hydrogen transmission and storage infrastructure, and refuelling stations. In addition, it supports the cost-effective integration of energy systems, in accordance with the energy-efficiency-first principle, which will be discussed further later in this chapter (Section 18.2.4). This integration extends to digital and transmission systems, as well as to synergies with the TEN-T, so that it 'aims to generate additional opportunities for the decarbonisation of transport from the new vision of energy infrastructure planning'.[36]

18.2.3 *The Trans-European Transport Network (TEN-T)*

As a policy, the TEN-T targets the development of a cohesive, efficient, multimodal, and high-quality transport infrastructure across the EU. The policy covers railways, inland waterways, short shipping routes, and the roads between urban nodes, ports, airports, and cargo terminals. It is governed by the TEN-T Regulation.[37] The TEN-T Regulation has recently been revised by replacing its previous version[38] to ensure that it accords with the EGD, the SSM Strategy, and

[33] Regulation (EU) 2022/869 of the European Parliament and of the Council of 30 May 2022 on guidelines for trans-European energy infrastructure, amending Regulations (EC) No 715/2009, (EU) 2019/942 and (EU) 2019/943 and Directives 2009/73/EC and (EU) 2019/944, and repealing Regulation (EU) No 347/2013 OJL 152/45.

[34] Katja Yafimava, 'The TEN-E Regulation: Allowing a role for decarbonised gas' (Oxford Institute for Energy Studies 2022) <www.oxfordenergy.org/publications/the-ten-e-regulation-allowing-a-role-for-decarbonised-gas/> accessed 27 July 2024.

[35] Regulation (EU) 2021/1153 of the European Parliament and of the Council of 7 July 2021 establishing the Connecting Europe Facility and repealing Regulations (EU) No 1316/2013 and (EU) No 283/2014 OJL 249/38.

[36] Mete and Reins 227.

[37] Regulation (EU) No 2024/1679 of the European Parliament and of the Council of 13 June 2024 on Union guidelines for the development of the trans-European transport network, amending Regulations (EU) 2021/1153 and (EU) No 913/2010 and repealing Regulation (EU) No 1315/2013 Text with EEA relevance OJ L 2024/1679.

[38] Regulation (EU) No 1315/2013 of the European Parliament and of the Council of 11 December 2013 on Union guidelines for the development of the trans-European transport network and repealing Decision No 661/2010/EU Text with EEA relevance OJL 348/1 (hereinafter: TEN-T Regulation).

the Zero Pollution Action Plan.[39] The 2024 TEN-T Regulation is based on a three-phase approach to the transport network. The TEN-T network will be developed or upgraded gradually in accordance with the new regulation, which sets clear deadlines for completion: the core network by 2030, the extended core network by 2040, and the comprehensive network by 2050. The problems of the 2013 TEN-T included inefficient and unattractive modes of sustainable transport, the inadequate integration of the alternative fuels infrastructure, the use of outdated digital tools for traffic management, insufficient network interoperability, the poor integration of urban nodes into the regulatory framework, and a misalignment between national investment plans and the TEN-T priorities.[40] The new Regulation is geared towards enhancing synergies between the TEN-T and TEN-E Regulation,[41] as well as ensuring access, particularly for heavy-duty road vehicles, to the hydrogen that is transported via the TEN-E corridors.[42] The refuelling stations that are required to that end should be positioned along the TEN-T corridors.[43] The HS already provides for synergies between the CEF Energy and CEF Transport. Those synergies should enable a dedicated infrastructure for hydrogen to be funded, and should make it easier to finance HRSs.[44]

The new TEN-T Regulation introduces, inter alia, a new provision on PCI, standards for infrastructural development, additional requirements for multimodal freight terminals and urban nodes, and new operational requirements that strengthen the connection between infrastructure planning and transport-service operations.[45] The charging and refuelling infrastructure for alternative transport fuels must conform to the provisions of the AFIR.[46] Therefore, the 431 cities that are identified as urban nodes in the TEN-T will be required to formulate Sustainable Urban Mobility Plans (SUMPs) by 2025.[47] They will also need to comply with the provisions of the AFIR. Accordingly, their plans should provide for the deployment of at least one HRS, which may be integrated into a multimodal hub to serve buses and coaches.[48]

18.2.4 *The Energy-Efficiency-First Principle*

The European HS casts hydrogen as a promising alternative fuel in transportation, especially when electrification is difficult or infeasible as a matter of practice. This framing of the choice between hydrogen and electricity reflects a preference for the latter – hydrogen is reserved for cases in which electrification would engender extraordinary difficulties. The preference for electrification accords with the notion that cars and vans with directly rechargeable electric batteries are considerably more energy efficient than cars and vans that have fuel cells. That

39 Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions, Pathway to a Healthy Planet for All – EU Action Plan: 'Towards zero pollution for air, water and soil' (COM) 2021/400 final.

40 Dieter Frizberg, 'Briefing – Initial appraisal of a European Commission Impact Assessment. Revision of the Trans-European Transport Network Regulation' (European Parliamentary Research Service, May 2022) <https://europarl.europa.eu/RegData/etudes/BRIE/2022/730316/EPRS_BRI(2022)730316_EN.pdf> accessed 23 January 2024.

41 TEN-T Regulation Article 5.1(f).

42 Ibid Recitals 75–76.

43 Mete and Reins 228.

44 Hydrogen Strategy 9.

45 Monika Kiss, 'Briefing – EU legislation in progress. Revision of the Trans-European Transport network guidelines' (European Parliamentary Research Service, June 2023) <https://europarl.europa.eu/RegData/etudes/BRIE/2022/729314/EPRS_BRI(2022)729314_EN.pdf> accessed 23 January 2024.

46 TEN-T Regulation Recitals 75–76 and Articles 38 and 41.

47 Ibid Article 41 and Annex II.

48 Ibid Article 41.1(c).

proposition also holds true for the trucks that operate in cities, but not for long-haul heavy-duty trucks. In the latter case, using fuel-cell technology would be more sensible.[49] In consequence, the preference for transport solutions based on electric vehicles or fuel cells must be justified by reference to the energy-efficiency-first principle.[50]

The SSM strategy posits that 'energy efficiency shall be a criterion for prioritising future choice of suitable technologies looking at the whole life-cycle'.[51] Since the adoption of the new EED, the energy-efficiency-first principle has become an overarching principle in energy policy.[52] The HS refers to two focal areas for the utilisation of hydrogen in mobility. First, hydrogen should be adopted early in 'captive applications', such as municipal buses and commercial fleets (for example, taxis). In most cases, those applications have to do with public transportation and highly regulated private services. In such instances, regional or local electrolysers can easily supply HRSs. The introduction of such arrangements ought to be made contingent on a comprehensive analysis of demand for fleets and of the distinct requirements of light- and heavy-duty vehicles. Secondly, the SSM strategy promotes the use of hydrogen fuel cells in heavy-duty vehicles, in conjunction with electrification. The term 'heavy-duty vehicle' is defined to include coaches, specialised vehicles, and long-haul freight trucks, all of which produce substantial CO_2 emissions. Notably, the 2025 and 2030 targets from the CO_2 Emission Standards Regulation[53] are expected to create an advanced market for hydrogen solutions once fuel-cell technology becomes sufficiently cost effective.

Inspired by efficiency reasons, by way of derogation from the targets for HRSs' deployment, according to Article 6.4 AFIR, HRS implementation is not required in areas with little heavy-duty vehicle traffic on the TEN-T core network. In such cases, Member States have the flexibility to reduce the capacity of publicly accessible HRSs by up to 50 per cent, as long as specified requirements related to the maximum distance between stations and dispenser pressure are met. The Member States must report all Article 6.4 derogations to the Commission and continuously review the circumstances in which they were imposed to ensure that the conditions that are set out in that article are still being met.

18.3 REGULATORY BARRIERS TO THE DEPLOYMENT OF HYDROGEN REFUELLING STATIONS ALONG THE HYDROGEN VALUE CHAIN

The conditions under which hydrogen can be deployed in the transport sector depend on the entire content of the regulatory framework that governs its production, transport, storage, and supply for end uses, as well as on the legislation that defines the objectives of the transition to renewable energy.[54] Certainly, the ultimate utilisation of hydrogen for transport and mobility

49 Transport and Environment, 'Wednesday's EU hydrogen strategy needs to prioritise hard-to-decarbonise transport modes' (3 July 2020) <https://?transportenvironment?.org/discover/wednesdays-eu-hydrogen-strategy-needs-prioritise-hard-decarbonise-transport-modes/> accessed 23 January 2024.

50 The energy-efficiency-first principle was introduced through Article 2.18 of the Regulation on the Governance of the Energy Union. For a theoretical elaboration, see Tim Mandel and others, 'Conceptualising the energy efficiency first principle: Insights from theory and practice' (2022) 15 Energy Efficiency 41 <https://doi.org/10.1007/s12053-022-10053-w> accessed 23 January 2024.

51 Sustainable and Smart Mobility Strategy 4(19).

52 EED Recitals 16–21 and Article 3.

53 Regulation (EU) 2023/851 of the European Parliament and of the Council of 19 April 2023 amending Regulation (EU) 2019/631 as regards strengthening the CO2 emission performance standards for new passenger cars and new light commercial vehicles in line with the Union's increased climate ambition OJL 110/5.

54 On the hydrogen regulatory challenges, see Íñigo del Guayo Castiella, Lorenzo Mellado, and José Antonio Redondo, 'Una breve introducción a los retos regulatorios del hidrógeno y otros gases renovables en la Unión Europea, España y

services depends on a series of favourable legal preconditions. These include legislation outlining rules for its production, regulations governing its transport from production sites to points of end use, and storage. This proposition cuts both ways: the regulatory challenges are also shaped by the design of infrastructure.[55] For example, much depends on whether an HRS supplies hydrogen that is produced in a single facility (*in situ* production) or in external production plants. In the latter case, hydrogen can be carried through dedicated networks of pipelines; through repurposed natural gas pipelines; or in gaseous or liquefied form, in which case it can be transported by road, rail, or sea. In addition, the regulatory burden on HRSs may come to be as heavy as the one that is imposed on infrastructures that are employed for other purposes.

It is also important to note that, at present, the regulations that affect the hydrogen value chain are largely formulated at the national level. Therefore, it is in the Member States that the main barriers to the rollout of end-use hydrogen in the mobility sector are detected and anticipated. European regulation does not prevent particular Member States, such as Germany,[56] from developing the necessary infrastructure at a more rapid rate. Harmonisation is of fundamental importance, as is the subsequent monitoring of the transposition and application of the relevant EU law. Furthermore, other types of legislation, such as environmental law, also directly affect the rollout of HRSs.[57] The regulations that govern environmental impact assessments and integrated environmental authorisation supply salient examples. The subsections that follow outline the regulatory barriers that could influence the uptake of hydrogen in transportation.

18.3.1 *The Transport Sector and Hydrogen Production*

The production of hydrogen, in contrast to the production of gas or electricity, faced a deficiency in a comprehensive regulatory framework until 2023. This lacuna constituted the initial regulatory impediment to the overall advancement of hydrogen and its application within the transportation sector. The revision of the regulatory framework is poised to accelerate the adoption of production technologies. For instance, the revised Industrial Emissions Directive (IED)[58] will exempt electrolyser-based production facilities with a capacity below 50 megawatts (MW) from protracted permitting procedures.[59] This modification will advantage HRSs equipped with on-site hydrogen production. Furthermore, the regulations in force until the first half of 2024 did not differentiate between alternative sources or different purposes;[60] in

Andalucía' in Iñigo del Guayo Castiella and Lorenzo Mellado Ruiz (eds), *Retos Regulatorios de los Gases Renovables en la Economía Circular* (Marcial Pons 2023); Kim Talus, Jaqueline Pinto, and Francisca Gallegos, 'Realism at the end of the rainbow? An argument towards diversifying hydrogen in EU regulation' (2024) Journal of World Energy Law & Business <https://doi.org/10.1093/jwelb/jwae007> accessed 1 July 2024.

55 On hydrogen policy plans in the European Union across various sectors, see Ruven Fleming, 'The Hydrogen Revolution and Natural Gas: A New Dawn in the European Union?' in Damilola Olawuyi and Eduardo Pereira (eds), *The Palgrave Handbook of Natural Gas and Global Energy Transitions* (Palgrave MacMillan 2022) 123.

56 Matteo Genovese and others, 'Current standards and configurations for the permitting and operation of hydrogen refueling stations' (2023) 48(51) International Journal of Hydrogen Energy 19357 <https://doi.org/10.3390/en16062890> accessed 23 January 2024.

57 Ruven Fleming, 'Clean or renewable – Hydrogen and power-to-gas in EU energy law' (2021) 39(1) Journal of Energy and Natural Resources Law 43 <https://doi.org/10.1080/02646811.2020.1795382> accessed 23 January 2024.

58 Directive (EU) 2024/1785 of the European Parliament and of the Council amending Directive 2010/75/EU of the European Parliament and of the Council on industrial emission (integrated pollution prevention and control) and Council Directive 1999/31/EC on the landfill of waste.

59 Annex I (j) revised Industrial Emissions Directive OJ L 2024/1785.

60 The only exception is found in the definition of 'energy storage', in which hydrogen is covered as follows: 'the conversion of electrical energy into a form of energy [hydrogen from renewable sources] which can be stored, the storing of such energy, and the subsequent reconversion of such energy into electrical energy or use as another energy'

addition, a regulatory framework concerning safety indirectly shapes hydrogen production by establishing a set of requirements. For this reason, the legislation did not fully account for the possibility of using hydrogen as an energy vector.[61]

Urban planning restrictions can also obstruct the rollout of HRSs. Hydrogen production typically entails the production of an inorganic gas – that is, it is a chemical-industrial process. This legal classification has important consequences for urban planning because the plants in question, whatever their size, need to be confined to industrial areas. For instance, in Spain, as well as in several other Member States, hydrogen production plants may not be located in urban areas. The EU has limited competences in the domain of urban planning. Therefore, this barrier must be overcome at the national level. Under the current regime, it is difficult for private fuel-cell vehicles to access HRSs outside of cities. Consequently, fuel-cell technology will largely be restricted to heavy-duty vehicles, which are more likely to transit in industrial areas.

The stricter environmental law requirements for small-scale hydrogen production matter, too. Under the Directive on Environmental Assessment,[62] public and private projects with potentially significant effects on the environment can only be authorised upon completion of an environmental impact assessment. Annex I circumscribes the set of projects for which such assessments are mandatory across the Union. Annex II lists the types of projects that the Member States may subject to environmental impact assessments if they so choose. Even though neither Annex refers to the production, transport, or storage of hydrogen, those activities are highly likely to be caught by the 'integrated chemical installations'[63] category in Annex I. Therefore, an environmental impact assessment must be completed for all production installations, including HRSs with *in situ* production. This arrangement increases the regulatory burden for the operators of small-scale projects, which compromises the financial viability of those projects.

The *in situ* production of hydrogen for HRSs is expected to occur primarily at small power-to-gas installations that rely on water electrolysis. At those installations, hydrogen is derived from substantial amounts of water. Consequently, in most Member States, it will be necessary for those who run such projects to obtain administrative authorisation or, in cases in which the annual volume of water consumption at the installation is expected to be relatively high, water concessions. Authorisation requirements vary widely across the EU. For instance, in Spain, water is designated as a public good. Therefore, green hydrogen production will likely require the grant of concessions. Such grants are conditional on the order of preference that is contained in the hydrological plans of each river basin district, in which industrial uses other than electricity production tend to come fourth.[64] Hydrogen production through electrolysis falls into that category, and it is not treated as equivalent to the production of electricity.

(Article 2 (59) of Directive 2019/944 of the European Parliament and the Council on common rules for the internal market for electricity OJL 158/125).

[61] Lorenzo Mellado Ruiz 'Marco Jurídico actual y futuro de la industria del hidrógeno en la Unión Europea: transición energética e hidrógeno verde' (2023) 125 Revista Vasca de Administración Pública 17 <https://doi.org/10.47623/ivap-rvap.125.2023.01> accessed 23 January 2024 (hereinafter: Mellado Ruiz).

[62] Directive 2011/92/EU of the European Parliament and of the Council of 13 December 2011 on the assessment of the effects of certain public and private projects on the environment OJL 26/1.

[63] Annex I(6)(b) of Directive 2011/92/EC, defines 'integrated chemical installations' as installations for the manufacture, on an industrial scale, of substances through the use of chemical conversion processes in which several units are juxtaposed and linked functionally to one another.

[64] Mellado Ruiz 27.

18.3.2 *Mobility, Transport, and Storage of Hydrogen*

The EU can only fulfil its commitment to develop an internal market for hydrogen that smooths the decarbonisation of the economy by building an appropriate infrastructure.[65] Dedicated hydrogen networks and cross-border networks should enable trade between the Member States while also promoting competition. The success of HRSs with no onsite production depends on the availability of such an infrastructure because pipelines are likely to be the most cost-efficient transportation solution. This is the first legal hurdle encountered in efforts to transport and store pure or blended hydrogen through the gas grid until the adoption of the hydrogen and decarbonised gas market package (the Hydrogen Package).[66] The main objective of the Hydrogen Package is to adapt the rules that currently apply to the natural gas market to the specificities of the infrastructure for the transport, storage, and supply of hydrogen. The new Package includes specific provisions on dedicated hydrogen networks and storage infrastructure. The European experience in energy shows that three key conditions must be met if market competition is to be guaranteed: open and non-discriminatory access to the network for third parties; regulated tariffs; and rules on unbundling.[67] For an in-depth analysis of the contents of the Hydrogen Package, see Chapter 2, authored by Leigh Hancher and Simina Cuciu.

The absence of a dedicated regulatory framework for the terrestrial transport of hydrogen is also a cause for concern. Only transport through networks falls within the scope of the Hydrogen Package. Hydrogen can also be transported in liquified or condensed form. In that case, trucks, boats, and trains may be used as means of transportation. Whether these operations are energy efficient depends on the context. The transport of hydrogen by road is regulated by the agreements on the transport of dangerous goods, particularly the European Agreement concerning the International Carriage of Dangerous Goods by Road (ADR) and Directive 2008/68/EC on the inland transport of dangerous goods.[68] Furthermore, depending on the transport vector, the regulations concerning the International Carriage of Dangerous Goods by Rail (RID) and the European Agreement concerning the International Carriage of Dangerous Goods by Inland Waterways (ADN) also apply. These legal instruments give rise to various regulatory barriers for emerging synthetic compounds classified as Liquids Carriers Organic Hydrogen (LCOH). Notable among them are specific conditions governing the transport of hazardous materials via rail, ship, or road, including designated dates and times. Against this backdrop, as explained previously, the new guidelines of the TEN-T Regulation stress the need to align with the TEN-E and the AFIR to deploy alternative fuels refuelling infrastructure.[69]

The final regulatory problem that ought to be considered here has to do with the hefty environmental law burdens that the providers of small-scale hydrogen storage bear. The Directive on Environmental Assessment is applicable to hydrogen storage. Annex I, which

[65] Ruven Fleming, 'Hydrogen Networks: Networks of the Future?' in Ruven Fleming, Kaars de Graaf, Leigh Hancher, and Edwin Woerdman (eds), *A Force of Energy: Essays in Energy Law in Honour of Professor Martha Roggenkamp* (University of Groningen Press 2022) 121 <https://doi.org/10.21827/61eff4099c992> accessed 23 January 2024.

[66] The Package includes a Directive of the European Parliament and of the Council on common rules for the internal markets in renewable and natural gases and in hydrogen (recast) and a Regulation on the internal markets for renewable and natural gases and for hydrogen (recast).

[67] Lavinia Tanase and Ignacio Herrera Anchusteguí, 'EU Hydrogen and Decarbonized Gas Market Package: Unbundling, Third-Party Access, Tariffs and Discounts Rules at the Core of Transport of Hydrogen' in Iñigo del Guayo Castiella and Lorenzo Mellado Ruiz (eds), *Retos Regulatorios de los Gases Renovables en la Economía Circular* (Marcial Pons 2023) <https://dx.doi.org/10.2139/ssrn.4431113> accessed 23 January 2024.

[68] Directive 2008/68/EC on the inland transport of dangerous goods OJL 260/13.

[69] TEN-T Regulation Article 5(c).

contains a list of projects for which an extensive ex ante assessment is required, refers to facilities for the storage of petroleum, petrochemicals, and chemical products, a category that includes hydrogen. The corresponding obligation to complete an extensive assessment applies to facilities with a capacity of at least 200,000 tonnes. A simplified environmental assessment is mandatory for lower-capacity projects.

18.4 HYDROGEN REFUELLING STATIONS

The wide availability of HRSs[70] is a prerequisite for the adoption of hydrogen as an energy carrier.[71] This issue poses several economic and regulatory challenges that tend to resemble the classic chicken-and-egg dilemma. If the sustainable energy transition is taken seriously, then the law should incentivise behavioural transformations among the public. Fuel-cell vehicle advocates argue that these vehicles provide a range and refuelling experience comparable to traditional internal combustion engine vehicles.[72] This situation is posited to confer a competitive edge to hydrogen-powered vehicles over their electric counterparts. Indeed, according to a survey that the Clean Hydrogen Partnership conducted,

> only a quarter of customers consider charging times longer than 30 minutes acceptable. This means that even if fast-charging time could be halved, 75% of customers would not be satisfied. Consumer preferences are vital to take into consideration. For the decarbonisation of transport to succeed, consumers must be willing to purchase and drive the offered vehicles. Only if the range of models meet the requirements of consumers will their adoption increase, triggering a further scale-up and acceleration of investment into new models.[73]

These conclusions rest on the presumption that drivers will maintain current usage patterns, disregarding intrinsic energy efficiency considerations. This assumption fails to consider the ongoing evolution of electric battery technology and the potential emergence of new modes of private transportation. Moreover, it neglects the imperative to formulate a sustainable energy policy in the transportation sector that addresses broader societal needs, beyond the preferences of affluent individuals who can afford alternative-fuel vehicles. Consequently, it is crucial to advocate for public policies integrating sustainability, justice, and energy efficiency principles, transcending individual preferences and specific industrial interests. Sustainable mobility plans at various territorial levels, as delineated in the SSM, play a significant role in fostering such integration.

The AFIR imposes binding targets on Member States. The aim of those targets is to ensure that a robust and publicly accessible infrastructure for hydrogen-based road vehicles will be established. The targets call for alignment between the TEN-E and TEN-T at the European level. Such a development would accelerate the flow of investment to hydrogen infrastructure. The alignment in question can only be achieved through sound infrastructural planning, which

70 Matteo Genovese and Petronilla Fragiacomo, 'Hydrogen refueling station: Overview of the technological status and research enhancement' (2023) 61 Journal of Energy Storage 106758 <https://doi.org/10.1016/j.est.2023.106758> accessed 23 January 2024.

71 Mihaela Iordache, Dorin Schitea, and Ioan Iordache, 'Hydrogen refuelling station infrastructure roll-up, an indicative assessment of the commercial viability and profitability in the Member States of Europe Union' (2017) 42(50) International Journal of Hydrogen Energy 29629 <https://doi.org/10.1016/j.ijhydene.2017.09.146> accessed 23 January 2024.

72 Clean Hydrogen Partnership, *Hydrogen Roadmap Europe: A Sustainable Pathway for the European Energy Transition* (Fuel Cells and Hydrogen: Joint Undertaking 2019) 28 <https://clean-hydrogen.europa.eu/system/files/2019-02/Hydrogen%2520Roadmap%2520Europe_Report.pdf> accessed 23 January 2024.

73 Ibid.

should be informed by the TYNDPs. Furthermore, it remains unclear whether the Member States will meet the targets for hydrogen refuelling infrastructure that are set forth in AFIR by the 31 December 2030 deadline.

Turning to the specific issue of HRSs, it should be noted that the AFIR does not distinguish between refuelling stations that produce hydrogen onsite and stations that only store it. According to Article 2.59 AFIR, a 'refuelling station' is a single physical installation that has one or more refuelling outlets. The emergence of differences in national permit procedures that depend on whether hydrogen is generated onsite or offsite would be highly problematic.

Importantly, the binding targets for a minimum number of stations that are included in the AFIR apply only to publicly accessible HRSs. A 'publicly accessible' station is defined as 'an alternative fuels infrastructure which is located at a site or premises that are open to the general public, irrespective of whether the alternative fuels infrastructure is located on public or private property, whether limitations or conditions apply in terms of access to the site or premise and irrespective of the applicable use conditions of the alternative fuels infrastructure' (Article 2.45 AFIR). It follows that the enabling legal framework of the AFIR does not apply to refuelling outlets that are located on private property if access to them is restricted to a limited and determinate set of individuals. The parking places of an office building, if they are available only to employees or other authorised individuals, provide a salient example. If the construction of HRSs at such non-publicly accessible premises is cost effective, it may be desirable to consider energy communities[74] or other self-consumption formulas, especially ones that involve industrial participation. Those arrangements could benefit from coverage in the enabling legal frameworks of the RED, the EED, and the Internal Market for Electricity Directive.[75]

The AFIR provides that the national policy frameworks for the deployment of alternative fuels in the transport sector, that the Member States adopt, ought to include measures that eliminate potential impediments to the planning, authorisation, procurement, and operation of alternative fuel infrastructures, be they publicly accessible or not. The responsibility for the effective implementation of measures for the establishment of an adequate hydrogen refuelling infrastructure lies with national legislatures and authorities. Finally, it is important to note that the AFIR establishes an indifference rule for publicly accessible HRSs – the operator or owner of a publicly accessible refuelling station must ensure that the station can serve both light- and heavy-duty vehicles.[76]

18.5 CONCLUSION

Transport, especially road transport, has witnessed an increase in GHG emissions since 1990. This trend is in stark contrast to those that have been observed in other domains of economic and social activity. For this reason, the decarbonisation of transport would be a stepping stone in the pursuit of the energy and climate targets of the EU. Accordingly, the various European strategies that form part of the regulation of the sustainability transition ascribe a central role to hydrogen, as well as to other alternative fuels.

A complex and coordinated legal framework must be created if the potential of this energy vector is to be exploited fully. That framework remains a work in progress, both as a general

[74] Benedetto Nastasi and Stefano Mazzoni, 'Renewable hydrogen energy communities: Layouts towards off-grid operation' (2023) 291 Energy Conversion and Management 117293 <www.sciencedirect.com/science/article/pii/S0196890423006398> accessed 27 July 2024.

[75] Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU OJL 158/125.

[76] AFIR Article 6 and Recital 35.

matter and in the specific contexts of mobility and transport. This chapter focused on a recent piece of legislation on HRSs, namely the AFIR. It transpires that, as far as infrastructure is concerned, there is a growing regulatory synergy between energy and transport. It is important to underscore that the deployment of end-use hydrogen in the transportation sector will primarily focus on long-haul heavy trucks. In addition, concerning other modes of transportation, such deployment should occur in strict accordance with the notion of a socially just transition and the principle of 'energy efficiency first'.

HRSs are one element of a large infrastructure. The infrastructure in question must be designed, planned, and implemented to further a broad vision. That vision ought to reflect considerations of, among others, social acceptability, energy efficiency, territorial cohesion, sustainability, and fair access.

The analysis of the regulatory barriers along the hydrogen value chain – that is, the legal problems that may affect the generation, transport, storage, and end use of hydrogen through HRSs – revealed several causes for concern. The AFIR, important though it may be, is not sufficient. Several avenues of research are open at present. First, the understanding of the challenges derived from the new Hydrogen Package. Second, scholars and policymakers must ensure that the content of the Package is coordinated with the content of other relevant instruments, such as the revised TEN-T. Third, a concerted effort should be made to ensure that the transposition, implementation, and planning measures that the Member States will adopt will be consistent with EU law and policy. Finally, the actual rollout of the hydrogen infrastructure should reflect the goals of the just transition, namely social benefits and environmental sustainability.

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19

The Regulation of Hydrogen Storage as End Use

Kaisa Huhta and Markus Sairanen

19.1 INTRODUCTION

Limiting global warming to 1.5 °C and reaching net zero around the middle of the century, as stipulated by the Paris Agreement, will require a swift and radical decarbonisation of energy production and consumption.[1] Achieving this goal will entail an unprecedented uptake of renewable energy sources. A progressive increase in renewable energy production is already underway, and this trajectory is expected to continue.[2] However, an increase in the share of intermittent energy sources in the overall energy mix introduces new technological and commercial challenges, which will vary depending on the sector in question.[3] While intermittent production on a small scale is not an issue, large-scale penetration of intermittent renewable energy poses technological and economic challenges that urge new types of governance approaches.[4]

In the electricity sector, a radical shift to intermittent renewable energy sources – predominantly wind and solar – means that electricity systems will need to be adjusted to take into account the increasing variability in production to ensure a reliable supply when renewable energy sources are not available.[5] While there are relatively developed technologies, such as batteries,

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[1] IPCC, H.-O. Pörtner et al. (eds.), Summary for Policymakers. Climate Change 2022: Impacts, Adaptation and Vulnerability. Contribution of Working Group II to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change (Cambridge University Press 2022), 9–11, 31.

[2] Matthew A. Pellow and others, 'Hydrogen or batteries for grid storage? A net energy analysis', 8 *Energy & Environmental Science* (2015) 1938–1952.

[3] Elizabeth Côté and Sarah Salm, 'Risk-adjusted preferences of utility companies and institutional investors for battery storage and green hydrogen investment', 163 *Energy Policy* (2022) 112821 (hereinafter: Côté and Salm); Ahmed M. Elberry and others, 'Large-scale compressed hydrogen storage as part of renewable electricity storage systems', 46 *International Journal of Hydrogen Energy* (2021) 15671–15690 (hereinafter: Elberry et al.).

[4] Don C. Smith, 'Developing and deploying energy storage technologies: A "holy grail" effort on which the world cannot afford to fail', 39(2) *Journal of Energy & Natural Resources Law* (2021) 131–136 (hereinafter: Smith); Dennis Anderson and Matthew Leach, 'Harvesting and redistributing renewable energy: On the role of gas and electricity grids to overcome intermittency through the generation and storage of hydrogen', 32 *Energy Policy* (2004) 1603–1614 (hereinafter: Anderson and Leach).

[5] Anderson and Leach.

that can store electricity for short periods of time, medium- and long-term storage continues to be a challenge.[6]

Hydrogen storage has been presented as a potential solution to this obstacle.[7] The gas can be stored for days, weeks and even months depending on the need, and can therefore provide seasonal storage where batteries cannot.[8] The storage options are also diverse: it can be stored in pressurised gaseous or liquified forms; in tanks or as part of a chemical structure;[9] or in salt caverns, water aquifers or depleted natural gas and oil reservoirs.[10] If upscaled sufficiently, hydrogen storage could be a technological solution to remedy the material and temporal shortcomings[11] of battery technologies as well as an economic solution to flatten energy price peaks by providing supply-side flexibility.[12] In practice, hydrogen would be produced and stored when renewable electricity generation is abundant and therefore cheap, and used to supply energy when renewable sources are unavailable or scarce and therefore more expensive.[13] Moreover, producing hydrogen from renewable electricity and storing it in tanks or trailers would allow the transportation of renewable energy to places that are inaccessible by transmission or distribution lines.[14]

The promise of hydrogen storage was recognised in research nearly four decades ago,[15] and its potential in balancing the intermittency of renewables-based energy systems has been discussed for quite some time in energy research.[16] Not surprisingly, given the urgency of the low-carbon transition, hydrogen storage has recently gained significant traction in energy research across disciplines. Its potential has been investigated in the context of microgrids,[17] profitability and economic rationale,[18] different jurisdictions,[19] different economic sectors[20] and different hydrogen storage technologies,[21] as well as in comparison to other energy storage technologies.[22] This

[6] Smith, 131–136; Evan Gray and others, 'Hydrogen storage for off-grid power supply', 36 *International Journal of Hydrogen Energy* (2011) 654–663 (hereinafter: Gray et al.).

[7] Côté and Salm; Anderson and Leach, 1604; Elberry et al.; Thijs Van de Graaf and others, 'The new oil? The geopolitics and international governance of hydrogen', 70 *Energy Research & Social Science* (2020) 101667.

[8] Matthew Little, Murray Thomson and David Infield, 'Electrical integration of renewable energy into stand-alone power supplies incorporating hydrogen storage', 32 *International Journal of Hydrogen Energy* (2007) 1582–1588 (hereinafter: Little, Thomson and Infield).

[9] Anderson and Leach, 1604; Elberry et al.

[10] Naser A. Al-Mufachi and Nilay Shah, 'The role of hydrogen and fuel cell technology in providing security for the UK energy system', 171 *Energy Policy* (2022) 113286 (hereinafter: Al-Mufachi and Shah); Anderson and Leach, 1604.

[11] Elberry et al.

[12] Little, Thomson and Infield.

[13] Eduardo López González and others, 'Energy evaluation of a solar hydrogen storage facility: Comparison with other electrical energy storage technologies', 40 *International Journal of Hydrogen Energy* (2015) 5518–5525 (hereinafter: González et al.); Little, Thomson and Infield.

[14] Elberry et al.

[15] Eduard W. Justi, A *Solar-Hydrogen Energy System* (Springer 1987); Joan M. Ogden, 'Prospects for building a hydrogen energy infrastructure', 24 *Annual Review of Energy and the Environment* (1999) 227–229.

[16] Anderson and Leach; Little, Thomson and Infield.

[17] Ehsan Haghia, Kaamran Raahemifar and Michael Fowler, 'Investigating the effect of renewable energy incentives and hydrogen storage on advantages of stakeholders in a microgrid', 113 *Energy Policy* (2018) 206–222.

[18] Gunther Glenk and Stefan Reichelstein, 'Economics of converting renewable power to hydrogen', 4 *Nature Energy* (2019) 216–222.

[19] E.g. Francisco Ferrada et al., 'The role of hydrogen for deep decarbonization of energy systems: A Chilean case study', 177 *Energy Policy* (2023) 113536; Little, Thomson and Infield (United Kingdom); Gray et al. (Australia); González et al. (Spain).

[20] E.g. aviation. See Yuekuan Zhou, 'Low-carbon transition in smart city with sustainable airport energy ecosystems and hydrogen-based renewable-grid-storage-flexibility', 1 *Energy Reviews* (2022) 100001.

[21] Elberry et al.

[22] González et al.

range and depth of interest notwithstanding, a host of technological and commercial questions remain unexplored.

This chapter examines the legal governance of hydrogen storage by evaluating the typical legal challenges and opportunities of using hydrogen storage to balance the intermittency of renewable energy sources in the low-carbon energy transition. To demonstrate how these questions can be governed through a transnational legal framework, the analysis focuses on the European Union's (EU) legal solutions for electricity and hydrogen. The EU provides an illustrative case, as its approaches to hydrogen have developed dramatically in recent years. The measures taken or proposed will all change the legislative scenery for hydrogen and hydrogen storage.[23] These include the hydrogen-specific strategy published in 2020;[24] the Fit for 55 package, proposed by the Commission in 2021; the Hydrogen and Decarbonised Gas Market package (Gas Package) proposed later that year; and the legal responses adopted to the Russian invasion of Ukraine in 2022 and 2023. While the earlier EU legal frameworks for hydrogen storage have been discussed in legal scholarship,[25] the literature lacks comprehensive analyses of these more recent legal and policy tools.

The remainder of the chapter is structured as follows. Section 19.2 discusses the legal challenges and opportunities of using hydrogen as energy storage. Here, the analysis takes an end-use-neutral approach; that is, it examines the legal governance of hydrogen storage in the form of power-to-gas irrespective of the purpose for which it is used after storage.[26] Section 19.3 focuses on EU law and policy as a case study to ascertain the applicable legal framework for hydrogen storage. Section 19.4 then identifies the approaches taken through the proposed legislative instruments and probes the gaps that still remain in the existing EU legal framework. Section 19.5 concludes with key insights from the analysis.

19.2 LEGAL CHALLENGES AND OPPORTUNITIES OF USING HYDROGEN AS AN ENERGY STORAGE MEDIUM

Any emerging technological innovation in the energy sector is likely to invite new types of legal questions; these will vary depending on the type of technology and energy carrier and the

[23] European Commission, 'Fit for 55': delivering the EU's 2030 Climate Target on the way to climate neutrality, COM (2021) 550 final and in literature Kaisa Huhta, 'The "Fit for 55"-package in the Context of EU Energy Law and Policy', *OGEL* (2022); European Commission, Proposal for a Directive of the European Parliament and of the Council on common rules for the internal markets in renewable and natural gases and in hydrogen, COM(2021) 803 final (hereinafter: proposed Gas Directive); European Commission, Proposal for a Regulation of the European Parliament and of the Council on the internal markets for renewable and natural gases and for hydrogen (recast), COM(2021) 804 final (hereinafter: proposed Gas Regulation).

[24] European Commission, A hydrogen strategy for a climate-neutral Europe, COM(2020) 301 final (hereinafter: Hydrogen Strategy).

[25] Francesco Dolci and others, 'Incentives and legal barriers for power-to-hydrogen pathways: An international snapshot', 44 *International Journal of Hydrogen Energy* (2019) 11394–11401; Moritz Wüstenberg, 'Regulating the future hydrogen trade in the EU: WTO law considerations', 41 *Journal of Energy & Natural Resources Law* (2023) <http://doi.org/10.1080/02646811.2023.2165315>; Ruven Fleming and Gijs Kreeft, 'Power-to-Gas and Hydrogen for Energy Storage under EU Energy Law', in Martha M. Roggenkamp and Catherine Banet (eds.), *European Energy Law Report* (Vol. XIII, Intersentia 2020), pp. 101–124 (hereinafter: Fleming and Kreeft); Ruven Fleming and Joshua P. Fershee, 'The "Hydrogen Economy" in the United States and the European Union Regulating Innovation to Combat Climate Change', in D. Zillman, L. Godden, L. Paddock and M. Roggenkamp (eds.), *Innovation in Energy Law and Technology: Dynamic Solutions for Energy Transitions* (Oxford University Press 2018), pp. 137–153; Ruven Fleming, 'Clean or renewable – Hydrogen and power-to-gas in EU energy law', 39(1) *Journal of Energy & Natural Resources Law* (2021) 43–63 (hereinafter: Fleming 2021).

[26] Similarly in Fleming and Kreeft, 101–124.

jurisdiction in which they are governed. This is particularly true for hydrogen storage, the technologies for which vary,[27] some being more emergent than others.[28] While a detailed analysis of the variety of legal questions that figure in the case of different hydrogen storage technologies[29] is beyond the scope of this chapter, it should be acknowledged that the choice of storage technology naturally influences the legal questions that may arise. For example, for a technology located deep underground the environmental permit processes or the safety requirements are likely to be different compared to those for a hydrogen storage facility sited in a residential area. Similarly, the jurisdiction in which the hydrogen storage is located may well determine the pertinent legal issues to be addressed. A region with an extensive natural gas infrastructure and a commensurately robust legislative framework is likely to encounter legal issues relating to the applicability of the existing legal framework to hydrogen storage whereas a jurisdiction with no natural gas infrastructure and no existing legal framework is likely to deal with very different issues.

Generally speaking, most jurisdictions do not have a legislative framework specific to hydrogen (storage), or such a framework is emergent at best.[30] The applicable legal framework for natural gas is often expected to cover key issues of hydrogen storage, and may present a significant opportunity for finding synergies between natural gas and hydrogen laws.[31] However, in the absence of a gas-specific governance framework applicable to hydrogen, the legislative framework relevant for hydrogen storage is likely to not only draw on legal frameworks for electricity and natural gas but also to tap legal fields beyond energy law, such as environmental law, administrative law or contract law. In what follows, four areas of law are presented which may offer relevant and applicable rules for hydrogen storage yet, at the same time, create challenges: financial incentives, spatial planning, environmental and administrative permitting, ownership and access.

Hydrogen storage requires considerable investments in what are often only nascent technologies and, in most if not all jurisdictions, are not comprehensively governed by legislative frameworks explicitly designed to incentivise investments financially. This being the case, legal and policy frameworks may undermine one another and frustrate efforts to provide a stable and supportive investment environment for hydrogen storage. For example, while a hydrogen policy instrument or a strategy may state that hydrogen storage is a key goal that must be incentivised, the legal framework might in practice disincentivise the pursuit of the very same goal. EU energy policy, for instance, presents hydrogen storage technologies as an important decarbonisation instrument, but under EU energy law hydrogen storage operators are taxed twice: they are taxed when they use electricity to produce hydrogen storage and when they inject power back into the grid.[32] This legislative setting, also referred to as double taxing or double charging, has been cited by industry and in previous energy research as a significant barrier, discouraging investment in hydrogen storage.[33] By the same token, creating optimal legal and policy frameworks to ensure sufficient investment in hydrogen storage has been identified as a key legal issue.[34]

[27] For a detailed examination, see Mehmet Sankir and Nurdan Demirci Sankir, *Hydrogen Storage Technologies* (Wiley 2018).

[28] Elberry et al.

[29] Anderson and Leach, 1604; Elberry et al.; Al-Mufachi and Shah.

[30] Dalia Majumder-Russell, *Hydrogen Projects: Legal and Regulatory Challenges and Opportunities* (Globe Law and Business, 2021) (hereinafter: Majumder-Russell).

[31] *Ibid.*

[32] David Parra and Romain Mauger, 'A new dawn for energy storage: An interdisciplinary legal and techno-economic analysis of the new EU legal framework', 171 *Energy Policy* (2022) 113262 (hereinafter: Parra and Mauger).

[33] Parra and Mauger. The proposed energy tax directive is expected to change this setting, but it had not yet entered into force at the time of writing (1 August 2023). European Commission, Proposal for a Council Directive restructuring the Union framework for the taxation of energy products and electricity (recast), COM(2021) 563 final.

[34] Côté and Salm.

The second challenge is spatial planning. Its effects, again, depend heavily on the particular hydrogen storage technology used and the jurisdiction in which the planning takes place. In any event, land rights must generally be secured to gain access to privately owned land.[35] This might take place through voluntary contracts or through statutory acquisition rules depending on the situation and the jurisdiction. Furthermore, the extent to which land ownership rights reach below ground varies between jurisdictions.[36]

Third, in a consideration inherently connected to spatial planning, environmental and administrative permit processes are likely to influence the attractiveness and feasibility of hydrogen storage projects. These concerns are similar to those affecting any energy technology: its environmental impact, safety and location are subject to legal requirements that may or may not make pursuing the project too costly, too time-consuming, or both.

Finally, ownership and access have been cited as key issues that may create challenges for hydrogen storage.[37] It has been rightly pointed out that the ownership of energy storage facilities is a critical question for the development of hydrogen storage projects.[38] Specifically, the question of who is allowed to own hydrogen storage arises in connection with unbundling rules, which require the separation of network activities from those of production and supply. Robust and clear rules are needed to establish whether it is network operators, energy producers, or both, that are allowed to own hydrogen storage. The following section analyses how these potential opportunities and challenges have played out in the context of the EU legal framework.

19.3 REGULATING HYDROGEN STORAGE IN THE EU

19.3.1 *Applicable Policy and Legal Framework*

The EU's Hydrogen Strategy[39] and the Energy System Integration Strategy[40] view hydrogen energy storage as having several interrelated functions in the European energy system. One is that it stands to increase the flexibility of the energy system. Specifically, it provides an offloading option for renewable energy during times of abundant supply and additional generation capacity during times of scarcity. This in turn accommodates the changing needs of the grid and enables the energy system to manage the variability and uncertainty of demand and supply across all relevant timescales.[41] Furthermore, the two strategies point out that the buffering function of hydrogen has benefits that go beyond mere energy storage. As hydrogen can be stocked and transported, it can be used to transport stored energy across regions. It also makes it possible to connect different energy markets and end-use sectors as well as to reprice energy in specific hydrogen markets.[42] To realise these aspirations, the strategies point towards numerous regulatory issues, ranging from enforcing the implementation of existing energy market legislation to removing regulatory barriers and drafting a dedicated regulatory framework for hydrogen.

[35] Majumder-Russell, 47.

[36] Jean Howell, '"Subterranean land law": Rights below the surface of land', 53 *Northern Ireland Legal Quarterly* (2002) 268. Also see Madeline Taylor's chapter in this book (Chapter 5).

[37] Parra and Mauger.

[38] *Ibid.*

[39] See Hydrogen Strategy.

[40] European Commission, Powering a climate-neutral economy: An EU Strategy for Energy System Integration, COM (2020) 299 final (hereinafter: Energy System Integration Strategy).

[41] Commission Staff Working Document, Energy storage – Underpinning a decarbonised and secure EU energy system, SWD(2023) 57 final, 5 (hereinafter: Commission Staff Working Document).

[42] Hydrogen Strategy, 1, 6, 14; Energy System Integration Strategy, 4, 12.

Furthermore, the Hydrogen Strategy notes that the deployment of hydrogen storage will require supportive policies and legislation as well as private and public funding for the required investments.[43]

In the EU electricity legislation, the most important provisions for hydrogen storage are found in the Electricity Directive[44] and Electricity Regulation.[45] These legislative acts lay down rules on who can own and operate energy storage and how grid charges are established. The applicability of these substantive provisions hinges on the definition of energy storage. The Electricity Directive provides the following definitions relating to energy storage:

> Energy storage means, in the electricity system, deferring the final use of electricity to a moment later than when it was generated, or the conversion of electrical energy into a form of energy which can be stored, the storing of such energy, and the subsequent reconversion of such energy into electrical energy or use as another energy carrier.[46] . . .
>
> Energy storage facility means, in the electricity system, a facility where energy storage occurs.[47]

Hydrogen storage fits well within the definition of energy storage when all three phases – conversion of electricity into hydrogen, storing the hydrogen produced and reconverting it into electricity – are carried out within a single facility.[48] However, as hydrogen can be transported and stored, each of these phases can be carried out independently of each other in separate facilities and even by different operators. It is therefore less clear whether facilities that only take part in one or two of these phases should be considered energy storage facilities.[49] In this regard, the Directive is clear only to the extent that reconversion is not necessary for an operation or facility to be classified as energy storage. In other words, a facility where electricity is converted into hydrogen can be classified as an energy storage facility even if the hydrogen is not reconverted later.[50] The Directive provides less guidance for the other possible combinations of these phases. For instance, it is unclear whether a combined hydrogen storage and electricity generation facility would be considered an energy storage facility or a normal electricity generation facility.[51]

There are several groups of actors that may be interested in operating hydrogen storage facilities, such as electricity generators, electricity transmission and distribution system operators (network operators), independent energy storage facility operators and electricity customers. In general, the electricity legislation sees energy storage as a competitive market-based activity, meaning that market participants are generally allowed to own and operate energy storage facilities but electricity network operators are usually prohibited from doing so.[52] Although network operators might be interested in running energy storage facilities to fulfil their tasks under the Directive, the electricity market legislation would prefer that they procure storage

[43] Hydrogen Strategy, 8–9, 15; Energy System Integration Strategy, 12—18.

[44] Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU, OJ L 158, 14 June 2019, 125–199 (hereinafter: Electricity Directive).

[45] Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity, OJ L 158, 14 June 2019, 54–124 (hereinafter: Electricity Regulation).

[46] Electricity Directive, Article 2(59).

[47] *Ibid.*, Article 2(60).

[48] Fleming 2021, 51; Fleming and Kreeft, 107–108.

[49] Fleming 2021, 51; Fleming and Kreeft, 109.

[50] Fleming 2021, 51; Fleming and Kreeft, 108–109.

[51] Fleming 2021, 51; Fleming and Kreeft, 108–109

[52] Commission Staff Working Document, 19; Fleming 2021, 56–59; Fleming and Kreeft, 114–117.

services from the competitive market.[53] Nevertheless, the Directive provides some exceptions to these prohibitions.[54]

Although the Electricity Regulation lays down the general provisions constituting the framework for establishing grid charges, it does not provide unequivocal guidance as to whether double grid charges should be abolished. What is more, the other relevant legal instruments provide only a few limited clarifications on this issue: the Electricity Directive provides that active customers must not be subject to double charges for stored energy remaining within their premises or when providing flexibility services to the system operator;[55] and the Renewable Energy Directive (RED) has a similar provision pertaining to renewables self-consumers.[56] Beyond these, one finds only a general provision in the Electricity Regulation stipulating that network charges should not discriminate positively or negatively against energy storage.[57] Interestingly, this provision has been interpreted as both justifying the imposition of double charges and abolishing them. Since energy storage operators both consume and produce electricity, potentially using the grid twice, it can be argued that the prohibition of positive discrimination requires charging energy storage operators twice. The opposite view is that the operation of energy storage provides benefits to the grid, and therefore avoiding negative discrimination requires charging the energy storage operator only once.[58] Some Member States have imposed double grid charges whereas others have not, and some have set up special tariff structures to accommodate energy storage.[59]

19.3.2 *Storing Renewable Energy in Hydrogen*

One of the main drivers behind deploying hydrogen storage in the EU is to integrate renewable energy into the energy system. The bulk of the legal framework geared to supporting renewable energy in the EU is set out in the RED.[60] In particular, the Directive provides three main features underpinning the storage of renewable energy with hydrogen technologies: it defines what is considered renewable energy, including renewable hydrogen and renewable electricity; provides basic rules for issuing guarantees of origin; and sets targets for renewable energy consumption.[61] At the time of writing, the Directive is under review, with numerous proposed amendments to its provisions relating to hydrogen and energy storage. The EU's co-legislators have agreed on the text of the amendments, and while not yet formally adopted,[62] the revised Directive (RED III) is discussed where appropriate in what follows.

53 Electricity Directive, Articles 31–32, 36(1) 40, and 54(1), and Recital 62.

54 Ibid., Articles 2(51), 36(2) and 54(2). See also Parra and Mauger, 7–8; Fleming 2021, 56–58; Fleming and Kreeft, 115–117.

55 Electricity Regulation, Article 15(5).

56 Article 21(2) of Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources, OJ L 328, 21 December 2018, 82–209 (hereinafter: RED).

57 Electricity Regulation, Article 18(1).

58 Parra and Mauger, 8.

59 Commission Staff Working Document, 28; ENTEC, Study on Energy Storage. Publications Office of the European Union, 2023 <https://data.europa.eu/doi/10.2833/333409> accessed 8 November 2024 (hereinafter: ENTEC Study on Energy Storage), 138, 141.

60 RED, Article 1. For an example of a sub-target, see Article 25 of the Directive.

61 RED, Articles 2(1) and 2(12). See also Fleming 2021, 47–49.

62 See European Parliament legislative resolution of 12 September 2023 on the proposal for a directive of the European Parliament and of the Council amending Directive (EU) 2018/2001 of the European Parliament and of the Council, Regulation (EU) 2018/1999 of the European Parliament and of the Council and Directive 98/70/EC of the European

The RED recognises that hydrogen produced from renewable electricity can be considered a form of renewable energy and that its renewable qualities can be certified through guarantees of origin.[63] A guarantee of origin is a document that is used to show the final customer that a given share of the energy supplied to it has been produced from renewable sources. Guarantees of origin can be traded independently of the energy to which they pertain, meaning that they essentially serve as evidence of renewable energy.[64] Indeed, this is the sole function of guarantees of origin, and the system plays no role in calculating the attainment of different renewable energy targets under the RED.[65]

Rather than using guarantees of origin, the attainment of the different renewable energy targets is calculated using the rules provided in the RED. The rules for what are known as 'renewable fuels of non-biological origin' have become particularly important in the case of renewable hydrogen, as they set out how renewable electricity for hydrogen production needs to be sourced if the hydrogen produced is to be considered renewable.[66] The main principles informing these rules are set out in the Directive and further detailed in what is known as the Additionality Regulation.[67] These rules aim to ensure that the electricity used for the production of hydrogen is renewable and that the production of hydrogen leads to emissions reductions and increased deployment of renewable electricity generation.[68] Strictly speaking, the rules only apply to calculating whether the renewable energy targets under the Directive are achieved.[69] However, in practice other instruments, such as state aid guidelines, refer to the calculation rules, widening their actual scope of application.[70]

The RED and the Additionality Regulation provide different calculation rules for different circumstances. The rules frequently use the so-called additionality, temporal correlation and geographical correlation criteria. In brief, additionality criteria require that the electricity for hydrogen production is sourced from new installations.[71] Temporal and geographical correlation criteria stipulate that hydrogen is produced at times and in places where renewable electricity is available.[72]

When the electrolyser and electricity generation facilities are connected by a direct line, the calculation rules allow for the hydrogen produced to be considered renewable if certain additionality criteria are met.[73] Hydrogen produced from grid electricity can be deemed entirely

Parliament and of the Council as regards the promotion of energy from renewable sources, and repealing Council Directive (EU) 2015/652 (hereinafter: RED III).

63 RED, Article 19(7). See also Fleming and Kreeft, 105–106; Ruven Fleming, 'The Hydrogen Revolution and Natural Gas: A New Dawn in the European Union?', in Damilola Olawuyi and Eduardo Pereira (eds.), *The Palgrave Handbook of Natural Gas and Global Energy Transitions* (Palgrave MacMillan 2022) pp. 123–140, 132–133 (hereinafter: Fleming 2022).

64 RED, Article 19(7). See also Fleming and Kreeft, 105–106; Fleming 2022, 132–133.

65 RED, Article 19(2).

66 *Ibid.*, Article 27(3) (Article 27(6) RED III).

67 *Ibid.* Commission Delegated Regulation (EU) 2023/1184 of 10 February 2023 supplementing Directive (EU) 2018/2001 of the European Parliament and of the Council by establishing a Union methodology setting out detailed rules for the production of renewable liquid and gaseous transport fuels of non-biological origin, OJ L 157, 20 June 2023, 11–19 (hereinafter: Additionality Regulation).

68 RED, Recital 90.

69 See ibid., Article 27(3) (Article 27(6) RED III).

70 See e.g. paragraph 19(70) in European Commission, Guidelines on state aid for climate, environmental protection and energy 2022, C/2022/481, OJ C 80, 18 February 2022, 1–89 (hereinafter: CEEAG).

71 RED, Article 27(3), subparagraph 5 (Article 27(6), subparagraph 2 RED III); Additionality Regulation, Article 3 subparagraph 2 point b and Article 5.

72 See Additionality Regulation, Recital 8 and Articles 6–7.

73 *Ibid.*, Article 3. The article also applies to co-located renewable electricity and hydrogen production.

renewable if the electricity is sourced from installations generating renewable energy and the additionality, temporal correlation and geographical correlation criteria are met.[74] However, in some circumstances it is not necessary to meet the three sets of criteria for the hydrogen produced to be considered renewable. There are two situations where none of the criteria need to be met and one situation where the additionality criteria do not apply. First, hydrogen produced from grid electricity is considered entirely renewable when it is produced during a period of oversupply of electricity and the energy stored enables the use of renewable electricity to a greater extent than would otherwise be possible.[75] Second, there are specific calculation rules, which are not subject to the three sets of three criteria, for the production of hydrogen from grid electricity in bidding zones where the proportion of renewable energy in the electricity mix exceeds 90 per cent.[76] Finally, it is not necessary to comply with the additionality criteria if the hydrogen is produced in a bidding zone where the emission intensity of electricity is below a certain threshold. In this case, the hydrogen produced is considered fully renewable if the electricity used is sourced from renewable sources and the geographical and temporal correlation criteria are met.[77]

Although clear rules for converting renewable electricity into renewable hydrogen are in place, the RED does not consider electricity generated from renewable hydrogen as renewable energy. According to the Directive's definition, electricity is considered renewable when it is generated from renewable sources; yet even though the energy content of renewable hydrogen is derived from renewable sources, hydrogen is considered an energy carrier rather than an energy source.[78] Consequently, electricity that is produced from renewable hydrogen cannot be considered renewable energy. Furthermore, the provisions on guarantees of origin make no references to energy storage or the option of granting guarantees to electricity produced from renewable hydrogen.[79] However, there have been attempts to circumvent this obstacle in the context of energy storage.[80]

19.3.3 *State Aid for Hydrogen Storage*

Member States may want to facilitate and accelerate the deployment of hydrogen storage by granting financial support from public funds. In the EU, such support is usually considered state aid, which the Member States are generally prohibited from providing, although there are extensive exceptions to this rule.[81] In practice, Member States must notify the Commission of their intention to grant state aid, after which the Commission assesses the measure and approves or prohibits it.[82] Most importantly, the Commission may decide to allow Member States to grant aid that facilitates the development of certain economic activities, including those in the energy sector, provided that the aid does not affect trading conditions in the EU too negatively.[83] The notification of a measure to the Commission by a Member State and subsequent assessment by

74 RED, Article 27(3), subparagraph 6 (Article 27(6), subparagraph 3 RED III); Additionality Regulation, Article 4(4).
75 Additionality Regulation, Article 4(3).
76 *Ibid.*, Article 4(1).
77 *Ibid.*, Article 4(2).
78 See Article 2(1) RED.
79 *Ibid.*, Article 19(7)(a). See also ENTEC Study on Energy Storage, 149–152.
80 E.g. in Austria. See ENTEC Study on Energy Storage, 153–154.
81 Article 107 of the Consolidated version of the Treaty on the Functioning of the European Union, OJ C 326, 26 October 2012, 47–390 (hereinafter: TFEU).
82 *Ibid.*, Article 108(3).
83 *Ibid.*, Article 107(3)(c).

the Commission of the measure take place under the rules provided in the General Block Exemption Regulation (GBER)[84] and the Commission Guidelines on State Aid for Climate, Environmental Protection and Energy (CEEAG).[85] The GBER exempts aid measures from notification and assessment if certain general conditions are met – such as not exceeding the maximum thresholds for the amount of aid provided – and if the measure meets the category-specific criteria laid down in the Regulation. Measures that are not exempted from notification are individually assessed by the Commission under the CEEAG.[86]

The GBER exempts several categories of aid from notification and assessment, including investment aid for projects that are considered energy infrastructure. This category includes aid for large underground hydrogen storage facilities that are subject to tariff regulation and third-party access rules, as well as energy storage facilities owned by electricity network operators.[87] The category also includes aid for hydrogen storage projects that are identified as Projects of Common Interest under the Trans-European Energy Networks Regulation.[88] Also exempt from notification under the GBER is aid for behind-the-meter electricity and hydrogen storage when these are deployed together with renewable electricity generation or renewable hydrogen production.[89]

The catch-all category under which aid for most types of hydrogen energy storage projects is assessed is section 4.1 CEEAG. The section lays down specific rules for assessing aid for the reduction of greenhouse gas emissions. Most importantly, it applies to support schemes for energy storage when their primary objective is to reduce emissions, for example by facilitating the incorporation of a higher share of renewable energy in the energy system.[90] In addition, section 4.1 covers hydrogen storage infrastructure that is combined with energy production or use. Finally, it acts as a fall-back category for 'dedicated infrastructure projects'[91] that are 'built for one or a small group of ex ante identified users and tailored to their needs'[92] and do not fall within the definition of energy infrastructure (assessed under section 4.9 CEEAG).[93] These could include smaller hydrogen storage installations that have a limited number of users. Aid schemes for hydrogen energy storage may also be assessed under section 4.8 CEEAG when the energy storage is primarily used for ensuring the security of electricity supply.[94]

In response to the coronavirus pandemic after 2019 and the escalation of the Russo-Ukrainian war in 2022, the general state aid framework discussed above has been complemented with

[84] Commission Regulation (EU) No 651/2014 of 17 June 2014 declaring certain categories of aid compatible with the internal market in application of Articles 107 and 108 of the Treaty Text with EEA relevance OJ L 187, 26 June 2014, 1–78 (hereinafter: GBER).

[85] See CEEAG.

[86] On state aid generally in the energy sector, see Leigh Hancher and Francesco Maria Salerno, 'State Aid in the Energy Sector', in Leigh Hancher and Juan Jorge Piernas López (eds.), *Research Handbook on European State Aid Law* (2nd ed., Edward Elgar 2021) pp. 64–86, especially 79–84.

[87] GBER, Articles 2(130)(c) and 48; CEEAG, points 19(36) and 376 and nn. 27, 28 and 142.

[88] GBER, Article 2(130)(f); CEEAG, para. 19(36)(f). Regulation (EU) 2022/869 of the European Parliament and of the Council of 30 May 2022 on guidelines for trans-European energy infrastructure, amending Regulations (EC) No. 715/2009, (EU) 2019/942 and (EU) 2019/943 and Directives 2009/73/EC and (EU) 2019/944, and repealing Regulation (EU) No. 347/2013, OJ L 152, 3 June 2022, 45–102.

[89] GBER, Article 41.

[90] CEEAG, para. 83.

[91] *Ibid.*, para. 84.

[92] *Ibid.*, n. 27.

[93] *Ibid.*, para. 84.

[94] *Ibid.*, para. 326.

temporary crisis measures.[95] Specifically, the Commission's state aid guidance now includes the Temporary Crisis and Transformation Framework,[96] which was adopted in March 2022 and has been amended several times.[97] The latest version of the Framework includes specific sections on accelerating the rollout of renewable energy, expanding electricity storage and promoting storage of renewable hydrogen. These sections provide assessment criteria for investments and operating aid for electricity that are simpler and less stringent than those under the CEEAG. The Framework is applicable to aid measures granted by the end of 2025 and implemented by the end of 2028.[98]

19.4 GAPS AND FUTURE DIRECTIONS IN THE EU

As seen above, while the current EU legislative framework addresses numerous regulatory issues that affect hydrogen electricity storage, it still has unclear provisions and gaps and can be described as emergent. Many of the gaps and issues will be addressed by the ongoing legislative projects, which are expected to enter into force in the coming years. Most importantly, the Gas Package will provide a specific regulatory framework for hydrogen infrastructure and mark a complete overhaul of major legislative instruments.[99] Planning and permitting issues have recently become a key theme in the EU's energy policy debate and RED III will amend the Renewable Energy Directive to address these concerns.[100] What follows gives a brief overview of how these developments stand to affect hydrogen storage.

The questions of whether, how and to what extent the current EU gas legislation applies to hydrogen storage have been discussed in the literature.[101] The main consequence of applying gas legislation to hydrogen storage would be having to decide whether ownership unbundling and third-party access rules apply to facilities storing hydrogen.[102] To summarise this discussion, the scope of application of gas legislation to hydrogen energy storage is unclear, and depends on the specifics of the storage facility and the interpretation of the gas legislation.[103] The proposed recast Gas Directive[104] and Regulation[105] aim to improve this situation by establishing separate

[95] European Commission, State aid: Commission sets out future of Temporary Framework to support economic recovery in context of coronavirus outbreak, 18 November 2021 <https://ec.europa.eu/commission/presscorner/detail/en/ip_21_6092> accessed 8 November 2024; European Commission, State aid: Commission adopts Temporary Crisis Framework to support the economy in context of Russia's invasion of Ukraine, 23 March 2022 <https://ec.europa.eu/commission/presscorner/detail/en/statement_22_1949> accessed 8 November 2024.

[96] European Commission, Temporary Crisis and Transition Framework for State Aid measures to support the economy following the aggression against Ukraine by Russia, 2023/C 101/03, OJ C 101, 17 March 2023, 3–46 (hereinafter: TCTF).

[97] European Commission, State aid: Commission adopts Temporary Crisis and Transition Framework to further support transition towards net-zero economy, 9 March 2023 <https://ec.europa.eu/commission/presscorner/detail/en/ip_23_1563> accessed 8 November 2024.

[98] TCTF, section 2.5 and n. 107.

[99] In general, see European Commission, Hydrogen and decarbonised gas market package <https://energy.ec.europa.eu/topics/markets-and-consumers/market-legislation/hydrogen-and-decarbonised-gas-market-package_en> accessed 8 November 2024.

[100] In general, see European Commission, Enabling framework for renewables <https://energy.ec.europa.eu/topics/renewable-energy/enabling-framework-renewables_en> accessed 8 November 2024.

[101] See Fleming and Fershee, 147–150; Fleming 2021, 51–53; Fleming and Kreeft, 109–114; Fleming 2022, 133–134.

[102] See Articles 15, 26, and 31–33 of Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC, OJ L 211, 14 August 2009, 94–136.

[103] Fleming and Fershee, 147–150; Fleming 2021, 51–53; Fleming and Kreeft, 109–114; Fleming 2022, 133–134.

[104] See proposed Gas Directive.

[105] *Ibid.*

legal frameworks for hydrogen and natural gas, clarifying which rules apply to hydrogen infrastructure and which apply to mainly methane-based natural gas infrastructure.[106]

The proposed gas legislation aims to apply third-party access rules to large underground hydrogen storage facilities.[107] This reflects the current situation, in which storage in salt caverns is the only proven technology for large-scale hydrogen storage. Yet only a limited number of appropriate geological formations exist and they are located unevenly among the Member States, resulting in a need to regulate access to the storage sites.[108] The proposed Gas Directive defines a 'hydrogen storage facility' as a large facility stocking hydrogen at a high grade of purity. According to the definition, the qualifier 'large' refers in particular to large-scale underground storage and excludes smaller, easily replaceable storage installations.[109] Read together with the proposal's background, the definition encompasses large-scale underground storage and excludes all other types of storage installations. After the Directive enters into force, Member States will be required to ensure that a strict system of regulated third-party access to hydrogen storage facilities is applied.[110] This differs from the regulation of natural gas storage facilities, which gives Member States a choice between applying a negotiated or a regulated third-party access regime.[111] However, the proposed gas legislation also includes several exemptions to third-party access rules.[112]

The proposed Gas Directive would also lay down horizontal and vertical unbundling rules for hydrogen storage and network operators. The proposed directive does not consider hydrogen storage facilities to be part of hydrogen networks and therefore sets out separate sets of rules for hydrogen storage operators and hydrogen network operators.[113] The vertical unbundling rules are intended to separate operating hydrogen storage from hydrogen production and network operations. Most importantly, hydrogen storage operators that are part of a vertically integrated undertaking would need to be independent of unrelated activities, including the production of hydrogen. As a result, operators of large-scale hydrogen facilities could not operate hydrogen production facilities.[114] In turn, horizontal unbundling rules restrict hydrogen network operators from operating electricity and natural gas networks. However, only account unbundling rules would apply to hydrogen storage facilities; that is, hydrogen and natural gas undertakings would need to keep separate accounts for hydrogen storage and other activities as if these were being carried out by separate undertakings.[115]

Recent developments have heightened the importance of addressing planning and permitting issues at the EU level. The escalation of the Russo-Ukrainian War in 2022 prompted the EU to quickly reduce its dependence on Russian energy imports and accelerate the energy transition. As a follow-up, the EU institutions adopted several emergency measures to expedite and

[106] *Ibid.*, Articles 1 and 2(1). See also Ruven Fleming, 'Hydrogen Networks: Networks of the Future?', in Ruven Fleming and others (eds.), *A Force of Energy – Essays in Energy Law in Honour of Professor Martha Roggenkamp* (University of Groening Press 2022), pp. 121–130, 124–128.

[107] Proposed Gas Directive, Article 33.

[108] *Ibid.*, Recital 72. See also pp. 10, 38, Table 35 in SWD(2021) 455 final.

[109] Proposed Gas Directive, Article 2(6).

[110] *Ibid.*, Article 33.

[111] See *Ibid.*, Articles 29 and 33.

[112] E.g. *Ibid.*, Article 60.

[113] *Ibid.*, Articles 2(6), 2(20), 2(22), 42, 56, 62–65, 67, and 69.

[114] *Ibid.*, Articles 2(37), 56 and 67.

[115] *Ibid.*, Articles 63–64 and 69. For further detail, Lavinia Tanase and Ignacio Herrera Anchustegui, 'EU Hydrogen and the Decarbonized Gas Market Package: Unbundling, Third-Party Access, Tariffs and Discounts Rules at the Core of Transport of Hydrogen', 11–12 <https://ssrn.com/abstract=4431113> accessed 8 November 2024.

streamline the permitting of renewable energy projects.[116] The Commission then went on to propose amending the RED to include stronger rules on spatial planning and permitting for renewable energy projects. These amendments have been incorporated into RED III. Under the Directive, Member States will have to identify and designate areas well suited for renewable energy projects as 'renewables acceleration areas'.[117] The provisions on such areas also apply to what is known as co-located energy storage, which is defined as 'an energy storage facility combined with a facility producing renewable energy and connected to the same grid access point'.[118] To support and complement renewables acceleration areas, Member States may also designate dedicated infrastructure areas for the development of grid and storage projects that are necessary to integrate renewable energy into the electricity system.[119] These areas are selected with environmental considerations in mind to enable a simplified environmental assessment when considering individual projects in them.[120]

RED III will also require Member States to streamline permitting procedures. They will have to establish maximum limits on the duration of the permitting procedures and designate contact points to facilitate the permit-granting process and guide applicants. The rules on streamlining procedures will apply to projects located in the renewables acceleration areas and elsewhere, but the Directive will impose stricter time limits and other requirements for projects within acceleration areas.[121] Finally, RED III includes an article on the principle of overriding public interest. The principle provides that when balancing legal interests in individual cases, renewable energy projects, including storage assets, are presumed to be in the overriding public interest and to serve public health and safety. This presumption enables the projects to benefit from derogations under certain instruments of EU environmental legislation.[122]

19.5 CONCLUSIONS

This chapter has analysed the legal approaches to hydrogen storage with particular reference to electricity and renewable electricity. It has reviewed the legal challenges and opportunities of using hydrogen as an energy storage medium and examined the definition of end use in this context; the focus throughout has been on the legal questions that emerge in using hydrogen as a storage medium to balance the intermittency of renewable energy sources in the low-carbon energy transition. To concretise the analysis with examples from a specific jurisdiction, the chapter explored the EU legal frameworks for electricity and hydrogen storage and demonstrated how the EU legal framework handles financial incentives, spatial planning, environmental and administrative permitting, as well as ownership and access issues.

The analysis has revealed that many of the issues in the existing legislative framework for hydrogen are often definitional: they hinge on whether or not, or to what extent, the existing

116 European Commission, Recommendation on speeding up permit-granting procedures for renewable energy projects and facilitating Power Purchase Agreements, C/2022/3219 final, especially paras. 2–7; European Commission, Guidance to Member States on good practices to speed up permit-granting procedures for renewable energy projects and on facilitating Power Purchase Agreement, SWD(2022) 149 final, especially Section 6(b). Council Regulation (EU) 2022/2577 of 22 December 2022 laying down a framework to accelerate the deployment of renewable energy, OJ L 335, 29 December 2022, 36–44.

117 RED III, Article 15c.

118 *Ibid.*, Article 2(44d).

119 *Ibid.*, Article 15e.

120 *Ibid.*, Articles 15b, 15c, 15e and 16a.

121 *Ibid.*, Articles 16, 16a–16d.

122 *Ibid.*, Article 16f.

rules on natural gas, electricity and renewable energy apply to hydrogen storage. It is clear that the EU legal framework still suffers from a number of gaps and challenges posing obstacles to effectively advancing the uptake of hydrogen storage. However, the analysis on the future directions clearly shows that the EU policy instruments widely recognise these shortcomings and that recent or upcoming legal instruments are likely to bridge many of the gaps identified or at least clarify the status quo. Nevertheless, the interpretation of the recent, and especially the proposed, pieces of legislation has not yet been tested in EU courts, whereby it will take years before the interpretation of the new legislative framework can be considered settled.

Overall, it is clear that the increasing ambition of EU climate measures and the proposed Gas Package alone have placed unprecedented pressures on hydrogen storage to serve as a storage medium in a low-carbon energy system. This fundamental change, combined with the legislative changes brought about by the COVID-19 pandemic and the Russo-Ukrainian war, has further increased the pressure to develop the EU legislative framework to adequately govern hydrogen energy storage.

FURTHER READING

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Fleming, Ruven 'The Hydrogen Revolution and Natural Gas: A New Dawn in the European Union?', in Damilola Olawuyi and Eduardo Pereira (Eds.), *The Palgrave Handbook of Natural Gas and Global Energy Transitions* (Palgrave MacMillan 2022) pp. 123–140

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20

The Regulation of Hydrogen in the Heating Markets

Pim Jansen and Leonie Reins

20.1 INTRODUCTION

In an era that is increasingly defined by concerns about climate change, the imperative to transition to a low-carbon economy has gained prominence in policy and legal frameworks at both the national and international level.[1] As part of this multifaceted transition, the potentially transformative role of hydrogen is beginning to be recognised in the EU.[2] Gaseous fuels account for approximately 22 per cent of total EU energy consumption at present. The figures for electricity and heat production are 20 and 39 per cent, respectively.[3] Moreover, these fuels account for 64 per cent of the energy that is being used to heat homes, a market in which demand is price inelastic.[4] This chapter scrutinises the end uses of hydrogen in the heating markets.[5] Critically, it examines the applicable legal framework as it pertains to the dynamics of

[1] See, for example, R Fleming, 'Clean or renewable – hydrogen and power-to-gas in EU energy law' (2021) 39 Journal of Energy and Natural Resources Law 43; M Wüstenberg, 'Regulating the future hydrogen trade in the EU: WTO law considerations' (2023) 41(4) Journal of Energy & Natural Resources Law 1; K Hainsch and others, 'Energy transition scenarios: What policies, societal attitudes, and technology developments will realize the EU Green Deal?' (2022) 239 Energy 1, This is supported in reports from authoritative international organisations such as the International Energy Agency (IEA) and the International Renewable Energy Agency (IRENA); see IEA, 'The future of hydrogen, seizing today's opportunities' (2019) <https://iea.org/reports/the-future-of-hydrogen> accessed 3 October 2023; and IRENA, 'Hydrogen from renewable power: Technology outlook for the energy transition' (2018) <https://irena.org/publications/2018/sep/hydrogen-from-renewable-power> accessed 3 October 2023.

[2] The EU's hydrogen strategy and REPowerEU plan offer a broad framework designed to promote the adoption of renewable and low-carbon hydrogen. This aims to cost-effectively reduce the EU's carbon footprint and lessen its reliance on imported fossil fuels. See Commission, 'Energy systems integration: Hydrogen' <https://energy.ec.europa.eu/topics/energy-systems-integration/hydrogen_en> accessed 3 October 2023. Aligned with this ambition is the recent Commission, 'Proposal for a Directive on common rules for the internal markets in renewable and natural gases and in hydrogen' SEC (2021) 431 final.

[3] Commission, 'Proposal for a Directive of the European Parliament and of the Council on common rules for the internal markets in renewable and natural gases and in hydrogen' COM (2021) 803 final 1.

[4] Commission, 'Commission staff working document: Impact Assessment report accompanying the Proposal for a Directive of the European Parliament and of the Council on common rules for the internal markets in renewable and natural gases and in hydrogen (recast) Proposal for a Regulation of the European Parliament and of the Council on the internal markets for renewable and natural gases and for hydrogen (recast)' SWD (2021) 455 final 28 (hereinafter: Commission).

[5] In practical terms, hydrogen offers multiple pathways to achieve a lower-carbon heating sector. It can be burned in boilers to generate heat. Alternatively, in fuel cells, hydrogen can react with oxygen to produce electricity and heat.

the Dutch market.[6] Intriguingly, for the Netherlands, embracing hydrogen as a source of heating energy is a return to the future – the 'city gas' on which many Dutch households relied prior to the emergence of natural gas for lighting, cooking, and heating was largely composed of hydrogen.[7] In the 1960s, over a number of years, the Netherlands transitioned from heating with town gas and coal to heating with natural gas. This energy transition was prompted by the discovery of natural gas at Slochteren in the north of the Netherlands in 1959, at a depth of over 2.5 kilometres.[8]

The aims of this chapter are to analyse the instruments that regulate the integration of hydrogen into the Dutch heating market and to identify gaps and sources of uncertainty for certain stakeholders. This analysis is important because a sub-optimally designed regulatory structure can obstruct the transition to a low-carbon heating network.[9] The analysis is anchored in the broader context of EU policy. The key EU initiative that shaped our discussion is the so-called Hydrogen and Decarbonised Gas Markets Package (HDGMP),[10] which was introduced on 15 December 2021. This legislative package is the cornerstone of the EU strategy for reducing fossil-fuel dependency, which entails promoting the use of hydrogen and other renewable gases. By situating the Dutch experience within this broader EU framework, the chapter provides a comprehensive analysis of the manner in which hydrogen is being integrated into the heating markets and the implications of this development for the future of sustainable energy.

20.2 THE CASE FOR HYDROGEN REGULATION IN THE HEATING MARKET

The heating of buildings and industrial enterprises accounts for more than 50 per cent of final energy consumption globally, as well as for a third of energy-related CO_2 emissions.[11] Hydrogen could change the heating sector by providing a clean and sustainable alternative to fossil fuels such as natural gas and coal.[12] The realisation of this possibility may be critical for the attainment of the 2050 climate-neutrality objective that the EU has set for itself. The European Commission is pursuing this opportunity actively by promoting a robust value chain

Hydrogen can also be blended with natural gas in existing pipelines to incrementally reduce greenhouse gas emissions, particularly if the hydrogen is produced using renewable energy sources. It offers particular promise in regions abundant in renewable energy, where surplus electricity can produce green hydrogen through water electrolysis. See P Dodds and others, 'Hydrogen and fuel cell technologies for heating: A review' (2015) 40 International Journal of Hydrogen Energy 2065–83 (hereinafter: Dodds).

6 See for a recent paper on storage of hydrogen in the Netherlands, J Juez-Larre and others, 'A detailed comparative performance study of underground storage of natural gas and hydrogen in the Netherlands' (2023) 48 International Journal of Hydrogen Energy, 28843–68.

7 L. Heijne, 'Waterstof: technische, economische en maatschappelijke acceptatie: een literatuuroverzicht' (2023) <https://research.hanze.nl/ws/files/48255895/Waterstof_technische_economische_-en_maatschappelijke_acceptatie._Een_literatuuroverzicht_2023.pdf> accessed 3 October 2023 (hereinafter: Heijne).

8 See 'Andere Tijden', Season 21, Episode 1, 'Heel Nederland aan het Aardgas', NPO Start <https://npo.nl/start/serie/andere-tijden/seizoen-21_1/heel-nederland-aan-het-aardgas/afspelen> accessed 5 February 2024.

9 M Dieperink, 'Wordt wetgeving de bottleneck van ons klimaat-en energiebeleid?' (2022) Ars Aequi 544–542 <https://arsaequi.nl/product/wordt-wetgeving-de-bottleneck-van-ons-klimaat-en-energiebeleid/> accessed July 2024, See also the Dutch public consultation on the organisation of the hydrogen market.

10 Commission.

11 Dodds, which, in turn, refers to IEA, 'Heating without global warming: Market developments and policy considerations for renewable heat' (2014) <https://iea.org/reports/heating-without-global-warming> accessed 3 October 2023.

12 Fuel Cells and Hydrogen 2 Joint Undertaking, 'Hydrogen Roadmap Europe Fuel Cells and Hydrogen Joint Undertaking (2019) Publications Office of the European Union 11 (hereinafter: Fuel Cells and Hydrogen 2 Joint Undertaking).

for hydrogen and renewable gases across Europe.[13] However, there is a conspicuous gap between the ambitions of the Commission and reality – hydrogen presently accounts for less than 2 per cent of European energy consumption, and its use is largely restricted to industrial sectors such as chemical manufacturing and fertiliser production.[14]

Understanding the role of hydrogen in the heating markets, therefore, could be crucial for the long-term sustainability goals of the EU.[15] As far as built environments are concerned, hydrogen has numerous alternatives. These include heat pumps, solar thermal collectors, and district heating systems that use waste heat, as well as thermal energy storage and geothermal energy solutions. However, when the deployment of these alternatives is not feasible or when energy must be stored, hydrogen re-emerges as a viable option.[16] In the European Union, Member States are divided on the question of whether hydrogen should be used within the heating sector. Several Member States, such as France and Germany, argue that hydrogen is not a viable alternative for the heating sector and heat pumps are a better alternative.[17] They argue that, inter alia, the 'most efficient use of energy carriers doctrine' of the EU should be applied, according to which scarce energy carriers should be used in the most efficient way.[18] Hydrogen is still very scarce and, according to these governments, needs to be prioritised in its usage to decarbonise heavy industry, cement, steel, and so on. The Netherlands is taking a different path, as discussed further below.

Given the essential role of governments in catalysing the energy transition, the importance of a sound legal framework cannot be overstated.[19] The theorem by economist Ronald Coase, which describes the link between property rights and transaction costs, is highly relevant in this context.[20] A well-structured legal framework could minimise transaction costs by clearly defining the roles, responsibilities, rights, and obligations of all relevant stakeholders. By reducing inefficiency, such a legal framework could facilitate the expeditious realisation of a wide assortment of policy objectives, thereby contributing to a smoother and more successful transition.[21] In countries such as the Netherlands, this theoretical conjecture is already being tested empirically, as will be discussed below.

[13] C Banet, 'Building Europe's Hydrogen and Renewable Gas Markets: Short-Term Priorities for Grid Regulation' (2023) Centre on Regulation in Europe, and references made. This policy direction was affirmed as far back as the 2018 European Long-Term Strategic Vision Communication. Since the publication of its Hydrogen Strategy in July 2020, the European Commission has endorsed numerous private sector initiatives to foster this emergent industry. This is because the Commission sees hydrogen as not merely a clean energy alternative but as a strategic lever for enhancing global competitiveness and sustainability.

[14] IEA, 'Global Hydrogen Review' (2022) International Energy Agency, 57 <https://iea.org/reports/global-hydrogen-review-2022> accessed 3 October 2023.

[15] Fuel Cells and Hydrogen 2 Joint Undertaking 11.

[16] Heijne.

[17] H von Mark, 'Wasserstoff im Heizkessel "keine Alternative"' (2023) zdf Heute <https://zdf.de/nachrichten/politik/wasserstoff-energie-heizung-waermepumpe-zukunft-100.html> accessed 6 February 2024.

[18] European Commission, 'Energy Efficiency First principle' <https://energy.ec.europa.eu/topics/energy-efficiency/energy-efficiency-targets-directive-and-rules/energy-efficiency-first-principle_en> accessed 6 February 2024.

[19] Similar reasons were provided in the context of the planned overhaul of the Dutch Gas Act and the Electricity Act 1998 into the Energy Act by the Dutch Minister for Climate and Energy Policy, see *Kamerstukken II* 2022/23 (hereinafter: *Kamerstukken II*), 36 378, no. 5 See, more generally, DG Tempelman, 'De rol van het recht in de energietransitie – En wat de energietransitie vraagt van de jurist: Lectorinstallatie mr Dr. Daisy G. Tempelman' (2023) Hanze University of Applied Sciences 7 (hereinafter: Tempelman).

[20] R Coase, 'The problem of social cost' (1960) 3 Journal of Law and Economics 1–44.

[21] M Baumgart and S Lavrijssen, 'Exploring regulatory strategies for accelerating the development of sustainable hydrogen markets in the European Union' (2023) Journal of Energy & Natural Resources Law 1–30 <https://doi.org/10.1080/02646811.2023.2257528> accessed 6 February 2024 (hereinafter: Baumgart and Lavrijssen).

The Dutch government has accumulated considerable technical expertise, and it has established localised hydrogen supply chains.[22] For example, the HyWay27 report described the conditions under which a national hydrogen transport network that uses existing gas pipelines could be developed.[23] However, the extant legislation, most notably the Dutch Gas Act (*Gaswet*), is inadequate for the demands of this project.[24] This finding, among many others, emerged from the Progress Policy Agenda Cabinet Vision on Hydrogen of the Dutch government. That document prompted many to call for legal reform as a matter of urgency.[25] The Netherlands Authority for Consumers and Markets (Autoriteit Consument & Markt; ACM) formulated a provisional framework as a response to those calls, which it called the 'Temporary Guidelines for Hydrogen Pilots: Regulatory Forbearance for Network Operator Involvement in Hydrogen Pilot Projects in Built Environments' (*Tijdelijk kader waterstofpilots: Gedoogbeleid voor betrokkenheid van netbeheerders bij pilots met waterstof in de gebouwde omgeving*).[26] This framework, which is provisional, serves a dual purpose: it enables network operators to participate in hydrogen pilot projects as well as laying an empirical groundwork for the future refinement of the relevant regulatory norms.[27]

The Netherlands has initiated a series of pilot projects across various municipalities.[28] Diverse stakeholders are engaged in those projects, including network operators and energy providers.[29] For instance, the Lochem pilot involves twelve residences whose occupants are engaged as co-initiators. It adopted a temporary model whereby tube trailers are used to deliver hydrogen.[30] A project in Wagenborgen includes 50–60 residences; the occupants can avail themselves of an individual opt-in mechanism. An electrolyser that is situated on farmland is used to produce hydrogen.[31] The Hoogeveen pilot, which is a part of the broader Green Deal initiative, connects 100 newbuilds and 100 terraced houses to a hydrogen-based heating system. Hydrogen will initially be supplied via tube trailers, but a shift to electrolyser-based production is planned. The intention is to continue supplying hydrogen via the existing gas network after the trial.[32] The Stad aan 't Haringvliet pilot is another Green Deal venture. It is designed to supply approximately 600 homes with hydrogen through the gas network. Older homes are its primary target. The objective is to transition permanently to hydrogen, and the launch of the project is scheduled for 2025.[33]

[22] *Kamerstukken II* 2022/23, 36 378, no. 3, p. 186 (MvT).

[23] PricewaterhouseCoopers Advisory NV, 'HyWay 27: waterstoftransport via het bestaande gasnetwerk? Eindrapport voor het ministerie van Economische Zaken en Klimaat' (2021) <www.rijksoverheid.nl/documenten/rapporten/2021/06/30/eindrapport-onderzoeksproject-hyway27> accessed 3 October 2023.

[24] Kamerbrief over voortgang beleidsagenda kabinetsvisie waterstof d.d. 11 december 2020. Specifically, the Act lacks provisions for crucial parameters such as consumer protection, safety, and supply security in the realm of hydrogen applications. See *Kamerstukken II*.

[25] Ibid.

[26] ACM, 'Tijdelijk kader waterstofpilots Gedoogbeleid voor betrokkenheid van netbeheerders bij pilots met waterstof in de gebouwde omgeving' (2022) <https://acm.nl/nl/publicaties/tijdelijk-kader-voor-waterstofpilots> accessed 3 October 2023 (hereinafter: ACM).

[27] Ibid.

[28] Ibid 1.

[29] Some of these pilot projects are part of the Green Deal H2 Neighbourhoods with the national government.

[30] See also Alliander, 'Lochem gaat op waterstof' <https://alliander.com/nl/energietransitie/pilots-met-waterstof/lochem/> accessed 3 October 2023.

[31] See also Groningerhuis, 'WaterstofWijk Wagenborgen' <https://groningerhuis.nl/projecten/waterstofwijk-wagenborgen/> accessed 3 October 2023.

[32] See also Groenemorgenhoogeveen <https://?groenemorgenhoogeveen?.nl/> accessed 3 October 2023.

[33] See also H2GO, 'Groene waterstof voor een duurzame gebouwde omgeving' <https://h2goeree-overflakkee.com/project/stad-aardgasvrij-hydrogen-city/> accessed 3 October 2023.

In the Netherlands, these initiatives are embedded into an overarching narrative.[34] They catalyse dialogue about the rules and regulations that will govern the conditions under which various stakeholders – both public and private – will be allowed to participate in the hydrogen market.[35] Those rules and regulations will also delineate the rights and obligations of end users. Numerous questions have emerged from this debate.[36] Some of those questions revolve around the conditions that will govern eligibility to engage in activities such as production, electrolysis, transport, underground storage, and the establishment and management of import or export terminals.[37] The answers to others might emphasise the need to ensure that access to these services will be both wide and equitable.[38]

Market regulation is indispensable for the management of a complex and evolving ecosystem with many stakeholders.[39] Without a coherent and comprehensive regulatory framework, sector practice would become inconsistent, accountability would be curtailed, and market behaviour may well turn anti-competitive. These points are further emphasised by the critical roles and responsibilities that regulation assigns to the various parties that are involved in hydrogen production, distribution, and consumption. As noted previously, a non-existent or suboptimal regulatory system would obstruct the transition to a low-carbon economy. Instead, sector-specific regulation should ensure the competitiveness and fairness of the market, pave the way for innovation, and safeguard the interests of consumers. Effective regulation would also facilitate the mobilisation of capital by eliminating uncertainty. Since the deployment of hydrogen in the built environment is now at the experimental stage of its development, a flexible yet robust regulatory framework is needed urgently. After having showcased the fact that EU Member States have different opinions and views on hydrogen in the heating markets, it is now time to explore what EU legislation and policy has to say on the issue, before diving into the case study of the Netherlands, which has tentatively and cautiously embraced hydrogen in the heating market.

20.3 THE EU LEGAL FRAMEWORK

The EU legislator proposed the HDGMP to integrate hydrogen into the energy law *acquis*.[40] A central aim of the Package is to incorporate provisions on hydrogen into the Gas Directive,[41] which governs the internal gas market and is set to be recast.[42]

Many of the policy initiatives that preceded the HDGMP reflected an acute awareness of the importance of hydrogen for the heating market. For instance, the System Integration Strategy identified hydrogen as a means of decarbonising the heating sector when direct heating or electrification are not feasible or efficient as one of the three 'complementary and mutually

34 Kamerbrief over ordening en ontwikkeling waterstofmarkt en antwoorden op Kamervragen over 'waterstofmiljarden' 10 December 2021, DGKE-E/21293648.

35 Consultatie naar de ordening van de waterstofmarkt, p. 1 (Dutch public consultation on the organisation of the hydrogen market).

36 Ibid.

37 Ibid.

38 Ibid.

39 Baumgart and Lavrijssen.

40 Details on the package can be found in Chapter 2 by Hancher and Suciu in this book.

41 Council Directive 2009/73/EC concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC (2009) OJ L 211, 94; Commission 17.

42 This chapter will not discuss that package in depth, which was done in Chapter 2. Here the focus will be on the aspects relevant to the heating sector.

reinforcing concepts'.[43] The Hydrogen Strategy,[44] which was published alongside the System Integration Strategy, shifted the conversation towards industrial applications and mobility, rather than heating.[45] Yet it recognised that local hydrogen clusters, known as 'Hydrogen Valleys', which have dedicated hydrogen infrastructures, could provide heat for residential and commercial buildings.[46] One of the first funded Hydrogen Valleys is actually situated in the north of the Netherlands and consists of thirty-one public and private parties from six European countries.[47] Furthermore, the impact assessment report[48] stressed that the current regulatory framework for gas prioritises natural gas over alternatives such as biomethane and other gaseous fuels, including hydrogen.[49] It concluded that low-carbon hydrogen and low-carbon fuels generally have considerable untapped potential and that potential is poised to drive the evolution of transport infrastructure and influence future end-user behaviour.[50]

The proposal for a recast Directive focuses on hydrogen infrastructure, quality of hydrogen, and hydrogen markets, but it does not directly address end users or heating. The explanatory memorandum accompanying this proposal underscores that developing infrastructure is essential for the successful exploitation of hydrogen's end-use applications. Should such developments occur, various sectors would be decarbonised, the electricity system would become more flexible, and energy security would be bolstered due to the potential reduction of natural gas imports. It would also become possible to store and produce more electricity.[51] Additionally, the memorandum recognises the link to the Energy Taxation Directive. This directive established a preferential minimum taxation level for renewable and low-carbon hydrogen fuels used for heating at €0.15/gigajoule (GJ), in contrast to €0.6/GJ for natural gas.[52]

The energy-efficiency-first principle[53] is also emphasised in the context of the Energy Performance of Buildings Directive and the Energy Efficiency Directive. While these measures primarily address heating in general and not specifically the application of hydrogen, the explanatory memorandum does mention the benefits of delivering clean and safe hydrogen to end users.[54] Likewise, the sixth Recital to the Gas Directive, which is in force at present, indicates that the instrument in question is designed to harness the potential of new gases to accelerate the attainment of the climate objectives of the Union. The Directive also purports to create a regulatory framework that reflects the transitional role of fossil gas, the need to avoid lock-in, and the desirability of phasing out fossil gas 'in all relevant industrial sectors *and for heating purposes*'.[55] Hydrogen is only mentioned indirectly.

[43] Commission, 'Powering a climate-neutral economy: An EU Strategy for Energy System Integration' (Communication) COM (2020) 299 final 2.
[44] Discussed further in Chapter 2.
[45] Commission, 'A hydrogen strategy for a climate-neutral Europe' (Communication) COM (2020) 301 final 10 17.
[46] Ibid 6.
[47] Hydrogen Valley – New Energy Coalition <https://newenergycoalition.org/en/hydrogen-valley/> accessed 21 February 2024.
[48] Commission.
[49] Ibid.
[50] Ibid 10.
[51] Ibid.
[52] Ibid 5.
[53] See for a more detailed discussion A Houtman and L Reins, 'Energy Transition in the EU: Targets, Market Regulation and Law' in G Wood and others (eds), *The Palgrave Handbook of Zero Carbon Energy Systems and Energy Transitions* (Palgrave Macmillan 2022).
[54] Commission 4.
[55] Ibid recital 6 (emphasis added).

When looking at the explanatory memorandum of the Proposal for a recast Regulation on gas markets and hydrogen, it also becomes apparent that the heating sector is not the central focus of EU law and policy. One reason for this is that, given the wildly diverging views of Member States on the question of hydrogen in heating markets, EU policy abstained from taking sides on this controversial issue. As with the explanatory memorandum to the recast Directive (with which there is significant overlap), end uses are predominantly discussed in the context of market fragmentation. This fragmentation is anticipated due to the increasing penetration of biomethane, hydrogen, and liquified natural gas (LNG) in the gas infrastructure.[56] Recital 43 to the Regulation acknowledges this point, which preserves the right of Member States to make decisions about blending while also providing for a Union-wide cap on it.

It can be concluded from the foregoing that EU legislation and policy, while directed at stimulating the end use of hydrogen, are somewhat general, especially in the context of the heating sector. The Member States thus enjoy considerable discretion. That there are no specific regulations on this matter is unsurprising – in most cases, end-use solutions are local in their effects, and their design depends significantly on the energy infrastructure and mix of the Member State in which they are being implemented. We will now turn to discuss how the Netherlands has used this margin of discretion.

20.4 THE INTERPLAY BETWEEN MARKET REGULATION AND THE HEATING MARKETS

Dutch law regulates electricity, natural gas, and thermal energy, but generally not hydrogen.[57] Several market consultation exercises focused on the structure of the hydrogen market and on quality standards, but they are yet to yield specific results.[58] The insufficiency of the regulatory framework is becoming more apparent as pilot projects begin to integrate hydrogen into the built environment for heating purposes. The national energy regulator ACM highlighted this gap, most notably in its Signal 2021 report, in which it observed that the absence of regulation undermines consumer protection and that, at present, the participation of network operators in such projects proceeds in the absence of a legal basis.[59] The latter problem also affects hydrogen suppliers, appliance manufacturers, property owners, and lessees.

A critical step of the regulatory framework is the definition of 'gas' under the Gas Act, which is currently ambiguous regarding hydrogen. To elucidate, the Gas Act defines 'gas' in the following manner:

1. Natural gas that, at a temperature of 15° Celsius and at a pressure of 1.01325 bar, exists in a gaseous state and mainly consists of methane or another substance that is equivalent to methane due to its properties, and
2. A substance that
   – is generated in a production facility that exclusively uses renewable energy sources or

[56] Commission, 'Proposal for a regulation of the European Parliament and of the Council on the internal markets for renewable and natural gases and for hydrogen (recast)' COM (2021) 804 final 8.

[57] Tempelman 78.

[58] See internetconsultatie.nl, 'Marktordening waterstof' (Overheid.nl 2022) <https://internetconsultatie.nl/?marktordeningwaterstof?/b1> accessed 3 October 2023.

[59] ACM, 'ACM Signaal 2021 – Afspraken over voorwaarden bij waterstofexperimenten noodzakelijk' (2021) <www.acm.nl/nl/publicaties/acm-signaal-2021-afspraken-over-voorwaarden-bij-?waterstofexperimenten?-noodzakelijk> accessed 3 October 2023.

- is generated in a hybrid production facility that uses both renewable and fossil energy sources and
- at a temperature of 15° Celsius and at a pressure of 1.01325 bar, exists in a gaseous state and mainly consists of methane or another substance that is equivalent to methane in terms of its properties, to the extent that it is possible and safe to transport this substance according to Chapter 2.[60]

Hydrogen does not consist mainly of methane or an equivalent substance. Hydrogen and methane are chemically distinct and exhibit different properties, including energy content, flammability range, and density.[61] Although hydrogen can be produced from renewable sources, say through the electrolysis of water, it is not explicitly mentioned as an equivalent to methane in the statute. Article 1.2 of the Gas Act provides a pathway for the inclusion of substances other than those that are mentioned specifically in Article 1.1, namely the issuance of a general administrative order (*algemene maatregel van bestuur*) that extends the application of the Act partially or wholly to other gaseous substances. So far this has not been enacted. In this context it is important to take stock of the current technical and safety limitations set by the Dutch government, as reflected in the Ministerial Decree on Gas Quality (*Regeling gaskwaliteit*), which limits hydrogen content in the natural gas network. This decree stipulates a maximum hydrogen content of 0.5 mol.-%[62] in certain network areas, indicating a cautious approach towards integrating hydrogen into the natural gas system due to current technical and safety constraints.[63]

In the context of market regulation, the Gas Act's implications for hydrogen's integration into the heating market are significant. One key aspect under the Gas Act is the regulation – or lack thereof – of networks and pipelines dedicated solely to hydrogen. Currently, in the Netherlands, the establishment and management of such hydrogen-specific networks are not regulated activities.[64] This absence of regulation suggests a potential area for development in the heating market, as entities other than traditional network companies and operators are at liberty to engage in such operations. This flexibility extends to the production and storage of hydrogen, subject to compliance with safety and environmental regulations.[65]

Under the Gas Act, network operators (*netbeheerders*) are bound to tasks specifically assigned by law (as outlined in Article 10A(a), paragraph 1).[66] This legislative framework currently precludes them from directly engaging in hydrogen production. However, their role in relation to hydrogen, especially as a potential carrier for heat, raises critical questions in the context of the

[60] 'Artikel 1.1 In deze wet en de daarop berustende bepalingen wordt verstaan onder: … b.gas: 1°.aardgas dat bij een temperatuur van 15° Celsius en bij een druk van 1,01325 bar in gasvormige toestand verkeert en in hoofdzaak bestaat uit methaan of een andere stof die vanwege haar eigenschappen aan methaan gelijkwaardig is en 2°.stof die: –is opgewekt in een productie-installatie die uitsluitend gebruik maakt van hernieuwbare energiebronnen of –is opgewekt in een hybride productie-installatie die gebruik maakt van zowel hernieuwbare als fossiele energiebronnen en – bij een temperatuur van 15° Celsius en bij een druk van 1,01325 bar in gasvormige toestand verkeert en in hoofdzaak bestaat uit methaan of een andere stof die vanwege haar eigenschappen aan methaan gelijkwaardig is voor zover het mogelijk en veilig is deze stof overeenkomstig hoofdstuk 2 te transporteren' (authors' translation).

[61] V Arutyunov and others, 'The fuel of our future: Hydrogen or methane?' (2022) 1 Methane 96–106.

[62] While mol.% is based on the weight of each of the gas components per volume, vol.-% is the percentage of a given gas in terms of the total volume of the mixture.

[63] See especially Appendix 1–5.

[64] BJM van Oorschot and VV Jacobs, 'Opschalen van groene waterstof: mogelijkheden en belemmeringen binnen het huidige juridische kader' (2021) 2 Nederlands Tijdschrift voor Energierecht 73 (hereinafter: Oorschot and Jacobs).

[65] Ibid; *Kamerstukken II* 2016/17, 34 627, no. 12, 50.

[66] Artikel 10Aa 1Een netbeheerder verricht geen andere werkzaamheden dan die nodig zijn voor een goede uitvoering van de bij of krachtens de wet aan hem toegekende taken.

ongoing debate about potential market liberalisation in the Netherlands. If heat supply were to be subject to market liberalisation, the potential involvement of gas distribution system operators (DSOs) in handling hydrogen, including its use as a heat carrier, must be carefully examined.

This is particularly relevant considering EU regulations on horizontal unbundling, which mandate the separation of energy production and supply from network operations. Allowing gas DSOs to manage hydrogen, especially in the heating sector, could pose challenges to this regulatory principle. Conversely, network companies are allowed to partake in hydrogen-related activities to a limited extent, as provided by Article 10(d)(2)(e) of the Gas Act.[67] However, the extent of this participation and how it aligns with the broader regulatory framework, especially considering the potential liberalisation of the heating market, remains a complex and evolving issue.

The blending of hydrogen into the natural gas network, another critical aspect of the heating market, is subject to rigorous regulation, especially under the current limitations of the Gas Act regarding the use of pure hydrogen for heating. According to the technical standards set out in the first paragraph of Article 11 of the Gas Act and further detailed in the Ministerial Decree on Gas Quality, gases in the Dutch natural gas networks, including H-gas, G-gas, and L-gas, must meet specific criteria at various stages from intake to delivery in both regional and national networks.[68] A critical aspect of these regulations is the stipulation of permissible hydrogen content in the gas mixture. As set out above, for reasons of safety and in accordance with current technical capabilities, the regulation restricts the hydrogen content to a maximum of 0.5 mol.% in regional distribution networks and a significantly lower limit of 0.02 mol.% in national transmission networks. This approach indicates a cautious stance towards the integration of hydrogen, considering safety and technical considerations.

The current regulations are thus tailored to a network that is built primarily for fossil fuels, and they limit the possibility of adaptations to emerging alternatives such as hydrogen. However, policymakers have the legal ability to temporarily relax these restrictions to promote sustainable energy.[69] There are (at least) three avenues that could be taken.

First, the Dutch authorities could amend the rules on hydrogen blending in the natural gas network by updating the Ministerial Regulation on Gas Quality.[70] The extent of these changes would be limited by the technical parameters of the existing infrastructure, potentially necessitating alterations to accommodate higher hydrogen concentrations. At present, no specific rules require or encourage blending. Instituting such a mandate could stabilise the market for green hydrogen by generating consistent demand, which would benefit both producers and consumers. It is crucial for national policies of this nature to align with those set by other EU/European Economic Area Member States.

Second, Article 1(i) of the Gas Act permits delegated legislation to deviate from the existing regulations, provided that the deviations do not violate EU law. This article allows for

[67] Article 24b of Book 2 of the Dutch Civil Code defines the terms 'group' and 'group company'. The definition reads: 'A group is an economic unit in which legal entities and companies are organizationally connected. Group companies are legal entities and companies that are interconnected within a group.' Therefore, the network group consists of the network operator and other legal entities within the same group. This group, which includes a network operator, is known as the network group. The legal entities within this group are group companies. To determine whether there is a group in the sense of this provision, factors such as economic unity, organisational connection, and central or common leadership are considered. In this context, decisive control and special voting rights are relevant factors.

[68] Regeling Gaskwaliteit (2023).

[69] Oorschot and Jacobs 74.

[70] Ibid 73.

experiments that contribute to advancements in decentralised production, transport, and/or supply of gas, particularly when the gas is produced locally using only renewable energy sources.[71] The third paragraph of the article outlines the requirements for the delegated legislation. Such an administrative order must specify the permissible deviations from the Gas Act, identify the potential categories of affected consumers, stipulate the intended duration of the measure, define the success metrics, and clarify whether the duration of the measures can be modified. The fourth paragraph of the article covers accountability and oversight, mandating the responsible Minister to submit a report on the experiment's efficacy and outcomes to the House of Representatives (*Tweede Kamer der Staten-Generaal*) no more than three months after its conclusion. This report should also convey the Minister's stance on the potential continuation of the experiment.

However, a challenge with Article 1(i) of the Gas Act is that it can only be invoked if the experiment involves a substance that qualifies as a 'gas' under the Act. As noted in the preceding section, hydrogen does not fall under this classification. The applicability of the Act can be extended to hydrogen through an administrative order.[72] While it might seem counterintuitive to expand the scope of the Act solely to introduce an exception to it by order, this move could eliminate some of the challenges network operators and network companies encounter when working with green hydrogen. Furthermore, this adaptable legal approach could pave the way for experimental projects, such as those involving the mandatory blending of large hydrogen volumes into natural gas.[73]

By enabling experimental projects under Article 1(i) Gas Act, especially those focused on integrating hydrogen into the gas infrastructure, the heating sector could witness a significant shift towards sustainable energy sources. Such experiments could serve as catalysts for developing and refining technologies and practices necessary for the widespread use of hydrogen in heating. They would also provide valuable insights into the practicalities and efficiencies of hydrogen as a heating medium, helping to shape future regulations and market structures. Furthermore, successful experiments could pave the way for broader legislative changes, fostering an environment conducive to the adoption of hydrogen in residential and commercial heating systems.

The third avenue for reform involves assigning responsibilities to network operators temporarily by way of administrative order.[74] According to Article 10(b) of the Gas Act, the competent Minister has the authority to act in this fashion[75] when the following criteria are met: the temporary roles are related to the existing duties of the operator under the current legislation, they are crucial for the future oversight of the gas transportation network, and market provision is deficient. However, this expansion of roles must be carefully balanced with the principle of unbundling, as mandated by EU regulations. The increased involvement of network operators in hydrogen activities, particularly in areas traditionally handled by market entities, could potentially blur these lines.

None of these avenues has been followed yet, paving the way for the ACM to introduce Temporary Guidelines for Hydrogen Pilots. The ACM, sharing the legislators' concerns, has also expressed dissatisfaction with the current regulatory framework's inability to adequately address safety and consumer protection in pilot hydrogen-delivery projects.[76] At the same time,

[71] Gas Act (*Gaswet*) 2000 Article 1i, second paragraph.
[72] Oorschot and Jacobs 74.
[73] Ibid 74.
[74] Ibid 75–76.
[75] Gas Act (*Gaswet*) 2000 Article 10b, first paragraph.
[76] ACM 1.

the ACM has taken the view that it is crucial that these operators gain hands-on experience in the distribution of hydrogen.[77]

Recognising the criticality of these gaps, and the necessity for network operators to gain practical experience in hydrogen distribution, the ACM has taken a proactive stance. To circumvent the constraints posed by the existing Gas Act, the ACM has introduced the Temporary Guidelines for Hydrogen Pilots: Regulatory Forbearance for Network Operator Involvement in Hydrogen Pilot Projects in Built Environments.[78]

This innovative approach represents a significant departure from the traditional enforcement of the Gas Act, as it allows network operators to engage in hydrogen distribution pilots under a provisional framework. In practice, this means that the ACM will not enforce the Gas Act against them as long as the pilot projects meet certain conditions. The Guidelines contain generic, consumer protection, and safety conditions. The generic conditions concern the purpose of the pilot, its scope and duration, and the roles and responsibilities of the entities that are involved in it. Many of these conditions were outlined in the 2021 Signal report, but the Temporary Guidelines also set a maximum timeframe for regulatory forbearance. The aim of a pilot should be to explore the use of hydrogen as a source of heat in built environments.[79] The role of the network operator must be confined to installing, managing, and maintaining a hydrogen distribution network, and it should not be involved in the production, trade, or delivery of hydrogen.[80] Each pilot must be designed to fulfil a clearly defined learning objective for the network operator, which must be communicated transparently to the market both during the project and upon its conclusion. Importantly, the scale of the project should be calibrated carefully so that it does not exceed what is necessary for the learning objective in question to be met. This regulatory forbearance is temporary – it is set to last until the role of the network operator is formalised, until the learning objectives of the project are met, or until it becomes evident that they are unfeasible. As for duration, a pilot project can run for up to five years from the date of the publication of the conditions. Those who organise such projects can choose to extend this period if new legislation that supports such extensions is introduced in the interim.[81]

The consumer protection rules for hydrogen are designed to mirror the standards that apply to natural gas under the Gas Act.[82] The specifics are laid out in the Annex to the Guidelines, which covers matters as varied as civil law safeguards, analogies to the Gas Act, and hydrogen-specific provisions. The consumer protection standards that apply to natural gas are largely replicated.[83] The Annex also outlines various information-disclosure requirements, most of which originate from the Dutch Civil Code. The clauses from the Gas Act that are relevant to hydrogen include complaint procedures for network operators, the reporting of defects, energy cost estimates and invoices, and stipulations on the information that contracts and bills ought to contain.[84] There is also an obligation to supply at reasonable rates and under

77 Ibid.
78 Ibid.
79 Ibid 2.
80 Ibid 1.
81 Ibid 1.
82 Ibid 2.
83 Back in 2014, the ACM created a document called 'Information Provision on the Consumer Market for Energy' (*I nformatievoorziening op de consumentenmarkt voor energie*). This guide offers a tailored overview of the rules and regulations that energy providers should follow to ensure transparency for consumers: ACM, 'Informatievoorziening op de consumentenmarkt voor energie' (2014) <https://acm.nl/nl/publicaties/publicatie/13480/I?nformatievoorziening?-op-de-consumentenmarkt-voor-energie> accessed 3 October 2023.
84 Ibid.

reasonable conditions, as well as to adopt certain policies for disconnection.[85] The following regulations also apply: the Decision on Invoices, Consumption, and Indicative Cost Overview for Energy (*Besluit factuur, verbruiks- en indicatief kostenoverzicht energie*), the Regulation on Consumers and Monitoring under the Electricity Act 1998 and the Gas Act (*Regeling afnemers en monitoring Elektriciteitswet 1998 en Gaswet*), the ACM Policy Rule on Billing Periods for Energy 2021 (*ACM Beleidsregel factureringstermijnen energie 2021*), and the Regulation on Disconnection Policy for Small Consumers of Electricity and Gas (*Regeling afsluitbeleid voor kleinverbruikers van elektriciteit en gas*). Finally, the Annex contains specific hydrogen-related obligations that apply universally, regardless of the identity of the parties that are involved in a hydrogen pilot. As far as contractual structure is concerned, the emphasis is on clarity and transparency.[86]

The temporary framework places high importance on the security of hydrogen supply, ensuring it matches the reliability of natural gas. This includes provisions for scenarios such as supplier insolvency or supply interruptions, with measures to maintain sufficient supply even in extreme weather. The framework also addresses indoor installations, mandating that conversion, safety checks, and maintenance fall under the responsibility of the pilot organisers. This benefits consumers by eliminating conversion costs and guarantees a return to pre-pilot conditions at no charge if the pilot ends early. Financial aspects, such as costs and tariffs, are thoroughly regulated. Consumers must be fully informed about their financial obligations and the responsibilities of pilot participants before enrolment, ensuring financial predictability. Notably, the total cost for hydrogen-based heating should not surpass that of the nearest alternative.

Finally, the Ministry of Economic Affairs and Climate also established a temporary policy on hydrogen safety. Compliance with that policy is a prerequisite for the commencement of a pilot.[87] The State Supervision of Mines (*Staatstoezicht op de Mijnen*; SodM) is responsible for its enforcement. The safety provisions echo the commitments of the EU and the Netherlands to ensuring that new technologies are held to existing high standards.

The chapter concludes with a brief discussion of the new draft Energy Law, which, in the future, is expected to further address and potentially reshape the regulatory landscape for hydrogen in the Dutch heating market.

On 9 June 2023, a proposal for a law on energy markets and energy systems, the Energy Law, was submitted to the Dutch House of Representatives, where it is still pending.[88] Although the Energy Law was not declared controversial following the fall of Prime Minister Rutte's cabinet, it has yet to be passed by the House of Representatives. In Dutch politics, when a cabinet

[85] Gas Act (*Gaswet*) 2000 Artikel 35d Gaswet – Klachtenprocedure netbeheerde; Artikel 35e Gaswet – Meldpunt voor gebreken; Artikel 42b Gaswet – Energiekostenramingen en facturen; Artikel 42c Gaswet – Informatie in contracten en rekeningen; Artikel 44 Gaswet, eerste lid – Leveringsplicht tegen redelijke tarieven en voorwaarden; Artikel 44 Gaswet, achtste lid – Afsluitbeleid; Artikel 52b Gaswet – C onsumentenbescherming ; Artikel 52d Gaswet – Klachtenprocedure leverancier.

[86] ACM 4ff.

[87] RVO, 'Richtsnoeren voor veilig omgaan met waterstof' (2022) <https://rvo.nl/onderwerpen/richtsnoeren-waterstof> accessed 3 October 2023.

[88] Energy Act (*Wetsvoorstel energiewet*), *Kamerstukken II* 2022/23, 36 378, no. 2 (hereinafter: Energy Act). According to its explanatory memorandum, it serves three functions. Its first aim is to modernise and update the regulations on electricity and the gas market with a view to supporting the energy transition. To that end, the Electricity Act and the Gas Act will be merged. Its second aim is to implement the (fourth) revised Electricity Directive and several regulations on electricity, which are also known jointly as the Clean Energy Package, and to re-implement the Third Gas Package. The third aim of the proposal is to execute some national policies, including some parts of the Dutch Climate Agreement (*Klimaatakkoord*). See Rijksoverheid, 'Wat is het Klimaatakkoord?' <https://rijksoverheid.nl/onderwerpen/klimaatverandering/klimaatakkoord/wat-is-het-klimaatakkoord> accessed 3 October 2023.

(government) falls or resigns, it is customary for the parliament to determine which pending legislative matters are 'controversial'. This implies that these matters are significant or contentious enough that they should not be decided by a caretaker government, but rather should wait until a new, fully mandated government is in place. In this specific case, the Energy Law was not labelled as controversial, which means that it could have been processed and potentially passed even by the caretaker government. However, despite not being declared controversial, the law has not yet progressed through the House of Representatives and timing is unclear.

The Dutch Energy Act (*Energiewet*) stands at a pivotal juncture, indicative of a broader legislative evolution in response to the changing energy landscape, particularly in the context of hydrogen gas. The Act, as it currently stands, represents an initial step in a more comprehensive regulatory overhaul, one that is poised to adapt in response to emerging European Union directives and market realities. As highlighted in the Explanatory Memorandum, the law is expected to undergo further amendments, particularly influenced by ongoing developments within the EU framework – discussed in Section 20.3 above.[89] The current iteration of the *Energiewet* adopts a policy-neutral stance towards all gas-related matters, hydrogen included, with the exception of aspects pertaining to consumer protection. This approach effectively places hydrogen under a similar regulatory umbrella as other gases, maintaining a status quo that is likely to be temporary. It underscores a transitional phase in policy, where hydrogen gas regulation is acknowledged but not yet distinctly or comprehensively addressed. Future revisions to the *Energiewet* are anticipated, contingent on the outcomes of the EU's negotiations and the HDGMP's directives. These revisions are expected to introduce a more specific and evolved framework for hydrogen, moving beyond the policy-neutral approach currently in place.

The proposed Energy Law contains several – comparatively insignificant – changes relevant to the regulation of hydrogen in heating markets. Firstly, the connection duty of the (national and regional) network operators for gas has been amended in this draft law compared to the Gas Act.[90] It has been clarified that the gas connection duty is less extensive than for electricity, and room has been created for further rules for the connection of producers of gas from renewable sources. One of the objectives is to provide more direction on how regional network operators for gas, in particular, weigh the need for expensive investments to accommodate the injection of gas from renewable sources. In addition, the national network operator for gas is, under conditions, obliged to take in and blend hydrogen gas as long as it is reasonably possible.[91] Furthermore, the existing legal framework within which network companies also have room for actions and activities regarding other infrastructure than for electricity and gas has been tightened.[92] It describes exactly which type of infrastructure it concerns: CO_2, hydrogen gas, gaseous substances from renewable sources other than gas (less than 75 per cent methane), heat, and cold. Network companies are allowed to build and manage such infrastructure, perform transportation, and conduct measurement activities. The reason for providing production and storage facilities for certain energy carriers is that the same as for electricity and gas: owning or making these facilities available without any conditions or restrictions can jeopardise the independence of system operators. Here too, the transitional law will provide a provision for existing activities under this name; for new activities, an Administrative Decree for the allocation of new actions and activities may offer a solution.

89 *Kamerstukken II* 6.
90 Energy Act Article 3.40; *Kamerstukken II* 24–25.
91 Energy Act Article 3:48.
92 Energy Act Article 3.19; *Kamerstukken II* 65.

20.5 CONCLUDING REMARKS

As the world confronts the challenges of climate change and the pressing need for a low-carbon economy, hydrogen has surfaced as a promising alternative to fossil fuels, especially in sectors like heating. The Netherlands has been at the forefront, championing several initiatives and leading numerous discussions on specialised regulatory frameworks. This chapter provided an overview of the regulatory landscape in both the Netherlands and the EU. We highlighted significant gaps, underscored the need for sector-specific regulations, and discussed their implications for market participants.

The 2009 Gas Directive, albeit amended, presents a milestone development. However, its approach to hydrogen lacks depth and specificity. Both the updated European Green Deal and the Clean Energy Package underscore the importance of clean energy, but they do not fully provide for a hydrogen-specific regulatory guide. Positioned within the broader climate ambitions of the EU, the Netherlands has ventured into this nebulous domain. Currently, the Dutch Gas Act regulates the gas market, but it has not evolved to consider the rise of hydrogen. This regulatory void posed challenges and dissuaded network operators from engaging in pilot hydrogen projects.

Stepping into this, the ACM introduced a temporary framework. The current regulatory approach to integrating hydrogen into the Dutch heating market, as led by the ACM, involves Temporary Guidelines that permit network operators to distribute hydrogen with an emphasis on consumer protection. These guidelines are a provisional measure, offering valuable experience in handling hydrogen within the heating sector, yet they are not a comprehensive solution.

The draft Energy Law, still pending approval, has been met with some disappointment due to its limited scope concerning hydrogen-specific regulations, particularly for heating applications. While it proposes to merge the Electricity Act and the Gas Act, simplifying alignment with EU law, its current form does not significantly advance the regulatory framework for hydrogen in the heating market. However, it does lay a foundation that could be built upon in the future.

As for the long term, both the EU and the Netherlands find themselves in a transitional phase in which the absence of a hydrogen-specific regulatory framework necessitates temporary measures and adaptations to existing laws. Energy policy in the Netherlands is thus at a curious juncture – projects are being piloted while futureproof regulation is still being formulated. In summary, while challenges abound in both the Netherlands and the EU, concerted efforts are being made to weave hydrogen into the fabric of the energy systems of the future. That process appears to be guided by the principles of innovation, consumer protection, and safety.

FURTHER READING

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21

Conclusion

Ruven Fleming

21.1 INTRODUCTION

Ten years ago, Werner Franz, the fourteen-year-old cabin attendant on the airship Hindenburg,[1] died on 13 August 2014 at the age of ninety-two. According to his widow, he lived a long and 'very fulfilled'[2] life after the Second World War. Franz had been traumatized by the events of 1937, but still took pleasure in sharing his knowledge about hydrogen as he guided visitors through a Zeppelin Hall for the airship shipping company after the disaster.[3]

Just as in the life of Franz, the relationship between hydrogen and mankind intertwines in a complex weave. This is particularly true for the relationship between hydrogen and the law, which transcends mere legal frameworks; it embodies a convergence of technological advancement, environmental stewardship, and socio-economic imperatives. As we delved deeper into this relationship, chapter by chapter, it became evident that the legal landscape plays a pivotal role in shaping the trajectory of hydrogen's journey towards becoming a cornerstone of our sustainable future.

At its core, the interplay between hydrogen and the law revolves around the regulation, promotion, and integration of hydrogen technologies into existing socio-economic structures. Legislative bodies worldwide seem to have embarked on a journey to formulate first, tentative frameworks that, at best, address the multifaceted dimensions of hydrogen production, transmission, and utilization. From incentivizing research and development to establishing safety standards and fostering international collaboration, legal instruments have served as catalysts for unlocking hydrogen's transformative potential.

One of the primary drivers behind the surge in hydrogen-related legislation is the imperative to mitigate climate change and reduce greenhouse gas emissions. As nations grapple with the pressing need to transition towards low-carbon energy systems, hydrogen can function as a versatile ally in this quest for sustainability. We will now go on to create an inventory of key findings of this book concerning the relationship between hydrogen and the law.

[1] His role is discussed in the introduction to this book (Chapter 1).

[2] 'Letzter Überlebender der "Hindenburg"-Katastrophe gestorben', *Der Spiegel* (29 August 2014), available at <https://spiegel.de/panorama/hindenburg-katastrophe-letzter-ueberlebender-werner-franz-gestorben-a-988852.html> accessed 19/February 2024.

[3] Ibid.

21.2 KEY FINDINGS AND FUTURE DIRECTIONS

The intersection of hydrogen and the law extends beyond domestic jurisdictions, encompassing regional collaborations and future international agreements. Given the global nature of climate change and energy transition, cooperation among nations is imperative to harness the full potential of hydrogen as a clean energy vector. Progress, however, differs from region to region and the question of how best to create a hydrogen economy seems to have split the world. (At least) two different approaches have been identified in this book: either starting with the establishment of a legal framework and then looking for investments or securing investments first, with a legal framework growing thereafter.

The first approach is epitomized, inter alia, by the EU. In Chapter 2, Hancher and Suciu describe how the EU is currently working to establish a comprehensive legal framework on hydrogen and establishing clear rules for EU Member States. However, the focus is different in other parts of the world and an alternative approach is taken there. In Chapter 3, Attanasio and Briggs explain the approach of the United States. Here, the focus is on a massive stimulation effort to bring billions of dollars of private investments to the hydrogen sector, while regulatory uncertainty is still looming large. The approach of first securing investments for hydrogen has also been taken in the Middle East and North Africa (MENA) region, as Olawuyi and Aryanpour report in Chapter 6. However, the focus here lies with the creation of export opportunities, for example, for green ammonia, including huge state investments in export infrastructure specifically.

A similarly dynamic development can be seen in Latin America. Chile, Colombia, and Brazil, aiming to capitalize on their abundant (renewable) resources, have moved to outline ambitious hydrogen strategies and legislation. But Foy argues in Chapter 4 on Latin America that the speed of legislative movements is not sufficient to keep pace with the developers that are continuing to forge ahead, undeterred by the gaps and inadequacies in existing governance. Even amidst a backdrop of regulatory uncertainty, the industry is making strides in turning policy visions into concrete projects. Foy attributes this paradox between incomplete regulation and robust project activity to these countries' constitutional provisions, which enshrine a principle of freedom of enterprise. Namely, in Chile, Colombia, and Brazil, business activity can proceed freely absent explicit prohibition, requiring no prior authorizations or permits except as provided by law and that, according to Foy, has benefitted the hydrogen sector in its development.

The export of hydrogen is also a key driver of legal developments concerning hydrogen in Oceania. While New Zealand seems to lag behind a bit in its development, Australia recently embraced the opportunities of hydrogen. In Chapter 5, Taylor argues, however, that export requires hydrogen production capacities in the first place. While Australia has plenty of sunshine and wind to produce green electricity for green hydrogen, the legal governance of land use is an issue, according to Taylor. While the complicated system of pastoral leases developed into diversification leases in some parts of Australia, which will permit hydrogen development on pastoral land, the developments and impacts differ from one region to another. Taylor argues that many crucial aspects of the future renewable hydrogen supply chain and licensing systems will be regulated by states and territories. In practical terms, this requires measurable national strategies aligned with state and territory planning systems to design regulatory frameworks. Principles for renewable hydrogen development are crucial to guide and develop consistent and coherent licensing and planning regulatory regimes.

In Chapter 7, surveying the situation in Southeast Asia, Eiamchamroonlarp pays attention to a clear and mutual understanding of what green or renewable hydrogen is to create export and trade opportunities. He points towards a development in Southeast Asia that differs from many other parts of the world, where electrolysis will be used as the method of choice to produce green hydrogen. As opposed to this, in Southeast Asia, a traditionally agricultural region, a different path is being pursued, namely steam reforming from biofuels to produce green hydrogen. Accordingly, the legal frameworks in Southeast Asian countries focus more on the traditional regulation of industrial power plants and factories. Eiamchamroonlarp argues that this approach to regulation also makes sense to produce green hydrogen from steam reforming of biofuels, as there will be a considerable number of hydrogen power plants in that region using this technology in the future. However, ASEAN countries are at the initial stages of hydrogen production.

What green or renewable hydrogen is, also seems to be a key debate in other parts of the world. For the EU, the discussion boils down to the question of sustainability criteria for hydrogen against which imports from other regions are benchmarked. In Chapter 10, Mauger, Villavicencio-Calzadilla, and Fleming explain how just copy-pasting known sustainability criteria that exist for bioenergy might not be an ideal way forward. They do not sufficiently include considerations of water consumption in water-scarce areas and the social impacts.

Social impacts are also a key driver behind the democratization of energy through hydrogen, which can hold the promise of empowering communities and fostering inclusive development. By decentralizing energy production and enabling local energy generation through technologies such as electrolysers and fuel cells, hydrogen can transcend geographical constraints and empower communities to become energy self-sufficient. The role of local authorities in this should not be underestimated, as Chapter 9 by Nieuwenhout aptly demonstrates. If clear political will exists, municipalities and small regions can create a 'bottom-up' approach to the introduction of hydrogen in our energy systems in at least three ways. First, they can bring parties together and position the specific region as a hydrogen hotspot. Second, they can create local demand through the public procurement of public transport services and/or maintenance vehicles, also in areas where there is no industrial demand for hydrogen (yet). Third, local and regional authorities can also play a role in system integration.

For this development to succeed, however, the active participation of citizens in hydrogen developments and legal frameworks is required, as Squintani and Schouten argue in Chapter 11. Currently, however, this is not guaranteed in effective ways by the legal framework, as they demonstrate, with EU and Member States as well as local legal frameworks serving as examples. According to Squintani and Schouten, the lack of explicit requirements on public participation in the EU regulatory framework for renewable energy, in general, and energy production and transport is echoed by the lack of a participatory process for the establishment of the National Hydrogen Programme and related National Roadmap. Also at a regional level, the retrieved policies, plans, and programmes for the development of the hydrogen economy do not show the presence of public participation.

However, amidst the myriad opportunities presented by hydrogen, it is essential to navigate the associated challenges judiciously. The creation of hydrogen markets, as Mulder argues in Chapter 8, can be achieved via several routes, but a clear legal framework is crucial to protect and ease transactions. Looking into the entire hydrogen supply chain from production to end use through an economic lens shows, according to Mulder, that certain regulatory strategies that worked in the natural gas and particularly the electricity sector should be used for the regulation of hydrogen markets, while other aspects, like environmental externalities of production, require a different type of regulation.

The fact that certain aspects of the hydrogen supply chain might require different regulation is evident from Andreasson's Chapter 12 on offshore production and transport of green hydrogen in Denmark and the Netherlands. She identifies the lack of legislation that specifically addresses the permitting procedure for offshore hydrogen production as a key legal barrier and, coming back to the theme identified earlier in these conclusions of what should come first, investments or legal framework, takes a clear stance for the offshore area. She argues that a robust and enabling legal framework is needed to facilitate the development of offshore hydrogen infrastructure. Without such a framework, investments will not be made and new developments, such as offshore electrolysers, will not be deployed.

As opposed to offshore, in Chapter 13, Tissari gives an example of the development of onshore electrolysers. Her scrutiny of the Finnish permitting regime unearths a regime that was initially designed around many individual permits that may, however, be applied for online in most cases. But there are recent efforts to streamline the regime and make it easier for the user via the so-called accelerated permission procedure for green transition projects. Tissari explains that it will significantly shorten the processing time for permit handling to a maximum of twelve months. With this trend, Finland stands as an example for many other countries that are currently investigating permitting regimes for hydrogen production facilities and are eager to create one-stop shops for users, or at least streamline the process.

When it comes to hydrogen production, it can be observed that many permitting regimes are centred around environmental aspects like water, wastewater, and air quality. Campion adds to that list in Chapter 14, but also makes clear that the way in which we look at the regulation of these elements as such might need to be reconsidered in the context of hydrogen. New Zealand is currently wrestling with the question of how to incorporate indigenous perspectives into the consenting regimes. Campion argues for the establishment of a hydrogen-specific permitting framework in New Zealand that takes indigenous perspectives into account better – a point that may also be of interest to other parts of the world when contemplating future legal and regulatory frameworks on hydrogen.

Once the hydrogen production facility – for example, an electrolyser – obtains the necessary permits, the hydrogen produced needs to be transported to the end users. In Chapter 15, Jansen provides a case study on Germany which illustrates that a whole set of permits is required to build and/or operate the transport infrastructure. Jansen compares the erection of new hydrogen pipelines and storage with the required permits for the conversion of existing gas pipelines and storage to hydrogen and concluded that the latter is particularly supported by the German system. Several procedural privileges have been specifically designed to make the reuse of natural gas infrastructure for hydrogen purposes attractive from a legal point of view. This is particularly the case because the German regulator is currently in the process of issuing permission to a so-called hydrogen core grid, which will just fall short of 10,000 kilometres, and the reuse of existing pipeline infrastructure will provide the majority (around 60 per cent) of that core grid. Thus, Jansen concludes that the government's recent decision to construct a hydrogen core grid, accompanied by an acceleration law, sets the right course.

A similar approach to hydrogen infrastructure regulation has been taken in the Netherlands, as discussed by Broersma, Jäger, and Holwerda in Chapter 17. The country also aims to create a national hydrogen network mainly consisting of reused natural gas pipelines, as studies have shown this to be a more cost-effective alternative to new hydrogen pipelines. This needs to be accommodated for in legal terms, as there might, as a result, be times when a mingled or blended stream will be in the main networks. Given the fact that current regulation in the Netherlands effectively sees hydrogen as an impurity to the natural gas stream and only allows a very small percentage of hydrogen in the pipelines, this will require a fundamental rethinking of legislative perspectives. Luckily, changes to the existing framework are on their way. One of the key challenges that remains, however, is how to regulate the access of others to the hydrogen network. Broersma, Jäger and Holwerda argue that opening access to hydrogen infrastructure components on a regulated third-party access (TPA) basis might be counterproductive to the speed and scale of the rollout of the hydrogen economy.

The general issue of a lack of an existing legal framework for hydrogen transportation may also be encountered in other countries. Zerde argues in Chapter 16 on the French legal regime, however, that this has been identified and tackled by the legislator. The adoption of a specific chapter in the French energy code that also includes provisions on the transport of renewable hydrogen in natural gas pipelines and autonomous transport networks has been a positive move in the right direction. Zerde characterizes the regulatory technique followed in the case of hydrogen legislation in France as moving away from prescriptive technical rules. Instead, it is moving towards the setting of important targets – that is, hydrogen injection with respect to the proper function and security of the grid. This latter approach leaves it to the market participants to determine, based on individual characteristics, how safety can be achieved.

The safe transport of hydrogen is needed for several end-use sectors. One of the early adopters of hydrogen is the heavy-duty transport sector. In Chapter 18, Cocciolo thus focusses particularly on the regulation of hydrogen road refuelling infrastructure, where safety issues also play a vital role. Using the example of European legislation, Cocciolo demonstrates how the deployment of hydrogen refuelling stations requires a careful analysis of the various legal barriers that affect the value chain of hydrogen. In this sense, he calls for a holistic approach to the identification and resolution of legal hurdles. Cocciolo poses that the actual rollout of the hydrogen refuelling infrastructure should reflect other, broader goals and align with them, namely social/societal benefits, and environmental sustainability.

Societal benefits and the furtherance of environmental sustainability also lie at the heart of the idea of using hydrogen in a different sector – for the storage of electricity. In Chapter 19, Huhta and Sairanen analyse the legal questions that emerge in using hydrogen as a storage medium to balance the intermittency of renewable energy sources in the low-carbon energy transition. They find that, much as with the debate about the definition of the different colours of hydrogen, the questions surrounding the existing legislative framework for hydrogen storage are often definitional: they hinge on whether, or to what extent, the existing rules on natural gas, electricity, and renewable energy apply to hydrogen storage.

As opposed to these definitional issues, where the general direction and political will are clear, Jansen and Reins conclude the book with Chapter 20 on the regulation of hydrogen in heating markets. Whether or not hydrogen should be used in heating is already subject to political debate. With the help of a case study, hydrogen heating regulation in the Netherlands, Jansen and Reins make the case for using hydrogen to abate the greenhouse gas (GHG) emissions of the heating sector. However, they bemoan the lack of a coherent and comprehensive legal framework for hydrogen in the heating market in the Netherlands and have little hope concerning the new and upcoming Dutch Energy Act. In the short to medium term a temporary framework, drawn up by the energy regulator in the Netherlands provides some relief to market players, but this cannot be a long-term solution, according to Jansen and Reins.

21.3 CONCLUSION

What all these fascinating glimpses into the world of hydrogen regulation have taught us is that legal frameworks, which promote transparency, accountability, and stakeholder engagement, are essential in fostering a just transition towards a hydrogen-based economy. Furthermore, the transition to a hydrogen economy necessitates a holistic approach that transcends siloed thinking and embraces interdisciplinary collaboration. Lawyers, policymakers, scientists, engineers, and stakeholders from diverse backgrounds must come together to navigate the complex terrain of hydrogen deployment effectively. Interdisciplinary research and industry implementation can facilitate synergies between legal, technical, and socio-economic perspectives, enabling informed decision-making and policy formulation.

In conclusion, the nexus of hydrogen and the law embodies a convergence of technological innovation, environmental imperatives, and socio-economic dynamics. Legal frameworks serve as enablers, catalysts, and guardians in shaping the trajectory of hydrogen's journey towards sustainability and resilience. By fostering innovation, ensuring safety, facilitating international cooperation, and promoting inclusive development, the law plays a pivotal role in unlocking the transformative potential of hydrogen as a cornerstone of our sustainable future.

It has become clear from this conclusion that the current regulation of hydrogen around the globe and along the entire hydrogen value chain is not yet sufficiently developed and there are several areas that require attention and improvement. In some respects, this result does not come as a surprise, as the idea of regulating hydrogen is relatively new to lawmakers and lawyers. However, driven by the current rate of investments and high-level policy plans, the dynamics are highly promising and the scale of developments is breathtaking. Ten years ago, it was common to discuss future electrolyser projects at the scale of some kilowatts (kW) and up to 10 megawatts (MW) (with the latter being considered very big).[4] In 2024, however, we are frequently discussing electrolysers of 320 MW capacity and more.[5] Legal frameworks will have to keep pace with these rapid developments and much further research into the legal frameworks is required in the coming years to trace developments and identify regulatory and legislative trends. This book has merely created a first, tentative inventory that will soon require substantive updates in many respects.

This is no small enterprise and may even seem daunting at times. It is important for legal scholars and everybody working on hydrogen issues to remember a thought that should comfort us as we navigate the complexities of the hydrogen economy. Ultimately, it is incumbent on all of us to harness the power of the law to steer towards a future where energy is clean, equitable, and abundant for all.

[4] See for example EU Horizon 2020 'STORE & GO Deliverable 7.2 European Legislative and Regulatory Framework on Power to Gas', available at <https://storeandgo.info/fileadmin/downloads/20171030_STOREandGO_D7.2_RUG_submitted.pdf> accessed 26/February/2024, at 13.

[5] See for example for Germany, the EWE, 'Clean Hydrogen Coastline', available at <https://clean-hydrogen-coastline.de/de/projekte/ipcei-elektrolyse-ostfriesland> accessed 26/February/2024.

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